TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

JT-3.1.1

2-AMPCO-88
Reference: 2-AMPCO-28 (b)

Alectra Utilities provided the defined thresholds and approval pathways for the Project Change Request (PCR). The response indicates that PCRs are required for capital project changes of ≥ $0.3MM to < $1.00MM (cumulative with prior changes) and capital project changes of >$1.0MM (cumulative with prior changes).

a) Please provide a copy of the PCRs for each of the projects that meet the above thresholds.

b) Please provide the Project Closure Reports for each project identified in part (a).

RESPONSE:

As described at 2A-1-1 p.129-130, the governance framework encompassing the Project Management Office (PMO) and Transformation Management Office (TMO) only applies to a small subset of Alectra Utilities' projects, primarily within the General Plant category. This governance framework has been in place since later 2025.

a) The requested PCRs can be found in JT-3.1.1_Attach 1_PCRs.

b) The completed projects with PCRs in response a) are attached as JT-3.1.1_Attach 2_Closure reports. All other projects are not yet completed and therefore a closure report is not yet required.

JT-3.1.1

Attachment 1
PCRs

1.0 PROJECT IDENTIFICATION

CL Project Name	SilverBlaze Replacement Project - Discovery		
CL #	152361	**Request #**	PCR-2025-01
Project Manager	Aleem Ulla	**Project Sponsor**	Linas Medelis
Project Lead	Jon Evangelista	**Project Alias**	NCCP
Requested By	Brian Baxter	**Request Date**	June 20, 2025
Reviewer Name	Patricia Girling	**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change
Provide a brief description… *Current Situation:* SilverBlaze Replacement Project – Discovery was intended to conclude in December 2024, but additional due diligence was required on the Document of Understanding (DOU) requiring a project timeline extension. Since the second phase on this project – Implementation of the solution – is dependent on the Discovery phase, that Implementation project will require a deferred timeline as well. This PCR addresses the impact on the entire Business Case. *Proposed Change:* Timeline for the Discovery phase extended out to December 2025 to allow for time to complete implementation of SOW and project plan. This will significantly reduce Alectra's exposure to cost over-runs as experienced on previous projects. Extension of the Implementation phase from January 2025 to a TBD date to support the extension on Phase 1. The vendor has estimated 12 to 16 months for vendor (SEW) completion of implementation phase. A more precise duration of the implementation phase will follow from the analysis conducted in discovery The implications to 2026 costs will be a) Alectra resources to support SEW implementation, Customer Service team has decided to priority the replacement of Silverblaze in 2026 and realize potential lost opportunity by not being able to support other projects in 2026. Continued Alectra resource support for 2025 is estimated at $70,000 b) SEW implementation costs moved from 2025 to 2026 and To support this PCR, $1.33MM has been removed from the Q3 2025 forecast with the intent of moving into fiscal year 2026 c) costs for continued Sliverblaze support until SEW implementation is completed. Approximately [redacted] will be required to support SEW into June 2027. – Discovery.

Type of Change Requested	☐ Scope Change ☒ Schedule Change ☒ Budget change ☒ Financial Benefit change ☒ Resource change ☐ Technology change
Justification	*Reasons for change:* Document of Understanding (DOU) has taken longer than anticipated. The additional time is needed to ensure scope deliverables are adequately clarified to minimize future cost impacting change requests. Historical experience with the vendor encourages Alectra to spend the time up front to clarify scope and avoid unexpected cost over-runs. As a result of this extension on Phase 1 – Discovery, the request is asking that the Implementation Phase move to 2026. *Benefits of the change (e.g. revenue, efficiency, productivity, and other benefits):* This change will enhance the project efficiency by having greater cost certainly *What are the risks this change is mitigating?:* Future cost increases
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	*Low/Medium/High:* High *Rationale:* Alectra and SEW must continue working on a) Implementation SOW and b) Implementation plan that frames the overall project engagement. There will be additional costs incurred to maintain the Silverblaze platform until such time as the SEW solution is in place. At this time the costs are being negotiated with Silverblaze An estimate of the costs to maintain Silverlbaze into June 2027 are: [redacted]. Note this needs to be validated with SIlverblaze
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	No impact to project scope
Schedule Impact	*Describe the extent and size of the change impact on the project schedule:* Discovery phase originally intended to complete in December 2024. PCR 1 proposes

	an extension of Phase 1 – Discovery to December 2025. This extension was presented to and approved by the Executive Steering Committee (ESC). The extension of this Phase will require an extension of Phase 2 – Implementation, since there is a finish to start dependency between Phase 1 and Phase 2. *Explain the assumptions used for the re-estimation of the work that has changed.* *Carryover to Next Fiscal Year: (Y/N) and impact on any next year's work plan (deferrals of other projects).* Discovery phase will be concluded no later than December 2025. Current assumption is that the Implementation (Phase 2) will be completed in 2026. The exact timeline is unknown at this time and will require the information from Phase 1 in order to validate the exact timeframe. This PCR is assuming Implementation Phase can be completed within a 12 to 16-month timeline. *Planned Project Completion Date:* December 30, 2024 Phase 1; July 30, 2025 Phase 2 *Revised Project Completion Date:* December 30 2025 - Phase 1; December 30, 2026 to April 30 2027- Phase 2
Resource Impact	*Describe the extent and size of the change impact on resources* There are 3 resources (Approximately 550 Phase 1 project hours) working on Phase 1 Discovery. These resources will continue to work on the Discovery phase until the end of December 2025, adding an additional 550 hours to Phase 1 Discovery (estimated cost of $70,000 all non-incremental). By elongating Phase 1, the dependent Phase 2 – Implementation Phase will be delayed into 2026. This will require Implementation resources originally assigned in 2025 to now be required in 2026. The Implementation effort was estimated to be 4,350 internal hours for this Implementation Phase 2 work at an approximate cost of $555,000 for 2025. The new estimated internal labour cost for 2025 for the Phase 1 work will be 70,000 which is captured on OM&A. , The 2026 internal labour cost for Phase 2 work is estimated to be $550,000
Budget Impact	*Describe the extent and size of the change impact on the project budget including any key cost drivers, assumptions used to calculate the incremental change (labour hours, unit rates or contractor pricing), and new information since the budget was approved* Incremental costs due to timeline extension of PCR. In addition to the incremental costs below the resources identified will be less available for other projects. Internal Alectra resourcing costs for Phase 1 – Discovery are as follows: • [redacted] – 12 months x 15% allocation = $30,240 • [redacted] – 12 months x 5% allocation = $23,856 • IT Resource for consultation – 12 months x 10% allocation = $15,960 Total internal cost of Discovery phase 12 month extension approximately $70,000. This may also impact other assignments resources could have been assigned to. This opportunity cost to other projects cannot be estimated with a dollar value however will impact delivery of other projects In addition, Silverblaze will have to be retained for 6 months into 2027 at a total cost of approximately [redacted].

	Complete Budget Table below
Financial Benefit Impact	*Describe the extent and size of change impact on the project financial benefits* Extending Phase 1 and the resulting Phase 2 Implementation will move the go-live Phase 2 Implementation estimated date of Dec 31, 2025, to December 30, 2026- April 30, 2027 (to be confirmed). The original estimated benefits for this project were $13 MM. With this new implementation date, the impact to the benefits estimate will delayed by 12 to 16 months The implications to 2026 costs will be a) Alectra resources to support SEW implementation, b) SEW implementation costs moved from 2025 to 2026 and c) costs for continued Sliverblaze support until SEW implementation is completed *Complete Financial Benefits Table below*
Technology Impact	*Whenever changes are introduced in a project, it is critical to evaluate how these changes will impact the underlying technology stack. This assessment ensures that changes do not cause unforeseen issues in the technology infrastructure. Key considerations include:* *•Technology Dependencies: Identify if the change impacts any technology dependencies or integrations with other systems.* *•Scalability: Ensure the change does not negatively affect the scalability of the technology stack, particularly if new features increase data load or processing requirements.* *•Performance and Availability: Assess if the change impacts system performance (e.g., latency, throughput) or availability (e.g., failover capabilities).* *•Infrastructure Changes: Determine whether new hardware, software, or cloud services are needed to support the change, and whether these changes introduce additional complexity.* *•Resource Capability: Consider whether external technology expertise will be required, and technology resources will require training on the new technology to accommodate the change.* No known technology impact

Budget Tables: To support this PCR, $1.33MM has been removed from the Q3 2025 forecast with the intent of moving into fiscal year 2026

4.0

Year to Date - Actuals to (Month)_____:

	Current FY Year Budget	YTD Budget	YTD Actual	Variance	Funds Remaining	% Spent	Q1 Forecast	Q2 Forecast	Q3 Forecast
CapEx	1.455MM	0.848MM	0.025MM	0.823MM	0.823MM	3%	1.0MM	0.8MM	0.1MM
Opex	0								
Total	1.455MM	0.845MM	.025MM	0.823MM	0.823MM	3%	1.0MM	0.8MM	0.1MM

Approved Multi Year Budget To support this PCR $1.33MM has been removed from the Q3 2025 forecast with the intent of moving into fiscal year 2026

NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx	0.165MM	1.455MM	0.338MM	0.226	0.135MM	0.135MM	0.17MM	0.120MM	2.95MM
OpEx		0							
Total	0.165MM	1.455MM	0.338MM	0.226	0.135MM	0.135MM	0.17MM	0.120MM	2.95MM

Revised Budget under this Project Change.

NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
CapEx	0.165MM	0.12MM	1.455MM	0.338MM	0.226	0.135MM	0.135MM	0.17MM	0.120MM	2.95MM
OpEx			0							
Total	0.165MM	0.12MM	1.455MM	0.338MM	0.226	0.135MM	0.135MM	0.17MM	0.120MM	2.95MM

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
CapEx	0	1.33MM	(1.77)MM	(0.118)MM	(0.085)MM	0	0.035MM	(0.05)MM	(0.120)MM	0
OpEx										
Total	0	1.33MM	(1.77)MM	(0.118)MM	(0.085)MM	0	0.035MM	(0.05)MM	(0.120)MM	0

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit	0	0	0.232 MM	0.237 MM	0.241 MM	0.246 MM	0.251 MM	0.256 MM	1.463 MM
Avoided Cost	0	0	0	0.136 MM	0.138 MM	0.141 MM	0.144 MM	0.147 MM	0.716 MM
Expected Reduction	0	0	0407 MM	0.553 MM	0.564 MM	0.574 MM	0.586 MM	0.597 MM	2.695 MM
Total	0	0	0.639 MM	0.926 MM	0.943 MM	0.961 MM	0.981 MM	1.00 MM	4.874 MM

Revised Benefits under this Project Change –Budget under this Project Change -Approximately [redacted] will be required to support SEW into June 2027.Approximately [redacted] will be required to support SEW into June 2027.Approximately [redacted] will be required to support SEW into June 2027.

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
Efficiency Benefit	0	0	0	0.232 MM	0.237 MM	0.241 MM	0.246 MM	0.251 MM	0.256 MM	1.463 MM
Avoided Cost	0	0	0	0	0.136 MM	0.138 MM	0.141 MM	0.144 MM	0.147 MM	0.716 MM
Expected Reduction	0	0	0	0.407 MM	0.553 MM	0.564 MM	0.574 MM	0.586 MM	0.597 MM	2.695 MM
Total	0	0	0	0.639MM	0.926MM	0.943MM	0.961MM	0.981MM	1.00MM	4.874MM

Variance –

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
Efficiency Benefit	0	0	(0.232) MM	(0.005) MM	(0.004) MM	(0.005) MM	(0.005) MM	(0.005) MM	0.256 MM	0.00
Avoided Cost	0	0	0	(0.136) MM	(0.002) MM	(0.003) MM	(0.003) MM	(0.003) MM	0.147 MM	0.00
Expected Reduction	0	0	(0.407) MM	(0.146) MM	(0.011) MM	(0.01) MM	(0.012)MM	(0.011) MM	0.597 MM	0.00
Total	0	0	(0.639) MM	(0.287) MM	(0.017) MM	(0.018) MM	(0.020) MM	(0.019) MM	1.00 MM	0.00

The tables listed above capture the OM&A benefits. The additional benefits, such as Customer Centre (7.885 MM), Customer Communication (0.754 MM), IT Technical Risk (0.822 MM) and Reputational Risk (0.453 MM) will be realized by 2032. The overall benefit of 13.864 MM remains the same.

Resources required to complete Discovery phase in 2025 are as follows:

- [redacted] - 12 months x 15% allocation = $30,240
- [redacted] – 12 months x 5% allocation = $23,856
- IT Resource for consultation – 12 months x 10% allocation = $15,960

As part of working on the Discovery phase in 2025 these resources may not be able to work on other projects creating an opportunity cost.

Expected resources to complete implementation phase in 2026 will be prioritized over other projects in order to complete the required implementation tasks. Thus Silverblaze prioritization will create an opportunity costs for potential 2026 projects.

Costs to extend Silverblaze support into 2027 is approximately [redacted].

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy
Resources that were available in 2025 may not be available later in 2025 or in 2026 to complete the work as they may be required to work on higher priority projects.	**1**	**Resources will be obtained on a high priority basis.**
Originally stated benefits may no longer be achievable moving the project into a negative value or lower value position.	**1**	**Benefits will be delayed by 12 to 16 months to complete the implementation phase**
Vendor supporting this project may have other SOWs that compete for the work we are envisioning to be completed in 2025 and 2026.	**1**	**SEW has committed to prioritize project completion**
May not be able to extend the SilverBlaze maintenance contract on the existing system by an additional year and/or costs might be too high to entertain.	**1**	**Currently in discussion with Silverblaze to extend the support the contract beyond current expiry of December 2026. Alectra will have to secure additional funding if implementation extends beyond December 2026. Estimate of 6 months support into 2027 at a cost of [redacted]**

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*			**mm/dd/yyyy**
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			**mm/dd/yyyy**
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			**mm/dd/yyyy**
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			**mm/dd/yyyy**
Name	**Title/Role**	**Department**	**Signature**	**Date**
	Approval			
Linas Medelis	*Project Sponsor*	Customer Service	[redacted]	07/10/2025
Jon Evangelista	*Project Lead*	Customer Service	[redacted]	06/29/2025
Patricia Girling	*Director PMO*	BT		

1.0 PROJECT IDENTIFICATION

CL Project Name	Metering Renewal - Technology		
CL #	152559 (and related rate zone projects)	**Request #**	PCR-2025-01
Project Manager	Tracy Martin	**Project Sponsor**	Shelley Parker
Project Lead	Tracy Martin	**Project Alias**	AMI Renewal
Requested By	Tracy Martin	**Request Date**	12/3/2025
Reviewer Name	Shelley Parker	**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change
Provide a brief description… AMI 2.0 is a multi-year project extending to 2032. Where opportunities exist to move activities and costs from future years into 2025, it lowers the overall cost to serve within the Network Metering portfolio. It is less expensive to replace AMI 1.0 meters proactively in a planned and structured manner before they fail, than to replace meters reactively, as they fail, one-by-one. AMI 2.0 meters are [redacted] (on average) less than an AMI 1.0 meter. The Network Metering team has strategically expanded its AMI 2.0 network where it makes sense to do so to reduce the number of AMI 1.0 meters that must be deployed. This technique, along with the re-deployment of non-depreciated AMI 1.0 meters, has reduced both the new connections and meter failure actual costs as compared to budgets, while work volumes have remained the same (new connections) or increased (meter failures). This has provided the opportunity within Network Metering's budget envelope to advance the AMI 2.0 project. The AMI 2.0 project's actual spend is $4.4MM over its 2025 budget, but remains on track overall to its $295.7MM project plan. Likewise, the total Network Metering capital plan was delivered "on budget" for 2025.

Type of Change Requested	☒ Scope Change ☒ Schedule Change ☒ Budget change ☒ Financial Benefit change ☒ Resource change ☐ Technology change
Justification	*Reasons for change* *Benefits of the change (e.g. revenue, efficiency, productivity, and other benefits)* *What are the risks this change is mitigating?* This change will reduce risks related to:

	• Compliance with mandated requirements to provide meters in good working order (Measurement Canada), provide customers with accurate bills (Distribution System Code) exclusive of estimated meter reads, and provide customers with a bill every calendar month • Cyber security and privacy • Safety and • Reliability While reducing capital expenditures as compared to alternative deployment strategies.
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	*Low/Medium/High:* High *Rationale:* The risk of increasing failures is high as the area being addressed by this increased funding has increased from 5% at the beginning of 2025 7% failure rate.
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	*Describe the extent and size of the change impact on the project scope* *Explain if another project or initiative is impacted by this change* Advanced meter installations planned for 2030 - 2031 and delivered earlier, in 2025 (40,972 meter installs).
Schedule Impact	*Describe the extent and size of the change impact on the project schedule* *Explain the assumptions used for the re-estimation of the work that has changed.* *Carryover to Next Fiscal Year: (Y/N) and impact on any next year's work plan (deferrals of other projects).* *Planned Project Completion Date:2032* *Revised Project Completion Date: 2032* Although funding was advanced from 2030 - 2031 into 2025 to support the delivery of additional scope earlier in the schedule (additional 40,972 meters), the overall project completion date remains unchanged at 2032.
Resource Impact	*Describe the extent and size of the change impact on resources* Third-party resources were engaged to support the delivery of additional meter installations. The associated costs were accommodated within the approved 2025 budget increase.
Budget Impact	*Describe the extent and size of the change impact on the project budget including any key cost drivers, assumptions used to calculate the incremental change (labour hours, unit rates or contractor pricing), and new information since the budget was approved* *Complete Budget Table below* The total approved project budget remains unchanged. Funding of $4.4M has been advanced into 2025 to support project execution.
Financial Benefit Impact	*Describe the extent and size of change impact on the project financial benefits* *Complete Financial Benefits Table below* Financial Benefit Change - Financial benefits associated with the reduced cost per meter were advanced with the installations - $2MM was achieved in 2025 that was estimated for 2030 – 2031 based on the volume of installed meters - Dispensation was requested and approved in 2025 ahead of anticipated timing - Additional benefits were achieved related to reduced failures and will be realized in 2026 when onboarded -
Technology Impact	*Whenever changes are introduced in a project, it is critical to evaluate how these changes will impact the underlying technology stack. This assessment ensures that changes do not cause unforeseen issues in the technology infrastructure. Key considerations include:* *•Technology Dependencies: Identify if the change impacts any technology dependencies or integrations with other systems.*

	•Scalability: Ensure the change does not negatively affect the scalability of the technology stack, particularly if new features increase data load or processing requirements. *•Performance and Availability: Assess if the change impacts system performance (e.g., latency, throughput) or availability (e.g., failover capabilities).* *•Infrastructure Changes: Determine whether new hardware, software, or cloud services are needed to support the change, and whether these changes introduce additional complexity.* *•Resource Capability: Consider whether external technology expertise will be required, and technology resources will require training on the new technology to accommodate the change.* No technology change as part of this project change request.

4.0 Budget Tables:

Year to Date - Actuals to (Month)_December_____:

	Current FY Year Budget	YTD Budget	YTD Actual	Variance	Funds Remaining	% Spent	Q1 Forecast	Q2 Forecast	Q3 Forecast
CapEx	10.62	10.6	15.0	4.4				12.3	14.0
Opex									
Total	10.62	10.6	15.0	4.4				12.3	14.0

Approved Multi Year Budget NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
CapEx	13.8	10.6	10.4	38.2	57.6	57.4	49.8	44.6	13.3	295.7
OpEx										
Total	13.8	10.6	10.4	38.2	57.6	57.4	49.8	44.6	13.3	295.7

Revised Budget under this Project Change NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
CapEx	13.8	15.0	10.4	38.2	57.6	57.4	47.8	42.2	13.3	295.7
OpEx										
Total	13.8	15.0	10.4	38.2	57.6	57.4	47.8	42.2	13.3	295.7

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	2032	Total
CapEx		4.4	0	0	0	0	-2.0	-2.4	0	0
OpEx										
Total		4.4	0	0	0	0	-2.0	-2.4	0	0

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost		1.1	1.5	5.1	14.4	12.8	15.4	49.1	99.5
Expected Reduction		1.9	0.9	3.3	10.3	9.9	9.4	9.4	45.1
Total		3.0	2.4	8.4	24.7	22.7	24.8	58.5	144.6

Revised Benefits under this Project Change

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost		0.7	2.4	5.1	14.4	12.8	15.4	49.1	99.9
Expected Reduction		3.7	0.9	3.3	10.3	9.9	8.5	8.5	45.1
Total		4.4	3.3	8.4	24.7	22.7	23.9	57.6	145.0

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost		(0.4)	0.9	0	0	0	0	0	0.4
Expected Reduction		1.8	0	0	0	0	-0.9	-0.9	0
Total		1.4	0.9	0	0	0	-0.9	-0.9	0.4

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*			mm/dd/yyyy
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
	Director, PMO			mm/dd/yyyy
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

1.0 PROJECT IDENTIFICATION

CL Project Name	ERP Continuous Improvement		
CL #	150469	**Request #**	PCR-2025-01
Project Manager		**Project Sponsor**	Neetika Sathe
Project Lead	Anurekha Bakaraman	**Project Alias**	ERP Enhancement
Requested By	Alan Palmer	**Request Date**	November 11, 2025
Reviewer Name		**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change	
The original 2025 capital budget for ERP Continuous Improvement was approved at $584,157, supporting delivery of approximately 25 Change Requests (CRs). Throughout early 2025, multiple business units requested additional ERP enhancements to address operational gaps and efficiency opportunities. In response, an additional $1,000,000 in capital funding was approved in the spring, increasing the total available budget to approximately $1.6MM and enabling expansion of the delivery plan to 65 CRs. While the additional budget was incorporated into corporate financials, the associated KPI for total CRs deliverable in 2025 was not updated at that time. This PCR formally adjusts the KPI and project scope to reflect the budget that was approved earlier in the year.	
Type of Change Requested	☒ Scope Change ☐ Schedule Change ☒ Budget change ☐ Financial Benefit change ☐ Resource change ☐ Technology change
Justification	The current Corporate KPI still reflects the original 2025 scope of 25 CRs aligned to a $584K budget. With the additional $1MM approved in the spring, project capacity expanded significantly, and the planned workload was increased to 65 CRs. Updating the KPI is necessary to align performance expectations, budget, and scope. This adjustment ensures transparency, accurate reporting, and proper alignment with the budget and delivery commitments that have already been authorized.
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from	Medium – The additional budget was approved in the spring, and several discussions have taken place throughout the year requesting alignment of the KPI to the revised plan. However, no formal adjustment process was initiated until now. This PCR ensures that the KPI, scope, and approved funding are finally brought into alignment before year-end and prior to the IT change-freeze period.

escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	Scope increases from the originally planned 25 CRs (based on a $584K budget) to 65 CRs supported by the revised $1.6MM budget. This accurately reflects the expanded delivery plan enabled by the additional capital funding.
Schedule Impact	There are no expected changes to the project schedule Planned Project Completion Date: December 31, 2025 Revised Project Completion Date: December 31, 2025
Resource Impact	No material resource impact. The ERP team has the capacity to complete the expanded scope before the year-end change freeze, as the ERP upgrade is now complete and resources have transitioned back to enhancement work.
Budget Impact	Forecasting for a Q3 budget of $1,599,183 to complete these CRs
Financial Benefit Impact	
Technology Impact	

4.0 Budget Tables:

Year to Date - Actuals to (October 2025)_____:

	Current FY Year Budget	YTD Budget	YTD Actual	Variance	% variance	Q1 Forecast	Q2 Forecast	Q3 Forecast
CapEx	584,157	486 797	570 630	83833	17.2%	1,599,183	1,599183	1,599,183
Opex								
Total								

5.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy
No significant delivery risks, as the scope and budget have already been in active use throughout the year. The primary risk is continued misalignment between budget and	**5**	Formalize the KPI update through this PCR to ensure accurate governance, reporting, and performance tracking.

KPIs if this adjustment is not approved.		

6.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*			mm/dd/yyyy
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
	Director, PMO			mm/dd/yyyy
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

1.0 PROJECT IDENTIFICATION

CL Project Name	OMS – Bridge Upgrade Phase 2		
CL #	152549	**Request #**	PCR-0#
Project Manager	Aleem Ulla	**Project Sponsor**	Jim Butler/Neetika Sathe
Project Lead	Lorne McHoull	**Project Alias**	
Requested By	Lorne McHoull/Aleem Ulla	**Request Date**	August 8, 2025
Reviewer Name		**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change	
Provide a brief description… *Background* *Phase 1 of the OMS Bridge, included a bridge to the Hexagon solution for the East and an upgrade to the latest version of the software. Since Hexagon solution was new, they wanted to test it out for the East to see if it was a viable solution. This scope was completed.* *Phase 2 extends the Surveliant OMS solution to the East region* *Current Situation:* The Original C55 Business Case was created to implement the Hexagon application as a temporary solution to reduce risk of failure with the East OMS. The business case stipulated that the application would be deployed for Central South, West, and East foundation OMS. *Proposed Change:* Alectra has selected Survalent as the preferred East OMS solution, replacing the Hexagon direction. This PCR also extends the business case into 2026 since the East region upgrade was not completed in 2025	
Type of Change Requested	☒ Scope Change ☒ Schedule Change ☒ Budget change ☒ Financial Benefit change ☐ Resource change ☒ Technology change
Justification	*Reasons for change* Survalent has vastly improved their OMS application allowing Alectra to confidently move forward with East deployment *Benefits of the change (e.g. revenue, efficiency, productivity, and other benefits)* • Cityview Control Room East Region will transition to a unified OMS platform (Survalent), aligning with Central North and Guelph.

	• Enables a consistent operator interface, reducing complexity and enhancing operational efficiency. Operational Synergies • Promotes resource flexibility and cross-training opportunities by leveraging existing staff already proficient with Survalent in the Cityview control room. • Enhances potential shift coverage and reduces reliance on region-specific expertise. • Unified Application reporting. • Reliability, System Planning, etc. Business Value • Streamlines OMS support, training, and maintenance across Alectra. • Supports long-term goals for standardization, scalability, and reduced total cost of ownership. *What are the risks this change is mitigating?* OMS System obsolescence in East region
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	*Low/Medium/High* High urgency *Rationale* East region OMS systems is currently on a version that is 12 years old and at risk of failure
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	*Describe the extent and size of the change impact on the project scope* • Vendor application change to Survalent for East region OMS system. • Additional functionality has been added to scope, which includes three new functions: GIS Wizard, PDS and virtual sources. Additional functionality costs $187,852 (Capital). ○ GIS Wizard: Introduces functionality that allows Alectra Enterprise GIS data to be automatically extracted and imported to the Survalent OMS Application. GIS Wizard will be implemented in East via the East OMS Bridge Build and is a requirement of East implementation

	○ Project Development System (PDS): Introduces functionality that verifies data content from the GIS Wizard and/or SCADA environment and "pushes" to the Production Survalent Application ○ PDS will be implemented for the current Brampton & Guelph sectors and the newly implemented East sector ○ Virtual Sources: Introduces functionality of Single Line diagram map representation allowing more efficient restoration of large scale outages. It dynamically powers bot GIS and SLD maps *Explain if another project or initiative is impacted by this change* • Assuming vendor costs are constrained at the forecasted $634,078 there will be no implications for other project funding., • The project's shift to 2026 will not affect resources, as the division's dedicated team remains focused on OMS work, which is the division's top priority. No additional resources are needed for Survalent implementation beyond those used for Hexagon. • GIS Wizard can then be introduced to Brampton & Guelph sectors already present in the current Survalent OMS Ecosystem in the future via C55 Project 150563 (SCADA/OMS Software Upgrade Cycle)
Schedule Impact	*Describe the extent and size of the change impact on the project schedule* • Project schedule has been validated with vendor through the Statement of Work (SOW). • The East phase of the OMS project is scheduled to begin in November 2025, with application deployment planned for August 2026. Hypercare is expected to finish by the end of September, and the previous application will be decommissioned in November 2026 upon project completion. *Explain the assumptions used for the re-estimation of the work that has changed.* • Vendor changed from Hexagon to Survalent • • . *Carryover to Next Fiscal Year: (Y/N) and impact on any next year's work plan (deferrals of other projects).* **See chart at Budget description** *Planned Project Completion Date:* December 15, 2025 *Revised Project Completion Date:* November 30, 2026
Resource Impact	*Describe the extent and size of the change impact on resources* • The project's shift to 2026 will not affect resources, as the division's dedicated team remains focused on OMS work, which is the division's top priority. No additional resources are needed for Survalent implementation beyond those used for Hexagon. • Delayed project start will require Alectra resource utilization to spill over to FY 2026. OMS Bridge will be prioritized over other 2026 initiatives. No planned

	project scheduled or resourced in 2026 will be impacted as a result shift in OMS Phase 2 schedule into 2026.
Budget Impact	*Describe the extent and size of the change impact on the project budget including any key cost drivers, assumptions used to calculate the incremental change (labour hours, unit rates or contractor pricing), and new information since the budget was approved* See budget table below
Financial Benefit Impact	*Describe the extent and size of change impact on the project financial benefits* See budget table below
Technology Impact	*Whenever changes are introduced in a project, it is critical to evaluate how these changes will impact the underlying technology stack. This assessment ensures that changes do not cause unforeseen issues in the technology infrastructure. Key considerations include:* *•Technology Dependencies: Identify if the change impacts any technology dependencies or integrations with other systems.* Rollout of Survalent solution to East region reduces technology risk and allows Alectra to modernize OMS systems in East region. *•Scalability: Ensure the change does not negatively affect the scalability of the technology stack, particularly if new features increase data load or processing requirements.* Rollout of Survalent solution to East region will improve scalability *•Performance and Availability: Assess if the change impacts system performance (e.g., latency, throughput) or availability (e.g., failover capabilities).* Performance improvement will be experienced for east region *•Infrastructure Changes: Determine whether new hardware, software, or cloud services are needed to support the change, and whether these changes introduce additional complexity.* Survalent OMS solution already in place at Alectra will be rolled out to the East region *•Resource Capability: Consider whether external technology expertise will be required, and technology resources will require training on the new technology to accommodate the change.* *Alectra will rely on a third-party vendor, Survalent to complete the project deliverables*

4.0 Budget Tables:

	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Budget (C55)	$ 1,608,384	$ 547,227							$ 2,155,610
OPEX		$ 105,475	$ 107,585	$ 109,737	$ 111,822	$ 113,946	$ 116,225	$ 118,550	$ 783,339
Total Budget	$ 1,608,384	$ 652,702	$ 107,585	$ 109,737	$ 111,822	$ 113,946	$ 116,225	$ 118,550	$ 2,938,950
Approved Budget CAPEX (a)	$ 1,608,384	$ 547,227	$ -						$ 2,155,610
Actuals To Date (b)	$ 1,239,654	$ 369,625	$0						$ 1,609,279
Forecast to Completion (c)		$ 92,000	$542,078	0	0	0	0	0	$ 634,078
Variance (d= a-b-c)	$ 368,729	$ 85,602	$ (542,078)						$ (87,747)
Approved Budget OPEX		$ 105,475	$ 107,585	$ 109,737	$ 111,822	$ 113,946	$ 116,225	$ 118,550	$ 783,339
Actuals To Date	$0	$0	$0	$0	$0	$0	$0	$0	$ -
Remaining Forecast	$0	$0	$0	$0	$0	$0	$0	$0	$ -
Variance	$ -	$ 105,475	$ 107,585	$ 109,737	$ 111,822	$ 113,946	$ 116,225	$ 118,550	$ 783,339

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit	Data Entry Vendor: $80,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $1,200,000 East OMS/GIS Licensing: $900,000		
Avoided Cost									
Expected Reduction	$80,000	$420,000	$420,000	$420,000	$420,000	$420,000	$2,180,000		
Total									

Revised Benefits under this Project Change

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit		0	0	0	0	0	0	0	0
Avoided Cost				Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	Data Entry Vendor: $240,000 East OMS/GIS Licensing: $180,000	$2,100,000
Expected Reduction									0
Total				420,000	420,000	420,000	420,000	420,000	$2,100,000

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost		$80,000							$80,000
Expected Reduction									
Total		$80,000							$80,000

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy
Resource commitment moved from 2025 to 2026	100%	Analyze resource conflicts relative to other high priority projects and adjust accordingly

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor *Jim Butler*	Network Services		
	Executive Sponsor/Pillar Lead EVP *Julia Zhu*	Information Technology		
	Steering Committee (EVP >$0.5M & <$2.5M)			
	Executive Committee (>$2.5M)			
	TMO (<$0.5M)			
	Awareness			
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

1.0 PROJECT IDENTIFICATION

CL Project Name	Customer Service Strategy – CX Project		
CL #	151854	**Request #**	PCR-2025-01
Project Manager	Mark Talaska (transitioned over the life of the project)	**Project Sponsor**	Linas Medelis/William Schmidt (transitioned after retirement to Julia Zhu)
Project Lead	Dianne Petrucci/Ramez Hakeem	**Project Alias**	Project Atlas
Requested By	Dianne Petrucci	**Request Date**	
Reviewer Name		**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change	
The CX project began in 2022 and completed in 2024. A small amount of the work performed in 2024 was not invoiced in 2024 but rather invoiced in 2025. This work was not accrued for in 2024. Project included the replacement of end of life customer portal leveraging a new application to support improving customer experience and digital channels. Since the project ended in 2024 there was no budget to absorb carryover expenses that slipped into 2025 due to missed accruals. Current Situation: Project capitalization and completion December 2024 Proposed Change: Carryover expenses not accrued in 2024	
Type of Change Requested	☐ Scope Change ☐ Schedule Change ☒ Budget change ☐ Financial Benefit change ☐ Resource change ☐ Technology change
Justification	The majority of spending in 2025 is attributable to carry over expenses that were not accrued in 2024. There was no budget in 2025 because the project was completed in 2024.
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical.	*Low/Medium/High* Approvals are needed to support the carryover spending on a 3 year project that has completed and closed out..

Low: can be handled at a convenient time without significant impact on operations or outcomes.	
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	*N/A*
Schedule Impact	*N/A*
Resource Impact	*N/A*
Budget Impact	Budget assigned for 2025 was $0. The majority of the $313,184 spend in 2025 relates to work completed on the project in 2024 that was not accrued for 2025.
Financial Benefit Impact	*N/A*
Technology Impact	*N/A*

4.0 Budget Tables:

Year to Date - Actuals to (Month)_____:

	Current FY Year Budget	YTD Budget	2025 YTD Actual	Variance	Funds Remaining	% Spent	Q1 Forecast	Q2 Forecast	Q3 Forecast
CapEx	$0.0	$0.0	$313,184						
Opex									
Total	$0.0	$0.0	$313.184						

Approved Multi Year Budget N/A this project ended in 2024

NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx									
OpEx									
Total									

Revised Budget under this Project Change N/A this project ended in 2024

NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx									
OpEx									
Total									

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx									

OpEx									
Total									

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Revised Benefits under this Project Change

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *Linas Medelis* *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*	Customer Service		mm/dd/yyyy
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
	Director, PMO			mm/dd/yyyy
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy

Name	Title/Role	Department	Signature	Date
	Approval			
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

1.0 PROJECT IDENTIFICATION

CL Project Name	Guelph CC&B Consolidation		
CL #	153091	**Request #**	PCR-01
Project Manager	Tina Bekeros	**Project Sponsor**	Linas Medelis Neetika Sathe
Project Lead		**Project Alias**	Guelph CIS Convergence
Requested By	Tina Bekeros	**Request Date**	October 31, 2025
Reviewer Name	Patricia Girling	**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change

BACKGROUND:

The Consolidation of Guelph's CIS from its legacy HTE system to Alectra's CC&B system is a multi-year project (2024 – 2026) with the dependency on the exit of water billing back to the City of Guelph in parallel.

In addition to the Guelph activities, Alectra is managing the water transition from its CC&B system for the City of Hamilton in parallel. The City of Hamilton selected a CIS vendor in March 2020 to support managing its water billing services in-house.

The Guelph CIS budget and timeline were developed in May 2024 with an anticipated go-live date of December 2025. The City of Guelph was granted an Extension Agreement for water billing services until April 2026 with a further service contingency extension to continue to bill water services as required until June 30, 2026.

May 2024 - The City of Guelph and Alectra agreed to target the water exit on **February 28, 2026,** followed by 90-days of hyper-care. In parallel to the Guelph Project, the **City of Hamilton** was targeting an exit date of **November 2025** followed by 90-days of hyper care. The projects were staggered appropriately to allow for stabilization of systems.

UPDATE:

August 2025 – The City of Hamilton formally requested an extension of its water billing services to March 31, 2026, due to delays in its CIS conversion and the need for additional testing, automation of pre-authorized payment re-registration, and enhanced customer communications.

Alectra requires a minimum of 60-days between Hamilton's exit and Guelph CIS integration to allow for system stabilization, customer support and internal change management. To support Hamilton's revised timeline, Guelph was amenable to extending its transition to May 31, 2026. This extension will allow for more robust testing and integration with its third-party vendors while providing Alectra with a 60-day buffer between the transitions.

Approved Recommendation Summary

Following the request from the City of Hamilton and subsequent discussions with the City of Guelph a special meeting was held on September 3rd with a subset of the CIS Project Executive Committee (James, Julia, Nathalie, Linas) and the CFO (Danielle). At the meeting the recommendation to extend the Projects were endorsed and later approved by Brian in a response to the Shareholder request on September 11th via the email.

The CIS budget envelope is mainly sufficient to complete the Project; however, capital funding will need to shift from 2025 to 2026 with the change to the timeline.

PROPOSED CHANGE

Background

The City of Guelph is transitioning from its legacy HTE system to Alectra's Customer Care & Billing (CC&B) system.

The project includes the parallel exit of water billing services.

Original CIS Conversion Plan (business case & budget created - May 2024)

- **CIS Go-Live Target**: December 2025
- **Water Services Exit**: December 2025
- **Budget**: Multiyear – 2024 – 2026 approved in May 2024 (C55 entry)

Revised Plan (August 2025)

- **City of Guelph and Alectra agreed to the following:**
  - **Water Services Exit:** By May 31, 2026
  - **Target CIS Integration:** June 1, 2026, including metering systems
  - **Water Services Contract Expires:** On or before June 2026 (allows City of Guelph – 30 days contingency if required from May 2026 – water exit date)
  - **Post-Go-Live Support:** 90-day hyper-care period (Aug 2026) – contractual obligation

Budget Implications

- The multi-year **approved budget remains largely sufficient** to support the project.
  - Additional $0.2M in budget may be required to support an additional testing cycle. Vendor CR is in progress and not validated at this time.
- However, a **budget range of ($1.9M - $2.1M) will need to shift** from 2025 to 2026 to align with the revised timeline.
- Internal resources to be extended, back fill for the positions to be extended.
- Contracts for 3rd party vendors / contactors to be extended.

Proposed Change

- Update the CIS project timeline **to reflect the go-live date of June 1, 2026**
- Hyper-Care: June – August for both CIS & the water exit. Project end date: August 2026
- Adjust budget forecasts **to reflect the revised spending profile across 2025 and 2026.**
- Shift estimated range of $1.9 - $2.1 M from 2025 capital spend to 2026
  - Shifting of spending range is contingent on 2025 deliverables
- *Estimate as noted in the charts below ~$1.9M in funding will need to shift from 2025 to 2026 with an additional $0.2M estimated required to complete the project for a total of $2.1M to support 2026 CIS implementation activities.*

Type of Change Requested	☐ Scope Change ☒ Schedule Change ☒ Budget change ☒ Financial Benefit change ☒ Resource change ☐ Technology change
Justification	Alectra is managing two shareholders in parallel with the exit for water billing services for the City of Hamilton and the City of Guelph, plus its CC&B integration. This integration includes metering-related systems, applications, and processes. And the exit of Guelph's water billing services in parallel. Urgency to integrate the Guelph Rate Zone into CC&B is high as a means of managing overarching operational and regulatory compliance risks associated with the Guelph legacy CIS. Current regulatory compliance is being managed manually in Guelph's legacy system. Alectra offered the City of Guelph an option to integrate water billing services into its CC&B system. The costs were estimated at $1.0M in custom programming to support the Guelph services contract. Alectra proposed that water billing services could continue until at least 2028. To avoid multiple changes for customers and to gain efficiency with its tax roll system (for arrears), the City of Guelph decided to advance the repatriation of its water accounts to its new in-house solution. It was determined that by completing the exit of water billing from Guelph's legacy system in parallel with the CIS integration provided efficiencies and eliminated the need for custom work in the legacy Guelph system to support a single service for billing and rework and regression testing. The exit of water billing for the City of Hamilton and the City of Guelph must be staggered to allow for system stability, customer and internal change management. Alectra needs a minimum of 60 days between these exits to ensure a smooth transition for customers. The City of Hamilton's water transition and the Guelph activities are customer facing with inherent reputational customer and shareholder risk factors associated with the conversions.

	Allowing the time required to gain full confidence in the solutions through robust testing, customer communications and internal OCM are critical for success.
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	***Medium Urgency*** Based on current information the 2025 Plan Approval budget is mainly sufficient to support the Project, however the timing of the Capital $ spend between 2025 and 2026 requires amendment. In advance of finalizing 2026 project planning and the capital spend this change request needs to be addressed to ensure the shift of spending and timing is incorporated into the Capital Plan. Note: Q2 forecast – was reduced by $0.700M with a note that $1.0M was likely a permanent variance in 2025. The amount was required to shift to 2026 to complete the Project.
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	No changes to the scope of the Project activities except the timing of implementation timeline and associated budget shift between 2025 and 2026.
Schedule Impact	Timelines are shifting from the Project go-live date of December 2025 to May 2026. Plus, the 90-day hyper care period shifts from Q1 2026 to August 2026. Contingency planning for the City of Guelph's services contract also shifted from April to June 30, 2026. Resource planning was completed for 2025 with the shift in timing taken into consideration. Upon review with the PMO, shifting the Project into 2026 doesn't impact other known projects except for the IR period for the CoS Application. Many of the resources are 3rd party and contract extensions have been secured. Planned Project Completion Date: December 2025 Revised Project Completion Date: August 2026 – Inclusive of hyper-care
Resource Impact	Many of the resources are contract resources and 3rd party resources. The redundant positions (mainly filled by temp staff) in Guelph will need to be maintained until August 2026 to support hyper care. Backfill resources are factored into the overall budget and service fees up to the water billing exit date. Contracts for the 3rd party vendors have been secured. Testing timelines in January to be adjusted to accommodate the IR period and resource constraints. IT has been consulted on resourcing needs and any additional needs have been incorporated within this PCR.
Budget Impact	The Capital $ budget shift is forecasted at $1.9 - $2.1M to shift from 2025 to the 2026 budget. Note: Additional $0.2M included in the above noted range and may be required. Benefits: Reduction of 6 CS positions are related to the CIS Integration for Guelph (unrealized merger savings). The positions have been extended in the 2026 budget to support the Project, Hyper-Care and Stabilization. Benefits to commence - Jan 2026. The Business Case was created in May 2024 with a project completion date of February 2026. The 6 positions are included in the total number of 15 positions that were identified as redundant positions tied to Four Water Exits (Hamilton, Guelph, Markham and Vaughan) plus CIS integration. The Water PCR was created to change the timelines for the water exits and the 2026-2031 budget plan was updated with incremental revenue & costs. Summary: • Four positions have been extended to the end of 2028 to support Markham and Vaughan continued services. • Two redundnant positions should commence Jan 2026 with the exit of Guelph and Hamilton. • Six positions related to Guleph CIS - Should commence Jan 2026 • Three New Connection Clerks were identified as merger savings originally to be released with the Silver Blaze Replacement. Positions were extended until December 2026.

Technology Impact	No technology impacts. Timing to align to the New Connection Process, Fieldworker and GIS will require some manual work around or temporary interfaces for an interim period. These have been discussed with the Business Units.

4.0 Budget Tables:

Summary Approved Budget by Year (May 2024)

Guelph Integration - Approved Capital Budget 2024 - 2026				
Year	**2024**	**2025**	**2026**	**Total**
Capital Budget (C55)	0.9	4.8	0.5	6.2
Actual	0.7			
Variance	0.2			
Carry Over		0.2		
Capital Budget (C55)	**0.7**	**5.0**	**0.5**	**6.2**

Summary Proposed Change by Year

Guelph Integration - Forecast Capital Budget 2024 - 2026				
Year	**2024**	**2025**	**2026**	**Total**
Capital Budget (C55)	0.9	4.8	0.5	6.2
Actual	0.7			
Variance	0.2			
Carry Over		0.2		
Capital Budget (C55)	**0.7**	**5.0**	**0.5**	**6.2**
Forecast	**0.7**	**3.1**	**2.6**	**6.4**
Variance to Carry Over	0.0	1.9	2.1	0.2

Annual Actual & Forecast by Work Groups and Year

Transition Work Order 2024	2024 Budget	Total 2024 YTD Spend (December)	YTD Remaining as of December 31	Forecast	Projected Spend YTD Actuals + Forecast Health Status	Variance From Budget
634132 - Guelph CIS Migration	$878,682.00	$697,465.23	$181,216.77	$0.00	$697,465.23	$181,216.77

Transition Work Order 2025	2025 Budget	Total 2025 YTD Spend (Sept)	YTD Remaining as of September 30	Forecast	Projected Spend YTD Actuals + Forecast Health Status	Variance From Budget
634132 - Guelph CIS Migration	$4,959,632.00	$1,355,918.62	$3,603,713.38	$758,254.86	$2,114,173.48	$2,845,458.52
658820 - Customer Service - Guelph		$300,858.53	-$300,858.53	$232,111.50	$532,970.03	-$532,970.03
658821 - Customer Excellence		$74,700.75	-$74,700.75	$99,078.00	$173,778.75	-$173,778.75
658822 - Metering		$166,154.20	-$166,154.20	$76,440.00	$242,594.20	-$242,594.20
	$4,959,632.00	$1,897,632.10	$3,061,999.90	$1,165,884.36	$3,063,516.46	$1,896,115.54

Transition Work Order Go Live May 2026	2026 Budget	Total 2026 YTD Forecast	Variance	Forecast	Projected Spend YTD Actuals + Forecast Health Status
634132 - Guelph CIS Migration	$532,205.00	$1,487,277.17	-$955,072.17	$1,487,277.17	$1,487,277.17
658820 - Customer Service - Guelph		$665,304.00	-$665,304.00	$665,304.00	$665,304.00
658821 - Customer Excellence		$309,086.00	-$309,086.00	$309,086.00	$309,086.00
658822 - Metering		$167,731.20	-$167,731.20	$167,731.20	$167,731.20
	$532,205.00	$2,629,398.37	-$2,097,193.37	$2,629,398.37	$2,629,398.37 $2,097,193.37

5.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy
Parallel Projects with the exit of Water Services & Electricity – Project Team extended and redundant positions.	**4**	Established governance structure in place. Offset to costs of redundant positions mitigated by monthly service fees.
Financial Risks with unknown pricing for 3rd parties. Contracting underway but not completed	**4**	High-level estimates included in forecast. Fixed price contracts to be negotiated with final pricing.
Data issues – incomplete data, mapping concerns	**2**	Manual updates in CC&B to avoid mapping delays. Scripting in CC&B as required
EPP Plans – Regulatory	**3**	CR in process for programming to split the water and electric accounts to accommodate EPP for regulatory compliance.

Guelph Transition Agreement Delay	**4**	Targeting end of Oct. We are working collaboratively with the City of Guelph. NDA executed.
SMEs – Small Team	**3**	Temporary business resources being added within budget to manage manual work and support lack of capacity. Should it be required, other projects would be reprioritized to support the implementation of this project. At this time, the extension can be supported through internal and third-party resources without a major impact to other projects.
Data Transfers	**4**	Time to run the data transfers is extensive – I.T. increased pipe size to accommodate as part of a planned upgrade.

6.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*			mm/dd/yyyy
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A)* *or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A)* *or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
Patricia Girling	*Director, PMO*	BT		mm/dd/yyyy
Ramez Hakeem	*Project Lead*	Digital & Innovation		mm/dd/yyyy
Dianne Petrucci	*Project Lead*	Customer Service		mm/dd/yyyy
Kerry Lakatos-Hayward	*Project Lead*	Customer Service		mm/dd/yyyy
Tina Bekeros	*Project Manager*	Customer Service		mm/dd/yyyy
Neetika Sathe	*Project Sponsor*	Digital & Innovation		
Linas Medelis	*Project Sponsor*	Customer Service		
James Douglas	*EVP Customer Experience*	Customer Service		

Name	Title/Role	Department	Signature	Date
	Approval			
Julia Zhu	*EVP Digital & Innovation*	Digital & Innovation		

1.0 PROJECT IDENTIFICATION

CL Project Name	Work Force Management / Mobile Dispatch		
CL #	102263	**Request #**	PCR-2025-01
Project Manager	Angela Gooden	**Project Sponsor**	Jim Butler
Project Lead	Stanton Sheogobind	**Project Alias**	
Requested By		**Request Date**	1/1/2025
Reviewer Name		**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

A decision was made to combine the Workforce Management System	
A decision was made to combine the Workforce Management System (WFM) and the Enterprise Asset Management System(EAM) into a combined project instead of two separate projects. The decision was made due to identifying potential savings through combing the projects with respect to implementation costs. The project was delayed to further explore the potential savings.	
Type of Change Requested	☒ Scope Change ☒ Schedule Change ☒ Budget change ☐ Financial Benefit change ☐ Resource change ☐ Technology change
Justification	*A potential savings of $8 million dollars in implementation cost savings by implementing to two projects together instead of executing both projects separately.*
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	*Low* *While delaying the project delays the benefits of the WFM to the organization, the costs savings on implementation is significant enough to delay the benefits from WFM.*
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	*The scope of both projects remains unchanged only the timing of implementation is changed.*
Schedule Impact	*The change in project schedule is only in timing.*
Resource Impact	*From an internal perspective there is no impact to resourcing other than timing of their availability.*
Budget Impact	*Describe the extent and size of the change impact on the project budget including any key cost drivers, assumptions used to calculate the incremental change (labour hours, unit rates or contractor pricing), and new information since the budget was approved* *Complete Budget Table below*
Financial Benefit Impact	*Describe the extent and size of change impact on the project financial benefits* *Complete Financial Benefits Table below*
Technology Impact	*There is no technology impact.*

4.0 Budget Tables:

Year to Date - Actuals to (Month)_____:

	Current FY Year Budget	YTD Budget	YTD Actual	Variance	Funds Remaining	% Spent	Q1 Forecast	Q2 Forecast	Q3 Forecast
CapEx	0	1,084,794	0						
Opex									
Total									

Approved Multi Year Budget NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx		1,084,794	1,881,253	4,666,833	3848148	4,988,471			
OpEx			250,000	525,874	530871	940,238			
Total		1,084,794	2,131,254	5,192,707	4,379,019	5,933,707			

Revised Budget under this Project Change NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx		0	1,084,794	1881253	4666833	3848148	4988471		
OpEx				250000	525874	530871	940238		
Total			1,084,794	2,131,254	5,192,707	4,379,019	5,933,707		

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx		- 1,084,794	1,084,794						
OpEx									
Total									

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Revised Benefits under this Project Change

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	Probability (1 -5)	Mitigation Strategy
The project takes longer	**3**	**Good project management**

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
	Project Sponsor (VP) *<$0.1MM (OM&A) or* *<$0.3 MM (Capital)*			mm/dd/yyyy
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or* *≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or* *>$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
	Director, PMO			mm/dd/yyyy
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

1.0 PROJECT IDENTIFICATION

CL Project Name	Meter-to-Cash CIS CC&B Modifications (Regulatory Enhancements)		
CL #	150453	**Request #**	PCR-2025-02
Project Manager	Doris McGuire	**Project Sponsor**	Linas Medelis/Neetika Sathe
Project Lead	Leslie Lim	**Project Alias**	
Requested By		**Request Date**	
Reviewer Name		**Review Date**	

2.0 PROJECT CHANGE REQUEST DESCRIPTION

Description of Change	
The scope of this project includes the delivery of several Regulatory related projects/initiatives throughout 2025. Confirmed projects include: New SA Type and Rate Structure for Net Metering Combined with Gross Load Billing (1573,2336), EV rate (ALM 2353), and Market Renewal (ALM 1642). As part of the 2025 Year-End true up process, there was a variance between the capital budget for 2025 and the Year-End Actual spend. The PCR is designed to document the reason for the variance, since the Meter-to-Cash CIS CC&B Regulatory project has an identified variance. The approved Business Case in CopperLeaf (CL) for this project had an approved budget of $604,211. The actual spend for 2025 was identified as $53,963, a variance of $550,248 for 2025. The reason for the decreased spending is due to additional regulatory initiatives not materializing. Since the budget is forecasted to cover several regulatory related initiatives, these initiatives not materializing reduce the actual costs in the year.	
Type of Change Requested	☐ Scope Change ☐ Schedule Change ☒ Budget change ☐ Financial Benefit change ☐ Resource change ☐ Technology change
Justification	There is a variance between the Approved capital budget for 2025 and the Actual spend at Year-End.
Urgency High: prompt action is required as there is a current negative impact on the organization (e.g. significant financial, reputational or compliance risk) Medium: should be addressed soon to prevent minor issues from	Medium *Rationale* Only in-flight testing (Distribution rates and EV rates) remained for delivery at the time of Q3 forecast, however there was expectation that other initiatives might emerge.

escalating, but not immediately critical. Low: can be handled at a convenient time without significant impact on operations or outcomes.	
Additional Comments:	

3.0 IMPACT ASSESSMENT

Change type	Description
Scope Impact	*Describe if the variance is due to project scope change.* Variance is due to planned work not materializing.
Schedule Impact	*Describe the extent and size of the change impact on the project schedule* *Explain the assumptions used for the re-estimation of the work that has changed.* *Carryover to Next Fiscal Year: (Y/N) and impact on any next year's work plan (deferrals of other projects).* No carryover *Planned Project Completion Date:* December 31,2025 (original date reflected March 23, 2026 but targeted to complete by end of year as no new work has materialized) *Revised Project Completion Date:*
Resource Impact	*Describe the extent and size of the change impact on resources* None. They are allocated/planned to perform testing. Development has been completed.
Budget Impact	*Describe the extent and size of the change impact on the project budget including any key cost drivers, assumptions used to calculate the incremental change (labour hours, unit rates or contractor pricing), and new information since the budget was approved* *Complete Budget Table below* *The table below indicates that this project has a variance. Please indicate why? OR was there a change in the Capital budget that is not reflected here.* Variance $ based on YE Actuals. **Total Variance ($604,211−$53,963) = $550,248** This project is a responsive type project where the work involved is not well known at the time of the budget being planned. Work emerges throughout the year based on what the Regulator presents to Alectra. Underspend is associated with less project work emerging than originally budgeted for.

	Cap 2025 Budget	2025 Actual	Variance, $	Variance, %
Regulatory Project	$604,211	$53,963	$550,248	

Financial Benefit Impact	*Describe the extent and size of change impact on the project financial benefits* *Complete Financial Benefits Table below* None
Technology Impact	*Whenever changes are introduced in a project, it is critical to evaluate how these changes will impact the underlying technology stack. This assessment ensures that changes do not cause unforeseen issues in the technology infrastructure. Key considerations include:* *•Technology Dependencies: Identify if the change impacts any technology dependencies or integrations with other systems.* None *•Scalability: Ensure the change does not negatively affect the scalability of the technology stack, particularly if new features increase data load or processing requirements.* None *•Performance and Availability: Assess if the change impacts system performance (e.g., latency, throughput) or availability (e.g., failover capabilities).* None *•Infrastructure Changes: Determine whether new hardware, software, or cloud services are needed to support the change, and whether ` changes introduce additional complexity.* None *•Resource Capability: Consider whether external technology expertise will be required, and technology resources will require training on the new technology to accommodate the change.* None

4.0 Budget Tables:

Year to Date - Actuals to (Month)__October____:

	Current FY Year Budget	YTD Budget	YTD Actual	Variance	Funds Remaining
CapEx (Reg)	$604,211	$604,211	$53,963	$550,248	

Approved Multi Year Budget NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx		604211	588850	588850	586807	585063	587025	590106	
OpEx									
Total									

Revised Budget under this Project Change NPV: _____

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
CapEx									
OpEx									
Total									

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total

CapEx									
OpEx									
Total									

5.0 Financial Benefit Tables:

Approved Multi Year Benefits

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Revised Benefits under this Project Change

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

Variance

	Prior to 2025	2025	2026	2027	2028	2029	2030	2031	Total
Efficiency Benefit									
Avoided Cost									
Expected Reduction									
Total									

6.0 Risk Mitigation

This section identifies the potential risks coming from the proposed change. Consider all types of risks such as financial, technical, cyber security, regulatory, health and safety, employee culture, etc. (ntd – add link to the risk assessment). Where the change results in a carryover to the next fiscal year, identify any new or upcoming project that is at risk of being deferred or having a later start than planned.

Risks (Proposed Change)	**Probability (1 -5)**	**Mitigation Strategy**
Regulatory	**3**	**Maintain resource (both $ and people)**

7.0 APPROVALS AND NOTIFICATIONS

Assessment and Approval will be based on the magnitude of the change. Following the decision regarding approval/rejection /escalation of the request, that decision will be recorded on this form. Individuals noted in the Charter as Project Key Stakeholders and Project Team Resources must be informed of the approved change requests.

Name	Title/Role	Department	Signature	Date
	Approval			
Ramez Hakeem		IT / Product Management		Dec 04th 2025
Neetika Sathe	*Project Sponsor (VP)* *<$0.1MM (OM&A) or <$0.3 MM (Capital)*	IT / Product Management		12/04/2025
	Steering Committee (EVP) *≥ $0.1MM to < $0.25MM (OM&A) or ≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	TMO *≥ $0.1MM to < $0.25MM (OM&A) or ≥ $0.3MM to < $1.00MM (Capital)*			mm/dd/yyyy
	Executive Committee *>$0.25MM (OM&A) or >$1.00MM (Capital)*			mm/dd/yyyy
	Awareness			
	Director, PMO			mm/dd/yyyy
	TMO			mm/dd/yyyy
	Capital Reporting			mm/dd/yyyy
	Finance Reporting			mm/dd/yyyy
	Other (Define)			mm/dd/yyyy

JT-3.1.1

Attachment 2
Closure Reports

PROJECT CLOSURE REPORT

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Customer Service Strategy – CX Project

1.0 PROJECT IDENTIFICATION

Project Lead/Manager	Dianne Petrucci / Ramez Hakeem	**Project Sponsor**	Linas Medelis / William Schmidt (transitioned after retirement to Julia Zhu)
Project Start Date	4/1/2021	**Project End Date**	2/5/2025
Division Name	Customer Service	**Document Version**	V3

2.0 PROJECT CLOSURE SUMMARY

Project Planning and Schedule	The CX Project was a multiply year, multi-phase project. The discovery phase ran from April 1, 2021 to December 30, 2022 designed to better understand the requirements and how the initial SEW solution supported those requirements. Original plan was to complete this phase by May 30, 2022. The implementation phase ran from September 6, 2022 to February 5, 2025. This Phase included the implementation of the eBilling functionality, as well as Phase 1A and 1B. Original plan was to complete this phase by July 31, 2024. The overall project was completed in December 2024 with a 60-day warranty period.
Project Execution and Delivery	The project was completed in December 2024 with a 60-day warranty period. The warranty period closed within the 60-day period. The discovery phase ran longer than originally anticipated, requiring additional time to map requirements to vendor functionality. The implementation phase was also elongated – the extension was required to resolve data mapping/complexity and to ensure requirements were met through either configuration of the system or development of additional functionality.
Project Resources	The project was completed in 2024. With unanticipated data complexity and related challenges, the amount and duration of resources allocated to the production workstream has increased.
Organizational Change Management and Communications	In coordination with the OCM team, there has and continues to be ongoing communication and training with impacted teams ensuring business alignment.

Risk/ Issue Management	Continued issues with deliverable, data quality and schedule adherence continue to be discussed within the governance framework.
Project Implementation and Transition	The project was transitioned to the production workstream at the end of 2024.

3.0 PROJECT PERFORMANCE

Key Metric	Forecast/Planned Result	Actual Result
Schedule Variance:	**July 31, 2024**	**February 5, 2025**
Budget Variance:	**$See budget tracking**	***$See budget tracking***
Benefit Variance:	**N/A**	**N/A**
Other (explain):	**N/A**	**N/A**
Cause of Variance(s):	The project was completed in 2024. Total cost of project is $20.6MM.	
All Deliverables Completed and Accepted	☒ Yes ☐ No If No, please explain: Also, list the number of scope changes in post-planning phases. Project is closed	
Outstanding Issues:	Project is closed	

4.0 LESSONS LEARNED

List and describe any lessons learned from this project and provide key recommendations that can be used to improve the delivery of future projects.

Description	Key Recommendations
Stronger governance	Hold regular risk reviews with clear owners, establishing priorities and mitigation plans
Improve estimation and planning discipline	Break work into smaller, measurable deliverables to reduce uncertainty. Leverage gating processes with clear entry and exit criteria.
Prioritize quality early to avoid expensive rework	Implement modular application demonstrations early to validate mutual understanding of solution and/or requirements
Vendor challenges	Having a vendor/solution manager helps hold the parties accountable for delivery quality and timing
Data challenges	In order to ensure data issues are prioritized, leverage gating criteria before enhancements to the solution or new modules are pursued.

5.0 APPROVALS

Name	Title/Role	Department	Signature	Date
	Linas Medelis	Customer Service		mm/dd/yyyy

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Name	Title/Role	Department	Signature	Date
	Dianne Petrucci	Customer Service		mm/dd/yyyy
	Rameez Hakeem	IT		mm/dd/yyyy

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PROJECT CLOSURE REPORT

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ERP Continuous Improvements

1.0 PROJECT IDENTIFICATION

Project Lead/Manager	Alan Palmer	**Project Sponsor**	Neetika Sathe
Project Start Date	1/1/2025	**Project End Date**	12/31/2025
Division Name	D&I/Finance	**Document Version**	Closure V1 – 12/2025

2.0 PROJECT CLOSURE SUMMARY

Project Planning and Schedule	The ERP Enhancements 2025 initiative was originally planned with an approved capital budget of $584,157, supporting delivery of approximately 25 Change Requests (CRs) throughout the year from January 1 to December 31, 2025. During early 2025, additional enhancement demand emerged across multiple business units to address operational gaps and efficiency opportunities. In response, an additional $1,000,000 in capital funding was approved in the first quarter, increasing the total available budget to approximately $1.6MM and expanding the delivery plan to 65 CRs. Project planning was effective in adapting to the increased demand and revised funding level while maintaining the overall delivery timeline through year-end. The primary planning issue was not related to delivery capability.
Project Execution and Delivery	Project execution and delivery were effective throughout the year. The ERP team continued enhancement delivery under the revised funding level and expanded scope without requiring a change to the approved completion date. Based on the PCR, there were no expected schedule impacts, and the planned completion date remained December 31, 2025. Overall, the project was executed in line with the operating model and revised budget, with the key variance being formal reporting alignment rather than project delivery delay. The baseline project scope increased materially from the original plan, but the execution approach remained stable and supported completion within the 2025 delivery window.
Project Resources	Project resourcing was effective and did not create material delivery risk. As noted in the PCR, there was no material resource impact associated with the expanded scope. The ERP team had sufficient capacity to complete the increased workload before the year-end change freeze, supported by the completion of the ERP upgrade and the transition of resources back to enhancement work.

	This resource flexibility was a key factor in enabling the team to absorb the expanded enhancement scope without requiring a formal schedule extension or major staffing change.
Organizational Change Management and Communications	Organizational change management and stakeholder communication were generally effective in supporting enhancement delivery across the business. Multiple business units were engaged throughout the year as additional enhancement needs were identified and prioritized. The main communication gap was at the governance/reporting level. Although the additional capital funding was approved and reflected in financial tracking, the formal project scope was not updated at the same time. This created a reporting misalignment that required late-year correction through the PCR process. Going forward, changes to budget, scope, schedule, and/or benefits should be updated in a single coordinated step to maintain alignment across delivery, governance, and reporting.
Risk/ Issue Management	No significant delivery risks were identified. The primary issue/risk noted was continued misalignment between approved budget, and project scope, if the change was not formally approved. This was an administrative and governance risk rather than a delivery risk. This risk was managed by initiating the PCR to formally align the approved funding, revised scope, and performance expectations before year-end and prior to the IT change-freeze period.
Project Implementation and Transition	Project implementation and transition were effective. Enhancement work continued through the normal ERP delivery process during 2025, and the team was able to support the expanded scope after resources transitioned back from the ERP upgrade to enhancement delivery. A significant milestone for the project was the first quarter approval of the additional $1,000,000 in capital funding, which expanded the annual plan from 25 to 65 CRs. A second key milestone was the formalization of this expanded scope through the PCR process prior to project closeout. Overall, implementation and transition were effective, with no material schedule or resource disruption identified in the PCR.

3.0 PROJECT PERFORMANCE

Key Metric	Forecast/Planned Result	Actual Result
Schedule Variance:	Project completion by December 31, 2025.	Completed December 31st 2025
Budget Variance:	Original capital budget of $584,157. Revised Forecast Budget of $1,599,183 approved through Q1 Forecast and subsequent PCR process (Nov 11, 2025) of an additional $1,000,000.	Actual project spend of $1,358,363. Actual budget spend was $774,206 in excess of original budget and $240,820 below Revised Forecast Budget.

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Key Metric	Forecast/Planned Result	Actual Result
Benefit Variance:		
Other (explain):	Original annual scope of 25 CRs.	71 CRs completed with actual annual savings of $675K, compounded to $2.2MM over 5 years
Cause of Variance(s):	The primary variance was driven by additional enhancement demand from the various lines of business and the subsequent approval of an additional $1,000,000 in capital funding during the first quarter of the year. While that funding was incorporated into financial tracking, the related formal project scope was not updated at the same time. As a result, the major variance was one of governance and performance alignment, rather than schedule or delivery execution.	
All Deliverables Completed and Accepted	☒ Yes ☐ No If No, please explain: One formal post-planning scope change, increasing the annual plan from approximately 25 CRs to 71 CRs following approval of additional capital funding.	
Outstanding Issues:	No issues are outstanding. A partial underspend (~$200K) of increased budget is due to hardware delivery delay outside of Alectra's control.	

4.0 LESSONS LEARNED

List and describe any lessons learned from this project and provide key recommendations that can be used to improve the delivery of future projects.

Description	Key Recommendations
Additional capital funding was approved and used during the year, but the associated formal scope baseline were not updated at the same time.	Utilize the PCR process to govern funding change approvals, update the project scope target, and governance records immediately to ensure budget, delivery expectations, and reporting are aligned.
The primary project risk was not delivery failure, but delayed formal alignment between financial approvals and project reporting.	Strengthen coordination between project management, finance, and governance stakeholders so approved changes are driven by the governed PCR process and reflected promptly in reporting, and project documentation.
The annual ERP enhancement program requires flexibility to respond to changing business needs during the year.	For future annual enhancement programs, establish explicit checkpoints for budget, scope, and forecast alignment to reduce late-year administrative correction.

5.0 APPROVALS

Name	Title/Role	Department	Signature	Date
Neetika Sathe	PROJECT SPONSOR	D&I		mm/dd/yyyy
Alan Palmer	IT Lead LEAD	D&I		mm/dd/yyyy
	OTHER (DEFINE)			mm/dd/yyyy

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PROJECT CLOSURE REPORT

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M2C CIS CC&B Modifications (Regulatory Enhancements)

1.0 PROJECT IDENTIFICATION

Project Lead	Leslie Lim	**Project Sponsor**	Neetika Sathe/ Linas Medelis
Project Manager	Doris McGuire	**CL#**	150453
Project Start Date	1/1/2025	**Project End Date**	12/31/2025
Division Name	D&I/Customer Service	**Document Version**	Closure V1 – 12/2025

2.0 PROJECT CLOSURE SUMMARY

Project Planning and Schedule	The CIS CC&B Modifications (Regulatory Enhancements) 2025 project includes the delivery of several regulatory related initiatives throughout the year. The project was originally planned with an approved capital budget of $604,211 supporting delivery of regulatory related initiatives that would be requested throughout the 2025 calendar year from January 1 to December 31, 2025. No new enhancement requests in 2025 emerged and the actual budget required for these changes amounted to $53,963. The projects confirmed included the following: • New SA Type and Rate Structure for Net Metering Combined with Gross Load Billing (1573,2336) • EV rate (ALM 2353) • Market Renewal (ALM 1642)
Project Execution and Delivery	Project execution and delivery were effective throughout the year. The team continued to deliver the required regulatory related initiatives within the prescribed governed model.
Project Resources	Project resourcing was effective and did not create material delivery risk. This resource flexibility was a key factor in enabling the unutilized team members to be absorbed into other customer service-related activity, thus maximizing resource utilization.
Organizational Change Management and Communications	Organizational change management and stakeholder communication were generally effective in supporting project delivery, including engagement of multiple business units.

Risk/ Issue Management	No significant delivery risks were identified. The primary issue/risk noted was continued misalignment between approved budget, and project scope, not unusual to a project that requires planning of budget, scope, and resourcing in advance of understanding fully the work required during the period of time.
Project Implementation and Transition	Project implementation and transition were effective.

3.0 PROJECT PERFORMANCE

Key Metric	Forecast/Planned Result	Actual Result
Schedule Variance:	Project completion by December 31, 2025.	Completed December 31st 2025
Budget Variance:	Original capital budget of $604,211.	Actual project spend of $53,963. Actual budget spend was $550,248 below the original budget.
Benefit Variance:		
Other (explain):	Original scope was to be determined and driven by the emergence of regulatory related requests.	A smaller than budgeted number of requests emerged for 2025.
Cause of Variance(s):	The primary variance was driven by a reduced modification/enhancement demand for regulatory driven initiatives.	
All Deliverables Completed and Accepted	☒ Yes ☐ No If No, please explain: All requested initiatives were completed.	
Outstanding Issues:	No issues are outstanding.	

4.0 LESSONS LEARNED

List and describe any lessons learned from this project and provide key recommendations that can be used to improve the delivery of future projects.

Description	Key Recommendations
The annual Regulatory Enhancement/Modification program requires flexibility to respond to changing regulatory needs during the year.	For future annual enhancement programs, establish explicit checkpoints for budget, scope, and forecast alignment to reduce late-year administrative correction.

5.0 APPROVALS

Name	Title/Role	Department	Signature	Date
Neetika Sathe	PROJECT SPONSOR			mm/dd/yyyy
	IT Lead LEAD			mm/dd/yyyy

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Name	Title/Role	Department	Signature	Date
	OTHER (DEFINE)			mm/dd/yyyy

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

JT-3.1.2

2-AMPCO-89
Reference: 2-AMPCO-28 (c)

AMPCO requested an explanation of how project performance is tracked at the portfolio level. The response indicates the performance of the portfolio of projects is tracked through a dashboard which provides a summary of the projects by project health status and overall budget, actuals, forecast and variance.

Please provide the year-end dashboard (for the portfolio of projects) for each of the years 2020 to 2025.

RESPONSE:

As described at 2A-1-1 p.129-130, the governance framework encompassing the Project Management Office (PMO) and Transformation Management Office (TMO) only applies to a small subset of Alectra Utilities' projects, primarily within the General Plant category. This governance framework has been in place since later 2025.

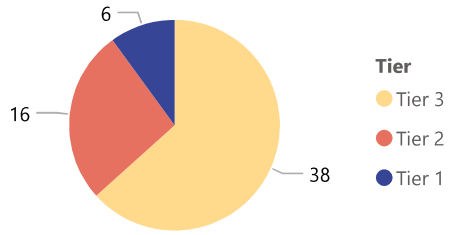
Please find in JT-3.1.2_Attach 1_2025-2020 Portfolio Dashboards.pdf the requested year-end project portfolio dashboards. The portfolio dashboard was implemented for 2025 and is provided. For 2020-2024, year-end portfolio reporting was done in a slide deck format as attached.

JT-3.1.2

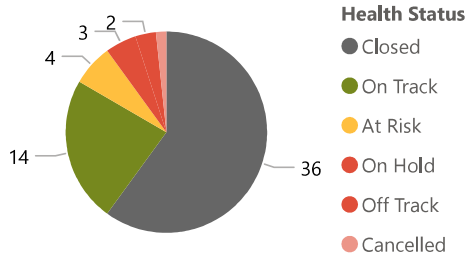
Attachment 1
2025-2020 Portfolio Dashboards

PMO/TMO Portfolio Insights

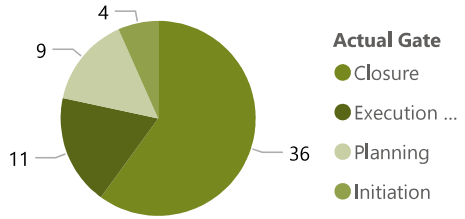
2025 Active Projects by Tier



2025 Active Projects by Health Status



2025 Active Projects by Actual Gate



Overall Portfolio: The Overall 2025 Portfolio Health Indicator is "On Track"

Schedule:
- A total of 36 projects were completed on schedule and closed by year-end.
- Cancelled (1): Metering Operational Data Storage (ODS) cancelled
- On Hold (1): WFM (for further evaluation and potential of introducing as a combined project)
- Deferred to later years (1): Aveva PI Upgrade differed to 2027

Resources:
- Resource constraints continue with the pull from Rate Rebasing and DSP but are being managed by Resource Managers & PMO

Project Change Requests:
- PCR anticipated for carry-over projects (3):
- SEW Customer Engagement eMobility - a portion of the scope has been deferred to 2026 due to vendor-related challenges.
- Enterprise Conversational GenAI Chatbot
- Guelph GIS Convergence

Data Quality:
- Reclassified from Tier 3 to Tier 4 (2): Customer Insights Program and New Customer Connections Process (NCCP) Portal Enhancements

Phase Gate Compliance:
- All projects but Meter Lab Software (EMTS) project were aligned on Phase Gates

Financial Overview:
- Although the Q3 Forecast suggested an overspend on portfolio overall budget, the Actual spend for 2025 was $32M, slightly lower than the Budget of $33M by $0.8M or 2.4%

EC Dashboard

Clear all slicers

Last Refreshed
2026-02-11 6:22:29 AM

Select Project Code: All

Select Project Name: All

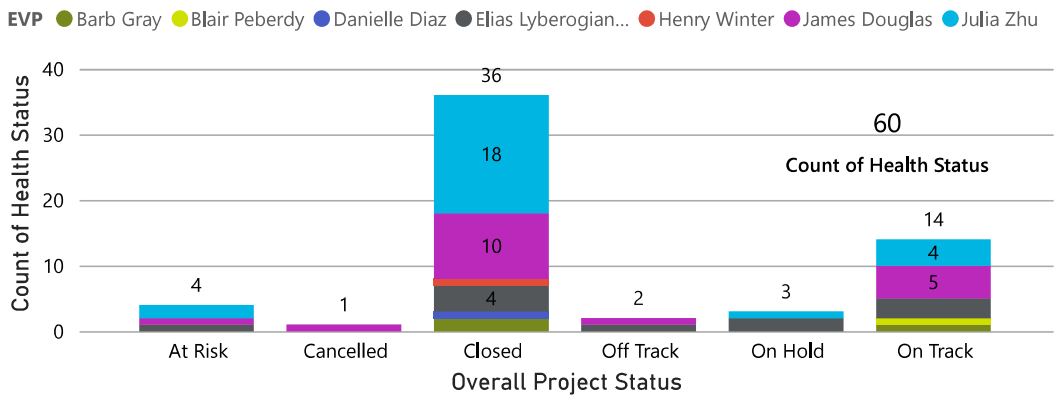
Reporting Month: December

BSC Project
- No
- Yes

EVP/SVP
- Barb Gray
- Blair Peberdy
- Danielle Diaz
- Elias Lyberogiannis

Project Tier
- Tier 1
- Tier 2
- Tier 3

of Projects, by Overall Project Status, by EVP/SVP

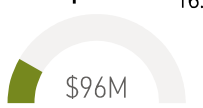


Budget Reporting 2025

Project Code	Actual	FY Budget	Net Q3 Forecast	FY Variance	Remaining to Spend
102098	$823,487	$824,445	$824,445	$0	$959
102263	$0	$1,084,794	$200,000	($884,794)	$200,000
103030	$47,940	$58,376	$58,376	($0)	$10,436
150325	$1,005,423	$718,903	$1,052,647	$333,744	$47,224
150437	$180,166	$42,577	$150,000	$107,423	($30,166)
Total	**$32,300,174**	**$33,085,946**	**$36,156,179**	**$3,070,233**	**$3,856,005**

Year to Date 97.63%

Since Inception 16.6%



Project Code	Project Name	Overall Project Status	Change Name	Change Impact	Milestones
		Cancelled			
		Closed			D1: Kick-off Meeting and System Configuration Document D2: Multi-Region Configuration Definition Meetings D3: Hexagon Staging Environment (Core) D4: Hexagon Staging Environment (non-Core) D5: Alectra Pre-Production Environment Setup D6: Delta Training D7: Report Portal Upgrade Support D8: System Acceptance Testing Readiness

Business Transformation Summary Dashboard

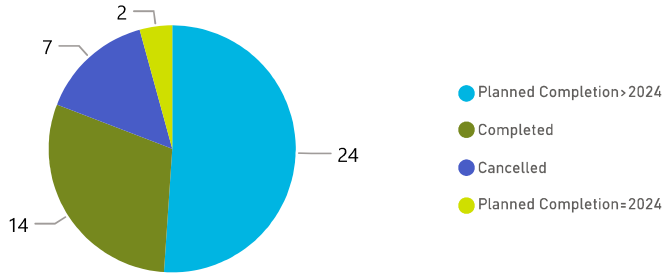
Reporting Month

- January
- February
- March
- April
- May
- June
- July
- August
- September
- December

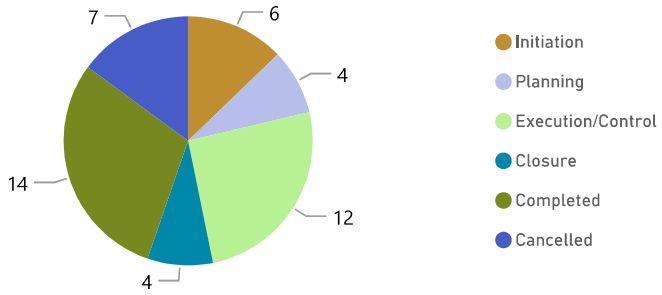
Number of Approved Projects

47

2024 Portfolio by Status



Projects by Approved Gate



Legend

Planned Completion=2024: active project planned to be completed in 2024

Planned Completion >2024: active project with expected completion dates beyond 2024

On Hold: project is on hold for funding

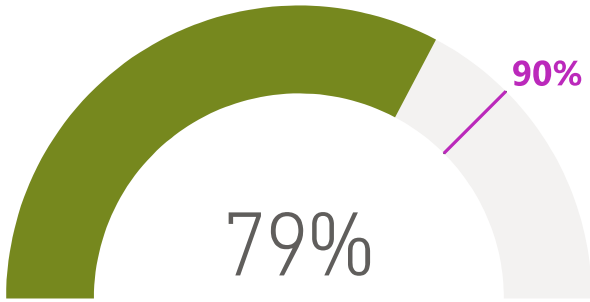
Completed: project completed in 2024

Cancelled: project cancelled in 2024

Delayed: projects planned to be completed in 2024 but completion delayed beyond 2024

Deferred: project start date deferred from 2024 into future years

Select General Plant Projects YTD Actual Scope & Cost vs Target



Productivity Framework YTD Actual Incremental Achieved Reduction Benefit vs Target

2024 Balance Scorecard Metrics:

- Completion of Selected General Plant Projects as per 2024 Scope and Capital Budget with a target of **90%**, threshold of 80%, and outstanding of 95%.
- Productivity Improvement target of **$2.1MM** measured as the actual Incremental benefits delivered in 2024 from Expected Reductions.

Business Transformation Summary Dashboard

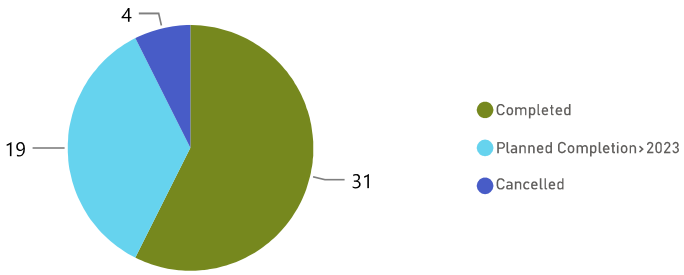
Month

- January
- February
- March
- April
- May
- June
- July
- August
- September
- October
- November
- December

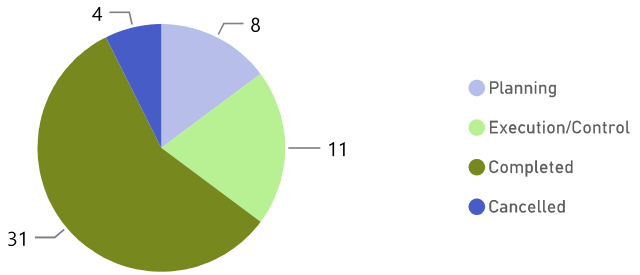
Number of Approved Projects

54

Number of Projects by Status



Projects by Approved Gate



Legend

Planned Completion=2023: active project planned to be completed in 2023

Planned Completion >2023: active project with expected completion dates beyond 2023

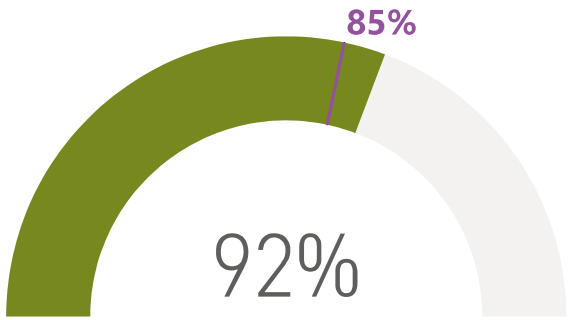
Completed: projects completed in 2023

Cancelled: project cancelled in 2023

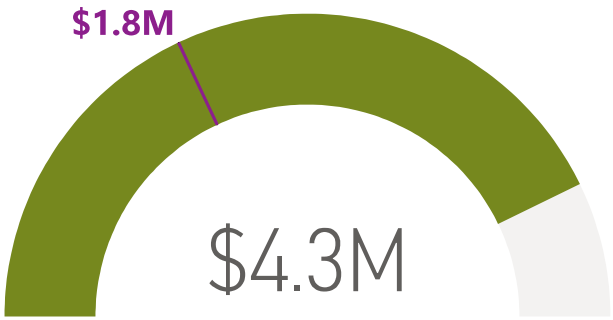
Delayed: projects planned to be completed in 2023 but completion delayed beyond 2023

Deferred: project start date deferred from 2023 into future years

Select General Plant Projects YTD Actual Scope and Budget vs Target



Productivity Framework YTD Actual Incremental Benefit vs Target



2023 Balance Scorecard Metrics:

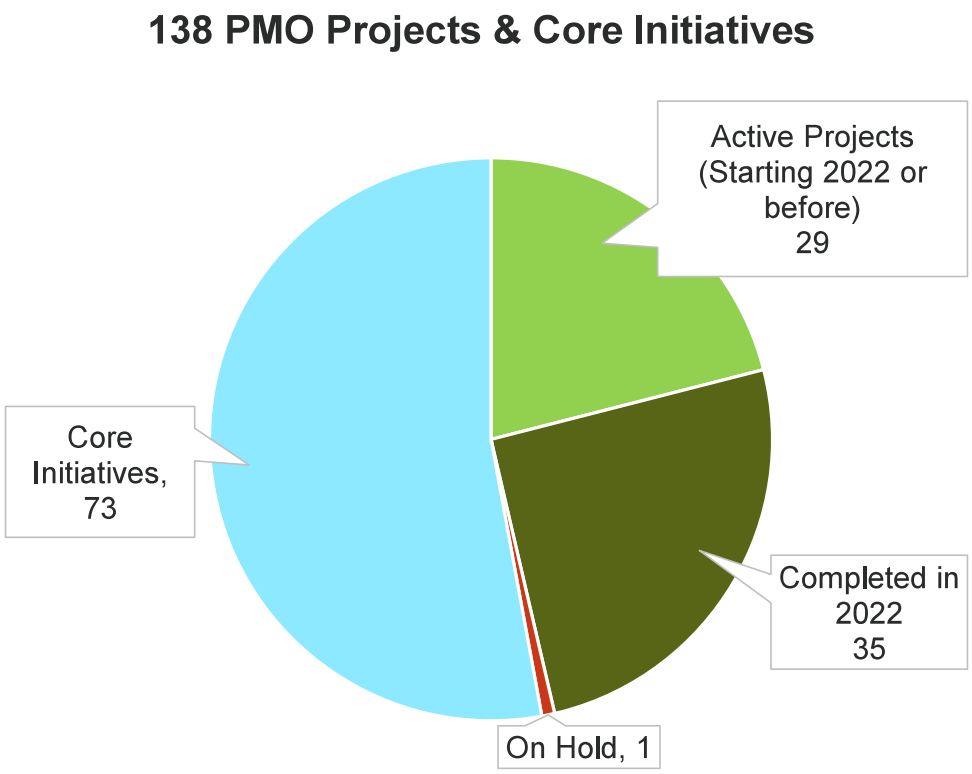
- Completion of Selected General Plant Projects as per 2023 Scope and Capital Budget within +/- 10%, with a target of 85%
- Productivity Improvement target of $1.8MM measured as the actual Incremental benefits delivered in 2023 from Expected Reductions, Avoided Costs and Efficiency Benefits.

Executive Committee – BT Q4 2022 Update

February 22, 2023

Business Transformation

PMO Projects Summary



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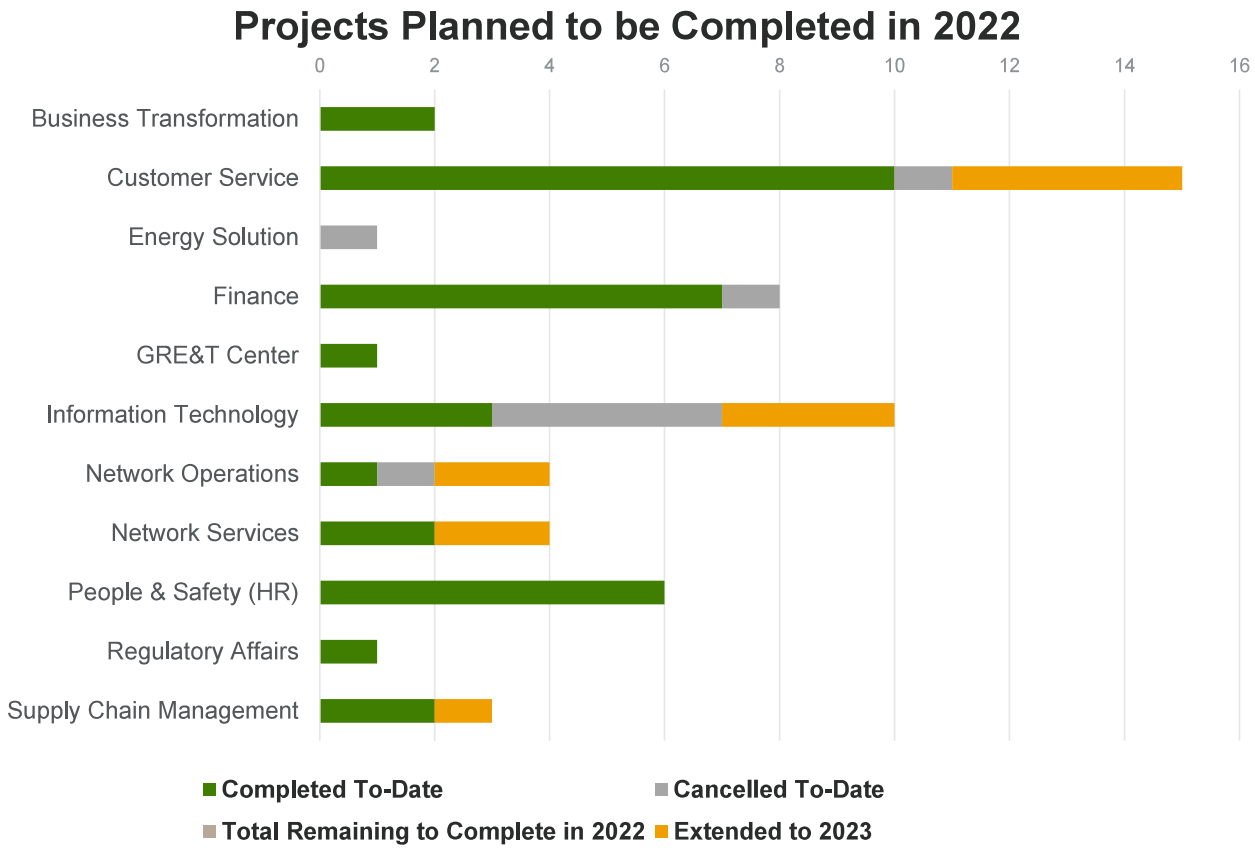
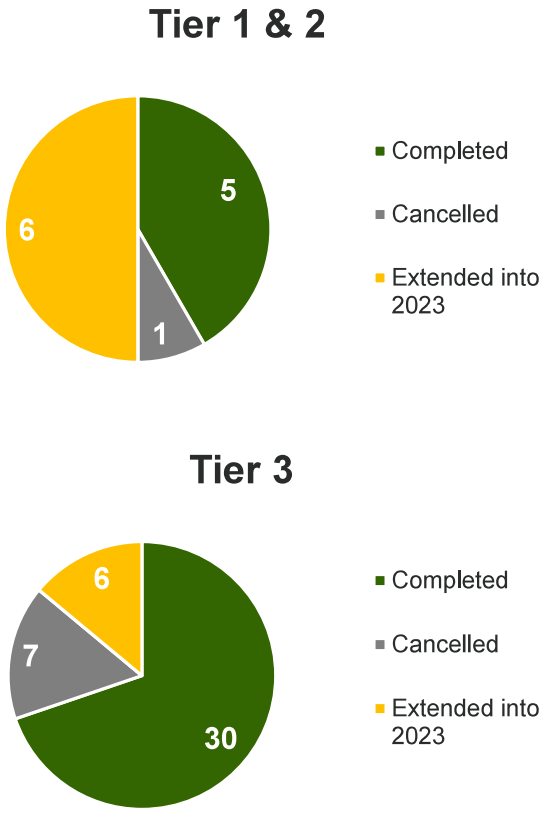
Projects Planned to be completed in 2022





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2021 Project Stats as of January 17, 2022

**Note, Trending stats are likely to be impacted as a result of the delays brought about with COVID-19*

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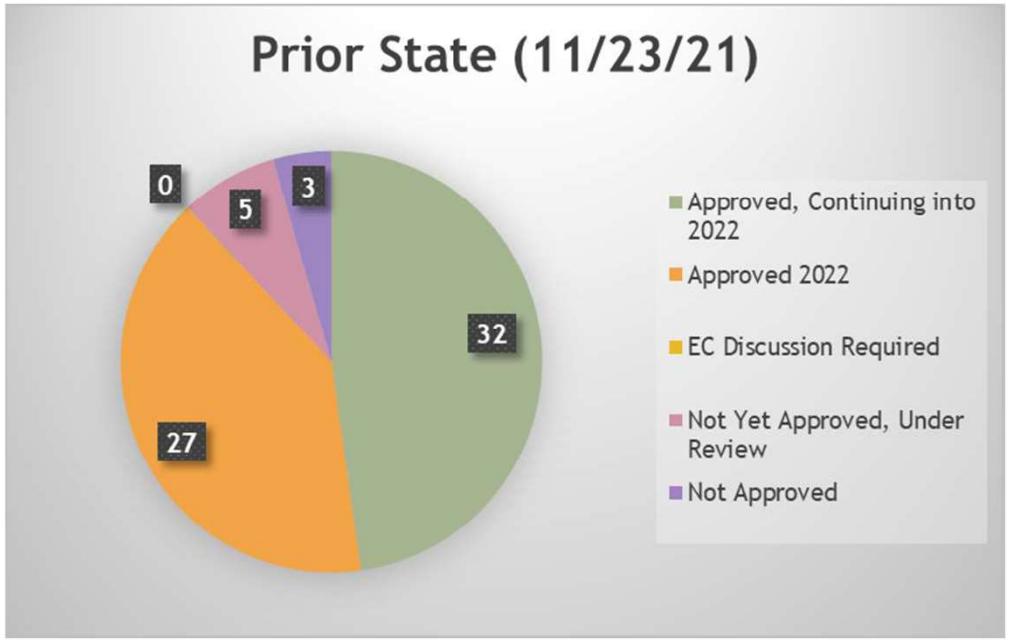
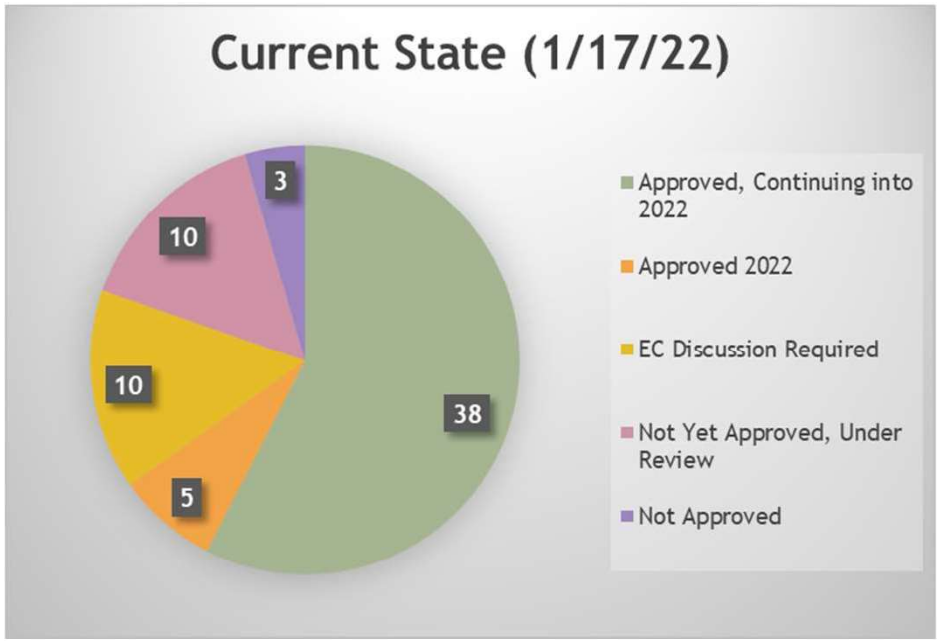
2022 Project Portfolio Overview





Note:

- Increase of additional 6 for “continuing into 2022” resulting from delayed 2021 projects (total 13)
- Decrease of 13 in “Approved” is a result of a shift to either, “EC Discussion Required” or “Under Review” and 1 deferral to 2023
- In total, 63 projects remain within the 2022 portfolio

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Business Transformation Year in Review

December 2020

2020 Projects Completed by Division

Division	Number of Projects
Business Transformation	1
Customer Service	5
Finance	1
Government and Corporate Relations	1
Information Technology	13
Network Operations	3
Network Services	1
People & Safety (HR)	2
Regulatory Affairs	1
Supply Chain Management	4
TOTAL	**32**

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

JT-3.1.3

4-AMPCO-90
Reference: 4-AMPCO-80 (b)

a) With respect to Table 1, please explain "n/a" for the forecast of Regular Hours and Overtime Hours for the years 2020 to 2025. In the response, explain why, in contrast, a forecast of Regular Hours is available for the years 2026 to 2031.

b) In the absence of a forecast of Regular Hours and Overtime Hours for 2020 to 2025, please explain how Alectra Utilities managed labour cost levels for the 2020 to 2025 period.

c) With respect to Table 2, please explain "n/a" for the forecast of Overtime Hours for the period 2026 to 2031. In the response please further explain Note 1 to Table 2; and how overtime $ amounts were determined in A4-AMPCO-80_Attach_1_2K for 2026 to 2031.

RESPONSE:

Parts a, b, and c: Alectra interpreted the request for the 'forecast' as something that is related to a forward-looking period (where there would be no differing number from the forecast as actuals were known). In response to this undertaking Alectra Utilities has provided a revised response which shows the Budgeted numbers for the 2020-2025 year relative to the actuals.

The planning software that Alectra utilizes accepts the overtime figures in dollars only, and not in hours. As such, Alectra does not have a value that can be provided for budgeted hours that would reconcile to the planned dollars.

In preparing this response, Alectra noted an error in the original response and has corrected the 2020 Overtime Hours – Actual hours in Table 1.

Table 1 – Budget vs. Actual Labour Costs

Labour	2020	2021	2022	2023	2024	2025
Regular Hours - Budget	2,949,880	2,937,599	2,992,652	3,008,775	3,018,778	3,113,887
Regular Hours - Actual	2,436,965	2,599,837	2,804,822	2,792,622	2,790,610	2,924,909
Overtime Hours - Budget	n/a	n/a	n/a	n/a	n/a	n/a
Overtime Hours - Actual	192,464	196,369	196,896	192,324	172,261	179,827
Regular $ - Budget	$196.0	$198.1	$209.5	$220.9	$231.5	$247.0
Regular $ - Actual	$188.2	$196.7	$202.3	$209.1	$219.0	$233.7
Overtime $ - Budget	$10.0	$10.0	$8.9	$10.8	$12.3	$16.0
Overtime $ - Actual	$18.1	$17.4	$19.0	$20.1	$18.6	$20.3

Note 1: The dollar figures are provided in ($MM).

Note 2: 2020 and 2021 ‘Regular Hours – Actual’ and ‘Overtime Hours – Actual’ exclude Guelph as the information is not available.

Note 3: The budget hours have been estimated on a best effort basis.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.2

Reference: 1-SEC-1

Provide the amount of the increase in property taxes from 2026 to 2027 that are attributable to the MCAP reassessment.

RESPONSE:

The increase in the forecasted property tax expense from 2026 to 2027 is $0.88MM. This forecast is based on:

i) A new MPAC Current Assessment Value (CVA) cycle for the 2026 – 2031 period.
ii) The gradual phase-in of the updated CVA increased evenly over the 2026-2031 period.
iii) An estimated decrease to property tax rates of 1.5% per year due to the relationship between CVA and property tax rates.

The $0.88MM increase can be segregated as follows:

Impact of phased-in CVA assessment increase from 2026 – 2027	$0.98MM
Impact of 1.5% decrease to property tax rates from 2026 - 2027	($0.1)MM
Total change from 2026 - 2027	$0.88MM

If the CVA assessment were not to occur and assuming a 5% increase in property taxes each year in 2026 and 2027 (based on the actual increase experienced from 2024 to 2025) the estimated increase in property taxes from 2026 to 2027 under this scenario would be $0.28MM.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.3

Reference: 1-SEC-1 and 4-SEC-78

Provide the OM&A in rates for 2017 to 2026 and how they were calculated.

RESPONSE:

The buildup of 'OM&A in Rates' line presented in 1-SEC-1_Attach_1_Board, page 23 is provided in Table 1 and Table 2 below.

Table 1 – Calculation of 'OM&A in Rates' 2017-2021 1-SEC-1_Attach_1_Board, page 23

	Prorated	**Full Year**				
'000	**2017**	**2017**	**2018**	**2019**	**2020**	**2021**
Inflation	1.9%	1.9%	1.2%	1.5%	2.0%	2.2%
Cohort 3	**1.60%**	**1.60%**	**0.90%**	**1.20%**	**1.70%**	**1.90%**
Horizon Utilities	$ 56,584	$ 61,728	$ 62,636	$ 63,557	$ 64,638	$ 65,866
Brampton	$ 21,805	$ 26,166	$ 26,401	$ 26,718	$ 27,172	$ 27,689
PowerStream	$ 88,153	$ 96,167	$ 97,033	$ 98,197	$ 99,866	$101,764
Enersource	$ 53,454	$ 58,313	$ 58,838	$ 59,544	$ 60,556	$ 61,707
Guelph				$ 16,149	$ 16,423	$ 16,735
OM&A in Rates	$219,996	$242,375	$244,909	$264,166	$268,656	$273,761
Footnote1 Adjustment Burden Pool Depreciation	$ 6,142		$ 5,760	$ 6,277	$ 6,305	$ 6,535
OM&A in Rates - per 1-SEC-1_Attach_1_Board page 23	**$226,138**		**$250,669**	**$270,443**	**$274,961**	**$280,296**

Note: 2017 figures are prorated. HRZ, PRZ and ERZ are prorated based on 11 months and BRZ is prorated based on 10 months

Table 2 – Calculation of 'OM&A in Rates' 2022-2026 1-SEC-1_Attach_1_Board, page 23

'000	**2022**	**2023**	**2024**	**2025**	**2026**
Inflation	3.3%	3.7%	4.8%	3.6%	2.6%
Cohort 3	**3.00%**	**3.40%**	**4.50%**	**3.30%**	**2.30%**
Horizon Utilities	$ 67,842	$ 70,149	$ 73,305	$ 75,724	$ 77,466
Brampton	$ 28,519	$ 29,489	$ 30,816	$ 31,833	$ 32,565
PowerStream	$104,817	$108,381	$113,258	$116,995	$119,686
Enersource	$ 63,558	$ 65,719	$ 68,676	$ 70,943	$ 72,574
Guelph	$ 17,237	$ 17,824	$ 18,626	$ 19,240	$ 19,683
OM&A in Rates	$281,974	$291,561	$304,681	$314,735	$321,974
Footnote1 Adjustment					
Burden Pool Depreciation	$ 6,389	$ 6,235	$ 6,647	$ 5,788	$ 5,883
OM&A in Rates - per 1-SEC-1_Attach_1_Board page 23	**$288,362**	**$297,796**	**$311,328**	**$320,524**	**$327,857**

Note: 2026 OEB approved rates were not known at the time of preparation.

The 2017 pro-ration for Horizon Utilities, Brampton, PowerStream and Enersource presented in Table 1 reflects the number of periods requiring adjustment for each rate zone based on the merger dates as the 2017 Actual results only reflect partial year information. The 2017 full year value of $242.4MM is reconciled in 4-SEC-78. The rows 'OM&A in Rates' in Table 1 and 2 are further normalized for 'burden pool depreciation recoveries allocated to depreciation' to align with the treatment of the recoveries presented in actuals.

The 2018 to 2026 figures on page 23 of the attachment in 1-SEC-1 are calculated by applying the approved OEB IRM inflation factor for Cohort 3 to the 2017 base year amount, with the results subsequently normalized as described in footnote 1. An estimate for the 2026 IRM inflation values was used as the approved value was not available at the time of preparation. The OM&A values for Horizon Utilities rates reflect the 2017-2019 HRZ CIR Updates. The IRM Cohort 3 rates are reflected for Horizon beginning in 2020.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.4

Reference: 1-CCC-5 Table 7

On a best-efforts basis, provide the annual forecasted merger savings for the Alectra-Guelph merger OM&A.

RESPONSE:

The following table presents the forecasted annual savings anticipated from the Alectra-Guelph merger, as outlined in the MAADs application, but excluding the years 2027 and 2028 due to early rebasing of Guelph. Please refer to EB-2018-0014, Alectra Utillities & Guelph Hydro s.86 (MAADs) Application, Exhibit B, Tab 6, Schedule 2, Page 3 of 4, Figure 22 – Total Cash Savings ($MM) (See OPEX Savings only).

Table 1 - Alectra-Guelph MAADs Forecasted OM&A Savings

$MM	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Gross Synergies											
Operating			**1.0**	**2.9**	**4.0**	**4.0**	**4.1**	**4.1**	**4.2**	**4.2**	**28.5**
Sustained			*1.0*	*2.9*	*3.9*	*4.0*	*4.0*	*4.1*	*4.1*	*4.2*	*28.2*
One-Time			*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.3*
Total OM&A Synergies			**1.0**	**2.9**	**4.0**	**4.0**	**4.1**	**4.1**	**4.2**	**4.2**	**28.5**
Transition Costs											
Charged to Operating			*3.7*	*0.6*	*0.3*	-	-	-	-	-	*4.5*
Total Transition Costs			**3.7**	**0.6**	**0.3**	**-**	**-**	**-**	**-**	**-**	**4.5**
Net Synergies											
Operating			(2.7)	2.4	3.7	4.0	4.1	4.1	4.2	4.2	23.9
Total Net OM&A Synergies			**(2.7)**	**2.4**	**3.7**	**4.0**	**4.1**	**4.1**	**4.2**	**4.2**	**23.9**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.5

Reference: 4-SEC-89, 4-Staff-171 and updated Appendix 2-K

Show how the addition of 99 positions contributed to the increase of 56.3 FTEs for 2027.

RESPONSE:

The increase of 56.3 FTE as it relates to the addition of 99 positions in 2027 is detailed in the table below.

Table 1 – 2027 FTE Increase

2027 FTE Increase	
Additional Positions	99
99 positions translated to FTE[1]	88.6
Reduction of FTE	-32.3
Net Increase in FTE in 2027	56.3

Note 1: Positions are translated to FTE by utilizing the budgeted start date and/or end date.

As part of Alectra Utilities' workforce planning processes, the utility regularly reevaluates its workforce needs based on work volumes and productivity gains, resulting in the repurposing and elimination of positions within the organization.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.6

Reference: 1-SEC-24, updated Appendix 2K

Provide the average start dates regarding the 99 positions referred to in Staff-171

RESPONSE:

The table below provides the budget start date for the 99 additional positions for 2027 referred to in Staff-171.

Table 1 – Budget Start Date

Budget Start Date	Position count
1-Jan-27	76
1-May-27	2
1-Jul-27	21
Total	99

The average start date for these positions is February 10, 2027. For positions with a start date of January 1, 2027, Alectra Utilities will begin the process in late 2026 to have candidates hired to start at the beginning of 2027.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.7

Reference:

Provide an update on the status of the hiring of new positions/new FTEs in 2026.

RESPONSE:

The table below provides an update on the status of hiring the 17 additional positions in 2026 which are referenced in 4-STAFF-171 Table 1. As this table shows, three months into 2026, Alectra Utilities has hired more than 50% of the roles it plans to add in 2026.

Table 1 – 2026 Position Status

Status	Positions
Filled	9
Offer Pending	1
Posted	4
Not yet posted	3
Total	17

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.8

Reference: 1-SEC-3

On a best-efforts basis, provide the full versions of the internal audit reports referenced on page 16 of Transcript, Day 3:

- May 2025 Contract Centre Productivity;
- July 2024, Productivity Benefits;
- January 2024, Productivity Reporting Framework;
- December 2022, Green Energy and Technology Centre;
- June 2022, New Connections;
- April 2022, Guelph Hydro ERP Final Report;
- January 2022, Software Asset Management Assessment;
- July 2021, Fleet Services;
- May 2021, Budgeting;
- December 2021, Shared Services;
- June 2020, Economic Evaluation Model;
- January 2020, Synergy Savings and Transition Costs;
- September 2019, Sustained Savings;
- April 2019, Capital Versus Operating Costs.

RESPONSE:

The requested internal audit reports have been combined and filed as Attachment 1 to this undertaking response. Additionally, Alectra Utilities has filed a status update on the recommendations included in those internal audits as Attachment 2 to this response. The

table below provides a breakdown of each document and their location in Alectra Utilities' filing:

Table 1 - Summary of Responsive Documents to JT-3.8

Audit Requested by SEC	Date of Publication	Location in Response
Guelph Hydro ERP Integration Report	April 2022	Attachment 1, Pages 1 to 11
Shared Services Cost Allocation Review	December 2020	Attachment 1, Pages 12 to 24
Fleet Services Review	July 2021	Attachment 1, Pages 25 to 45
Contact Centre Productivity & Efficiency Review	May 2025	Attachment 1, Pages 46 to 73
Sustained Synergies Review	September 2019	Attachment 1, Pages 74 to 85
Budgeting Review	May 2021	Attachment 1, Pages 86 to 101
Capital vs. Operating Cost Review	September 2019	Attachment 1, Pages 102 to 113
Green Energy & Technology (GRE&T) Centre Review	December 2022	Attachment 1, Pages 114 to 119
Synergy Savings & Transitional Costs Review	January 2020	Attachment 1, Pages 120 to 129
Economic Evaluation Model Review	June 2020	Attachment 1, Pages 130 to 143
Software Asset Management (SAM) Assessment	January 2022	Attachment 1, Pages 144 to 157
New Connections Review	June 2022	Attachment 1, Pages 158 to 172
Productivity Reporting Framework Review	January 2024	Attachment 1, Pages 173 to 186
Productivity Benefits Selected Projects Review	July 2024	Attachment 1, Pages 186 to 197

JT-3.8

Attachment 1
Internal Audits Compendium

Guelph Hydro ERP Integration
“Project Harmony”
Report #2

Internal Audit Department

April 2022

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1. Overview (Executive Summary)

Background

Project Harmony (Guelph Hydro ERP integration project) will bring Guelph employees from their existing ERP System (Central Square) to the Alectra JD Edwards (JDE) system. The JDE system is an Enterprise Resource Planning (ERP) solution that provides applications and tools across the business. It helps manage day-to-day business activities for finance, inventory, procurement, work orders, time & leave management, human resources and payroll functions of the organization. Project Harmony supports Alectra's Strategy 2.0 by integrating innovative, technological solutions into business practices across Alectra and leveraging them to benefit employees and the business. Similar to the ERP Convergence/Keystone Project, this is a foundational project for Alectra and will further enhance the "One Culture, One team" vision of the Alectra strategy.

Objectives

The objective of Internal Audit's involvement is to provide the stakeholders of the organization with an independent assessment of the progress of Project Harmony. Our goal is to provide timely feedback to the organization and the project team at regular intervals and at select key milestones during the implementation. Our early and ongoing involvement will allow us to provide observations and recommendations to the project team for their consideration. Internal Audit's goal is to make suggestions which will reduce the risk of shortcomings that could prevent the system from meeting the needs and requirements of the organization.

Scope

Internal Audit has identified nine areas of focus for the overall review, as detailed in **Appendix 2**. This is the second review for this project and generally covers project activities from January 1 to March 31, 2022. This period includes the Build phase and part of the Test phase. Specifically, we are seeking to identify any issues or risks in the proposed solution that may impact the system in the initial go-live or in the longer term. We are also seeking to verify that the solution proposed in the design phase has been constructed as designed.

Approach

Our approach for conducting the review included:

- Meetings with project team members;
- Attending regular (weekly) project meetings;
- Review of project Steering Committee Governance meetings;
- Obtaining and reviewing relevant documents from the project team;
- Obtaining clarity on relevant documents by discussing and reviewing these documents with key staff;
- Reviewing the "Unit testing" of the test phase;
- Discussing areas of concern or points for improvement with management and;
- Finalizing a report for presentation to management and the Audit, Finance & Risk Management Committee.

Summary

In our first report, dated January 2022, we identified four key risks (two high and two medium) and one low risk issue. As of April 2022 (the date of this report) all the observations noted in the first report were mitigated by the project team and those issues have been closed on our issues list.

The fieldwork for this second review was conducted during the months of February to March 2022. During that period, we attended several of the weekly project related meetings and reviewed the training for the unit testing approach on how to document the testing and where to log defects. We reviewed the Unit testing phase as well as the cutover plans and approach for Mock testing before the second phase of testing, Integration testing, begins.

In our pre-integration review and fieldwork for Q1, 2022, we identified no new keys risks. There were two low risk observations noted, discussed in greater detail below.

It should be noted that at this point of the project, Project Harmony is listed as "on track" with 70% completion noted on the Executive Status report. There is still key integration testing and Mock validations work that needs to be completed before "Go Live", currently scheduled for the end of May 2022.

2. Good Client Practices

We observed several important strengths in the project team and project governance which should support the successful execution of the project. These strengths are listed below:

In general, we found the project testing phase to be well organized, planned and documented. The project team leads have leveraged the benefits of previous roll-outs such as "Keystone" and "Tools upgrade" projects for test scripts, training and methodology. There was a robust tracking and monitoring system in place to keep track of the test statuses as well as passes, failures or blocked testing (referring to testing that was dependent on other testing before it could be passed/failed).

The weekly project reporting to the Steering Committee continues to provide up-to-date information to the project leadership and provides an effective project update mechanism.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix 1**.

Observation #1 **Priority: Low**	**Testing documentation missing (Operating Effectiveness)**
	Internal Audit reviewed the testing scripts for the unit testing phase. Three instances were noted where the tests had not been completed adequately and the test script documentation was missing the test step results/outcome of testing. It should be noted that all of these instances indicated that the overall tests had passed, despite the fact that the uploaded test scripts did not support that conclusion due to the missing test steps. There is a risk that test scripts are not accurately completed and could give an incorrect conclusion on whether the tests actually passed or failed.
Recommendation	We recommend that all testing scripts be reviewed by the test lead for the various work streams or a Senior Project Manager resource on the Project to ensure that all test scripts have been completed accurately and completely. The correct documentation of items is essential to ensure that testing is supported by the correct test results.
Response from Management	Test scripts were executed properly and completely, and they were marked as “Passed” accordingly. Some testers from Southgate were new to this process, hence there was an oversight of marking some steps within two of the scripts. Testers were informed about this and subsequently those steps were updated. Management will look at feasibility of assigning the task of performing a detailed review of all test scripts through the project process for future projects.
	Accountable Parties: Ingrid Brammer ERP Project Manager ERP- One Consulting Inc Roshan Lakmal ERP Application Specialist
	Estimated implementation date: Completed

Observation #2 **Priority: Low**	**Business requirements document (Operating Effectiveness)**
	A business requirements document (BRD) describes the business solution for a project i.e., what a new or updated product should do, including the user's needs and expectations, the purpose behind the solution, and any high-level constraints that could impact a successful deployment. We noted exceptions with the document, presented to Internal Audit, as follows: 1) The BRD should be drafted before any test plans, test scripts and testing, commences. The document was drafted and sent to Internal Audit at the beginning of March 2022 when it was requested by us. The test plan and scripts had been finalized by that time and certain tests had already commenced. 2) Although the BRD has been documented, it was not signed off by Senior Management. The BRD does have a sign off section, but it was not completed. There is a risk that critical requirements do not align to the business case and decisions taken, without obtaining proper prior approval.
Recommendation	The BRD should be finalized before any test plans or scripts have commenced. We recommend that Management takes the necessary steps to finalize the BRD with the appropriate sign-off by authorized personnel.
Response from Management	The delay in finalizing the BRD was largely attributed to confusion around the BRD Template which seems to be geared towards new Process implementation, rather than an integration type project. Regardless, the BRD document was completed, however the process of sign-offs was missed. It has since been submitted for approval, and all sponsors have signed off.
	Accountable Parties: Ingrid Brammer ERP Project Manager ERP- One Consulting Inc Roshan Lakmal ERP Application Specialist
	Estimated implementation date: Completed.

4. Additional Item for Consideration

The point below was identified as a service to Management. It does not require a response and is provided to assist with building more effective and efficient processes.

Testing documentation

Internal Audit noted that the documentation of test scripts and the results obtained, is a very manual process using Microsoft Excel. Testers also have to upload tests and mark defects in separate Excel files on the SharePoint site. Monitoring of outstanding issues, whether tests have passed failed or were blocked, as well as other key tracking metrics are also performed manually in Excel. Management should consider looking into an automated solution for consistently documenting test scripts and their outcomes. Software like Micro Focus Quality Center, formerly known as HP Quality Center, is a quality management software offered by Micro Focus that assists with testing documentation. Quality Center reduces the time and cost required to release a software application and lessens the risk of product errors and defects.

5. Acknowledgement of Review

Name and Title	Signature	Date
Alan Palmer Project Manager: Project Harmony	Approved by E-mail	April 25, 2022
Roshan Lakmal ERP Application Specialist: Project Harmony	Approved by E-mail	April 25, 2022
Ingrid Brammer ERP Project Manager - ERP-One Consulting Inc	Approved by E-mail	April 25, 2022
Marc Villett VP, Finance	Approved by E-mail	April 25, 2022
James Macumber VP, Supply Chain	Approved by E-mail	April 25, 2022
William Schmidt SVP, Business Transformation Interim VP, Information Technology	Approved by E-mail	April 25, 2022

APPENDIX 1: Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

APPENDIX 2: Project Review Scope

#	Focus Area	Review Activities
1	Review of Project Scope and Resources	• Organization chart (including steering committee) has appropriate resources with relevant expertise • Milestones are clearly defined with timeline
2	Review of Project Management	• Review the project risk register to ensure key risks are being tracked, managed and escalated where appropriate; determine if there are any additional risks that have not been considered. • Review updates to project plan to ensure continued progress or identify any significant delays • Review periodic project status updates; assess the accuracy and completeness of status reports and the attainment of milestones • Review Project financial status including budget outlook to completion • Attend steering committee meetings to understand key risks and concerns from the business stakeholders
3	Review of IT Testing	• Confirm that a Disaster recovery plan exists and the schedule for testing, review test results
4	Review of User Acceptance Testing	• Training and change management are in place • UAT testing is being appropriately conducted • Business is being involved • Scenarios (to the extent of the user knowledge) are being covered • Reports required by the users are created and included in testing
5	Conversion Review	• Review process to provide assurance over the conversion process (e.g. Reconciliation of data between the legacy and target systems) - review results of conversion testing
6	Functional Review	• Determine if the project team has identified key risks & internal controls in selected processes and conducted appropriate testing • Ensure process and internal control documentation is approved by management • Assess potential weaknesses in security which may allow fraudulent activity to occur undetected

7	Access Security and Confidentiality of the ERP Application	• Process and controls exist to protect against unauthorized logical access to the ERP • Restriction of access to the ERP configuration and confidential data • Use of encryption or other equivalent security techniques to protect user authentication information and the corresponding session transmitted over the network • Assess if management has ensured that roles and privileges have been assigned based on segregation of duties principles.
8	Review of Operational Readiness and Cutover Plan	• Review the operational readiness and cutover plan to determine if key activities have been covered and signed off • Assess level of user adoption and identify any key issues • Ongoing service support processes are in place (including service level agreements with 3rd party providers) • Assess the extent of business preparedness and for the rollout (including: existence of an approach document, preparedness of the users, communication on the rollout and ownership / understanding of responsibilities).
9	Project Closure Review	• Closure activities include • review sign-offs for cutover and data conversion • review of logs/defects • ensure ""super user"" system access for project team is removed after an appropriate support phase • Project closure-long term support processes in place

Shared Services Cost Allocation Review

Internal Audit Department

December 2020

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Appendix A: Risk Rating Key 13

1. Overview (Executive Summary)

As part of Alectra's 2020 Internal Audit Plan, the Internal Audit team conducted a review of the shared services cost allocation process for Alectra Utilities Corporation (AUC) to its affiliates. The purpose of the review was to determine if the cost allocation methods applied are following the Ontario Energy Board (OEB) requirements and to assess whether the cost allocations to each affiliate reflects the functions and services provided to the entity. The audit approach was discussed with Management and testing was completed for the period September 1, 2019 to August 31, 2020, inclusive. The audit review took into account the 2019 Financial Budget as reflected at the beginning of 2019.

The shared services cost allocation process refers to the method for allocating common corporate costs from one entity to another (i.e. among affiliates) when services are being provided across entities. These methods are set up to be aligned with the OEB Affiliate Relationship Code (ARC) requirements.

The objective of this internal audit review was to assess the design and operating effectiveness of the internal controls in place within the shared services cost allocation process. The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of audit.

The scope of the review was as follows:

- Confirm that the cost allocation methods are following the OEB's ARC requirements;
- Confirm internal processes for arriving at allocated costs are documented;
- Confirm that there are signed service level agreements (SLA) in place between Alectra Utilities Corporation and its affiliates that are current and valid;
- Review the functions and services provided to each entity;
- Review cost drivers assigned and assess reasonability;
- Assess the accuracy of the output resulting from Cognos;
- Confirm that the internal control process surrounding changes to cost allocation is adequate; and
- Review a sample of actual allocations to assess accuracy and determine whether it reflects current services provided and current costs for providing the services.

The following areas were either out of scope or de-scoped:

- Allocations from affiliates to AUC; there were no allocations noted except for CDM
- Allocations between various smaller affiliates; these were deemed immaterial as they accounted for approximately 3-4% of total allocation annually; and
- Manual adjusting entries regarding allocations to/from Conservation and Demand Management (CDM).

The effectiveness of IT general controls, application controls and reporting integrity controls was beyond the scope of this review but have a direct relationship to the effectiveness of the controls and information we tested.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures, wherever possible.

The overall design of the shared services cost allocation model was found to be generally satisfactory in most areas including the allocation factors used. The accuracy of the system calculation of the allocation amounts was deemed satisfactory. Opportunity for improvement in implementation and operating effectiveness of controls, were identified in the specific areas listed below:

1. Cost allocation model outdated (High)
2. Draft service level agreement (High)
3. Lack of process documentation (Medium)
4. Manual aspects of cost allocation process (Low)

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

The Regulatory and Financial Planning & Analysis/Budgeting teams worked closely, with the support from a subject matter expert outside consulting firm, to create Alectra's initial affiliate shared services cost allocation methodology. The Financial Planning & Analysis team offered their tools and resources to assist Regulatory in automating the shared service allocation model. The legacy process was strenuous due to complexity of multiplying allocation factors against allocation rates by business units on both a budget and actuals basis.

This successful initiative was supported by senior leaders throughout the organization and was well integrated into the annual budgeting process. We acknowledge the collaborative efforts of both teams to ensure the process is executed effectively, utilizing best industry practices.

The Budgeting team uses IBM Cognos TM1(Cognos) software in the development of the budget and the shared services cost allocation process. With Cognos, the team was able to automate the management fees so that outputs could be calculated and reported at the click of a button. This significantly reduces the manual effort for the cost allocation process and leads to greater efficiency.

The Budgeting team reperforms the cost allocation model at the end of every year based on actual costs, performs a comparison to budgeted costs and determines the adjusting amounts required. The year-end true up process, which took several hours in the past, is now available as soon as the year-end financial results are final. These adjusting amounts are posted by Accounting as true-up entries. This is done to ensure that the costs allocated to each affiliate are based on current, actual costs.

Despite the current lockdown due to the COVID-19 Pandemic, Management supplied all the documentation and support needed for the audit by electronic means. We also wish to recognize the excellent rapport and exchange of views with all personnel involved with the audit. The depth of this review could not have been achieved without the support received. The efforts of all were greatly appreciated.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1

Priority: High

Cost allocation model outdated

The allocation factors/cost drivers and the percentages assigned to each affiliate has not been updated since the cost allocation model was developed in 2018. Examples of these factors are headcount, invoices processed, workstations, financial reporting time assignment and legal support for non-regulated entities. These were developed based on 2017 information provided primarily through interviews and email correspondence with business unit leaders.

Additionally, each business unit had to apportion their total effort based on duties performed at that time. This process was done using judgemental estimates from business unit leaders and key employees. These estimates have not been updated since the finalization of the cost allocation model in 2018.

To perform the audit, a sample of business units was selected, and a verification performed of the applicable direct labour costs and non-labour costs for the 2019 and 2020 budgets. Due to the percentages assigned to the cost drivers being dated and subjective, detailed testing of the allocation factors and percentages could not be performed.

The allocation factors and percentages combined with business units' allocation of efforts, results in the costs allocated to each affiliate.

Below is an illustration of the Headcount allocation factor and percentages and the changes since 2018.

	As per Cost Allocation Model 2018		As per HR information			
Companies	Headcount 2018	%	2019	%	2020	%
Shared Services	606	38.17%	674	41.99%	612	40.50%
LDC	855	53.89%	831	51.78%	818	54.14%
Alectra Energy Solutions	8	0.50%	32	1.99%	35	2.32%
Alectra Energy Services	10	0.63%				
Alectra Power Services	28	1.76%	20	1.25%	14	0.93%
CDM	80	5.04%	39	2.43%	18	1.19%
GRE&T			9	0.56%	14	0.93%
TOTAL	1587	100.00%	1605	100.00%	1511	100.00%

There have been significant business changes such as the merger with Guelph Hydro and the formation of the GRE&T Centre, as well as the non-regulated business, that is not reflected in the model. It was noted however, that Management did account for the wind down of CDM and made adjusting entries to reduce the allocation amounts to CDM.

The return on assets calculation has not been updated since the development of the cost allocation model in 2018. Hence, the allocations for the shared assets are based on the carrying values as at 2017.

	This calculation apportions the carrying values of the shared assets which are computer software and equipment as well as general plant - land, buildings, and other office equipment. The shared assets costs for 2019 and 2020 are thus outdated. As a result, the model does not accurately reflect the current level of services provided to each affiliate due to the estimates and source information used being outdated. The use of outdated information may result in the allocations being misstated and or unreasonable.
Recommendation	We recommend that an annual review is done of the cost allocation model to determine its appropriateness. This should include but not limited to: • a review of the allocation factors; • a review of the percentages for each factor assigned to each affiliate company; • a review by business unit leaders on the estimates used for duties performed; and • a review and inclusion of key business changes that might have a significant impact on the allocation amounts. • an update of the return on assets calculation to reflect the net book value of the assets at the prior year's end.
Response from Management	Management agrees with the recommendations and will perform a comprehensive annual review to support the appropriateness of the affiliate cost allocations.
	Accountable Party: John Bonadie Director, Rates and Settlements
	Estimated implementation date: September 30, 2021

Observation #2	Draft service level agreement
Priority: High	It was noted that the legacy entities prior to the merger utilized service level agreements which outlined the services and cost allocation method to affiliates. Management has continued to rely on these prior agreements for the current cost allocation process as the services provided to the affiliates are similar to those prior to the merger. Service level agreements between Alectra Utilities Corporation and affiliate companies are currently being reviewed. **1) SLAs in draft form** The OEB's Affiliate Relationship Code stipulates in Section 2.2.1 "Where a utility provides a service, resource, product or use of asset to an affiliate or receives a service, resource, product or use of asset from an affiliate, it shall do so in accordance with a Services Agreement." The template for the SLA is currently in a draft form. Regulatory Management advised that in 2019 the process of drafting the service agreements was revisited, however, it has now paused because the cost allocation model is currently being reviewed. **2) Components of the Draft SLA** Internal Audit reviewed a draft master service agreement between Alectra Energy Services Inc. and Alectra Utilities Corporation with Alectra Energy Services Inc. as the provider of the shared services. We were also provided with drafts of "Schedule A" for each affiliate which provides a description of each shared service that is to be received. The document was reviewed to determine if it included all components required by Section of 2.2.1 of the ARC and it was noted that it does not include wording related to the cost allocation mechanisms and the apportionment of risks. It was noted that the draft master service agreement does not have the "DRAFT" watermark. Non-compliance with the OEB's ARC may result in regulatory implications with the OEB. Additionally, the lack of signed SLAs between the companies reflecting the new organizational structure may result in inconsistencies in the services provided and costs allocated as well as a lack of accountability.
Recommendation	We recommend that services agreements between Alectra Utilities Corporation and each affiliate company are finalized and signed by authorized personnel once the cost allocation model is revised and completed. We recommend that Management perform an update of the draft service agreement to ensure that it reflects all components required by the ARC and ensure that these are reflected in a manner that is clear and concise. The agreement should clearly document the services provided and the cost allocation methods utilized.

	Lastly, based on best practice, while the agreement is still in draft status, the word DRAFT should be clearly visible to distinguish from the finalized agreement.
Response from Management	Management agrees with the recommendation. We are currently performing a full review and update of the existing affiliate cost allocations and will ensure the recommendations related to the service level agreements are completed.
	Accountable Party: Michael Lister Director, Regulatory Policy & Strategy
	Estimated implementation date: September 30, 2021

Observation #3 **Priority: Medium**	**Lack of Process Documentation**
	Based on inquiry with Management, Internal Audit noted that there is no formal policy or procedure document that outlines the key components and steps of the shared service cost allocation process. The source information and knowledge of the process is concentrated with key leaders of the business units responsible for the process, hence, in their absence, information flow would be limited. The lack of harmonized procedural documents increases the risk of non-compliance to processes and procedures. Without clear procedure documents in place, it may lead to knowledge of the processes being concentrated in specific individuals which pose a risk in the event of staff turnover and future training.
Recommendation	We recommend that a policy and a procedure document be developed by Management to reflect the key components of the cost allocation model, compliance with the ARC and change management controls, including authorization. The process documents should furthermore be reviewed on a regular basis (at least annually) to ensure that they remain relevant and current and reflect any change in methodology.
Response from Management	Finance and Regulatory agree with the recommendation and will prepare documentation to outline the shared service cost allocation process.
	Accountable Party: Daniel Smith Manager, Financial Planning & Analysis John Bonadie Director, Rates and Settlements
	Estimated implementation date: March 31, 2022

Observation #4 **Priority: Low**	**Manual aspects of cost allocation process**
	1) Due to reporting requirements, the Budgeting department developed an internal allocation calculation that is an extension to the cost allocation model. It combines the allocations calculated automatically for Energy Services, Energy Solutions and Power Services and apportions the total based on the headcount of each business unit. The business units are Metering, Submetering, Business Development, Alectra Energy Solutions (VP office) and Power Services. This is manually performed by pulling a report with headcount information and performing the calculations in Excel. 2) The execution of the cost allocation model is a partly manual process. The costs allocations are calculated using Cognos within the Budgeting module. However, the rest of the calculations are performed in Excel which includes the shared assets allocation. Manual calculations are susceptible to human error and are time consuming to execute.
Recommendation	We recommend that there should be an effort to further automate the calculation process of the cost allocations. This includes the incorporation of the shared assets allocation, and the calculation to the business units of Energy Services, Energy Solutions and Power Services.
Response from Management	Finance agrees with the recommendation. A third party has been hired to review the model in 2021 and will ensure this portion of internal allocations are documented and automated in Cognos/ TM1.
	Accountable Party: Daniel Smith Manager, Financial Planning & Analysis
	Estimated implementation date: March 31, 2022

4. Additional Items for Consideration

The points below were identified as a service to Management. They do not require a response and are provided to assist with building more effective and efficient processes.

1. Annual compliance certification not specific to the Affiliate Relationships Code

The compliance certificate to Alectra Utilities Corporation Board of Directors dated December 31, 2019 includes Schedules A and B respectively. Schedule A is a listing of legislations that compliance is being confirmed including the OEB Act. Schedule B lists any exceptions.

A checklist is prepared and signed by senior management to support the specific requirements of each legislation in Schedule A of the compliance certificate. For the section titled “Ontario Energy Board Compliance Issues”, it includes a checkbox that states "All OEB Codes, applicable to the business of the Corporation, have been complied with." There is no specific reference to the ARC and its requirements.

We recommend that Management develop a compliance checklist with the specific requirements of the ARC which is completed and signed annually by the Director, Regulatory Policy & Strategy and the Vice President, Regulatory Affairs.

2. *Management Fees Reconciliation-variances not investigated*

The Budgeting department prepares a monthly Management fees analysis which compares the standing entries calculated as per the budget to the actual monthly standing entries posted in the General Ledger by Accounting. Based on our sample, two allocations to affiliates had the same minimal variances recurring monthly, since January 2020. Internal Audit noted that no explanations were included in the variance analysis for the reconciliation.

We recommend that where differences are noted between the standing entries as per the budget and the monthly entries posted, these should be investigated with Accounting personnel and explanations noted in the reconciliation.

5. Acknowledgement of Review

Name and Title	Signature	Date
Daniel Smith Manager, Financial Planning & Analysis	Approved via Email	February 16, 2021
John Bonadie Director, Rates & Settlements	Approved via Email	February 17, 2021
Michael Lister Director, Regulatory Policy & Strategy	Approved via Email	February 17, 2021
Marc Villett VP, Finance	Approved via Email	February 17, 2021
Indy Butany-DeSouza VP, Regulatory Affairs	Approved via Email	February 16, 2021
John Basilio EVP, Chief Financial Officer	Approved via Email	February 16, 2021

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Fleet Services Review

Internal Audit Department

July 2021

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1. Overview (Executive Summary)

As part of Alectra's 2021 Internal Audit Plan, the Internal Audit team conducted a review of the Fleet Services processes for Alectra Inc. The main purpose of the Alectra fleet is to support and maintain Alectra system reliability, to ensure vehicle availability to support operational requirements and to reduce response time for the customers within the communities that Alectra serves.

The Alectra fleet consists of approximately 821 assets, including SUVs, sedans, pickup trucks, vans, dump trucks, bucket trucks, trailers, and other fleet equipment, which are categorized into four segments. There are 608 vehicles in total, within those segments:

- 371 light vehicles (<4500 kg) or 61%;
- 51 medium vehicles (4501- 15000 kg) or 8%;
- 186 heavy vehicles (>15000 kg) or 31%, and
- 213 equipment items. For the purposes of this audit review, we have excluded the equipment category, consisting of such items as trailers and generators. Refer to **Appendix B** for further visualizations of the Alectra fleet.

Our analysis of the fleet data shows the fleet to be aging and overall mileage on the vehicles to be relatively low. Currently, 64% or 389 of the 608 vehicles are over five years old and 32% of the fleet (193 of the 608 vehicles) are older than 10 years with an average vehicle age of 10 years for the entire fleet of vehicles. During FY ending December 2020, the total amount billed for repairs and maintenance was $4M ($3.87M - Alectra excluding Guelph Hydro and $0.13M for GH)

The purpose of this review was to provide senior management with assurance about the adequacy and effectiveness of internal control over the audit area of Fleet Management as well as assess departmental practices regarding fleet acquisitions, fleet operations, repairs and maintenance, and disposal of fleet vehicles. The audit approach was discussed with Management and testing was completed for the audit period January 1, 2020 to March 31, 2021, inclusive.

The objective of this internal audit review was to assess the design and operating effectiveness of the internal controls in place within the Fleet services business unit. The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of the audit review.

The scope of the review was as follows:

- To ensure that sufficient written procedures exist for Fleet;
- To ensure that all acquisitions were properly approved and incorporated into Fleet on a timely basis;
- To ensure that an accurate inventory of vehicles is maintained and updated as necessary;
- To determine, on a sample basis, if fleet vehicles exist;
- To assess effectiveness of fleet monitoring metrics within the Fleet Garage Management System (GMS);
- To ensure that effective systems are in place for planned, preventative and response maintenance for all fleet vehicles including reporting of incidents to management;
- To determine, on a sample basis, if work orders for auto parts and repairs followed established procurement and approval processes;
- To ensure that reassigned or disposed vehicles had the required documentation and support maintained for the sale, if applicable;
- To determine if low usage fleet vehicles were reassigned as needed to optimize operations;
- To ensure that adequate security controls are in place to prevent theft or vandalism of the fleet vehicles; and

- To verify employee access to the Fleet GMS and Global Positioning Satellite (GPS) applications are appropriately restricted and to determine if access was disabled timely.

The following areas were out of scope or de-scoped:

- Order and manage GPS vehicle units;
- Driver safety training for fleet operators;
- Vehicle fuel cards as well as fuel supply and monitoring;
- Vehicle licence plate renewals;
- Commercial vehicle operator's registration (CVOR);
- Alectra's vehicle 407 transponders ordering and management; and
- Fleet rental units was descoped as the risk was reassessed as low due to one temporary unit during the audit period.

The effectiveness of IT general controls, application controls and reporting integrity controls, within the GMS and GPS systems, was beyond the scope of this review but had a direct relationship to the effectiveness of the controls and integrity of the data we tested.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures.

Opportunities for improvement in operating control design and operating effectiveness, were identified in the specific areas listed below:

1. Underutilization of light vehicles (High)
2. Funding from Fleet capital budget for net new headcount (High)
3. Monitoring exceptions within the Fleet processes (Medium)
4. Accuracy of the fleet asset database (Medium)
5. Formalized processes and documentation (Medium)
6. User access to Fleet IT sub-systems (Medium)

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

The Fleet department successfully implemented the Garage Management System (GMS) in partnership with an external vendor, Automotive Resources International (ARI), during the fall of 2020. This was a significant undertaking, consolidating the legacy fleet sub-systems under one system. ARI's GMS is a module within the overarching ARI insights system that helps manage technicians, vehicle preventive maintenance schedules, and unscheduled repairs and parts inventories, while simultaneously consolidating all vendor-in/vendor-out data. ARI's GMS includes a comprehensive reporting suite, including reports on parts, labour, inventory, as well as productivity, and can track and consolidate all costs, whether incurred from a third-party maintenance provider or internal garage, to the vehicle or equipment level. Similarly, the GPS (GeoTab) system was consolidated from three into one as well as incorporating all Guelph fleet data. GPS provides an efficient and effective method to capture, analyze, store and manage real-time and other information that is required to improve vehicle utilization, customer communications, driver awareness, dispatching and route optimization, productivity and efficiency measures, vehicle condition and maintenance through telematics. These two systems form the backbone of vehicle management and tracking of the fleet, which enables Alectra to control and monitor activities for the entire fleet.

The Fleet department runs an effective preventative maintenance service which provides repair, preventative maintenance, and seasonal inspections to Alectra vehicles and equipment. Fleet services performs the majority of preventative maintenance internally, with the department staff performing this work. Specific preventative maintenance inspections and or repairs are also conducted by third party service providers.

Internal Audit was able to verify the physical existence of 100% of the 25 item sample of vehicles selected for testing based on photographic evidence submitted for review. We also noted a positive culture of collaboration and teamwork within Fleet services, especially during the current work from home mandate. A Fleet Co-ordinator had to submit supporting documentation for the preventative maintenance audit testing and due to working from home, was unable to submit copies of the documents. The Fleet Supervisor took it upon himself to collect and submit the scanned documentation that was needed, on the Fleet Co-ordinator's behalf.

Due to Covid-19, replacement vehicles were not disposed of and sent to auction as they usually would. They were instead retained for single occupancy use. Management prioritized employee safety above an economic decision to dispose of vehicles and offset the cost of the replacement vehicles, acquired in 2020 or 2021.

We wish to recognize the excellent rapport and exchange of views with all personnel involved with the audit. The depth of this review could not have been achieved without the support received. The efforts of all were greatly appreciated.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: High**	**Underutilization of light vehicles (Design Effectiveness)** Internal Audit has identified a lack of central monitoring of vehicle utilization, which resulted in a number of vehicles with low usage that are not currently being identified. Management has also not established criteria to determine what is considered a low usage vehicle. 1) Internal Audit researched best practices amongst Canadian municipalities and crown corporations, in order to set a benchmark of 5,000 kms per year as a threshold for low usage. We analyzed Alectra vehicle fleet utilization using kilometrage data tracked in the GMS/GPS system, as provided by the Fleet Manager. Within the scope of our audit, we did not undertake steps to physically confirm the accuracy of vehicle kilometrage. An analysis was performed on the consolidated fleet utilization reports using the available data from August 2020 to March 2021. We used light vehicles (sedans, SUVs, minivans, and pickup trucks) only and excluded vehicles brought into service during 2020 - 2021. Our analysis identified 96 light vehicles that had less than 5,000 kms during this period, representing 16% of the total fleet vehicles and 26% of total light vehicles. 2) During Q4 2019, Fleet management retained the services of Mercury Associates Inc., a 3rd party consultant, on the utilization of the fleet vehicles and a right sizing exercise was performed in order to determine the optimal number of fleet vehicles for Alectra. The main finding was that 15 vehicles were identified that could be eliminated from the Alectra fleet, resulting in an estimated cost savings of $1.2M over a five-year period. Management have not yet eliminated all of these recommended vehicles from the fleet. Every vehicle needs to be serviced periodically, regardless of usage, to keep them in a safe and reliable condition. Vehicles that are underutilized create a cost burden and take up maintenance resources that could be better used on other vehicles.
Recommendation	1) We recommend that Fleet Services implement a process to identify underutilized light and passenger vehicles. Management should also establish criteria to determine what is considered a low usage vehicle, based on similar vehicles, performing similar functions, that should be documented in the Fleet processes. 2) Fleet should generate and send a list of underutilized light vehicles to Business Units (BUs) periodically (bi-annually or annually). BUs should be required to comment on why they continue operating these vehicles. 3) Fleet should further develop a transition plan for underutilized vehicles, eventually reducing the fleet of underutilized vehicles. The above recommendation would also be in alignment with the Mercury

	report, which recommended reducing the number of underutilized vehicles from the fleet to optimize and right size the Alectra fleet.
Response from Management	Without a consolidated fleet GMS and a GPS, the process to identify underutilized vehicles has been very manual and time consuming. These systems have been implemented during 2020 and our team continues to build the databases, test the data for accuracy and test the systems capabilities. We expect that this process will take another year to be fully harmonized. Working with key stakeholders, in response to the Mercury report recommendations, Fleet Operations was able to identify 12 vehicles that could be reduced within five years. All of these vehicles have been removed, resulting in $500K capital savings. In 2019, meetings took place with Network Operations' key stakeholders, to start the development of a long-term vehicle reduction plan; but due to the COVID-19 Pandemic in 2020/2021, these discussions were placed on hold as the focus changed to ensuring vehicle availability to support single occupancy to reduce the risk of the virus from spreading. From 2018 to 2020, Fleet has reduced a total of 41 vehicles with a capital budget savings of an estimated $5.4M. Several vehicles were scheduled to go to auction in 2020 but were held back to maintain single occupancy. Fleet Operations is assessing the possibility to start sending the old vehicles to auction later in 2022. Vehicle utilization cannot be determined only on vehicle mileage. That is a key indicator, but there are other factors that need to be considered before recommendations can be made. Many of the light duty vehicles support specific roles that require vehicles at a moment's notice, some are pool vehicles at each site (10 sites) used by many inside workers as needed and some are required to support the Collective Agreement Terms. Furthermore, for significant vehicle reductions to take place, business units will need to streamline their processes, work structure and practices. Since 2019, we are experiencing additional vehicle requests from the business units to support their long-term plans. Fleet Operations has had a process and practice to determine vehicle utilization even though they are not fully formalized and documented. Having these processes and practices formally documented as a Procedure, will ensure consistency and compliance of the process, and serve as a tool to help reduce vehicle inventory. Fleet Operations will work closely with key stakeholders and reach out to our GMS and GPS service providers for advice on the Process improvements and development.
	Accountable Party: Joseph Almeida Director, Supply Chain Operations
	Estimated implementation date: Q4, 2023

Observation #2 **Priority: High**	**Funding from Fleet capital budget for net new headcount (Design Effectiveness)**
	During the audit and risk assessment process, the Vice President of Supply Chain, indicated a concern regarding budgeted headcount for additional net new positions, without the corresponding budget for vehicle purchase requirements. Based on discussions with Management, Internal Audit agrees that there is a gap in the process for further enhancement for new vehicles, in addition to replacements. This is an ongoing issue for Fleet because BUs are changing and so do their needs. Internal Audit corroborated this concern with the Capital Budgeting Manager as well as the Director of Total Rewards. The Fleet Manager further supplied Internal Audit with evidence of four vehicle request examples where the operational BUs requested additional capital ask for vehicles, for additional net new head count, or additional vehicles required for the requesting BUs' departmental needs. Funds for these purchases would utilize the Fleet budget, resulting in Fleet having to delay critical replacement of vehicles budgeted for, under the replacement plan.
Recommendation	We recommend that Fleet Management work with People Services to develop processes, such as a requirements checklist whenever a net new headcount is budgeted to be filled. This checklist should account for items that the new employee would require as a tool of trade, such as a vehicle and also specify any additional requirements such as vehicle type or specifications. Fleet should furthermore confirm any requests, with the Capital Planning Team, during the finalization of the budgeting process, to ensure that the budget accounts for any new vehicle requirements.
Response from Management	Annually, during the capital budget process, Fleet Operations approaches all key stakeholders to identify any new vehicle requests and changes to vehicle specifications and assists in the development of business cases. As well, prior to the 2020-2026 capital budget process roll out, Fleet Operations worked with the Capital Planning & Reporting team to add a slide to the roll out deck to remind leaders to reach out to fleet operations with any new vehicle requirements for the next 5 years. Fleet Operations reached out to People Services earlier this year to establish a process that would see Fleet Operations being notified of any new hires during the 5-year plan that require a vehicle. People Services is looking into options to support us. Fleet Operations will work with People Services to modify the current "on-boarding" checklist to include a question on new vehicle requirements and specifications.
	Accountable Party: Joseph Almeida: Director, Supply Chain Operations in collaboration with People Services
	Estimated implementation date: Q1, 2022

Observation #3 **Priority: Medium**	**Monitoring exceptions within the Fleet Processes (Design Effectiveness)**
	1) There has been little analysis of the information contained in GMS, the fleet management system. In that respect, Fleet Services is not taking full advantage of the services ARI offers to help with monitoring fleet operations. While telematics and GPS devices are installed on all vehicles in the Alectra fleet, the data provided by these devices is not currently being used optimally to monitor fleet exceptions (fleet vehicles overdue on maintenance, excessive idling, registration expiry, etc.) and trends (cost increases over period, fuel usage, kilometers travelled, etc.). The GMS application has specialized reports called "insights", that offer users of the GMS application the ability to monitor certain exceptions, allowing Management to investigate further. Refer to **Appendix C** for further examples from the Fleet GMS Insights dashboards. 2) The GMS system also has a report to identify vehicle repairs. The report provided to Internal Audit, however, only provided information at a high-level review, at quarterly intervals and not at an individual vehicle level. Effective administration of fleet management requires that there are processes in place to review vehicle practices, to ensure that they comply with policy requirements. Management oversight should ensure that practices and controls function appropriately, and that early and remedial action is taken where significant deficiencies are encountered or improvements are needed. The absence of monitoring increases the risk that Alectra is not using its fleet in the most optimal way.
Recommendation	We recommend that Fleet Management, in partnership with leaders of BUs which use vehicles, should implement an effective monitoring program, and develop guidelines and tools to assist operational managers in monitoring the fleet performance. Management should review which GMS reports would serve Alectra best and then decide which ones to monitor for any exceptions and trends. We recommend that Management implement best practices and monitor unusually high vehicle servicing costs for individual vehicles. These should be detected and investigated by the Fleet Manager through the GMS system.
Response from Management	Fleet's GMS was launched early fall 2020 and like any system implementation, it will take some time to familiarize and stabilize the new ways of working. As this is a robust fleet management system with many modules, the learning curve is steep, and requires an extensive change management component to its successful implementation. In order to harmonize the fleet processes and practices from 5 different fleet shop operations, we will work with the BUs and our fleet system provider, ARI, to ensure that the above recommendations are incorporated into our processes.

	Accountable Party: Joseph Almeida Director, Supply Chain Operations
	Estimated implementation date: Q2, 2022

Observation #4	Accuracy of the fleet asset database (Operating Effectiveness)
Priority: Medium	The Fleet department maintains an Excel master database listing of vehicle details, as well as the IT sub-systems (GMS/GPS) which contains similar data. Internal Audit relied on Fleet Supervisors to submit photographic evidence to conduct a physical verification of the fleet assets using the information contained within the Excel master database listing. There were discrepancies noted with regards to the Excel master database listing when compared to the physical vehicles in our sample as well as using analytics on the entire database. 1) The vehicle license plates for two vehicles in our sample of 25 (8%) did not match what was noted in the Excel master database listing. Internal Audit followed this up with Management who indicated that once a license plate becomes old, and starts to fade or peel, it needs to be replaced. The replacement license plate number was thus not appropriately updated on the Excel master database listing for these vehicles. One instance was also noted on the Excel master database listing where a heavy-duty vehicle license plate was not captured on the master database. 2) Unit “2-5920” was not reflected on the master listing at the time of the audit review. This was a new vehicle that was purchased during 2020 and when Internal Audit compared the new purchases between the Excel master database listing and the fixed asset register, it was not reflected on the master database listing. The Fleet clerk updated the listing to reflect this vehicle when it was pointed out by Internal Audit. 3) 20 instances were noted where no fuel type was indicated on the Excel master database listing (one heavy duty vehicle and 19 light duty vehicles). 4) One vehicle has a vehicle description in the master listing database that is not consistent with the actual vehicle inspected. The vehicle description per the master database listing is a "FORD F250 SRW" and the vehicle observed in our sample, was a “Dodge Ram”. 5) One vehicle is listed under the Central location at Mavis, but this vehicle has been relocated to the Nebo Road, Hamilton facility. The master listing was not updated to reflect this change in location. The use of a manual process such as an Excel document is susceptible to human error or omissions and poses limitations on effectively monitoring, capturing and updating the vehicle data. Additionally, the need to maintain two sources of master data may further result in inefficiencies and inconsistencies.

Recommendation	We recommend that the Fleet Manager reviews and correct any missing or incorrect data and periodically compare actual fleet data against the Excel master database listing whenever vehicles are in the service shop during their preventative maintenance or repairs. Ideally, Management should consider making the GMS the master document if all the required fields are included, and Fleet is more proficient with the use, updating and extraction of data from the GMS system. This would be the best practice to have an automated database or system in place. To this end, Fleet should work with the vendor, ARI, to enhance the GMS to consider any critical fields that would need to be captured. Having one source of the master data would also aid in efficiencies, going forward.
Response from Management	Fleet Operations will make the necessary steps to correct the data discrepancies identified during this audit. One of the decisions to implement GMS was to have a centralized master database, with real time data to support the three fleet operational regions and replace current Excel spread sheets that are dependent on manual entries by the Fleet Clerks. Fleet Operations has been working with ARI in the last months to build this database and test the data for accuracy. Dashboards and reports will also be created to monitor data. Fleet Operations will also work with ARI to conduct sample annual data audits to ensure accuracy of the data.
	Accountable Party: Joseph Almeida Director, Supply Chain Operations
	Estimated implementation date: Q1, 2022

Observation #5	Formalized processes and documentation (Design Effectiveness)
Priority: Medium	In discussions with Fleet Management and while performing the audit walkthrough of process design and implementation, certain critical processes were found to be informal and not clearly established or documented. The Fleet department is currently still in the process of familiarizing themselves with the capabilities and data of the GMS that was rolled out during the fall of 2020. Consequently, some of the processes have not yet been harmonized, formalized, and or documented. 1) A new vehicle's final acceptance at the time of delivery is not supported by a receiving document. At present, the payment for the vehicle is the only formal acceptance of the delivered vehicles. Currently, Fleet is performing a visual inspection. There would be no proof available that a vehicle had the proper inspections and to indicate agreement with vehicle specifications before payment is made. 2) There are currently no Alectra process documents for the updates of the Fleet Excel master database listing, how to run GMS reports, etc. 3) Detailed process documents were only prepared for the vehicle replacement and disposal process, which includes the various sub-processes with narratives and process flow diagrams. However, it was noted that the process documents were still in "Draft" status. The draft date, version and sign off sections were also not completed. The lack of formalized processes increases the risk of non-compliance to processes and procedures as well as a lack of guidance to staff members, and possibly, inconsistent practices. Without clear procedure documents in place, it may lead to knowledge of the processes being concentrated in specific individuals which pose a risk in the event of staff turnover and future training.
Recommendation	We recommend that Management should implement and formalize all major Fleet processes such as Fleet utilization and new vehicle acceptance. To facilitate this, all end-to-end Fleet processes should be mapped out and any gaps where a process has not been formally put in place or documented, should be identified. These processes should then be documented, formally implemented, and shared with BUs who have fleet vehicles. We further recommend that Management takes the necessary steps to finalize the process documents that are currently in draft with the appropriate sign-off by authorized personnel. While the process documents are in draft status, the word "DRAFT" should be written in a watermark, to distinguish from finalized documents. The process documents should be reviewed on a regular basis (at least annually) to ensure that they remain relevant and current and reflect any changes in current procedures.

Response from Management	As a result of the merger, Fleet Operations continued to manage most of its operations on legacy utilities practices and processes until such time that a GMS and ERP (JDE) have been implemented and stabilized. Processes and practice such as the vehicle replacement criteria, the replacement plan and the preventive maintenance criteria and schedule have been harmonized during the last couple of years. In 2019, Fleet Operations started developing a list of key processes and practices to be harmonized and formally documented. Plans were underway to start the process in 2020 but due to change in focus and efforts to support COVID-19 plans and the implementation of GPS and GMS, these efforts were placed on hold. We estimate it will take up to 2 years to document all planned processes and practices. Fleet Operations recognizes the need to document as many processes and practices as possible and will make every effort to do so in the future. This formalization is part of Fleet Operations continuous improvement plan and will be addressed. It is important to note that Alectra Fleet Operations is managing its fleet based on industry, regulations and manufacturer best practice and processes.
	Accountable Party: Joseph Almeida Director, Supply Chain Operations
	Estimated implementation date: Q2, 2023

Observation #6 Priority: Medium	**User access to Fleet IT sub-systems (Operating Effectiveness)**
	The GMS and GPS systems are key in the operations of the Fleet processes. Granting and resetting access is maintained by the Fleet Manager as well as the software vendors. Users of these systems have access to the GMS and GPS systems that is not interfaced to the Alectra active directory or single sign on. These applications are stand alone and accessed through a web/online portal. The user access listings of the GMS and GPS systems were compared to a current HR list with user profiles and reviewed for appropriate access. 1) The user profile for one former employee, who had retired from Alectra in November 2020, was found to be active on the GMS access listing. 2) Internal Audit also identified five users on the current GPS access listing, who had left Alectra's employment during the audit period. Three of these former employees still had an active status to the GPS system. Without removing access of terminated users in a timely manner, the account could be used for unauthorized access to data or unauthorized activities in IT sub-systems, compromising data security and or privacy.
Recommendation	We recommend that Management makes improvements regarding the termination of user profiles including: • Reviewing GMS and GPS access listing periodically (i.e. quarterly) to ensure that all user profiles are legitimate, and that access is appropriate. • Removal of former employees' profiles on a timely basis. As per leading practices of application user termination, account terminations should be performed within 5 business days for regular users and immediately for sensitive users (e.g. Senior Management, IT admin users) especially considering remote working conditions where single sign on applications are not used.
Response from Management	Fleet Operations has reached out to People Services to develop a process that would allow Fleet Operations to receive this data as soon as it can be made available. Fleet Operations will put a process in place, to notify ARI of any changes so that the GMS and GPS Systems can be updated accordingly.
	Accountable Party: Joseph Almeida Director, Supply Chain Operations
	Estimated implementation date: Q1, 2022

4. Additional Items for Consideration

The points below were identified as a service to management. They do not require a response and are provided to assist with building more effective and efficient processes.

1. *Vehicle license plates peeling.*

   Ontario license plates must be kept clean and free of obstruction by any device that prevents digits from being accurately photographed, under Section 13 (1) of the Highway Traffic Act. Internal Audit noted three vehicles out of a sample of 25 (12%) where the license plate started to peel or bubble, making identification of the plate number more difficult. Failure to have clear and visible license plates, could result in fines. Now that Service Ontario COVID-19 access restrictions have been reduced, we recommend that Management replace all vehicle license plates that are faded, peeled, or bubbled and where the plate number is no longer clearly visible.

2. *Intelex incident report and vehicle unit number.*

   Alectra uses an internal reporting tool to collect incidents of health and safety concerns, including accidents involving fleet vehicles, called Intelex. The Intelex report did not consistently indicate which vehicles were damaged in 13 instances of the 42 reviewed by Internal Audit on the report, despite there being a field to indicate the vehicle number or documenting the vehicle number in the description field of the incident. A failure to identify the vehicle number, could result in damage not being reported to Fleet for adequate repairs to vehicles. We recommend that the Intelex administrator should highlight this through user-training and also upon review of vehicle incidents, follow up and update any missing vehicle numbers.

5. Acknowledgement of Review

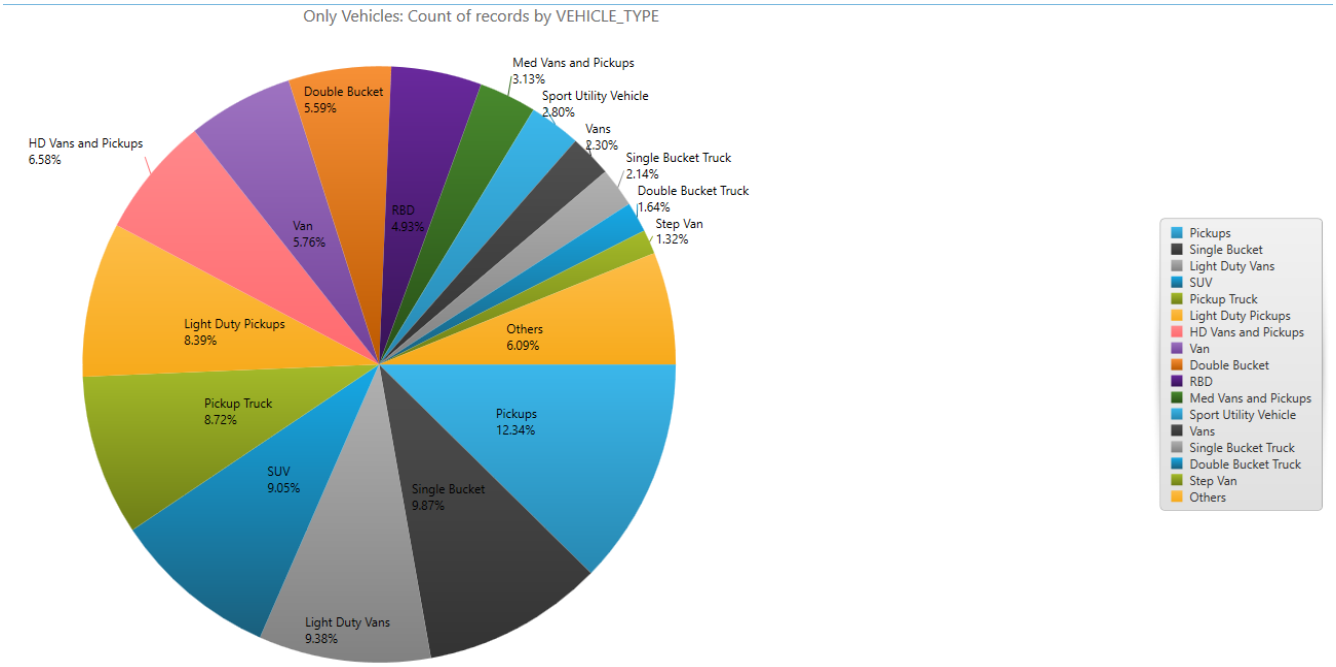
Name and Title	Signature	Date
Joseph Almeida Director, Supply Chain Operations	[redacted]	July 14th, 2021
James Macumber VP, Supply Chain	[redacted]	July 14th, 2021
Dennis Nolan EVP, General Counsel & Corporate Secretary	Approval by email	August 9, 2021

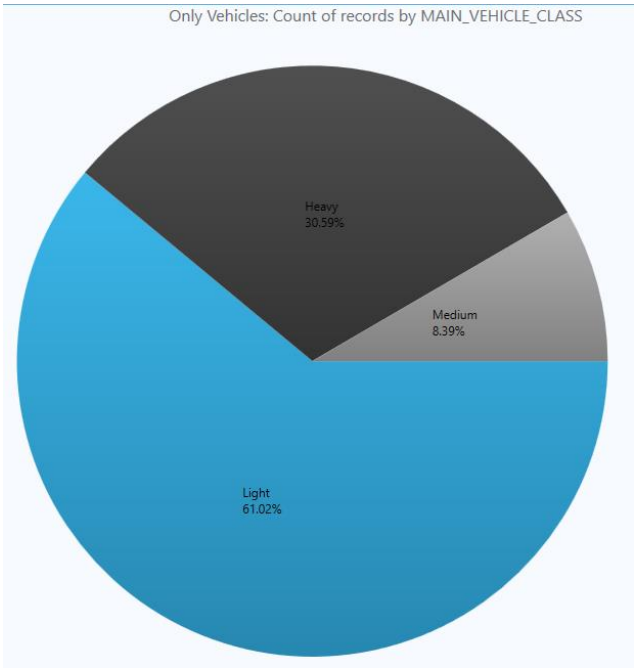
APPENDIX A: Risk Rating Key

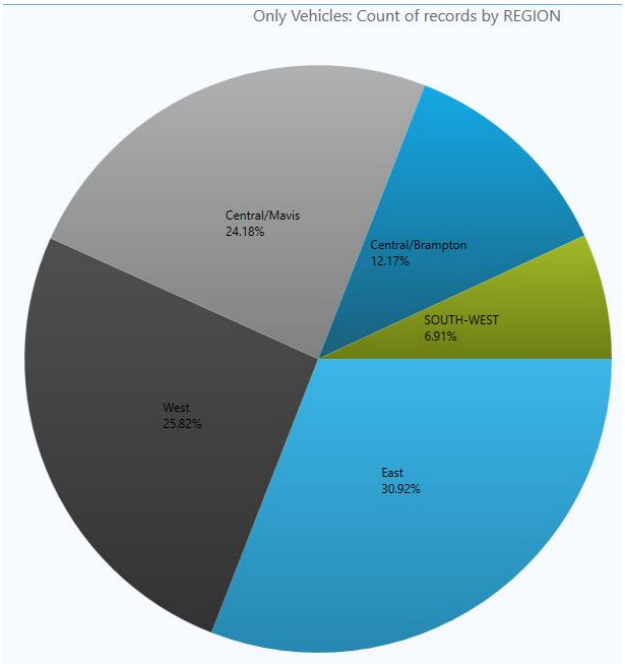
The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

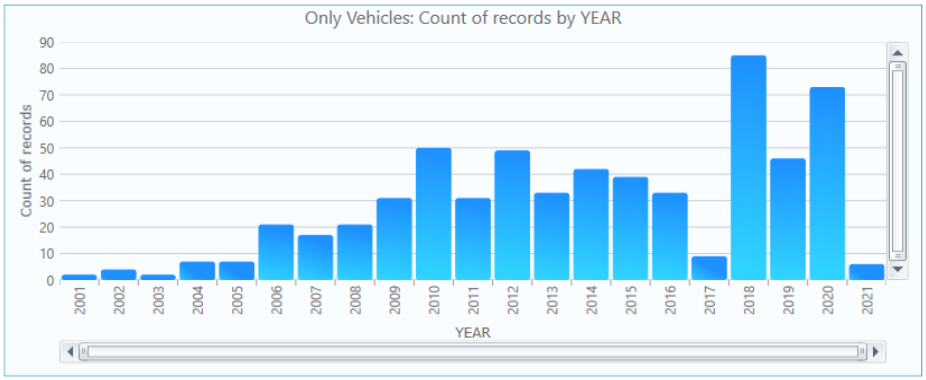
Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

APPENDIX B: DATA VISUALIZATIONS FOR FLEET









2021 represents new vehicles brought into service in 2021 as at May 2021

APPENDIX C: GMS INSIGHTS DASHBOARDS FOR FLEET

Inventory

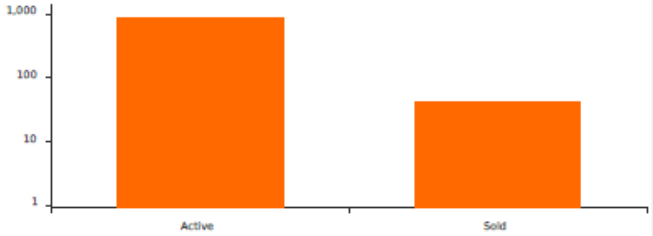
N/A — **Drivers Missing Emails** on active vehicles

26 — **Vehicles with Invalid VIN** on active vehicles

2 — **Data Changes** in the last 7 days

Inventory by ARI Status

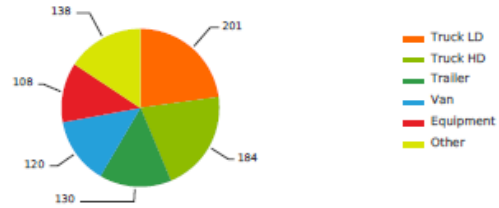
All Vehicles



15 — **VIN VehicleType/Asset Type Mismatch** on active vehicles

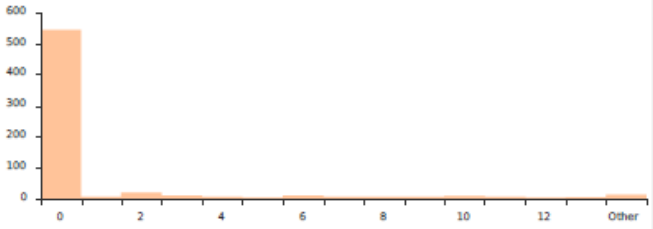
Inventory by Asset Type

Active Vehicles



Fleet Age Profile

Active Vehicles: Car, Bus, Van,...



Fuel

0 — **Fuel Cost and Transactions Exceptions** with $100 or more daily fuel or 3 or more transactions in last 7 day

0 — **Inactive Fuel Cards** in the last 30 days

0 — **Non Fuel Transactions** in the last 7 days

Fuel Consumption Trend

In thousands of Liters by quarter

No data available to display

0 — **Tank Capacity Violations** in the last 7 days

332 — **Vehicles Meeting Replacement Criteria** exceeding: 60 MIS, 120,000 miles(km), $5,000 in maintenance

Fuel Expenditure Trend

Cost in thousands by quarter

No data available to display

Fuel By Type

In the last 5 quarters In Liters

No data available to display

Maintenance

0 — **Vehicles Overdue** for preventive maintenance

0 — **Repairs Awaiting Authorization** as informational only

0 — **Vehicles Towed From Previous Day** in the last 7 days

Repairs by Vendor Type

By Vendor Type

Violations & Registration

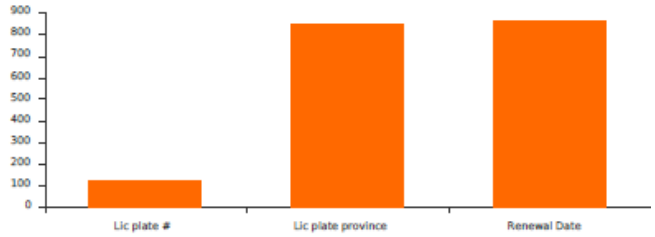
0 — **Vehicles with violations** of 1 or more in the last 7 days

0 — **Violation Notices Exceeding $100** in the last 7 days

0 — **Pending Regs for Replacement Vehicles** in 30 days for replacement vehicles

Missing Registration Information

Active Vehicles



Open License And Title

Letters Sent

No data available to display

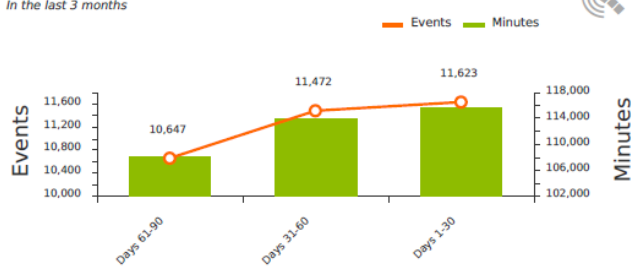
Fleet Services Review

Telematics Alerts: Review Daily

44 **Vehicle Not Reporting** in the last 7 day(s)	3 **Inactive Vehicles** All Inactive Vehicles - Telematics Device ID Populated	78 **Unauthorized Vehicle Use** event(s) in the last 7 days	0 **Possible Fuel Fraud** event(s) in the last 7 days	1,320 **Excessive Idling** event(s) for over 60 minutes in the last 7 days	26 **Vehicles with Invalid VIN** on active vehicles	1,277 **Engine Light On** in the last 30 days	297 **Low Battery Alert** event(s) in the last 30 days	272 **Telematics Diagnostic Codes** event(s) in the last 7 days
7,848 **Exceeding Posted Speed Limit** event(s) in the last 7 days	1,587 **Threshold Speeding** entry(s) over 80 KMPH for more than 5 minutes in the last 7 day(s)	0 **Vehicles Bookmarked** Standard with any color	2 **Data Changes** in the last 7 days			0 **Oil Life Remaining** less than 1 percent and Overdue for PM	4,752 **Driver Behavior** event(s) in the last 7 days	116 **VehicleDowntimeView** With Downtime More Than 24 Hours

Speeding

In the last 3 months



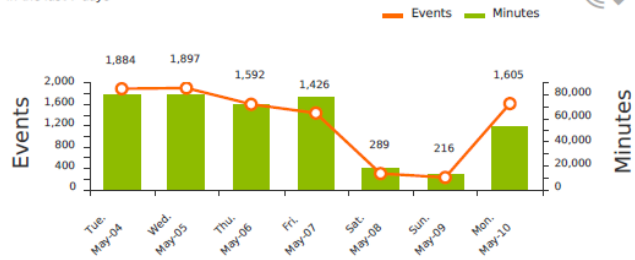
VehicleDowntimeView

Avg. downtime by make (Life of Vehicle)

Make	Avg Hours	Vehicles	Events	Hours
WESTER...	6,941	1	125	6,941
CHEVRO...	5,461	38	4,080	207,505
FREIGH...	5,011	138	17,481	691,570
NISSAN	5,008	8	908	40,064
HONDA	4,371	11	838	48,077

Idling

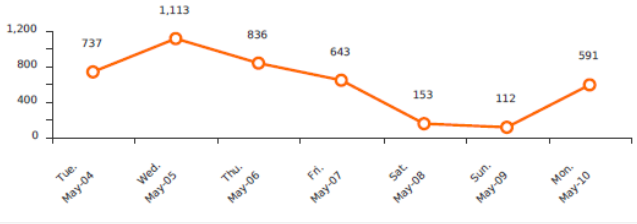
in the last 7 days



Vehicles per Program

Active Vehicles

Program	On Program	Not On Program
TMS	624	257
Credit Card	611	270
Telematics	571	310
Truck Service	256	625
Virtual Garage	6	875



VehicleDowntimeView

Vehicles by YTD maintenance downtime hours

Range	Vehicles	Events	Hours
< 8 hours	14	18	55.95
8-24 hours	16	42	303.26
24-48 hours	12	47	458.15
48-72 hours	18	127	1,130.82
> 72 hours	479	20,632	806,971.05
Total	**539**	**20,866**	**808,919**

Contact Centre Productivity and Efficiency

Internal Audit Department

May 2025

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1. Overview (Executive Summary)

As part of Alectra's 2025 Internal Audit Plan, the Internal Audit team conducted a review of the Contact Centre's productivity and efficiency. The purpose of the audit was to review the existing processes within the Contact Centre, to evaluate their effectiveness and efficiency, and to ensure compliance with OEB standards.

The audit review focused on the following objectives:

1. Evaluated the effectiveness of existing Customer Contact Knowledge Management and training;
2. Evaluated the governance of the Customer Relationship Management (CRM) and system data, including customer satisfaction surveys, escalations, and Quality Assurance (QA);
3. Reviewed the established KPIs and targets and determined areas requiring further improvement; and
4. Assessed compliance with the Ontario Energy Board (OEB) requirements.

The audit approach was discussed with Management and testing was completed for the audit scope period from January 1, 2024, to December 31, 2024, inclusive.

The scope of the review was as follows:

- Identified the risks associated with the Customer Contact procedures and evaluated the effectiveness of controls in place;
- Analyzed key performance indicators (KPI) results such as the average handling time, speed of answer, and average wait time to identify key patterns and trends;
- Performed benchmarking analysis to other LDCs of the customer focus performance metrics to ensure alignment with best practices in the utility sector; Assessed the customer feedback and satisfaction levels to identify opportunities for service enhancements;
- Examined the current QA and monitoring processes, focusing on call quality evaluation, QA Scoring, and feedback procedures.
- Reviewed the reliability and efficiency of the current technology and digital channels, such as the Alectra self service portal, and identified any frequent technical issues that hinder productivity;
- Reviewed the Interactive Voice Response (IVR) logs, reviewed call routing efficiency and identified bottlenecks;
- Analyzed resources utilization, whether they are appropriately scheduled and utilized, especially during peak call times;
- Reviewed the adherence to OEB requirements and Alectra's General Conditions of Service;
- Reviewed the existing reporting system and analyzed whether the targets are being achieved, and performed root cause analysis to identify gaps or areas that require improvement;
- Reviewed call logs and analyzed key patterns from call times, call durations, call abandonment rates, and identified common pain points from customer perspectives;
- Reviewed the service level agreements with Optima, the outsourced customer service provider, and conducted variance analysis on historical/ forecasted data versus actual results; and
- Evaluated the complaints resolution process and management of escalations.

The **out-of-scope** areas for this review were as follows:

- User Access Controls: Unauthorized system changes
- Data privacy and retention

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures, wherever possible.

The audit was conducted in conformance with professional standards established by the Institute of Internal Auditors. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

After a review of the process and supporting information, the opportunity for process improvements was noted. In general, there are existing controls in place to manage the Contact Centre processes. Opportunities for improvement in the design, implementation and operating effectiveness of controls, were identified in the specific areas, listed below:

1. **Non-compliance with the OEB service standards and insufficient oversight of third-parties KPIs (High):** Key performance indicators (KPIs) revealed that Alectra failed to meet the Ontario Energy Board's (OEB) service level target of 65% of calls to be answered within 30 seconds, due to various operational challenges faced by the Contact Centre. These included the IVR redesign, the new MyAlectra customer portal launch, an intensive approach to collections and reducing bad debt, Canada Post strike, and limited staffing due to budget restrictions. Internal Audit also identified a lack of performance oversight and KPIs monitoring over Alectra's third-party collection agency, CXAI.
2. **The escalation resolution process requires strengthening (High):** Escalations from July to December 2024 revealed weaknesses in Alectra's escalation resolution process. Over 50% of the escalations were not assigned until at least two business days after creation. Unresolved escalations over 90 days, were automatically closed in CC&B due to inaction. Additionally, the absence of escalation specific KPIs in Optima's service level agreement complicates timely resolution enforcement with the third-party contact centres.
3. **Inefficient After Call Work practices (ACW), elevated Average Handle Time (AHT), and high call Transfers impacting the Contact Centre performance (High)**: The 2024 key metrics identified that there is excessive usage of After Call Work (ACW) time, specifically by Alectra agents. Additionally, Average Handle Time (AHT) is identified as excessive, primarily due to extended ACW and frequent consultations with senior staff during calls.
4. **Inadequate monitoring of adherence to allocated schedules and idle time (High):** The review of schedule adherence revealed governance and monitoring gaps, with employees' schedules being changed, between 2 to 8 days after attendance. Additionally, Internal Audit found patterns of idle time and shrinkage among Alectra agents, with significant hours spent on team "huddles" and system downtime.
5. **IVR and website design require improvement (Medium):** A review of the IVR and Alectra's website, identified a need to enhance the customer experience and operational efficiency. The switchboard lacks specific options for common customer issues, leading to unnecessary usage and call transfers.
6. **Optimizing the Quality Assurance (QA) framework for improved oversight (Medium):** The Quality Assurance (QA) program lacked adequate coaching of Alectra agents. Despite the monthly review sessions, recurring performance weaknesses indicated that improvement opportunities with coaching exists. Third-parties demonstrated strong governance over their QA programs, promptly addressing performance issues and enforcing strict protocols.

7. **Enhancing Quality Assurance (QA) coverage and call selection to strengthen customer experience monitoring (Low):** The QA team currently reviews only 0.01% of total customer interactions due to resource constraints, limiting their ability to draw meaningful insights or identify call quality trends. The selection criteria focused on calls between 6 to 8 minutes, excluding longer, complex calls that might present higher risks and require deeper analysis.
8. **Need for enhanced customer experience integration and technology enablement (Low):** The JD Power benchmarking and OEB performance metrics indicated that the Contact Centre currently lacks the necessary technological infrastructure and a unified CRM, which impedes efficient management of omni-channel interactions and hinders the delivery of seamless customer experiences.
9. **Shifting from reactive Work Force Management (WFM) forecasting model to predictive Planning (Low):** Workforce Management forecasts from August 2024 to January 2025 revealed high variances in the collections call queue, especially in November and December. These variances were due to a drop in collections call volumes, creating surplus capacity that could have been used to support other high-volume queues.

It was recognized that the Contact Centre had areas with potential for improvement, particularly when assessed objectively by Internal Audit. The audit was initiated to identify opportunities to enhance productivity and efficiency, to gather actionable recommendations, and to develop a clear roadmap for achieving these process improvements. While many of these recommendations are expected to be implemented by the end of 2025, their completion is contingent on managing associated costs within the capital plan, and some are further dependent on technology enhancements scheduled for future years.

Overall assessment:

Requires Improvement

2. Good Client Practices

During the Contact Centre Productivity and Efficiency review, Internal Audit observed continuous efforts to improve the Contact Centre processes and customer experience. Key improvements included:

- The Contact Centre successfully transitioned from a manual to an automated online process for some move requests with further automation planned for Q3. This new self-serve functionality, accessible via the Alectra website, has reduced call volumes and improved customer experience;
- The Customer Service and GRE&T Centre developed an automated solution to extract and process meter readings received through voicemails, handling an average of 10 messages per day. This automation has freed up time for Customer Service Representatives (CSRs), allowing them to focus on higher value activities. Furthermore, both teams collaborated on analyzing high call volumes using AI and keyword analytics, which provided actionable insights to optimize the IVR system, reduce wait times, and enhance overall service level; and
- Despite limited staffing (two FTEs), the Quality Assurance team launched a robust QA program in 2024. The framework established, was designed to improve the quality of customer interactions and strengthen Alectra's brand reputation. In a short period, the team conducted detailed evaluations of all in-house agents as well as third-party providers, demonstrating a strong commitment to service excellence.
- Management has shown commendable initiative in adopting the corrective measures recommended by the internal audit review. This proactive approach not only exemplifies their commitment to continuous improvement but has also been instrumental in improving performance.

Refer to Section 4 – for Detailed Observations and Recommendations.

3. Acknowledgement of Review

Name and Title	Signature	Date
Jon Evangelista Director, Customer Service	[redacted]	July 19, 2025
Dianne Petrucci Director, Customer Service Excellence		July 18, 2025
Linas Medelis VP, Customer Service		July 21, 2025
James Douglas EVP, Customer Experience		July 21, 2025

4. Detailed Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: High**	**Non-compliance with OEB service standards and insufficient oversight of third-parties KPIs (Design Effectiveness)**
	During the review of the Contact Centre's performance for 2023 and 2024, Internal Audit noted that Alectra did not meet key performance targets mandated by the Ontario Energy Board (OEB). The following was noted: • The OEB requires that 65% of qualified incoming calls be answered within 30 seconds. Alectra achieved 53.4% in 2023 and 29.8% in 2024; • The OEB also mandates an abandoned call rate of 10% or less during regular business hours. In 2024, Alectra reported an abandoned call rate of 18.2%; and • Internally, Alectra has established a target of 82% for First Call Resolution (FCR). The reported FCR in 2024 was 77%. The shortfall in Alectra's performance is attributed to several operational challenges, including the impact of an Interactive Voice Response (IVR) redesign and the launch of the MyAlectra customer portal in April 2024, the collection campaign between May and November 2024, a Canada Post strike in December 2024, and reduced staffing at Optima, Alectra's outsourced Contact Centre services provider, due to budget constraints. Additionally, Alectra's implementation of the fully automated online move form, originally scheduled for 2024, was delayed. This form was intended to reduce the call volume of the move's queues supported by Optima. These disruptions notably impacted both Alectra and the third-party providers' performance. As a result, Optima's Service Level (SL) fluctuated significantly throughout the year, from a peak of 80% in February 2024 to a low of 8% in December 2024, as Optima had to reduce staff from 100 to 24 agents. Despite the budget restrictions, Optima had the second highest SL for the full year 2024 with a score of 46% and an FCR rate of 78%, which was similar to Alectra's overall result. Internal Audit also identified a lack of performance oversight for Alectra's third-party collection agency (CXAI). This agency handles all collections type of customer calls. Despite having a Balanced Scorecard outlined in their agreement, there was little evidence of KPI tracking or performance reporting. Based on the Internal Audit evaluation, CXAI ranked third in service levels for 2024, achieving 31.5%. Despite the current reporting gaps, it was noted that third-party providers have demonstrated performance levels that are comparable to, and in some cases exceeded, internal benchmarks. Failure to comply with OEB mandated service standards may lead to regulatory scrutiny, reputational damage, and diminished customer satisfaction. Additionally, insufficient oversight of third-party vendors creates a risk of underperformance, lack of accountability, and inability to take corrective actions in a timely manner.

Recommendation	It is recommended that Management implement the following actions, to improve the Contact Centre performance and oversight: i) Establish clear and measurable performance indicators at the individual agent level; ii) Regularly monitor established KPI metrics and implement structured performance improvement strategies, including targeted coaching, training programs, and engagement and reward initiatives. This approach will help motivate agents, recognize high performers, and drive overall service excellence. Performance targets should be clearly communicated to agents, and formal corrective action plans should be implemented in cases of persistent underperformance. iii) Strengthen the governance and oversight of third-party vendors specifically for CXAI, by implementing regular KPI tracking and reporting that is aligned with contractual obligations.
Response from Management	Management acknowledges the findings, and early performance improvements have been realized as of May 2025, such as: • increased service levels from 9% in January 2025 to 75% in May 2025, and • Reduced abandonment rate to 12%, down from 18.2% in 2024. Management confirms the following corrective actions have been initiated to address the Internal Audit recommendations: i) Agent-Level Performance Indicators: Implementation of Clear and measurable KPIs at the individual agent level, as well as a benchmarking and incentive framework. Development of KPIs, benchmarking, and incentive framework will be conducted throughout Q2 and Q3, 2025. ii) Structured KPI Monitoring and Performance Improvement: Regular KPI tracking, structured performance reviews, and standardized coaching protocols will be implemented. Training and support resources will be provided to ensure consistent application and timely corrective actions. Development of tools and processes to accomplish this will be conducted throughout Q2 and Q3, 2025. iii) Enhanced Third-Party Vendor Governance (CXAI): Contractually mandated KPI tracking and reporting frameworks will be formalized by incorporating them explicitly into vendor Services Agreement. Monthly and quarterly business reviews (MBRs/QBRs) are in place that review; projected SLAs based on budget, call volumes, transfer rate, AHT, QA scores, types of calls, staff absenteeism and attrition to ensure regular monitoring and accountability. Management confirms that the CXAI Agreement will formalize KPI tracking and business reviews for 2026 services. Management will continue monitoring and refining these measures to achieve full compliance with OEB standards by year-end 2026 and improve third-party performance oversight.
	Accountable Parties: Jon Evangelista Director, Customer Care
	Estimated implementation date: December 31, 2025.

Observation #2 **Priority: High**	**The escalation resolution process requires strengthening (Design Effectiveness)**
	As per Alectra's conditions of service, the Senior Customer Care representative or the Supervisor must contact the customer within two business days to address escalations. Internal Audit's review of escalation cases from July to December 2024 noted the following: • 53% of escalations (170 out of 318) were not assigned until two or more business days after their creation date; • 44 escalations of the 170 noted above, took more than 30 days to resolve. Alectra agents had an average resolution time of 10 days, while third-party agents averaged 12 days. Notably, the third-party service level agreement (SLA) of Optima does not include escalation specific KPIs, making it difficult to measure or enforce timely resolution expectations; and • Escalation cases that remained open and unresolved for more than 90 days were automatically closed by the CC&B system due to inaction. The Customer Care team explained that agents lose track of escalations during follow-ups with other departments. Currently, escalations that are in the system for more than 180 days are purged by CC&B. Delays in assigning and resolving escalations may lead to non-compliance with internal service standards, potential breaches of regulatory expectations, and deterioration in customer satisfaction and trust.
Recommendation	It is recommended that the Contact Centre develop weekly reports to monitor timely assignment and ensure regular tracking of escalations, especially those that are outside of the set parameters. Third-party SLAs should be updated to include clear KPIs regarding resolution timelines for escalations, with appropriate accountability measures.
Response from Management	Management acknowledges the findings related to delays in the escalation resolution process. To strengthen the escalation resolution process and ensure compliance with internal standards and regulatory expectations, Management is implementing the following actions: i) Automated Escalation Assignment and Tracking: By Q4, 2025, automated weekly reports will be developed and implemented to track timely assignments and escalate overdue cases. ii) Supervisor Accountability and Oversight: A dedicated supervisor will be assigned by mid-2025 to conduct weekly reviews of escalation reports and address overdue cases promptly. iii) Incorporation of Escalation KPIs into Third-Party SLAs: Management confirms Third-party SLAs will be revised and formalized for 2026 service and include clear, enforceable escalation KPIs and resolution timelines. Management confirms existing processes with Third-Party service providers to review the refinement of SLAs annually to enhance the language in the Services Agreement outlining SLA expectations and penalties for non-compliance.

	iv) Preventing Automatic System Closures: Automated reporting will be utilized and enhanced supervisor oversight to proactively address escalations at risk of automatic closure or purging. Management confirms that Supervisors have implemented a structured process to monitor and manage customer escalations through daily reporting of in-house "ToDo" items. By Q4 2025, a Change Request (CR) will be created to ensure that manually created "ToDos" do not auto-close, automated email reminders are triggered at 24, 48, and 72 hours, and alerts to notify agents and supervisors before any automated "ToDo" is closed. The CR will be prioritized by the CIS Steering Committee for development and implementation against several required CC&B system enhancements and compliance requirements.
	Accountable Parties: Jon Evangelista Director, Customer Care
	Estimated implementation date: Manual Implementation by December 31, 2025 Automation within CC&B dependent on system prioritization and capital resources.

Observation #3 **Priority: High**	**Inefficient After Call Work practices (ACW), elevated Average Handle Time (AHT), and high call Transfers impacting the Contact Centre performance (Operating Effectiveness)**
	Internal Audit reviewed the key Contact Centre metrics for 2024, including After Call Work (ACW), Average Handle Time (AHT), and call transfer rates, and noted the following: • <u>After Call Work (ACW):</u> Alectra agents spent more time on ACW (5–6 minutes) compared to Optima (approximately 2 minutes). A call log review from one week in December 2024 revealed 1,895 instances where ACW time exceeded talk time, including 79 cases where agents spent between 15 minutes to 1 hour in ACW. The Contact centre explained that the system setup has a one-hour ACW threshold to accommodate complex collection calls. However, there is no active control or monitoring to verify appropriate use of this time, nor the complexity of the calls. Additionally, the Quality Assurance (QA) testing highlighted multiple cases where Alectra ACW time was used for non-call related activities. In contrast, Optima enforces strict controls, requiring agents to limit ACW to 3 minutes, contributing to their lower ACW times. • <u>Average Handle Time (AHT):</u> The AHT currently averages 11 minutes. This is largely due to prolonged ACW and agents placing customers on hold to consult with senior staff. The current knowledge base available on the Alectra SharePoint site is reportedly time consuming and inefficient to navigate. • <u>Call transfers:</u> Call transfers accounted for 26% of total calls, with the highest rates observed in the Switchboard (63%), as it serves as call routing to the appropriate skills, followed by CXAI (20%) and Optima (12%). A review of one month's transfer logs revealed that many of these transfers resulted from skills-based routing, as they were frequently driven by ineffective IVR selections or customers' additional queries. Ineffective use of ACW, high AHT, and call transfer rates collectively reduce the Contact Centre's operational efficiency and customer experience. Excessive ACW leads to reduced agent productivity and increased labour costs. Prolonged AHT, driven by inefficient processes and delays in accessing information, further impacts service level targets and customer wait times. Additionally, high transfer rates and increased wait times can frustrate customers and reflect poorly on service quality.

Recommendation	It is recommended that the Contact Centre implements a robust monitoring framework for ACW, including system generated alerts for extended durations and mandatory justifications for ACW exceeding an efficient time threshold. This should ideally be reduced from the current one-hour limit and continue to refine to ensure ongoing efficiencies. Introducing real time reporting dashboards would enable Supervisors to proactively monitor and address excessive ACW usage. To further enhance efficiency, the Contact Centre should explore the adoption of AI powered tools such as "Agent Assist" or other AI tools to automatically capture call notes and generate summaries, reducing the need for manual data entry and minimizing ACW time. It is recommended that Management develop an AI Co-pilot chatbot to serve as an intelligent knowledge management resource. This tool would provide agents with instant, accurate responses to inquiries, thereby reducing reliance on senior representatives, and minimizing call AHT. Management should also conduct a comprehensive review of the IVR system and skills-based routing logic to identify opportunities for improvement and efficiency.
Response from Management	Management acknowledges the findings and recognizes the need for enhanced operational controls and proactive performance management. i) To address ACW inefficiencies, Management confirms it has reduced the ACW timer in its IVR from 60 minutes to 15 minutes, effective May 21, 2025. This adjustment aims to promptly identify inefficiencies and create coaching opportunities. Additionally, in 2025, Management is leveraging Five9 (telephony application) to develop an enhanced monitoring framework featuring system-generated alerts for prolonged ACW durations, mandatory justifications for cases exceeding 10 minutes, and real-time reporting dashboards to enable proactive oversight and timely interventions. ii) Regarding AHT, targeted refresher training sessions focused on collections, soft skills, and privacy compliance were delivered in Q1 2025 to improve agent efficiency and reduce overall handling times. Management is actively exploring AI-powered knowledge management solutions, including the implementation of Agent Assist tools. Management confirms that Agent Assist tools are currently being piloted using Five9 technology, which converts customer conversations into transcripts that CSRs can summarize and populate in CC&B. A full rollout of Agent Assist technology is planned for all in-house teams for 2026. iv) To mitigate high call transfer rates, Management has expanded third-party agent training to broaden their knowledge base, successfully achieving an initial 1% reduction in transfers with a targeted improvement of 5% by year-end. Additionally, IVR system enhancements were implemented in March 2025, with further refinements scheduled for May, aiming to optimize call routing accuracy and reduce unnecessary transfers, inclusive of the use of the Switchboard.
	Accountable Parties: Jon Evangelista Director Customer Care
	Estimated implementation date: December 31, 2026

Observation #4 **Priority: High**	**Inadequate monitoring of adherence to allocated schedules and idle time (Operating Effectiveness)**
	Internal Audit reviewed the individual adherence to allocated schedules and identified several governance and monitoring gaps. For September 2024, the schedules of 66 employees were modified between 2 to 8 days after attendance was recorded. The Workforce Management (WFM) specialist explained that most of these changes related to third-party agents, whose adherence is not tracked in-house. However, Internal Audit also found instances involving Alectra agents with retroactive schedule changes. For example, one schedule was updated to reflect system issues in Five 9 (telephony application), and CC&B, four days post-attendance, indicating a lack of timely oversight. Moreover, some of the changes were linked to compliance e-Learning training that were not scheduled in advance, which could have been planned more effectively to avoid operational disruption. In addition to schedule adherence concerns, Internal Audit noted idle time and shrinkage patterns for the Alectra agents as follows: • An average of 123 hours/month (17.6 workdays) was spent on team “huddles”. While these efforts were part of initiatives to improve employee engagement, they impacted agent availability. • On average, 180 hours/month (almost 26 workdays) were recorded as idle time due to system issues. Agents self report system downtime using “Not Ready” codes, which removes them from the queue, without affecting adherence to the individual schedules. This was introduced to reduce dependency on the WFM team, which has limited capacity (only one resource). However, this process lacks real time monitoring and control. The lack of governance over schedule adherence may lead to inaccurate performance metrics, unreliable forecasting, and reduced Contact Centre overall productivity. Additionally, excessive shrinkage time reduces agent availability, leading to longer customer wait times, missed service levels, and decreased satisfaction.
Recommendation	It is recommended that Management strengthen governance over schedule changes by introducing stricter controls, as retroactive modifications can compromise the accuracy of future forecasts, scheduling, shrinkage and idle time reporting. The Contact Centre should establish clear monitoring protocols for idle time and system-related downtime to prevent potential misuse. Additionally, the Contact Centre should consider recategorizing the "system issues" code to reflect its actual impact on adherence, since it currently removes agents from the queue without negatively affecting their metrics. It is recommended that Management review and optimize the time allocated to non-call activities such as “huddles” and employee engagement initiatives to strike an effective balance between employee communications, team morale, and operational efficiency.

Response from Management	Management acknowledges the findings and agrees that stronger governance and improved oversight are required to support operational effectiveness and workforce productivity. i) To address schedule adherence issues, Management confirms that in Q2, 2025, a formal Schedule Exception Process has been implemented for Supervisors and the Workforce Management (WFM) Specialist to reduce the volume and timing of retroactive updates. This process will standardize how schedule deviations are documented and approved. Additionally, by June 2025, baseline adherence scores will be established, excluding retroactive edits to better understand behavioral patterns and refine our current adherence target of 85%. ii) For idle time and system related downtime, real-time monitoring protocols and escalation procedures have been implemented to improve oversight. The “Not Ready – System Issues” code, which currently exempts agents from adherence metrics, was recategorized to ensure accurate representation of its operational impact and to prevent unintended misuse. iii) Regarding non-call activities, we recognize the need to balance engagement initiatives with staffing availability. Beginning June 2025, a more structured approach to team meetings will be implemented. A time utilization report is leveraged, providing improved visibility into how time is allocated and its impact on shrinkage. iv) The capabilities of the current WFM tool, which lacks key functionalities such as multi-layer event coding, real-time adherence monitoring, and detailed shrinkage reporting, is under review. Management will assess the ability to leverage third-party contact centre WFM technologies to support a wholistic view of all agents, both internal and external, as part of a planned RFP for third-party contact centre services to be conducted in 2025.
	Accountable Parties: Jon Evangelista Director Customer Care
	Estimated implementation date: December 31, 2025

Observation #5 **Priority: Medium**	**IVR and website design require improvement (Design Effectiveness)**
	Internal Audit reviewed the Interactive Voice Response (IVR) and the Alectra website and identified the following opportunities to improve customer experience and operational efficiency: The switchboard, which manually routes calls using one to two FTEs, is not reflected in performance KPIs as it only redirects calls without resolution. A keyword analysis performed by the GRE&T Centre for calls from May 1 -15, 2024 showed common terms like “account” (25%) and “login” (16.5%) are used by the customer when choosing the switchboard option, yet the IVR lacks specific menu options for these issues. The absence of available intuitive options for the customer’s selection contributes to unnecessary switchboard usage and call transfers. Additionally, within the collections, billing, and move menus, a vague submenu asking if customers have "questions about their account" may lead to misrouted calls due to its broad nature. This submenu should be restructured and moved to the main menu for clarity and proper routing. While a submenu currently exists for Hamilton water inquiries, establishing a dedicated main menu option for water would better distinguish it from electricity related services. This is particularly important as water services are outside of the OEB’s mandate and are being phased out by Alectra. Calls related to water should also be excluded from service level metrics. Within Alectra’s website, account login and bill payment functions are easy to find, however, the landing page is filled with numerous icons, links, and images. As a result, important information for customers may not stand out. Additionally, unlike Hydro One, which offers a real time chat option for customers or schedules a call back feature, which decrease’s customer wait times in queues, the Alectra website lacks a web chat or AI chatbot. Considering that digital channels now represent 35% of customer interactions (vs. 23% for calls in 2024, as reported by JD Power), expanding self-service options is increasingly essential. The current IVR structure and lack of self-service enhancements may lead to increased call transfers, longer handling times, and underutilized digital channels, reducing overall efficiency and customer satisfaction.
Recommendation	It is recommended that Management continue to enhance the IVR and website as part of an ongoing effort to align with evolving customer needs. As Alectra’s service offerings expands, more intuitive IVR options should be developed to reduce customer confusion and improve call routing. Customer Service should continue to analyze IVR call trends and leverage AI to replace or refine existing options with skill sets that better reflect customer inquiries. Additionally, it is recommended to remove water related inquiries from service level metrics and create a dedicated IVR menu option for water services. This change will not only improve service level accuracy but also support a smoother transition as the organization prepares to exit water

	billing, helping customers gradually differentiate between water and electricity queries. To improve operational efficiency, it is recommended that Management implements IVR-based customer authentication, such as requesting account numbers, PINs, or exploring AI driven voice recognition. This would streamline call handling, reduce talk time, and enable agents to assist more customers effectively. It is recommended that there be greater collaboration and alignment between the Corporate Communications and Customer Service teams in managing website updates, as the website serves as a key customer touchpoint. Integrating Customer Service feedback will ensure content reflects actual user needs. Additionally, leveraging AI driven tools such as virtual assistants or chat bots can help reduce queue wait times and improve the overall customer experience.
Response from Management	Management acknowledges the findings regarding the design effectiveness of Alectra's Interactive Voice Response system and website and will implement the following actions: i) IVR Enhancements: Management confirms that IVR routing has been updated to improve transfer rates and provide clearer menu options for common inquiries. Additionally, dedicated routing options have been added for water-related inquiries to further enhance accuracy and first-contact resolution. Water-related calls are excluded from service level metrics, however, call volumes are low as most customer inquiries bridge the total bill for both electricity and water services. ii) Website Improvements: The website's landing page will be streamlined to ensure key information stands out, addressing the cluttered layout identified in the audit. Alectra's website, layout and content is scheduled to be assessed in Q3 2025 with optimizations and changes prioritized for implementation over the 2025 / 2026 timeframe. Alignment between Customer Service and Corporate Communications will result in website modifications that will a streamline customer journey and promote consistent digital messaging. A new chatbot will launch in September 2025, providing guided support across high-volume journeys identified from AI analysis of over 30,000 customer calls. Additionally, a web chat feature is scheduled to be implemented by the end of Q4 to offer real-time assistance and reduce queue volumes. iii) Operational Efficiency Measures: To improve call handling, IVR-based customer authentication will be introduced, including account number validation and potential AI-driven voice verification through Five9 IVA technology in 2026.
	Accountable Parties: Jon Evangelista Director, Customer Care
	Estimated implementation date: December 31, 2025

Observation #6 **Priority: Medium**	**Optimizing the Quality Assurance (QA) framework for improved oversight (Operating Effectiveness)**
	Internal Audit reviewed the Quality Assurance (QA) program, that became effective as of March 2024 for the Alectra agents and January 2024 for the third-parties, and noted the following: • For Alectra agents: Among three Supervisors of the Contact Centre, two did not have any documented coaching notes or coaching dates, in some instances, and in one case, the coaching occurred five months after the related QA evaluation was conducted. Although Supervisors indicated that monthly one-on-one sessions take place to review QA results, recurring performance weaknesses observed in subsequent agent evaluations would indicate that coaching is not effectively driving improvement; and • Third parties demonstrate strong governance and responsiveness over their QA programs. For Optima, their 2024 QA score of 79% closely aligns with the Alectra score of 81% and reflects significant improvement. Third-party Supervisors promptly address performance issues through structured measures, including increased in-office presence for underperforming agents and strict protocols around critical areas like customer privacy and account verification violations that can lead to agent dismissal. While Alectra agents have stronger technical knowledge due to lower turnover, third-party agents tend to perform strongly in soft skills, adherence to their script, brand adoption, and promotional offerings to customers. A lack of coaching may hinder performance improvement, which increases the risk of diminished customer experience and missed opportunities for skill development.
Recommendation	It is recommended that Management strengthen the QA coaching framework for the Alectra agents by requiring mandatory documentation of steps taken during the coaching sessions and ensuring timely follow up after each evaluation. For agents with lower performance, tailored performance improvement plans should be developed and implemented promptly. Clear QA KPI targets should be established and communicated to all agents to ensure accountability and alignment with QA expectations. Additionally, Supervisors should regularly share their action plans for underperforming agents during monthly meetings with the QA team to enhance oversight and drive continuous, consistent improvement. Cross functional collaboration sessions can be held with Optima to share best practices.

Response from Management	Management acknowledges the findings regarding the Quality Assurance (QA) program for Alectra and third-party agents. To address this, a mandatory coaching documentation process has been implemented that includes capturing coaching notes and follow-up dates within a centralized system to ensure timely and trackable interventions. i) Performance improvement plans are now mandatory for agents demonstrating lower QA plans outline specific improvement areas and define actionable next scores. These steps for the agent. In parallel, in Q4 2025, QA KPI targets will be established and communicated to all agents to reinforce accountability and provide a clear understanding of expectations. ii) To enhance oversight, Supervisors are now presenting their action plans for underperforming agents during monthly meetings with the QA team. These sessions will help identify persistent issues and ensure follow-through on development actions. Monthly one-on-one coaching sessions between Supervisors and their teams will continue, supported by structured meeting cadences and a formalized coaching strategy. iii) For Q4 2025, an enhanced coaching template is being developed within Power BI, that consolidates historical call metrics, QA scores, soft skills performance, and written communication quality (e.g. customer email responses). This will allow Supervisors to better tailor coaching to individual agent profiles. iv) Beginning in Q4, 2025, to encourage continuous learning and process alignment, cross-functional collaboration sessions will be held with Optima to share best practices from their QA framework, including script adherence, brand alignment, and enforcement of privacy protocols.
	Accountable Parties: Jon Evangelista Director Customer Care
	Estimated implementation date: December 31, 2025

Observation #7 **Priority: Low**	**Enhancing Quality Assurance (QA) coverage and call selection to strengthen customer experience monitoring (Design Effectiveness)**
	Currently, the QA team reviews approximately 42 calls per month, about one per Alectra agent, out of a total call volume of 50,000. This represents only 0.01% of total customer interactions, which limits the ability to draw meaningful insights or identify trends in call quality. Resource constraints, with only two full time employees, hinder the ability to increase this sample size. The selection criteria for calls to review focuses solely on calls between 6 to 8 minutes to ensure broad agent coverage; however, this approach excludes longer, more complex calls that may present higher risks and require deeper analysis. Additionally, after call work (ACW) is no longer reviewed by the QA team, as of June 2024, due to staffing limitations, despite its importance in understanding the full scope of agent performance and customer service flow. Moreover, the QA process does not currently incorporate key performance indicators (KPIs) such as First Contact Resolution (FCR) or Customer Satisfaction (CSAT) results into its evaluation criteria. Calls associated with poor FCR or CSAT scores are often valuable for identifying coaching opportunities and process gaps. Lower coverage of calls through QA can lead to diminished service quality and missed opportunities for targeted coaching and process improvements.
Recommendation	It is recommended that Management enhance the QA program by leveraging speech analytics or AI to broaden the call review scope, with a focus on high-risk interactions such as long calls or those linked to low FCR or CSAT scores. Additionally, Management should evaluate options to increase QA capacity either through automation, reallocation of additional resources, or partial outsourcing, to ensure that a more representative and risk-based samples are consistently reviewed.
Response from Management	The QA team has engaged with the GRE&T Centre to explore options of leveraging AI to help support the QA program and create capacity to address a broader scope of QA and focus on higher risk interactions or areas of concern. The discovery of how to leverage AI is still in its infancy however, the team has gained some insights as to how it can be leveraged. In 2025, Management is looking to refine the opportunities to leverage AI for QA. A plan will be developed that will identify areas where AI can be leveraged vs where call review is required by a human. Budgets to support the AI call interactions will need to be assessed to determine how AI can be leveraged over the long-term. Preliminary investigations have indicated that certain skills or call interactions are difficult to assess via AI (i.e. empathy); however, call quality based on a binary outcome has a higher accuracy of identification for success. The deliverable for 2025 will include an assessment of how AI can be leveraged effectively with a timeline for implementation and adoption.

	The opportunity to assess the potential of adopting a third-party QA model/technology with the contact centre's RFP in 2025 will be leveraged. Resource augmentation for QA Specialists forms part of the 2027-2031 financial plan to help support expanding the QA function to all communication channels (voice, written, digital).
	Accountable Parties: Dianne Petrucci Director, Customer Service Excellence
	Estimated implementation date: December 31, 2026

Observation #8 **Priority: Low**	**Need for enhanced customer experience integration and technology enablement (Design Effectiveness)**
	Internal Audit reviewed the JD Power benchmarking and the OEB performance metrics across 55 utilities in Ontario and noted that while Alectra has improved its ranking from 11th to 9th place in 2024, there remains an opportunity for improvement in communication and customer experience management. Strengthening the organizational value proposition and corporate citizenship can be achieved by better showcasing Alectra's investments and achievements to customers, and promoting digital engagement, starting primarily with the Contact Centre, which serves as the front line of customer service. At present, the Contact Centre lacks the necessary technological infrastructure for efficient customer interaction management and a unified Customer Relationship Management (CRM), which hinders efficient management of omni-channel interactions. For instance, if a customer sends an email and calls the Contact Centre, agents may not have visibility across platforms, resulting in duplicated efforts, delayed responses, or fragmented service. These inefficiencies limit the ability to deliver seamless and consistent customer experiences. Without an integrated system for managing customer communications across channels, there is a higher risk of inefficiencies, missed or delayed responses, and inconsistent service. This can negatively affect customer satisfaction and hinder the ability to meet evolving regulatory and service expectations.
Recommendation	It is recommended that Management consider investing in a centralized CRM or omni-channel platform to unify customer interactions across calls, emails, and digital channels. This will enhance the Contact Centre's ability to manage inquiries efficiently and deliver a seamless and consistent customer experience. The CRM can be leveraged by the Contact Centre as a key communication channel to highlight organizational initiatives, customer successes, and digital transformation efforts to further strengthen customer engagement and trust.
Response from Management	Management recognizes that the introduction of a CRM system is imperative, not only to enhance delivery service to high-profile accounts but to all customers, enabling Alectra to centralize data, automate processes, and streamline customer interactions and operations. Alectra's diverse operational landscape and varied customer base necessitate a CRM solution that supports robust inter-departmental collaboration, crucial for strategic management and service improvement. Centralizing communications, including those interactions extending beyond the current capabilities of the Customer Information System (CIS), will include outage alerts, surveys, and program information, where comprehensive reach and efficiency can be achieved. Starting in 2027, and as part of the 2027-2031 financial plans, Alectra plans to implement a CRM system to enhance service delivery across all customer segments, addressing coordination and data management challenges while ensuring high-quality service and prompt resolution for every customer.

	Accountable Parties: Jon Evangelista Director Customer Care
	Estimated implementation date: Risk assumed, with expected implementation date of 2028

Observation #9 **Priority: Low**	**Shifting from reactive Work Force Management (WFM) forecasting model to predictive Planning (Design Effectiveness)**
	Internal Audit reviewed the WFM forecasts from August 2024 to January 2025 and noted significant variances in the collections call queue, particularly in November (50%) and December (35%). These variances resulted from a drop in collections call volumes, creating a surplus capacity for the collection queues. The extra capacity could have been reallocated to support other queues with high call volumes. However, due to the current reliance on historical data alone, the forecasting model lacks the ability to anticipate such changes and adapt proactively. Continued reliance on reactive planning reduces the organization's ability to manage workload fluctuations effectively, which would lead to limited adaptability in resource allocation, inefficiencies, and underutilized staff in certain queues.
Recommendation	It is recommended that Management explore the use of a predictive forecasting model that incorporates cross departmental inputs and AI driven analytics to anticipate future call volume trends. This enhanced model would enable real time adjustments in staffing and queue management, optimizing resource utilization and supporting improved service levels across all Contact Centre functions.
Response from Management	Management recognizes the need for a more agile and forward-looking approach to workforce planning, however, all queue skills are not transferable to all agents. Third party contact centre resources do have limitations in skills to manage more complex calls. To address this, Management is committed to transitioning from a reactive, historically driven forecasting model to a predictive planning framework that emphasizes design effectiveness. This enhanced model will be incorporated as follows: • Cross-departmental inputs to capture broader business drivers and campaign impacts. • AI-driven analytics to identify emerging trends and anticipate call volume fluctuations. • Scenario modeling to support dynamic resource allocation and real-time staffing adjustments. As part of the Contact Centre Services RFP process, Alectra is evaluating advanced forecasting tools, including Workforce Management (WFM) solutions that can be delivered as a service. This work is being carried out in collaboration with stakeholders across Operations, IT, and Data Analytics to ensure the selected solution supports predictive modelling, is scalable, and aligns with broader business objectives. Management confirms that in the interim, the following enhancements to current processes have been implemented: • Increased frequency of forecast reviews and variance analysis. • Established protocols for rapid reallocation of surplus capacity across queues. • Additional training to WFM teams on proactive planning techniques.

	Accountable Parties: Jon Evangelista Director Customer Care
	Estimated implementation date: December 31, 2025

5. Additional Item(s) for Consideration

The point(s) below were identified as a service to Management. They do not require a response and are provided to assist with building more effective and efficient processes.

1) WFM System limitations:

Five 9 reporting, the third-party vendor for IVR (Interactive Voice Response), does not capture changes made at the schedule level and does not allow for comparing agents' adherence to their designed shifts and breaks. To effectively monitor variations from the planned schedule and to keep track of productivity and any shrinkage or idle time, it is recommended to invest in a more advanced WFM system that has better reporting capabilities.

2) First Call Resolution improvements:

The percentage of FCR responses is based on the survey conducted after the call, which asks customers whether we addressed their needs with one call. Currently, this question is set as number three in the IVR order, and the response rate is very low (7%). We recommend changing the order of questions to make this the first question to encourage higher engagement from customers.

Appendix A:

Risk Rating Key

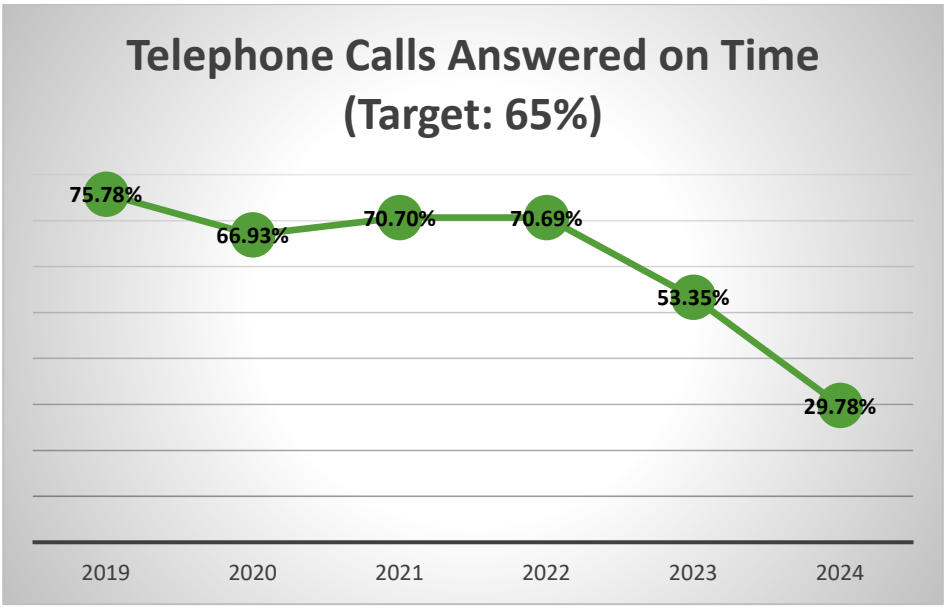
The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Appendix B:

Alectra Service Levels from 2019 to 2024:

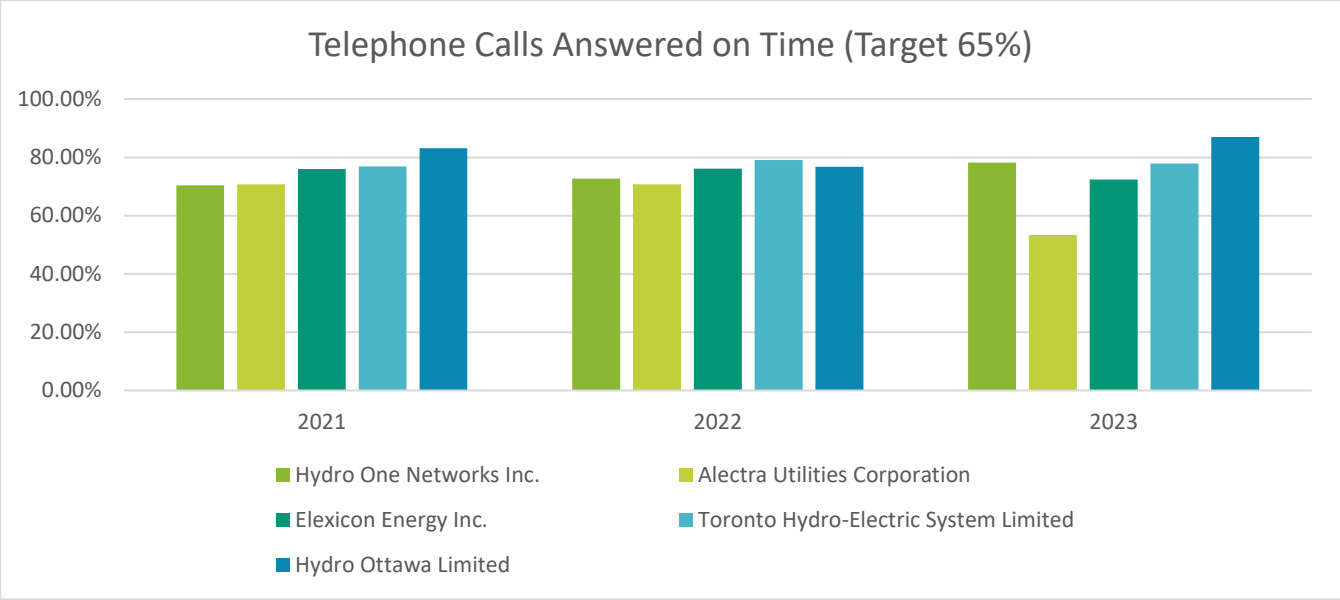
Performance Year	Telephone Calls Answered on Time (Target: 65%)
2019	75.78%
2020	66.93%
2021	70.70%
2022	70.69%
2023	53.35%
2024	29.78%



Appendix C:

Benchmark Analysis based on OEB Electricity utility performance assessment

Distributor	2021	2022	2023
Hydro One Networks Inc.	70.41%	72.65%	78.24%
Alectra Utilities Corporation	70.70%	70.69%	53.35%
Elexicon Energy Inc.	75.99%	76.06%	72.35%
Toronto Hydro-Electric System Limited	76.87%	79.08%	77.84%
Hydro Ottawa Limited	83.14%	76.81%	86.99%



*2024 performance metrics have not been published yet by the OEB

Sustained Synergies Review

Internal Audit Department

September 2019

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EXECUTIVE SUMMARY

As requested by the Integration Management Office (IMO) business unit, a review was recently completed of the sustained savings and transition costs for the period February 1, 2017 – June 30, 2019. The audit approach was discussed with management, and testing completed for the period.

The purpose of the review was to determine whether sustained synergy savings and transition costs, incurred from the inception of the Alectra merger in 2017, had been achieved and sustained over time, as reported at June 30, 2019.

The scope of the audit consisted of:

- Review detailed sustained synergy savings and transition costs contained in the business case;
- Understand the process used by the IMO team to track and report on sustained synergy savings and transition costs, including a review of any automated reports or spreadsheets used and ensuring consistency with past practices;
- Validate operating and capital sustained synergies and costs reported on a sample basis;
- Review assumptions made by the IMO to ensure they are reasonable and consistently applied and inline with past practices; and
- Validate that synergy results have been achieved in line with KPIs.

After a review of the process and supporting information, a net adjustment of $87K, unfavourable, would have to be made to the reported figures as at June 30, 2019.

Observation	**Amount in '000**
1. 1	(390)
2. 1	22
2. 2	11
2. 3	270
Total net adjustment required	**(87)**

Internal Audit has identified the following areas requiring further management attention:

1. Duplicated Synergy savings;
2. Discrepancies with reported values

In general, there continues to be controls in place to manage the synergy savings and transition costs reporting process. Many recommended courses of action from prior audits have already been put into place or are in the process of being implemented.

Overall assessment: **Effective, with opportunity for improvement**

1. Introduction

As requested by the Integration Management Office (IMO) business unit, a review was recently completed of the sustained savings and transition costs for the period February 1, 2017 – June 30, 2019. The audit approach was discussed with management, and testing completed for the period above. Internal Audit reviewed $14.2M of the reported $17M of net sustained synergy savings amount, representing 83.4% coverage.

2. Audit Objective

The purpose of the review was to determine whether sustained synergy savings and transition costs, incurred from the inception of the Alectra merger in 2017, had been achieved and sustained over time, as reported at June 30, 2019, and are valid based on supporting evidence.

Our audit methodology included:

- Interviews with management in identifying how the reported figures were generated;
- Review of the process involved;
- Review of source documents and backup on a sample basis; and
- Recalculation of material dollar amounts

3. Audit Scope

The scope of the review consisted of the following:

- Review detailed sustained synergy savings and transition costs contained in the business case;
- Understand the process used by the IMO team to track and report on sustained synergy savings and transition costs, including a review of any automated reports or spreadsheets used and ensuring consistency with past practices;
- Validate operating and capital sustained synergies and costs reported on a sample basis;
- Review assumptions made by the IMO to ensure they are reasonable and consistently applied and inline with past practices; and
- Validate that synergy results have been achieved in line with KPIs.

Legacy Guelph Hydro will be audited separately by Internal Audit later in the year and was thus excluded from this review.

4. Client Accomplishments

The IMO, People Services and Finance teams have been working well together to improve and streamline all facets of the reporting process and as a result, the reporting of monthly synergies and costs has greatly improved. This included rolling out new enhancements to the IMO headcount report that is shared with each business unit. On this report, they can see actual detailed headcount, position mapping and its link to the People Services' database.

The teams have implemented the recommendations from prior Internal Audit reviews and incorporated them into their processes. This included documenting processes and procedures to ensure that reporting would continue smoothly. It should also be noted that the IMO has validated all labour savings with the affected business units. The IMO team has been working collaboratively with the business since the merger, and it is encouraging that the target synergy savings have come to fruition, ahead of schedule. Internal Audit would like to thank the IMO for always ensuring that all requests for information were provided in a timely manner to ensure the audit process went smoothly.

5. Key Observations and Recommendations

The following observations and recommendations were identified:

<table>
<tr><td>Observation #1

Priority: Medium</td><td>Duplicated Synergy savings

During the review of detailed testing of backup support to the reported synergy savings/costs, Internal Audit noted that an item within the IT synergy savings was duplicated. The item related to backup services that would no longer be required for business continuity and disaster recovery services for the facility at Legacy HOBNI.

The synergy saving was reported by three separate BU’s as they each believed they should be accounting for the synergies. When the supporting backup was reviewed by Internal Audit, it was noted that it related to the same item. Only IT Security and Risk should account for the saving as that is where the original budget was raised.

Internal Audit could also not vouch the amount claimed per the synergy savings on the IT schedule to a cancellation order for that amount. The last invoice from the supplier of the service was used, and after being extrapolated for 12 months, was compared to the amount claimed.

<table><tr><th>BU/Line item</th><th>Amount</th></tr><tr><td>Enterprise Systems</td><td>380,000</td></tr><tr><td>IT security and Risk</td><td>389,000</td></tr><tr><td>Network Operations</td><td>252,000</td></tr><tr><td>TOTAL</td><td>1,021,000</td></tr><tr><td>Supported Amount</td><td>241,000</td></tr><tr><td>Adjustment required</td><td>780,000</td></tr></table>
The impact to the report as at June 2019 should thus be $390K (780K * 6/12) additional cost.</td></tr>
<tr><td>Recommendation</td><td>We recommend that the identified duplicated amounts be adjusted in the next reporting period. The duplicated line items should be removed, and the correct cancellation of the service value should be used in the synergy reporting.

Management should also institute a process whereby cross functional BU participation should be sought to avoid any duplication or changes in BU planning.</td></tr>
<tr><td>Response from Management</td><td>The IMO has removed the identified duplicated amounts and restated actuals per the recommendation of Internal Audit for the September reporting period. Furthermore, the IMO and IT teams have implemented corrective actions and enhancements to internal controls to ensure any future issues are identified and mitigated in advance.

The IMO has reviewed reported synergy results for prior years and can confirm no adverse impact to IMO corporate scorecard results as a result of this error.</td></tr>
</table>

	Accountable Party: Garen Boduryan, Director, Total Rewards & Analytics
	Estimated implementation date: September 30, 2019

<table>
<tr><td>Observation #2

Priority: Medium</td><td>Discrepancies with reported values

1) An item within the IT synergy cost should not have been claimed as there was a delay in the implementation date of the project. The item relates to the phone system implementation that will only be going live in 2020. These figures were not revised in the Synergy IT schedules by the Business Owner.

<table>
<tr><th>BU/Line item</th><th>Amount</th></tr>
<tr><td>Phone system consol cost</td><td>(269,456)</td></tr>
<tr><td>Phone system consol synergy</td><td>225,000</td></tr>
<tr><td>Net adjustment</td><td>(44,456)</td></tr>
</table>

The impact to the report as at June 2019 should thus be $22K (44.5K * 6/12) additional saving to be added back.

2) Internal Audit noted that the following items reviewed, out of the sample of 26 non-labour items, had discrepancies between the reported cost amounts and the backup support. In total, these amounted to $23K additional saving for 2019. The impact to the synergy report as at June 2019 would thus be $11K (23K * 6/12) additional savings

<table>
<tr><th>BU/Line item</th><th>Amount</th></tr>
<tr><td>Managed Services (over claimed)</td><td>(36,836)</td></tr>
<tr><td>Software licenses (under claimed)</td><td>7,333</td></tr>
<tr><td>Reduced 3rd Party Consulting Spend (under claimed)</td><td>6,690</td></tr>
<tr><td>TOTAL</td><td>(22,813)</td></tr>
</table>

3) Alectra obtained financing to purchase HOBNI from Hydro One in 2017. Financing was obtained for $675M, at a rate of 2.488%. The effective rate used in the synergies calculation was a notional interest rate of 2.8821 rounded to 2.9%. The synergy saving would thus be $54K more as at June 2019 (full year impact is $108K) if the percentage rate used, was not rounded. There would also be a decrease in cost for the interest for 2017 and 2018 amounting to $108K per annum, therefore $216K additional savings related to pre 2019.

4) There was also a formula error noted in one of the backup schedules. The total split between Capital and OM&A was incorrect, resulting in a small discrepancy but did not impact on the total net amount.</td></tr>
<tr><td>Recommendation</td><td>We recommend that the identified discrepancies be adjusted in the next reporting period.

We also recommend that IMO perform a reasonableness check on the supporting schedules that they report on to identify any casting or formula errors. This would, for example, have identified the issue in point number four above where the Capital amount exceeded the Net Synergies.</td></tr>
</table>

Response from Management	The IMO has adjusted the identified discrepancies for items 1 and 2 and restated actuals per the recommendation of Internal Audit for the September reporting period. The adjustment for item 3 will be applied in October reporting period.
	Accountable Party: Garen Boduryan, Director, Total Rewards & Analytics
	Estimated implementation date: September 30, 2019

6. Additional Items for Consideration

The points below were identified as a service to management. They do not require a response and are provided to assist with building more effective and efficient processes, as well as value added services.

1) Process documentation.

In a previous Synergy Internal Audit report, it was recommended that the Synergy process be documented. The IMO has documented the process for labour synergies, as that was the most complex aspect due to the number of employee movements. We recommend that the processes that will be beneficial for the Guelph Synergy reporting and the streamlined process for future reporting be documented.

2) Retention of supporting documentation.

When requesting supporting documentation from the business to support the reported values, it took some time to locate certain documents as there was no central location that retained this information. It was also confirmed that at the time of drafting the original business case, any subsequent changes that would impact on it were not consistently kept up to date and communicated to the IMO. We recommend, as good practice, that the IMO maintain their own folder of backup support going forward whenever changes are made to the synergy reporting figures, as they are obtained form the business.

7. Audit Assessment

Internal Audit has identified some recommendations for improvements within this process. The definitions for the ratings provided are located in Appendix A.

The audit has been rated as **"Effective, with opportunity for improvement"**

8. Acknowledgement of Review

Name and Title	Signature	Date
Garen Boduryan, Director, Total Rewards & Analytics	[redacted]	OCTOBER 29, 2019
Barb Gray, SVP, People and Safety		October 31, 2019

APPENDIX A: Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls); • Important issues are identified that could negatively impact the achievement of operational objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls); • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; • Issues identified are less significant but opportunities that could enhance operations exists; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Budgeting Review

Internal Audit Department

May 2021

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1. Overview (Executive Summary)

As part of Alectra's 2021 Internal Audit Plan, the Internal Audit team conducted a review of the budgeting process for Alectra Inc. The budgeting process refers to the annual preparation, review, and approval of Alectra Inc.'s consolidated financial 5-year plan, consisting of Alectra Utilities Corporation (AUC) and Alectra Energy Solutions (AES). The purpose of the review was to evaluate the overall process for planning and completing the budgeting process, to assess budgeting guidelines in place, compliance with and communication of same, and to assess the efficiency of the overall process. The audit approach was discussed with Management and testing was completed for the period January 1, 2020 to December 31, 2020, inclusive. This testing period correlates to the preparation timeframe for the 2021-2025 Alectra financial plan.

The objective of this internal audit review was to assess the design and operating effectiveness of the internal controls in place within the budgeting process. The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of audit.

The scope of the review was as follows:

- Confirm that comprehensive policies and procedures exist, are known and followed by staff.
- Confirm that the internal control process surrounding the development of the budget is adequate, including the revisions, review, and approval processes.
- Review of consolidation processes and IT subsystems utilized in creating the Alectra financial plan for 2021-2025.
- Review of inputs provided by Business Units and assess the timeliness in which the data was provided.
- Assess the accuracy of the automation efforts in Cognos TM1 (TM1).
- Review of assumptions used, such as interest rates, tax rates and inflation rates.
- Determine whether variance analyses are performed effectively.
- Review adherence to submission deadlines.
- Review any trend analysis performed in the preparation of the budget.
- Review of headcount information used and determine the accuracy of labour costs calculation; and
- Verify the employee access to TM1 is appropriately restricted and to determine if access was disabled in a timely manner.

The following area was out of scope:

- Capital budgeting process - to be included in a future audit plan.

The effectiveness of IT general controls, application controls and reporting integrity controls, within Cognos TM1, was beyond the scope of this review but has a direct relationship to the effectiveness of the controls and information we tested.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit.
- Interviews and inquiries with key management and operational staff as well as process walk-throughs.
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures, wherever possible.

The overall design of the budgeting process was found to be satisfactory in most areas. System controls within Cognos TM1 and Wdesk were found to enhance data accuracy and consistency during the

consolidation process. Opportunities for improvement in implementation and operating effectiveness of controls, were identified in the specific areas listed below:

1. Budget process delays (Medium
2. Headcount process delays (Medium)
3. Use of Asana tool in monitoring the budgeting process (Low)
4. Documentary evidence of budget approval (Low)
5. Cognos TM1 user termination not performed on a timely basis (Low)
6. Draft budget process documents (Low)

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

The Financial Planning & Analysis/Budgeting team has designed a very comprehensive budgeting process that resulted in the final output, the 2021-2025 Alectra financial plan. We acknowledge the collaborative efforts of all business unit stakeholders that provided their budget input to ensure the process was executed effectively.

The Financial Planning & Analysis team has developed numerous automated Cognos TM1 and Wdesk solutions to assist in the consolidation of the financial plan, such as the automated calculation of burdened labour, automated consolidation of labour inputs, standardized TM1 reports, and dashboard reconciliations. These innovations perform complex calculations, reducing the risk of manual errors and increasing efficiency during the planning process. As a result, the financial plan can be updated quickly and accurately, reducing the risk of late budget entries compromising the final deliverable of the five-year financial plan.

A key tool utilized by the Budgeting teams was a budget calendar/schedule that provides a detailed outline of all the tasks, timelines, and accountable parties for the budgeting process. This enabled progress monitoring of the process and accountability for outstanding deliverables. The monitoring efforts were enhanced using the web application Asana to track the progress of the financial plan. This software improves the ability to track the progress of deliverables, provides documentation that a process was completed, and significantly reduced the risk of overlooking key tasks.

Detailed draft process documents were also prepared that comprehensively capture the budgeting process and included the various sub-processes with narratives and process flow diagrams. The existence of process documents improves operational efficiency and consistency, aids in training and facilitates process improvement.

For inclusion in the 2021 budget, AES introduced five new business units which was seamlessly integrated into the existing budgeting process while still meeting all deliverables on time. Following the rigorous internal process guidelines and multiple stages of review AES had set for the budget process, the AES team was not only able to turn around the budgets by the required deadline but was able to do so with a high quality of financial information and level of transparency.

We also wish to recognize the excellent rapport and exchange of views with all personnel involved with the audit. The depth of this review could not have been achieved without the support received. The efforts of all were greatly appreciated.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: Medium**	**Budget process delays (Operating Effectiveness)**
	AUC The deadline for final Board approval of the 2021-2025 financial plan was met on November 26, 2020. During our review of adherence to due dates for tasks completion during the budgeting process, deviations were noted from the scheduled completion dates, as communicated within the Budget Team calendar. The main area in which delays were noted, was in relation to the completion and late submission of templates by business unit stakeholders. Delays were noted up to 20 days, where business unit stakeholders missed their deadline in completing the templates and consequently affected other business units submitting their deliverables on time. Non-compliance with stipulated deadlines during the budgeting process result in delays of submission of the financial plan, placing undue pressure to complete the budget in accordance with Board timelines.
Recommendation	We recommend that during the execution of the annual budgeting process the Budgeting team: • Implement hard submission deadlines for all business units. • Document and communicate in writing, key discussion points of the workshops held and receive agreement from the key stakeholders. We also recommend that the Budgeting team develops a materiality threshold, that is appropriate for the operating entity, in order to consider changes/edits after the deadlines and budget inputs have been received from the stakeholders. Additionally, any change requests following the submission deadlines should be accompanied by the approval from the respective Vice Presidents' (VP's).
Response from Management	Management agrees with the recommendation to implement hard deadlines for financial plan submissions. A schedule of all due dates with a list of accountable parties for each deliverable is already issued by the Financial Planning and Analysis team on an annual basis. Management agrees with the recommendation to consider materiality when reviewing changes/edits after the deadlines and to require VP approval for late budget submissions. After budget workshops are held the Financial Planning and Analysis team provides leaders with a budget reporting package which includes plan-over-plan analysis that documents and communicates in writing all changes to the plan. The Financial Planning and Analysis team obtains sign-off from each VP to confirm that they agree with their final OM&A budget submission.

	Accountable Party: Mike Malinowski Director, Financial Systems, Planning & Analysis
	Estimated implementation date: October 31, 2021

Observation #2 **Priority: Medium**	**Headcount process delays (Operating Effectiveness)** During the 2021-2025 Labour Budget Process, numerous headcount requests were submitted by the organization for consideration in the financial plan. Early on, the Executive Committee recognized that due to several extenuating factors, revised timelines and an extended assessment period would be required before a formal decision could be made on headcount, and agreed to delay submission of approved positions to FP&A until after EC approved the final plan. Throughout this process, Total Rewards and the FP&A team maintained open communication on the status of approvals and worked diligently to provide required inputs to support the budget process. Per the revised timelines, the Preliminary Labour Budget was provided to FP&A on June 30 and subsequent updates were provided in July and September. This impacted on the efficiency and the overall completion time as follows: • Burden changes to positions. • Changes in management fees and burden recovery requiring recalculation, reconciliation, and re-input into TM1. • The re-run of the budget proformas and, recoveries, and management fees in the financial plan. Deviation from stipulated deadlines during the budgeting process places undue pressure to complete the budget in accordance with Board timelines.
Recommendation	We recommend that regarding the provision and approval of the labour budget and headcount information, measures by Management to minimize delays may include: • The submission of the approved incremental labour budget positions at a date in advance of other deadlines. • Implementation of hard deadlines for all labour budget changes, after which changes to headcount would only be made with EC approval. • Total Rewards grouping adjustments to reduce the amount of rework performed by the Budgeting team. • Developing clear guidelines and criteria to aid in the decision-making process of the Budget Working Group for headcount changes as well as prioritization of critical positions.
Response from Management	Management agree with the recommendations and have implemented new measures for the 2022-2026 Financial Planning Process that better align headcount planning and approval activities with the overall timelines for the corporate planning process. These measures include an earlier start in the calendar year for headcount planning activities, contingency plans in the event of unforeseen events, review of materiality thresholds to limit subsequent plan updates and rework, and continued work to develop guidelines and decision criteria for the evaluation of critical positions.

	Accountable Party: Garen Boduryan Director, Total Rewards & Analytics
	Estimated implementation date: September 30, 2021

Observation #3 **Priority: Low**	**Use of Asana tool in monitoring the budgeting process (Design Effectiveness)**
	1) <u>AUC</u> The Asana tool is utilized by AUC to monitor the detailed tasks required in the budget calendar for the preparation of the financial plan. It was confirmed by Budgeting Management that some items are marked as complete, up to 2 weeks after the due date, due to additional review required by the budgeting team. This was despite the original deadline being met. The instances of late completion sign-offs may result in the assessment of efficiency of the budgeting process and adherence to deadlines being inaccurate. Additionally, this will cause the process to not be effectively monitored. 2) <u>AES</u> The Budget Workback Schedule, which is an Excel document used by the Finance team, effectively documents the steps in the budgeting process. However, it does not include completion sign-offs to properly track timeline adherence. AES also does not currently make use of the Asana tool used by AUC. The use of a manual process such as an Excel document is susceptible to human error and poses limitations on effectively monitoring and capturing the budget process. Additionally, the absence of one consistent tool to monitor the budgeting process may result in inefficiencies and the process being less cohesive.
Recommendation	We recommend that Management properly utilize the functionalities within the Asana tool and take additional steps to ensure that completion sign-offs reflected in Asana accurately reflects the actual completion dates within the budgeting process. We further recommend the use of the Asana tool by the AES Finance team to achieve greater efficiency and consistency in monitoring the timelines of the budget schedule in line with the current practices of AUC.
Response from Management	<u>Financial Planning and Analysis</u> Management will reassess Asana task tracking preferences to provide an improved documentation trail. <u>AES</u> AES Finance is currently working with IT to implement the Asana tool for use in the Budget process.
	Accountable Party: <u>Financial Planning and Analysis</u> Mike Malinowski Director, Financial Systems, Planning & Analysis <u>AES</u> Heather Clark Director, Financial Analysis & Investments

	Estimated implementation date: Financial Planning and Analysis October 31, 2021 AES Due to delays in receiving licenses this will be implemented for the 2023 Budget process.

Observation #4 **Priority: Low**	**Documentary evidence of budget approval (Design Effectiveness)**
	It was noted that the 2021-2025 financial plan goes through multiple levels of review prior to final approval. The review and approval process was found to be operating effectively and is accordance with the process outlined in the process documentation. However, regarding the final levels of approval from senior leadership, there is no formal tracking of approvals received and documented evidence of the approvals received. As a result, emails have to be relied on and in most instances, the approval was not expressly stated in emails by the approving senior leaders. The absence of evidence of approval may lead to a lack of accountability and uncertainty surrounding the dates on which approval was received by authorized personnel.
Recommendation	We recommend that Management develops an electronic sign off or written approval process for the different levels of review and approval and at the very least, approval for the final budget sign off. This is to facilitate efficient documentation of approvals and provide an audit trail that can be reviewed.
Response from Management	The Alectra Board of Directors is accountable for approving the annual financial plan. The approval of recommendations from Management to the AFRM and Board are documented in their minutes. Management will document that the CFO has reviewed the financial plan and approved for recommendation to the President & CEO.
	Accountable Party: Marc Villett VP, Finance
	Estimated implementation date: November 30, 2021

Observation #5 **Priority: Low**	**Cognos TM1 user termination not performed on a timely basis (Operating Effectiveness)**
	The user access for the Cognos TM1 application, which is key in the budget development process, was assessed for appropriate access by obtaining and comparing a current access list with user profiles to current employee records. Accounts were not all terminated in a timely manner. The user profiles for six former employees who had departed the company between early 2020 to March 2021, were found to be active. The risk is in part mitigated due to single sign on with Active Directory. Without removing access of terminated users in a timely manner, the account could be used for unauthorized access to data or unauthorized activities in Cognos TM1.
Recommendation	We recommend that Management makes improvements regarding the termination of user profiles including: • Reviewing Cognos TM1 access listing periodically (e.g. quarterly) to ensure that all user profiles are legitimate and access is appropriate. • Recommend the removal of former employees' profiles on a timely basis. As per leading practices of application user termination, account terminations should be performed within 5 business days for regular users and immediately for sensitive users (e.g. Senior Management, IT admin users) especially considering remote working conditions. • Raising tickets in Service Now to alert IT systems administrators persons who are no longer part of the business unit.
Response from Management	Management agrees with the recommendation to review the Cognos TM1 access on a periodic basis. The Finance Systems team already conducts this review on a quarterly basis. Financial Systems will receive an active directory listing from Information Technology to aid in this review. When employees leave the company, the IT department is notified through the offboarding process, and they proceed to disable the employee's active directory account. Since Cognos TM1 uses a single sign on that authenticates using the active directly logon, the former employee can no longer access Cognos TM1 once IT has disabled their active directory logon. Although the employee can no longer access Cognos TM1 once the active directory is disabled, their Cognos TM1 profile is not automatically removed. IT has confirmed Finance Systems will begin receiving a real-time active directory list to perform regular clean-up.
	Accountable Party: Mike Malinowski Director, Financial Systems, Planning & Analysis
	Estimated implementation date: October 31, 2021

Observation #6 **Priority: Low**	**Draft budget process documents (Operating Effectiveness)**
	Detailed process documents were prepared that capture the budgeting process comprehensively, including the various sub-processes with narratives and process flow diagrams. One of the appendices also effectively captures the budgeting process for AES, including Ring Fenced Solar and Solar Partnership. It was noted that all the process documents were still in Draft status (based on the heading), with draft dates ranging from December 2019 to May 2020. There was also no formal sign off from the process owner. The lack of finalized procedural documents increases the risk of non-compliance to processes and procedures.
Recommendation	We recommend that Management takes the necessary steps to finalize the procedure documents with the appropriate sign-off by authorized personnel. While the process documents are in draft status, the word “DRAFT” should be written in a watermark, to distinguish from finalized documents. The process documents should be reviewed on a regular basis (at least annually) to ensure that they remain relevant and current and reflect any changes in current procedures.
Response from Management	Management agrees that the budget process documents should be finalized and reviewed periodically.
	Accountable Party: Mike Malinowski Director, Financial Systems, Planning & Analysis
	Estimated implementation date: October 31, 2021

4. Acknowledgement of Review

Name and Title	Signature	Date
Mike Malinowski Director, Financial Systems, Planning & Analysis	Approved by email	August 9, 2021
Garen Boduryan Director, Total Rewards & Analytics	Approved by email	August 9, 2021
Heather Clark Director, Financial Analysis & Investments	Approved by email	August 9, 2021
Marc Villett VP, Finance	Approved by email	July 30, 2021
John Basilio EVP, Chief Financial Officer	Approved by email	August 9, 2021
Barb Gray SVP, People & Safety	Approved by email	August 9, 2021
John Matovich EVP, Energy Solutions & Services	Approved by email	August 9, 2021

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Capital vs Operating Cost Review

Internal Audit Department

May 2019

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EXECUTIVE SUMMARY

As part of Alectra's 2019 Internal Audit Plan, a review was completed of the Capital vs Operating costs. The purpose of the review was to ensure that adequate controls exist over costs incurred to ensure proper attribution to capitalization of costs or operational expenses. The audit approach was discussed with management and testing completed for the 2018 financial period.

The scope of the review consisted of the following:

- Review the policies and procedures in place to ensure controls and reasonableness of the Capital reporting function.
- Ensure legacy utilities applying current Alectra capitalization policy in a consistent manner.
- Ensure that the capital expenditures are valid and appropriate to capitalize and not operating expenses.
- Ensure that the time entries on work orders are coded to the correct capital expenditure projects.
- Ensure capitalized expenditure items have the appropriate supporting back up documentation.
- Assess the completeness of capital/operating expenses to ensure that everything that should have been capitalized was capitalized.
- Ensure selected repairs and maintenance expenses have the appropriate supporting back up documentation and are correctly attributable to the classification of expenses.

Guelph Hydro was excluded from detailed historical testing of purchase orders, work orders and time entries of employees during 2018 due to the effective date of merger being January 1, 2019.

After a review of the process and supporting information, the opportunity for process improvements was noted. In general, there are controls in place to manage the Capital and Operating cost processes, given that there continues to be four different ERP systems supporting the legacy utilities. Internal Audit has identified the following areas requiring further management attention.

1. Time billed to projects not captured or inconsistently captured.
2. No process owner to drive formalized procedure documents.
3. Inconsistency with set-up of capital work orders.

Overall assessment: **Effective, with opportunity for improvement**

1. Introduction

The purpose of the review was to ensure that adequate controls exist over costs incurred to ensure proper attribution to operational expenses or capitalization of costs. According to the financials within Alectra's Management Discussion and Analysis (MD&A) report as at December 2018, Capital Expenditures were $282M.

2. Audit Objective

As part of Alectra's 2019 Internal Audit Plan, a review was completed of the Capital vs Operating costs. The audit approach was discussed with management and testing completed for the 2018 financial period. As the audit covered a very broad scope, it was conducted at a high-level to identify areas of highest risk and Internal Audit drilled down deeper in those areas.

Our approach consisted of the following steps:

- Review of Capital Procedures;
- Interviews with management;
- Review the design and operating effectiveness of key controls; and
- Review of source documentation to determine validity and reasonability.

3. Audit Scope

The scope of the review consisted of the following:

- Review the policies and procedures in place to ensure controls and reasonableness of the Capital reporting function.
- Ensure legacy utilities applying current Alectra capitalization policy in a consistent manner.
- Ensure that the capital expenditures are valid and appropriate to capitalize and not operating expenses.
- Ensure that the time entries on work orders are coded to the correct capital expenditure projects.
- Ensure capitalized expenditure items have the appropriate supporting back up documentation.
- Assess the completeness of capital/operating expenses to ensure that everything that should have been capitalized was capitalized.
- Ensure selected repairs and maintenance expenses have the appropriate supporting back up documentation and are correctly attributable to the classification of expenses.

Guelph Hydro was excluded from detailed historical testing of purchase orders, work orders and time entries of employees during 2018 due to the effective date of merger being January 1, 2019.

4. Client Accomplishments

The Capital Reporting and Finance budgeting and reporting teams have been working diligently to ensure that the budgeting and reporting functions continue seamlessly post-merger. This has been done, without a final consolidated ERP system in place for Alectra.

It should be noted that the Capital Reporting team has been concentrating on Alectra's Distribution System Plan (DSP) submission to the OEB. Despite this, the information required by Internal Audit had been supplied promptly. Their efforts have been greatly appreciated and assisted with the review being conducted in an efficient and effective manner. Internal Audit would like to thank the members Capital and OM&A teams at each legacy utility that have assisted with this review.

5. Key Observations and Recommendations

Recommendations were developed through discussions with the Capital Reporting and Finance budgeting teams along with results from detailed testing.

Observation #1 **Priority: Medium**	**Time billed to projects not captured or inconsistently captured.**
	Internal Audit requested a detailed breakdown of the operating labour variance that was allocated to capital projects. There were instances identified where there was no budgeted capital dollars, yet actual capital spend was charged to Projects. Internal Audit analyzed three business units where capital costs were spent and booked and noted the following: 1. In 2018, two employees in Regulatory who were working 10-20% of their time on the Convergence CIS project were not billing their time towards the project, thus, their time was not capitalized to the project; 2. An employee within Legal at legacy PowerStream was also performing legal work of a capital nature for the other legacy utilities. The employee was not able to allocate timesheets for these legacy utilities as there are disparate legacy ERP systems for capturing timesheets. The employee would allocate that time to normal Operating, Maintenance and Administration (OM&A) spend, which under costs the capital projects they were working on. The costs were also not journalized to be included in Capital to the other legacy utilities, as the employee was unaware of the process to follow regarding journal re-allocations; 3. The IT Director at legacy Enersource was a dedicated resource and it was thought that 80% of their time would be for the CIS project, i.e. allocated towards capital expenditure. When this was reviewed by the Manager in IT at legacy PowerStream and Internal Audit, it was noted that this was not the case, indicating that not all of the 80% of the employee's actual time was billed towards the project. The actual time amounted to only 48%, as recorded in the system. 224 hours of billed and approved time for the IT Director was not captured for the CIS Convergence project; 4. There was inconsistency noted in the actual capturing/ allocation of time based on how staff recorded time on legacy systems; i.e. at legacy PowerStream staff were able to manually create a means to automatically allocate staff who were seconded to the project, on other systems staff had to manually enter time. At legacy Brampton if the time was not captured in the week it was worked then they lost out on the opportunity to report that time; 5. Within the IT group at legacy PowerStream, it was noted that the

	method of entering the project code in the timesheet was given as a reason by employees why they do not complete their timesheets accurately or consistently. The IT Manager sent out a QRC (Quick Reference Card) in the past to train users on how to input their time, but this has also proven to be unsuccessful.
Recommendation	We recommend that management emphasize the importance of capturing employees' time on projects. Project managers/ BU owners should download and review monthly cost reports out of the JDE Timekeeping system to identify that all employees that should be billing time on projects, are doing so and BU costs reflect accurately. There should be work orders created for billing employees' time on other legacy utilities' projects/ work orders. This issue may be mitigated once JDE is fully integrated and optimized. In the interim, a journal entry should be made to re-allocate employees' time between legacy utilities if they performed work on behalf of the other utilities. Management should be consistent in the way that project costs are captured and apply this approach across Alectra. Employees should ensure that they are using the correct work orders when submitting their timesheets and their Managers should be reviewing the accuracy before it is approved.
Response from Management	1. Management agrees that employees should use the correct work orders when submitting timesheets and that supervisors should review the accuracy of timesheets before they are approved. The training provided to all employees as part of the Project Keystone project launch has stated that employees who work on a project need to charge their time to the work order(s) for that project. Supervisors/Managers review and approve the timesheets of their employees on a weekly basis. Each BU owner receives an expense report on a monthly basis for their BU with details of actuals vs. budget and a written variance analysis for any expenses with a significant variance vs. budget. 2. With the launch of the new JDE system on July 2, 2019 all of Alectra will be using one ERP system. Therefore, there is no need to create additional work orders to charge time between legacy projects. All employees will have the ability to charge time directly to a project work order in JDE. 3. All dedicated resources to the Tier 1 IT projects (Project Keystone & Radiance) were asked to charge their time to those projects. As part of the Project Keystone project launch the training provided to employees has indicated that employees that work on a project need to charge their time to the work order(s) for that project.

	During the roll-out of the JD Edwards ERP system to legacy Guelph Hydro, the training will continue to reinforce the need for employees who work on the project to charge their time to the work order for that project.
	Accountable Parties: 1. All Alectra employees are accountable for entering their time correctly. 2. Management staff are accountable for reviewing the timesheets of their staff for accuracy. 3. Project Keystone staff provided training to employees on the timesheet process including the requirements to charge time to work orders and that Supervisors/Managers review and approve the timesheets of their employees on a weekly basis.
	Estimated implementation date: December 31, 2020

Observation #2 **Priority: Medium**	**No process owner to drive formalized procedure documents.** During our review of the Capital process, we noted the following: 1. There is no formalized procedural documentation in place for Alectra capitalization, Capital and OM&A reporting processes including the budgeting process. There was a legacy PowerStream procedural document for setting up capital work orders which made reference to the legacy practices and PowerStream's JDE ERP system; 2. The Alectra capitalization policy refers to a capitalization process document, but there was no such document made available for review. It is understood that this document will be drafted soon; and 3. There is also no central owner to co-ordinate the management of the documentation of the processes between capital and operating budgets and actual expenditure reporting. There is currently a division of responsibility between these two functions which creates a siloed approach.
Recommendation	We recommend that there be a uniform Alectra procedural document designed that covers all aspects of the capitalization processes as well as Capital and OM&A reporting. There should also be a central owner to co-ordinate the management of the process between capital and operating budgets, ensuring that the processes are properly mapped out, documented and implemented.
Response from Management	1. A draft Capitalization Procedure has been prepared and is currently under review. Finance has procedural documents that cover the OM&A reporting and budgeting processes. Detailed documentation of Alectra Utilities' capital budgeting process is provided in the 2020-2024 Alectra Utilities' Distribution System Plan. With the implementation of Alectra Utilities' common JD Edwards ERP system in July 2019, Network Services is finalizing the documentation of the capital reporting process. 2. Finance will appoint an employee to coordinate the documenting of the capital and operating processes. Network Services and Finance will work together to look for opportunities to improve coordination of the processes.
	Accountable Parties: 1. Finance will complete the capitalization procedure. **2.** Network services will finalize the process documentation related to capital reporting based on the new JD Edwards system.
	Estimated implementation date: December 31, 2020

Observation #3 **Priority: Medium**	**Inconsistency with set-up of capital work orders.** During our review of the set-up of the capital work orders, we noted the following: 1. Set-up of work orders are completed differently according to prior legacy practices. This could also be different among the business units within the legacy utilities e.g. work orders can be set up by different groups of people, or whoever is assigned access to create work orders; 2. There was a recent incident where a work order in legacy Enersource was assigned to an incorrect business unit and all the timesheets for that work order were attributed to the incorrect BU. There was no immediate process in place to identify this error and after it was brought to management's attention, it was corrected by re-allocating the time from the incorrect BU to the correct BU.
Recommendation	We recommend that Management assign responsibility for the set-up of capital work orders at a parent level, to one department within Alectra. This department should be responsible to ensure that the parent work orders are attributed to the correct BU's at all times.
Response from Management	1. With the implementation of a common JD Edwards ERP system in July 2019, Network Services will manage the set-up of capital work orders consistent with approved capital budgets. 2. As part of monthly capital reporting processes, the Capital Reporting department in Network Services will review capital expenditures with capital budget owners on a monthly basis to ensure work orders are mapped to appropriate parent level budgets.
	Accountable Party: 1. Capital Reporting will manage the set-up of parental capital budgets in JD Edwards. 2. Capital Reporting will track, report and oversee that work orders are mapped to the correct parent level budgets.
	Estimated implementation date: October 31, 2019

6. Additional Item for Consideration

The point below was identified as a service to management. It does not require a response and is provided to assist with building more effective and efficient processes.

Assets capitalized with small dollar values.
Internal Audit analyzed the Capital Reporting data file and noted that there were numerous small dollar items, appearing to be part of various work orders. Internal Audit noted that the Capitalization policy was not explicit on this. Each line item would have a work order attached to it, which creates certain inefficiencies e.g. creating a work order even for a small Dollar value item to be capitalized.
Best practice for many industries is to write off (expense) small dollar value items below a certain level, or put differently, only to capitalize items above a certain dollar value. The following table refers to the number and values for the individual capitalized items:

$ Threshold	Instances	Value
0-10	10	46.5
0-100	73	2,742
0-1000	313	122,860

7. Follow-Up Procedures

In general, controls are in place to manage the Capital and Operating reporting processes. These processes will be modified once the new ERP system is implemented in 2019.

8. Audit Assessment

Internal Audit has identified some recommendations for improvements within this process, most of which will carry forth once the new ERP system is in place. The definitions for the ratings provided are located in Appendix A.

The audit has been rated as **'*Effective with opportunity for improvement*.'**

9. Acknowledgement of Review

Name and Title	Signature	Date
Tracy Martin Manager, Capital Reporting	[redacted]	Jul 31/19
Igor Rusic Director, Budgeting		July 31/19
Tom Wasik Vice President, Asset Management		Aug 1, 2019
Marc Villett Vice President, Finance		Jul 30/2019

APPENDIX A: Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls); • Important issues are identified that could negatively impact the achievement of operational objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls); • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; • Issues identified are less significant but opportunities that could enhance operations exists; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Green Energy & Technology (GRE&T) Centre Review

(Executive Summary)

Internal Audit Department

January 2023

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1. Executive Summary

As part of Alectra's 2022 Internal Audit Plan, the Internal Audit team conducted a review of the Green Energy and Technology Centre (GRE&T Centre). The GRE&T Centre was established following the January 1, 2019 merger of Alectra Utilities Corporation (Alectra) and Guelph Hydro. The GRE&T Centre is a dedicated innovation hub that helps explore the possibilities for a bright new energy future. The three key strategic areas of focus are:

(i) Smart Cities-enabling e-Mobility,
(ii) Grid Innovation-supporting a sustainable grid and
(iii) Advanced Planning-harnessing emerging technologies.

The purpose of this review was as follows:

- To evaluate the overall process of monitoring and reporting the GRE&T Centre commitments stated in the Merger Participation Agreement between Alectra and Guelph Hydro to ensure they have been achieved;
- To determine whether projects' budgeting, operations and monitoring are being efficiently managed; and
- To assess compliance with project contracts, to determine whether financial targets and commitments to funding partners have been realized and appropriately monitored.

The audit approach was discussed with Management and testing was completed for the audit period July 1, 2021 to June 30, 2022, inclusive.

The objective of this internal audit review was to assess the design and operating effectiveness of the internal controls in place within the GRE&T Centre processes and to provide senior management with assurance about the adequacy and effectiveness of internal controls over the audit area. The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of the audit review.

The scope of the review was as follows:

- Review policies and procedures that exist and ensure that they are documented, known and followed by staff;
- Evaluate the overall process of monitoring and reporting the GRE&T Centre commitments stated in the Merger Participation Agreement between Alectra and Guelph Hydro to ensure they have been achieved;
- Confirm that there are signed project contracts in place between Alectra and external business partners that are current and valid;
- Determine whether there are adequate controls to ensure projects are effectively monitored regarding scheduling, status reporting and budget;
- Determine whether targets and commitments set by the external business partners have been achieved and are appropriately monitored;
- Ensure reporting to funding partners is performed on a timely basis;
- Confirm that cost identification methods are capturing all relevant internal costs and costs identified are in line with the respective project contract;
- Determine, on a sample basis, if invoices:
    - are adequately approved;
    - have adequate supporting documentation;
    - reflect eligible expenses in line with the project contract; and
    - are calculated accurately.

- Review the invoicing process and controls and assess compliance with the respective project contract; and
- Review a sample of project expenses incurred during the audit period and determine eligibility and accuracy in accordance with the project contract.

The following three projects were in scope:

- Independent Electricity System Operator (IESO) York Region Non-Wires Alternatives (NWA) project
- Power.House Hybrid
- Zero Emissions Vehicle Infrastructure Partnership (ZEVIP 1) project.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures, wherever possible.

Our audit was conducted in conformance with professional standards established by the Institute of Internal Auditors. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

We have identified the following improvements to the design effectiveness of the control:

1) Lack of process documentation (Priority: Medium)

There is no overarching standardized process document in place that cover the overall process of managing the GRE&T Centre's projects, encompassing planning, executing, managing of the projects and project closing. We recommend that an overarching, structural procedure document be developed by Management to reflect the key components of the GRE&T Centre processes and project management. The process documents should be reviewed on a regular basis (at least annually) to ensure that they remain relevant and current and reflect any change in methodology.

We have identified the following improvements to the operating effectiveness of existing controls:

2) Timely review of quarterly reporting to external business partners (Priority: Low)

Internal Audit reviewed the quarterly reporting to the external business partners for the projects in scope and performed comparisons to the respective agreements.

For the IESO Non-Wires Alternative (NWA) project, we noted that four of the five quarterly Milestone Report submissions (80%) reviewed, were emailed to the IESO more than 14 business days after the quarter ended, up to a maximum 24 days late. For the Power.House Hybrid project, the four quarterly progress reports submitted to Natural Resources Canada (NRCan) (the external business partner), were submitted later than their due dates. In addition, we also noted final quarterly financial reports were submitted to NRCan for recovery of funds, approximately three months past their due date. The late submission of progress reports and financial claims by Alectra results in delays to recover project costs already incurred by Alectra, impacting cashflow and non-compliance with contractual obligations.

We recommend that Management prepares the quarterly reports on a timely basis to ensure that all reviews are performed, and final submission is made to external business partners by the due dates stipulated in the agreements. We also recommend that where the submission of financial reports

results in Alectra recovering funds, that these reports are prepared expeditiously and submitted in advance of the due dates. For future project contracts with external business partners, we recommend that the stipulated timelines for report submissions factor in the due diligence process by the external business partner that may cause delays in final submission. Alternatively, the wording in future contracts should allow for flexibility to the adherence of the submission timelines.

3) Confidentiality & intellectual property obligations for employees (Priority: Low)

The GRE&T Centre has implemented a letter for employees to sign upon their resignation, that acknowledges their duty of confidentiality and intellectual property obligations. It was noted that one out of six employees that resigned during the audit period was not asked to sign the acknowledgment letter, it was confirmed that this was erroneously excluded from the offboarding process.

A former employee not abiding by their confidentiality and intellectual property obligations may lead to loss in potential revenues for Alectra. We recommend that Management collaborates with the People team to standardize the offboarding process to ensure that all employees sign the acknowledgment of their confidentiality and intellectual property obligations. We also recommend that for GRE&T Centre employees and all employees in business units that collaborate with the GRE&T Centre, the employment contract is amended to address intellectual property rights or a separate agreement with the employee to deal with intellectual property rights is executed.

Overall assessment: **Effective, with opportunity for improvement**

2. Management's Response

Response from Management	The GRE&T Centre team supports the recommendations by Internal Audit for the observations noted. The action items and their implementation dates to improve upon the audit observations are highlighted below: 1) The establishment of an overarching process document that summarizes project procedures for planning, executing, monitoring and closing projects (Q4, 2023). 2) The GRE&T Centre team will continue to prepare reports as promptly as possible and apply its most diligent efforts to meet timelines as outlined in contracts. The team will factor submission timelines in current and future project agreements (Q1, 2023). Best practices to effectively manage approval processes and meet timelines will be included in the procedure document to be developed (Q4, 2023). 3) The confidentiality letter should be formally incorporated into offboarding practices with the support of People Team (Q1 2023). Additionally, a refresher with all Managers/Leaders in the GRE&T Centre about the offboarding process and this letter will be scheduled (Q1, 2023).
	Accountable Parties: Neetika Sathe VP, GRE&T Centre
	Estimated implementation date: Q4, 2023

3. Acknowledgement of Review

Name and Title	Signature	Date
Neetika Sathe VP, GRE&T Centre	[redacted]	02/15/2023

Synergy Savings & Transitional Costs
2019 Year End Review

Internal Audit Department

January 2020

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1. Overview (Executive Summary)

As part of Internal Audit's ongoing review of synergy savings and transition costs, a review was recently completed of synergy savings and transitional costs. This was our 6th review of net synergy savings and the sustained synergy savings built on the net savings identified and audited for the period February 1, 2017 – December 31, 2019. The audit approach was discussed with management, and testing completed for the period above. Internal Audit reviewed $36.8M of the reported $41.8M net sustained synergy savings for reasonability and then selected specific sample items for detailed testing.

The scope of the review was as follows:

- Review detailed synergy savings and transition costs contained in the business case;
- Understand the process used by the IMO team to track and report on synergy savings and transition costs;
- Validate operating and capital sustained synergies and costs reported on a sample basis;
- Validate that synergy results have been achieved in line with KPIs;
- Review assumptions made by the IMO to ensure they are reasonable and consistently applied and in line with past practices; and
- Ensure proper classification of synergy savings and costs as to one-time achievement or sustained.

Legacy Guelph Hydro will be audited separately by Internal Audit and was thus excluded from this review.

The purpose of the review was to determine whether synergy savings and transition costs for 2019 were valid and substantiate, based on supporting evidence, those that had been achieved and sustained from the inception of the Alectra merger in 2017 through to December 31, 2019.

Our audit methodology included:

- Interviews with management in identifying how the reported figures were generated;
- Review of the process involved;
- Review of source documents and backup on a sample basis; and
- Recalculation of material dollar amounts

After a review of the process and supporting information, a net adjustment of $1.075M, unfavourable, was made to the net sustained synergy savings amount before the December 2019 year-end sustained synergies figures were finalized.

Observation	**Amount in '000**
1. 1.1	(229)
1. 1.2	271
1. 1.3	(20)
1. 2	(393)
1. 3	(75)
1. 4.1	25
1.4.2	(178)
2.	(476)
Total net adjustment required	**(1,075)**

	Sustained ('000)
Original IMO reported	42,059
Corrections from audit	(1,075)
Final IMO Net Sustained Synergies	**40,984**
Labour VSP (Obs.# 3.1), adj'd in Jan 2020	(37)
Final IMO unadjusted	**40,947**

Internal Audit has identified the following areas requiring further management attention:

1. Discrepancies with reported values;
2. Classification of sustained synergies; and
3. Discrepancies between severance liability worksheet and signed agreements.

In general, there continues to be controls in place to manage the synergy savings and transition costs reporting process. Many recommended courses of action from prior audits have already been put into place or are in the process of being implemented.

Overall assessment: **Effective, with opportunity for improvement**

2. Client Accomplishments

The IMO, People Services and Finance teams have been working well together to improve and streamline all facets of the reporting process and as a result, the reporting of monthly synergy savings and costs has greatly improved. This included rolling out new enhancements to the IMO headcount report that is shared with each business unit. On this report, they can see actual detailed headcount, position mapping and its link to the People Services' database.

The teams have implemented the recommendations from prior Internal Audit reviews and incorporated them into their processes. This included documenting processes and procedures to ensure that reporting would continue smoothly. It should also be noted that the IMO has validated all labour savings with the affected business units. The IMO team has been working collaboratively with the business since the merger, and it is encouraging that the target synergy savings have come to fruition, ahead of target. Internal Audit would like to thank the IMO for always ensuring that all requests for information were provided in a timely manner, and the collaborative approach to the adjustments that ensured the audit process went smoothly.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: Medium**	**Discrepancies with reported values**
	During the review of detailed testing of backup support to the reported synergy savings/costs, Internal Audit selected 37 line items from the sustained synergies total report and noted the following discrepancies: 1 – Supply Chain: 1.1.1) For the synergy saving related to volume discounts for inventory contract spend for one of our major suppliers, we noted the savings was overstated by $229K. There were two items included in the schedule amounting to $175K and $229K, both referencing the same savings. Internal Audit could only substantiate cost savings amounting to $175K. Supply Chain agreed that an error had been made during data extraction from the General Ledger; 1.1.2) For the synergy saving related to reduction in contractor costs, we noted that the reported values provided to the IMO by the Supply Chain group had been understated by $271K. When the requested backup was discussed with the Supply Chain group, it was noted that net additional negotiated savings had yielded more favourable results from our contracts with suppliers than previously reported; and 1.1.3) For the synergy saving related to price increase avoidance with suppliers, additional savings for 2018 had been identified by Supply Chain per the reported IMO schedule. We noted the savings differed to the backup support by $19.8K as received from Supply Chain. The amount claimed as a synergy saving was overstated by this amount as a result of including savings based on total invoice balances, inclusive of taxes. 2) One item in our review related to the synergy savings of not having to pay bonuses to legacy Enersource union staff. This was noted as a $1.9M saving in the synergy savings report. A backup schedule provided an average incentive payout for the 3 years before the merger (i.e. 2014, 2015, 2016) at a value of $1.52M. The adjustment resulted in a decrease to sustained savings in the amount of $393K. 3) One item in our review related to a late accrual posted after the synergy files had been sent to the IMO. The backup schedule requested, differed to the reported synergy, by $75K. Following our review and request for corresponding backup, the updated schedule was sent by the Finance department to the IMO in January 2020 and updated accordingly. 4) Two items in our review had discrepancies between the reported cost amounts and the backup support/schedules. The first related to an entry for “Reduced 3rd Party Consulting Spend (under claimed)” amounting to $24.8K as well as the Fleet department who budgeted, additional savings for heavy duty vehicle repairs, amounting to a difference of

	$178K (over claimed). The repairs for these vehicles did not materialize and was thus an avoided cost.
Recommendation	We recommended that the identified discrepancies be adjusted before the December 2019 Synergy reports were finalized. We further recommend that the IMO should include in their communication to the businesses a reminder to perform a thorough review of the supporting schedules provided and to ensure any changes following their initial submission be forwarded to the IMO as soon as possible.
Response from Management	The adjustments that Internal Audit found were built into the final December 2019 IMO results. The IMO will provide additional feedback from this audit to the business departments on requirements and providing supporting schedules.
	Accountable Party: Garen Boduryan Director, Total Rewards & Analytics
	Estimated implementation date: March 31, 2020

Observation #2 **Priority: Medium**	**Classification of sustained synergies** During the review of detailed testing of backup support to the reported synergy savings and transitional costs, Internal Audit noted that two items in our review out of the sample of 37 items, were incorrectly reported under “sustained synergies”. This was discovered when the reported synergy and the backup support was reviewed. The IMO schedule listed values in total, amounting to $476K as part of the “sustained” category, when in fact these items related to one-time savings according to the back up. The reclassification was confirmed with the respective business owner, Supply Chain.
Recommendation	We recommended that the IMO correct the classification of the items to reflect it as a one time saving, and not sustained as previously reported before the December Synergy reports were finalized.
Response from Management	The reclassification of the sustained savings to one-time savings has been completed.
	Accountable Party: Garen Boduryan Director, Total Rewards & Analytics
	Estimated implementation date: COMPLETED

Observation #3 **Priority: Low**	**Discrepancies between severance liability worksheet and signed agreements**
	During the review of detailed testing of the voluntary separation packages (VSP), we reviewed a sample of four terminations that became effective in the second half of 2019.The following discrepancies were noted: 1) One former executive had a clause in their VSP that indicated that they were entitled to a bonus payment of $84K per annum for two years since their COC (Change of Control) became effective. The November reported worksheet liability that Internal Audit reviewed only accounted for one year of bonus liability. This was corrected on the December 2019 worksheet. The December 2019 worksheet excluded the monthly car allowance for the former executive for a period of 24 months. The impact was $37K over the 24-period of the executive's severance pay. This amount was not corrected as the severance liability for the December 2019 year end close period had been concluded at the time of the synergy review, when this was identified by Internal Audit; and 2) There was a discrepancy in the final signed VSP agreement relating to the split between the lumpsum and salary continuance for one employee out of our sample of four VSPs selected for detailed testing. The net effect is nil. The starting date of when the continuation payments should start was also incorrect. This was corrected on the December 2019 worksheet. The incorrect amounts could be paid to an employee if the final worksheet schedule does not agree to the signed agreements. Payroll relies on the worksheet liability from People Services as support to continue/stop paying continuances to affected employees.
Recommendation	We recommend that the severance liability worksheet be corrected to reflect the accurate amounts and dates as identified.
Response from Management	The severance liability worksheet has been corrected.
	Accountable Party: Garen Boduryan Director, Total Rewards & Analytics
	Estimated implementation date: COMPLETED

4. Acknowledgement of Review

Name and Title	Signature	Date
Garen Boduryan, Director, Total Rewards & Analytics	[redacted]	Feb 19, 2020
Barb Gray, SVP, People and Safety		Feb 21/20.

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Economic Evaluation Model Review

Internal Audit Department

June 2020

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Appendix A: Risk Rating Key 14

1. Overview (Executive Summary)

As part of Alectra's 2020 Internal Audit Plan, the Internal Audit team conducted a review of the processes for the economic evaluations used at Alectra. The purpose of the audit was to ensure that the policies and processes governing the economic evaluation model (EEM) and the practices that are currently in place, meet management's objectives and are accurate and timely. In addition, the audit reviewed the efficiencies and timeliness of the processes in place to ensure that customer expectations and needs are met with regards to deposits. Developing a model, which could be used by all Alectra territories, was completed in early 2020. The harmonization of the model provides clarity to developers/customers throughout our service territory.

The audit approach was discussed with management and the testing focused on the new process adopted in 2020, with limited testing of the payments process for older contracts concluded in 2019. There were no payments processed under the new EEM process and as such older contracts which had concluded in 2019 were examined. All five of the legacy utilities were included in the review.

The review focused on the assessment of the design and implementation of existing internal controls over the process and the use of the EEM in Network Services for residential sub-divisions and industrial, commercial and institutional (ICI) type customers. The review also evaluated the operating effectiveness of the controls as at the date of the audit.

The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of audit, against generally accepted risks and controls for this area of the business.

The scope of the review was as follows:

- Review of the existing policy and procedure documents in place;
- Assumptions made within the EEM template are accurate and reasonable;
- Consistency of the logic and formulas used in the EEM as well as output reasonability;
- Alignment of the model to regulation (i.e. the distribution system code (DSC) of the OEB;
- Training and implementation of the new EEM;
- Segregation of duties between those responsible for developing the model and those responsible for operations/input and finance;
- Review of the reasonability of inputs to the model and their appropriateness on a sample basis for both subdivision-type projects and ICI's;
- Approval of the economic evaluations carried out on a sample basis;
- Finance coding and GL capturing of contracts;
- Account reconciliation and settlement process in Finance; and
- Developer expansion deposit refund process as well as rebates from unforecasted customers.

The following were out of scope:

- The legal aspects of the offer to connect contracts; and
- Operations completion of the projects.

Our audit methodology included:

- The examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with employees responsible for the performance of controls;
- Performance of sample tests; and
- Conducting analytical procedures of payments to existing customers wherever possible.

In general, the controls implemented by management over the economic evaluation process are executed appropriately but opportunity for improvement in implementation and operating effectiveness of controls was identified in the specific area listed below:

1. Delay in status change after energization and settlement of project (High);
2. Payment approval in JDE/TAP (High)
3. Economic evaluation model for Guelph (Medium);
4. Process documentation in Finance and Network Services (Medium);
5. Customer input information (Low); and
6. Approval of the economic evaluation model template and process manual (Low).

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

The Regulatory team has worked effectively with both Network Services and Finance to deliver a harmonized process for the EEM to be used at Alectra. This has been a meticulous process that involved many working group sessions, development and refinement to the model as well as feedback from stakeholders over a two-year period. This level of collaboration has culminated in the seamless implementation of the new process into Network Services and Finance processes. In conjunction with the new Model, Alectra's "offer to connect" (OTC) was also updated and harmonized for Alectra. Developer's summary of costs generated by the model, for Option A (Alectra undertakes the expansion) or Option B (client undertakes expansion) scenarios, are included in the Offer to Connect. As a result, the developer/customer is presented with firm costs to assist in selecting one of the two available options at the beginning of the OTC process.

The process manual, developed by Regulatory affairs, is vey detailed and offers an easy to follow guide to users of the model. The model is very robust, addressing the needs of both groups – Subdivisions and ICI, multiple rate zones, historic projects, etc. The model has also been enhanced to better capture condominium tower and industrial commercial type developments. Model enhancements were made to identify various unit and loading requirements to be captured. Several drop-down menus selections have been incorporated into the model to assist in selecting inputs. The model is nearly fully automated, making previously complex discounted cash flow, net present value and expansion deposit refund calculations effortless. This used to be a manual and tedious exercise in some of the rate zones in the past. In addition, the opportunity for any manual errors has been significantly eliminated.

Recent OEB amendments require that an economic evaluation be run for all expansion projects. The new Economic Evaluation Model includes provision for expansion work external to the residential subdivision. The model further provides five-year tracking of the expansion and calculates potential rebates to the originator of the expansion.

Despite the current lockdown due to the COVID-19 Pandemic, management supplied all the documentation needed for the audit, having to duplicate/scan files which were only available in hard-copy form, for submission and review by electronic means. We also wish to recognize the excellent rapport and exchange of views with all personnel involved with the audit. The depth of this review could not have been achieved without the support received. The efforts of all were greatly appreciated.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: High**	**Delay in status change after energization and settlement of project** In discussion with Finance Management, it was noted that the Cost Accountant downloads a report from JDE and manually reviews all the "status 91", which signifies "energized" projects. There is then co-ordination with the Operations group to confirm the cost of the development, and finalization of the projects for settlement, which is triggered in JDE under "status 98". The "as build" notes are updated in File Nexus to document when energization occurs, and an appropriate status change is made in JDE. When Internal Audit tested the timely settlement of customers after the transformers had been energized, it was noted that three payments in our sample of seven (43%), were settled later than eight months. The work orders for three instances in our sample had moved to "status 91" in October – November 2019, whilst the physical energization occurred months before. It was not clear if it was a result of the ERP implementation back log, where the status only changed several weeks later. There was also a legacy Horizon contract that was concluded in 2018, but payment to the customer occurred in December 2019, as part of a year end Finance review. Projects that are not moved to the energized status on a timely basis, could result in delays in project finalization and payment to customers, resulting in a loss of business confidence and reputational damage to Alectra.
Recommendation	We recommend that Network Services review the process to better understand the lag between physically energizing a transformer and changing the status code within JDE to "status 91", which would then commence the settlement of the project and produce the eventual customer payment, as required. Specific metrics and or KPI's could be built into the process to ensure that delays are appropriately identified, monitored and settlement occurs on a timely basis.
Response from Management	As part of Alectra's work management process (WMP), a set of standing agenda items is being established for the regular monthly production meetings that occur between Network Service, Network Operations and Supply Chain Management. One of those regular items going forward will be the review of all ICI and Subdivision projects. Particularly projects that have been energized by Lines will be noted and followed up to ensure their status within JDE is advanced to the appropriate status (91). The Program and Delivery Group (PDG) will have ownership of this task as they are the responsible party for moving the JDE status to 91. Furthermore, weekly reports will be generated by PDG and sent to Lines, which will identify any project deviations from their scheduled finished

	date. This will be another opportunity to flag projects that should be near completion and possibly ready to move to status 91. The process to trigger the JDE status movement to energization is dependent upon Lines updating PDG. PDG is responsible to track and monitor the progress of all projects. The above two items; weekly reporting and monthly production meetings, should resolve the observation findings.
	Accountable Party: Zoran Dabic Director, Program Delivery Network Operations
	Estimated implementation date: September 30, 2020

Observation #2 **Priority: High**	**Payment approval in JDE/TAP** The Cost Accountant prepares a refund request, with the proper backup and approvals from the Accounting and Network Services Supervisors. This is attached to the payment request for approval in TAP. When Internal Audit performed testing on the approval of the payments in TAP, it was noted that one payment, out of a sample of seven payments (14%) was not properly approved. The value of the payment was for $249K and should have been approved by the Vice President of Distribution Design, Network Services based on the approval matrix for Alectra. It was found the payment was only authorized by a Manager in Distribution Design, Network Services, who has an approval limit of $50K. There is a risk that customer payments can be made without obtaining proper approval in TAP.
Recommendation	We recommend that Management review the occurrence that led to this exceeded authorization limit and correct it. The automation programmed within JDE/TAP should always restrict approval of payments that exceed an employees' limit. Oversight of the process and preventing further processing of the refund is also a responsibility of the employees at different points of the process.
Response from Management	Management has reviewed the current approval matrix in TAP and has confirmed that the set up is correct based on the Corporate Authorization Policy and agrees that if the current matrix would have been the same at the time of payment, the payment should have gone to the VP for approval. Finance management reached out to IT to review the change logs and noticed that no changes were made to the matrix by comparing the offline versions maintained by IT. IT also reached out to the third party vendor to understand why this expense would have skipped the approval limits in place but due to the limitations of the tool on how long it keeps the audit trail for transactions was not able to retrieve the transaction logs since this transaction had occurred in Dec 2019. IT and Finance management tested the process using multiple examples but were not able to reproduce the issue as every expense was approved based on the appropriate approval hierarchy set up. Finance and IT management believe that this is an isolated occurrence and the automated controls in the system are working as designed. As an incremental control outside of the TAP system, Management will ensure that approval matrix is downloaded and saved offline each time that there is a change made to the matrix to ensure that each change is properly tracked. In addition, the snapshots of the approval matrix before and after are saved and reviewed each time there is a change to the Approval matrix.
	Accountable Party: Edlira Gjevori Director, Accounting
	Estimated implementation date: August 30, 2020

Observation #3 Priority: Medium	**Economic evaluation model for Guelph** Internal Audit selected a sample of projects which originated from the Guelph office, from 2020 to review compliance with the new Alectra process. The following inconsistencies practiced by the Guelph office were identified: 1) The EEM used is not the new Alectra process followed by the other legacy locations. Guelph is currently still using their legacy process and EEM; 2) There was no sign off page/tab for the approvals for all five of the Guelph projects reviewed by Internal Audit, to confirm approval. The sign off for the "offer to connect" (OTC) is consistently performed by a Supervisor responsible for residential subdivision developments. That same Supervisor inputs the data to run the legacy economic evaluation calculations. Segregation of duties issues are therefore a concern; 3) There is no process document/manual that was followed by the Guelph office; and 4) The Guelph office does not perform any economic evaluations for larger industrial type customers. This represents a change from the Alectra process, that covers both sub-division and ICI type of projects. Variations from the Alectra process could result in human error and inconsistent practices as well as inefficiencies if different processes are being followed.
Recommendation	We recommend that the Guelph office should be migrated to utilize the same process as Alectra does for both subdivision and ICI type projects. The EEM, customer input forms, calculations and sign off approvals should be consistent with the rest of Alectra.
Response from Management	The Alectra harmonized economic model (EM) is complete for both ICI and Subdivisions including Guelph. The harmonized model has been in use since late Q1 2020 except for Guelph. There have not been any ICI projects requiring the use of the harmonized EM in Guelph. The ICI process for utilizing the harmonized EM is in place and ready for use by Guelph staff should the need arise. Alectra will be able to utilize the harmonized EM for subdivision expansion by the end of August 2020. The EM model goes hand in hand with the overall Offer to Connect process. Subdivision has prepared a proposal with the PMO office which will introduce the harmonized Alectra EM and Offer to Connect in Guelph. In addition, the existing Guelph Master Service Agreement, with Drexler, is being reviewed with the intention of having Drexler complete Option A installations for Alectra consistent with the rest of Alectra (fixed price and supply of all materials).
	Accountable Party: Doug Fairchild: VP, Distribution Design
	Estimated implementation date: August 31, 2020

Observation #4 **Priority: Medium**	**Procedure documentation in Finance and Network Services** Although there is a process document/manual for the EEM that was documented by Regulatory, it does not provide any detail into the Network Services and Finance processes to be followed. These departments have specific critical functions to fulfill in this process and with the harmonization, has resulted in various process changes. Finance has not processed any of the new EEM contracts thus far, as none have become due to be paid out to customers. There is also a new requirement per the DSC to refund customers where new "unforecasted customers" expand on existing infrastructure during a five-year window period (collection horizon). There is currently no process in place in either Network Services or Finance of how to identify, process and issue this refund, which could lead to a lack of guidance to staff members, and possibly, inconsistent practices.
Recommendation	We recommend that a procedure document be drafted to detail the specific steps in Network Services and Finance, which would provide consistent guidance from the beginning to the end of the process. We further recommend that the procedure document incorporate how to deal with the unforecasted customers refunds due to existing customers during the collection horizon. This should be aligned to requirements of the DSC.
Response from Management	Regulatory, Finance and Network Services agree with the audit recommendations. Finance and Network Services will create a procedure document which will provide consistent guidance from the beginning to the end of the process as it relates to the financial steps involved for both ICI and Subdivision projects. Regulatory, Finance and Network Services will jointly develop a procedure for tracking unforecasted customer connections. Specifically, the purpose is for rebating those customers that had previously contributed towards a system expansion at hand. Tracking of expansion rebates occurs over a 5-year period. Regulatory has already provided training to Network Services on how to use the economic model. This occurred in Q4 of 2019.
	Accountable Parties: Doug Fairchild: VP, Distribution Design Edlira Gjevori: Director, Accounting Michael Lister: Director, Regulatory Policy & Strategy
	Estimated implementation date: End of Q1 2021

Observation #5 **Priority: Low**	**Customer input information** When a new customer's EEM is being completed, certain customer information and load requirements are provided by the customer. There is an application/CCRA form that is used to capture this detail. During the review, Internal Audit noted the following inconsistencies: 1) Four out of the sample of 20 Projects (20%) that were reviewed for the four former legacy utilities did not have the customer load information documentation available for our review. These were either not completed and was captured from the developer's drawings only or there was only a hard copy that was not scanned into the file for record keeping. These were all from the residential developer customers. Errors or discrepancies in calculations from the customer information could be made if this information is not included in the files and form part of managements' review. 2) The document used to capture the customer information as part of the input for the evaluation, such as customer details, number of units and energy load/needs over the connection horizon, was not consistently used by the legacy utilities. All the legacy utilities, except Brampton had used a co-branded legacy form, that had been in use before the process was harmonized. Legacy Brampton had stopped using the legacy forms and the Design Technicians request the customer information via email and input the data on the EEM. The lack of a consistent Alectra form could result in human error and inconsistency in the data that is required and obtained from customers.
Recommendation	We recommend that a single harmonized Alectra document be used to request the customer information for both sub-division and ICI type of contracts. This should be consistently used and should be retained on file by the Network Services group as part of the file retention process for each customer.
Response from Management	Network Services agrees with the recommendation. Subdivisions has been using a Harmonized Subdivision Application form since early February 2020. Offer to Connect and EEM's are not initiated until the form is received. This will be reviewed with all design staff. The Subdivisions SharePoint site has an electronic record of the customer Data form, Offer to Connect and EEM listed per project work order number. In addition, Technicians upload information on File Nexus. For ICI this observation is considered completed. Documentation for all five (5) legacies is now available for the new conditions of service (CoS). Previously we were unable to use a common OTC and Documentation since we had five (5) different legacy connection/expansion processes. The process is now harmonized into one.
	Accountable Party: Doug Fairchild: VP, Distribution Design
	Estimated implementation date: Sept 30, 2020

Observation #6 **Priority: Low**	**Approval of the economic evaluation model template and process manual**
	When reviewing the sign off approval for the EEM in use for 2020, there was no evidence of the sign off presented to Internal Audit. The Director in Regulatory affairs confirmed that the process was not straightforward and involved many parties to the development of the model, refinement and input, until a formal model was finalized and issued for use in the business. This was a two-year process and would be very difficult to retrieve sign off from the many emails, and conversations at each point along the way. This could result in non-agreed templates, assumptions or errors if the model has not been approved by all applicable departments within Alectra.
Recommendation	We recommend that going forward, any changes to the model, especially for the new annual rates in the model, be formally signed off, approved and retained by Regulatory Management before the model is issued to the business for use, as evidence of an audit trial for approval.
Response from Management	The sign off for the template and process was achieved through the collaborative effort of the cross-functional team. While a formal document may not exist, the sign off was achieved by the "team" presenting the final product to the Executive Committee for sign off. Going forward, Management supports that the sign off should be formalized and sign off should be documented annually, for changes to the rates.
	Accountable Party: Michael Lister: Director, Regulatory Policy & Strategy
	Estimated implementation date: End of Q1 2021

4. Additional Items for Consideration

The points below were identified as a service to management. They do not require a response and are provided to assist with building more effective and efficient processes.

1. Approval section for EEM in Operations and Network Services

When performing the testing of the design of controls, it was noted that the sign off page in the EEM for the Network Services group was not a physical sign off by the required authorizers. Instead, a name is typed into the EEM excel document that is in line with the Alectra authorization matrix hierarchy. This is a mitigating control but not a strong control that would prove that the person signing off the EEM was the actual person who did so, or if it was signed off at a late stage. Electronic approval via email or SharePoint would provide better evidence that all evaluations are adequately signed off and approved, as per the Alectra policy.

2. Updating process documentation

Although there were procedural documents available for the economic evaluation process from Regulatory, the document on the Network Services group's SharePoint was not the most updated version that Regulatory had prepared. The one on SharePoint had a date of February 28, 2020, whereas the most current manual was dated March 13, 2020, where some minor differences existed. We recommend that the most up to date version of the document be uploaded to and maintained on SharePoint.

5. Acknowledgement of Review

Name and Title	Signature	Date
Edlira Gjevori Director, Accounting	Approved via Email	July 20, 2020
Michael Lister Director, Regulatory Policy & Strategy	Approved via Email	July 20, 2020
Zoran Dabic Director, Program Delivery Network Operations	Approved via Email	July 20, 2020
Doug Fairchild VP, Distribution Design	Approved via Email	July 20, 2020
Mark Villett VP, Finance	Approved via Email	July 21, 2020
Indy Butany-DeSouza VP, Regulatory Affairs	Approved via Email	July 21, 2020
Chris Hudson SVP, Network Operations	Approved via Email	July 21, 2020
Mike Matthews SVP, Network Services	Approved via Email	July 27, 2020
John Basilio EVP, Chief Financial Officer	Approved via Email	July 21, 2020
Max Cananzi President	Approved via Email	July 20, 2020

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

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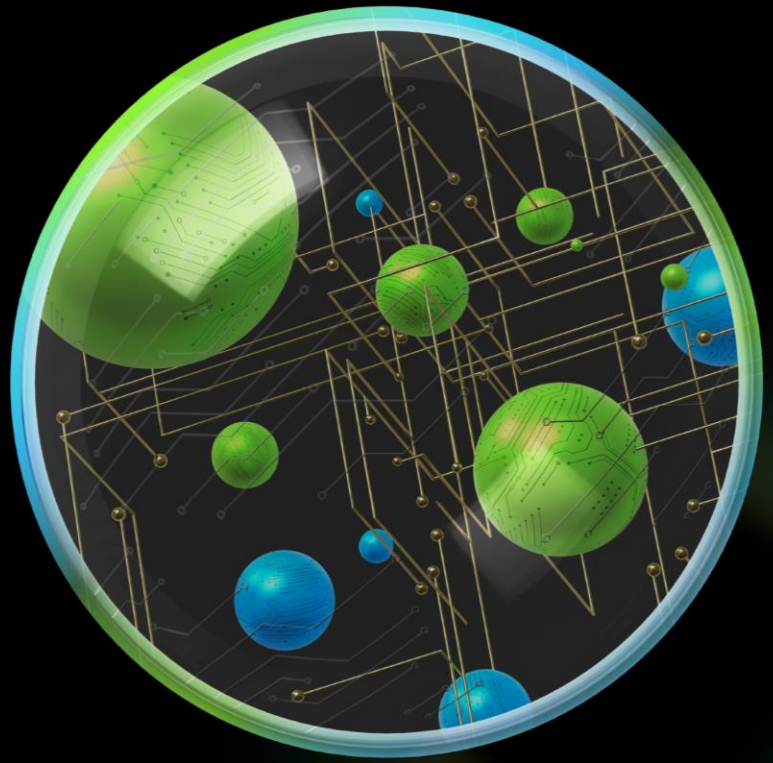

Alectra Utilities

Software Asset Management (SAM) Assessment

Current State Observations & Roadmap - Executive Summary

January 2022

Areas of Positivity to Embrace

Key takeaways from discovery interviews with Alectra employees in their program roles to understand what functions they perform and what maturity level services are delivered. Below highlights how much progress and value Alectra's Software Asset Management (SAM) offers today.

Observation	Impact
Team alignment and passion to making SAM better	The Alectra asset management team has a positive attitude towards continue improvements of the current SAM practice, understanding its untapped value and show an invested interest in achieving an enterprise SAM program. As key contributors, Candace and Peter are leading this program and enabling future success.
Industry leading Asset Management technology platform	Having implemented ServiceNow and its SAM Pro functionality, inclusive with an established software catalog and CMDB repository, it has provided Alectra with a foundational technology platform to enhance and potentially expedite asset management practice maturity.
Procurement & Change Management are integrated in ServiceNow	Critical to supporting SAM lifecycle business process, integrating contract management with ServiceNow platform, enabling automation for notification and renewal processes is a best practice that allows procurement visibility into contract entitlements and license use rights to support improved 3rd party negotiations.
High level of self-awareness	Being in the early stage of the SAM program development journey, Alectra is aware that establishing a mature practice capability across the SAM set of business processes takes time, calculation, collaborative effort and executive support. It is a process that requires many at the table with same goal in mind.

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Alectra Utilities SAM Program Development

Alectra is formalizing and enhancing the capabilities and processes needed to effectively manage its software assets and provide timely business intelligence to Alectra's various organizational stakeholders

Request of Deloitte

Deloitte was engaged to execute four work streams with the overarching objective supporting Alectra to clarify its vision for SAM and charting the development path to an enhanced and sustainable business operation. The scope consisted of four work streams:

- **SAM Program Current State Assessment –** Assessment of current Alectra capabilities against the Deloitte SAM framework (People, Process, Technology, Governance, & Data)
- **SAM Technology & Data Fit Gap Analysis –** Evaluation of supporting SAM technologies against capabilities to realize Alectra SAM objectives
- **Future State SAM Program Design & Roadmap –** Provide a strategic path forward for Alectra to realize the value and development required to accelerate practice performance
- **Key Performance Indicators –** Metrics to measure SAM program results

Overview of assessing and developing Alectra SAM program

1. Alectra engaged Deloitte to assess the existing SAM function, evaluate SAM technology capabilities, and define a future state program roadmap for SAM
2. Deloitte participated in discovery conversations with required Alectra employees to understand and assess the current state of SAM
3. Value Recognition: SAM transformation on a 24-month timeline following the roadmap delivery to Alectra executive stakeholders. Effectively align SAM resources, optimize use of SAM technology, integrate SAM lifecycle processes and enhance current state governance structures

SAM program assessment findings & focal points

We have summarized **5 areas for continuous investment** for SAM program increased effectiveness. These key process areas are derived from discovery findings during the Current State Assessment

Governance & Processes

Program governance requires additional definition – requirement for business area leadership involvement and integration with SAM lifecycle

Data Quality

Enhance ServiceNow capabilities to exhaust tech investment, reducing toil from manual interventions – unlock its true potential through integrations / API's out of the box to increase efficiency and effectiveness of SAM

Mitigate Risk Areas

No active risk heat map for third parties and higher risk / spend contractual agreements - limited integration with SAM program to minimize value leakage and operational risk

Lifecycle Automation

Increase visibility into software deployments and license use: "software installed and critical for business; installed, but not needed for business; unintentionally installed-investigate; and purchased, but not deployed/in use (shelfware)"

Organizational Integration

Prioritize SAM as an enterprise requirement, continuously invest in the program trajectory to maturity and SAM people skill and knowledge development

Continue to enhance collaboration within the lifecycle processes, company awareness of SAM, brand and value communication.

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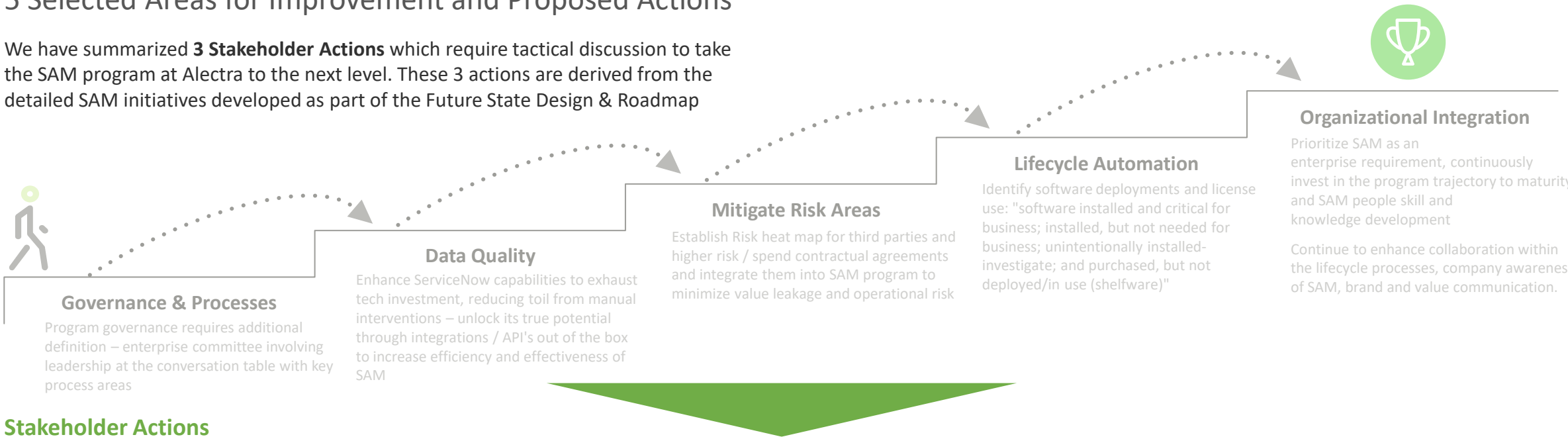
SAM Program Assessment

5 Selected Areas for Improvement and Proposed Actions

We have summarized **3 Stakeholder Actions** which require tactical discussion to take the SAM program at Alectra to the next level. These 3 actions are derived from the detailed SAM initiatives developed as part of the Future State Design & Roadmap



Stakeholder Actions

1	**Authorize SAM Mandate**	Establish and **authorize the SAM Program scope and mandate** with formalized objectives, performance metrics, leadership oversight
2	**Mitigate High Compliance Risk Areas**	Establish a **License compliance position** for Microsoft and Oracle – Exhaust ServiceNow capabilities to help expedite transition to the next level of SAM
3	**Organizational Integration**	Enable the **SAM team through further education/certification training, right sizing business demand vs team capacity to deliver value, continue to invest in innovative technology and efficient reporting capabilities** to create an enhanced "customer" experience and enriched services delivery to Alectra stakeholders

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Timeline to Value

Alectra SAM program development and path to establishing mature practice will take form over the next 24 months where return from effort of continuous improvements implemented will be realized by the enterprise.

Timeline	6 Months	12 Months	24 Months
Capability Developed	• Alectra SAM Governance framework • Identified Roles and Responsibilities • Communicated SAM strategy • Software inventory/consumption by business unit (consumption dashboards)	• SAM platform continuous improvements based on demands from the business, regulators and publishers • Complete integration of SAM lifecycle processes (Sourcing >>> Remove/ReUse) • Tier 1 Vendor compliance & initial optimization (Oracle, Microsoft)	• SAM lifecycle process & reporting enhancements • Ongoing Tier 1 Vendor optimization • Tier 2 Vendor compliance & optimization • SAM as a trusted advisor at the planning, contracting, M&A and the business transformation conversation table
Targeted Value Proposition	• Formalized scope, objectives & performance metrics / benchmarks • Improved accountability & consistent SAM program overwatch • Single source of truth for software inventory having >90% accuracy / completeness of discoverable assets • Open communication and collaboration between SAM team and lifecycle process owners and business stakeholders	• Just-in-time compliance reports for Tier 1 publishers (not point-in-time snapshots) • Foundational processes to enable maturation towards SAM best practices • Reduced exposure to compliance, legal, and security risks • Timely business intelligence provided to stakeholder groups to enable insightful business decisions	• Tier 1 & 2 Vendor spend optimization realized (~5% - 15%) and compliance events mitigated • Shift to proactive management of software assets, optimizing the software portfolio and reducing software spend • Integrate SAM into business processes, improving trust, reputation and services delivery value of the SAM team

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SAM Program Roadmap

Deloitte recommends Alectra widen the scope of the SAM team to be included in the entire lifecycle. Adopting this expanded scope would be best achieved by implementing the following three-phased approach:

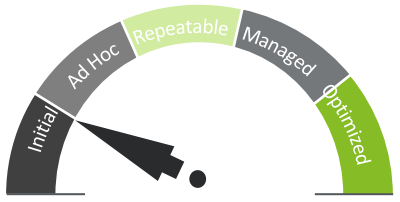
Phase 1
Establish Program Governance

Est. Timing: 6 – 12 months

Critical Activities:

- Define the Alectra SAM Charter (Policy, Standards, Processes, Procedures)
- Implement strategic SAM organization roles and functions – Key Process Areas
- Establish Asset Management Governance Council

SAM Capabilities



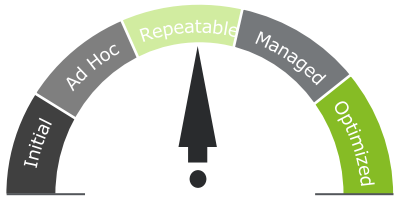
Phase 2
Top-Priority Program Enhancements

Est. Timing: 18 – 24 months

Critical Activities:

- Plan for increased demand and growth of SAM program as technology continuously evolves
- Define and implement the top-priority transformational processes
- Prepare and report license usage and compliance to executive stakeholders on a recurring basis

SAM Capabilities



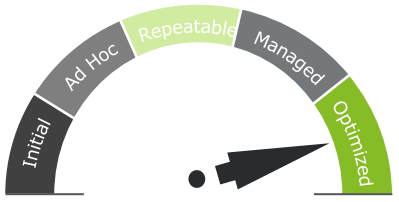
Phase 3
Drive to Maturity

Est. Timing: 24 months+

Critical Activities:

- Establish single software services catalog and perform product rationalization
- Monitor and track compliance issue remediation
- Implement demand forecasting capability and leverage usage reports for software cost-optimization
- Enhance customized reporting capability to align with KPI's to further enable SAM across the enterprise

SAM Capabilities



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Executive Summary

Each SAM initiative in the program roadmap will contribute to accelerating the maturation of Alectra's SAM capabilities with tangible activities, actions and outcomes that will deliver measurable value and program sustainability.

Area	Finding	Initiative	Summary Activities
Governance & Process	• Current SAM program governance requires refinement. Charter, roles and responsibilities to be defined.	Establish Governance Framework	• Formalize SAM governance structure, councils and mandates • Execute, revise, and enhance recurring/periodic governance meetings • See list of missing framework documentation
Data Quality / Reporting Capabilities	• Limited performance measurement, customized dashboards and reporting	Enable Organizational Reporting	• Identify key consumers of SAM data and reporting/intelligence requirements • Enable dashboards and canned reports, as capabilities are developed (inventory -> compliance) • Automate report generation and self-services access for stakeholders
Publisher Onboarding & Data Connectors	• Additional titles for Tier 1 software publishers need to be onboarded into SAM technology for holistic compliance view	Enhance Entitlement	• Identify top publishers by annual spend and onboard all software titles into ServiceNow ensuring all contract and purchase record information are up to date, as well as use rights known and included in compliance analytics. • Leverage vendor's APIs to enable ServiceNow as single source of truth
Mitigate High Risk Compliance Areas	• High risk contract vendors are being reactively managed	Establish ELP for Oracle, Microsoft	• Once publishers are fully onboarded, a full Effective License Position (ELP) should be performed, and repeated every 6 months to be audit ready, reduce compliance risk, assist in true-up and contract renewals.
Organizational Integration	• Continuous improvement program requires additional definition • Limited collaboration between SAM and stakeholders	Communicate SAM	• Define SAM's core objectives/obligations supporting the SAM lifecycle stakeholders • Implement a RACI chart with clearly articulated responsibilities • Communicate SAM strategy and responsibilities across the organization
		SAM as a Trusted Advisor	• Standardize and implement purposeful interactions between SAM and the businesses • Apply licensing expertise to increase the SAM team's authority and credibility

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Management Comments

Response:	**Alectra IT agrees with Deloitte's findings ; based on their roadmap and recommendations we are committed to achieving the following actions in a phased approach :** **Phase 1:** Complete entering all software entitlements into the ServiceNow SAM module Complete Alectra ITAM framework incl. SAM charter Identify SAM Roles and Responsibilities Develop SAM process documentation Communicate SAM processes/responsibilities/framework Develop dashboards and reports to share with Stakeholders and Executives **Phase 2** Develop SAM audit function internally to ensure processes and responsibilities are being adhered to Develop just-in-time compliance reports for Tier 1 publishers Develop reclamation process to release and reuse unallocated licenses Assess vendor contract information regarding licensing compliance and audit capability **Phase 3** Develop software consumption reporting by business unit for show-back/ charge-back capability Develop understanding of license usage for top tier publishers for SAM administrators Position SAM as a trusted advisor at the planning, contracting, M&A, and business transformation conversation table	

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Accountable Parties:	- **James Ilari: Director, IT Innovation and Governance** - **William Schmidt: SVP, Business Transformation & Information Technology** - **EVP Chief Digital and Innovation Officer (vacant)**	
Estimated Implementation Date(s):	**Phase 1: end of 2022** **Phase 2: end of 2023** **Phase 3: end of 2024**	

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Acknowledgement of review & acceptance

Name	Signature	Date
James Ilari Director, IT Innovation and Governance	Approval by email	February 8, 2022
William Schmidt SVP, Business Transformation & Information Technology	Approval by email	February 8, 2022
EVP Chief Digital and Innovation Officer (vacant)	Approval outstanding as position is currently vacant	Outstanding

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Appendix 1 - Deloitte’s Software Asset Management (SAM) Framework

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Appendix 2 - Glossary

Acronym	Meaning
CMDB	Change Management Database
ELP	Effective License Position
HW/SW	Hardware / Software
ITAM	Information Technology Asset Management
KPI	Key Performance Indicator
RACI	Responsibility Assignment Matrix (Responsible, Accountable, Consulted, Informed)
SAM	Software Asset Management

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Deloitte's team is an industry leader dedicated to SAM

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New Connections Review

Internal Audit Department

June 2022

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1. Overview (Executive Summary)

As part of Alectra's 2022 Internal Audit Plan, the Internal Audit team conducted a review of new connections for Alectra Utilities Corporation (AUC). The new connections process refers to the execution of new connections requests for various service categories including temporary service, residential, small and large commercial, industrial, institutional and flat rate (streetlights and traffic signals). The New Connections team uses SilverBlaze, a third-party software to manage all new connections requests from customers.

As defined by the Ontario Energy Board (OEB) Distribution System Code Section 7.1 ""new service" means a connection that requires an Electric Safety Authority certificate before the connection can be completed. This includes, but is not limited to, connections associated with a service upgrade and connections that involve the installation of an additional meter on the distribution system where no meter previously existed."

The purpose of this audit was to determine the extent that customer requests, customer connections, metering and follow through to billing sub-processes are efficiently managed. The audit approach was discussed with Management and testing was completed for the audit period April 1, 2021 to March 31, 2022, inclusive.

The objective of this internal audit review was to assess the design and operating effectiveness of the internal controls in place within the new connections process and to provide senior management with assurance about the adequacy and effectiveness of internal controls over the audit area. The audit followed a risk-based methodology with a focus on the areas deemed to be of significant risk. The audit findings and conclusions noted in this report are based on a review of the existing processes and controls at the time of audit review.

The scope of the review was as follows:

- Review policies and procedures that exist and ensure that they are known and followed by staff;
- Review the new connections process and controls and assess compliance with the written procedures across the entire organization for uniformity;
- Determine, on a sample basis, for each of the 5 project types (temporary, residential, small commercial, industrial, commercial and institutional (ICI) and flat rate) if online new connections requests:
    - have collected the required deposits/payments prior to start of field work;
    - have set up accounts in accordance with the established procedures for all service territories;
    - have adequate supporting documentation, including the Electricity Safety Authority (ESA) form;
    - are processed timely;
    - are adequately performed and approved by Design staff; and
    - are billed timely and accurately after connection is set up.
- Verify the length of time between when the request was received, the Field Activity (FA) was first created and when the meter was installed;
- Review user access rights to process new connections in Customer Care and Billing (CC&B) and SilverBlaze systems;
- Review of overall segregation of duties in the new connections process;
- Determine compliance with OEB's regulatory operational and reporting requirements for new connections; and
- Perform analytical review of new connections requests for the audit period.

The following areas were out of scope:

- Same day reconnections;
- Online new connections requests for DER (Distributed Energy Resources) generation including backup generators which follow a different process; and
- Planned permanent service removals

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit.
- Interviews and inquiries with key management and operational staff as well as process walk-throughs.
- Performance of detailed testing on selected samples; and
- Conducting analytical procedures, wherever possible.

The overall design of the new connections process was found to be satisfactory in most areas. Opportunities for improvement in implementation and operating effectiveness of controls, were identified in the specific areas listed below:

1. Inconsistencies in customer payments processing (Medium)
2. New connection requests monitoring (Medium)
3. Review of field activity completion time (Medium)
4. Inconsistent methods of distribution of field activities (Medium)
5. Draft procedure documentation (Medium)
6. User access to SilverBlaze system (Low)

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

The New Connections team has continued to benefit from the efficiencies of utilizing the SilverBlaze system that was developed as a part of the New Customer Connections Process (NCCP) project that began in 2018. The system manages all new connection requests from initiation to all service conditions being completed to allow for service connection for customers. To achieve greater efficiency, the New Connections team is currently in the next phase of the NCCP project to further enhance customer experience, greater automation and integration of workflow and exploring other third-party software packages to possibly replace SilverBlaze.

Over the past year, Management has transitioned the New Connections Call Centre from Util-Assist to in-house representatives. This transition has significantly increased the quality of service with a reduction in call wait times and a decrease in call abandon rates.

During the past year, the New Connections team improved staffing resources and hired a senior clerk and five clerks and upskilled all existing New Connections Clerks. A comprehensive new connections training document was prepared in 2021 and enhanced the training program for all team members.

Management has recognized the need for improvement in monitoring new connection requests and have reduced operational backlog of service upgrade requests by 75% between July 2021 and June 2022 through Short Interval Control (SIC) meetings with Lines departments across the utility, working closely with those groups to illustrate progress and to make the case for additional resources where required to support backlog reduction.

In 2021, the New Connections team, in collaboration with the design, operations and metering teams, have achieved compliance with the OEB’s service quality requirements. The OEB's Distribution System Code outlines the requirements for connection of new services, appointments scheduled and appointments met.

Management was able to prioritize and provide more than ample support and access to documents related to the review. We wish to recognize the excellent rapport and exchange of views with all personnel involved with the audit. The depth of this review could not have been achieved without the support received. The efforts of all were greatly appreciated.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: Medium**	**Inconsistencies in customer payments processing (Operating Effectiveness)**
	As per discussions with Management all payments for new connection requests made by customers should be received by the Collections & Payments team and processed in JDE system. After processing, the Collections & Payments team should upload a daily spreadsheet summary in SharePoint notifying the New Connections team of the payment. The New Connection team relies on this notification to update SilverBlaze and mark the service condition of the required payment as "complete" before proceeding to create the field activity in CC&B system for service connection to be executed. **1) <u>Delays in customer payments processing</u>** From our sample of 25, one exception was noted where the customer made payment via electronic funds transfer for a request in November 2021 for $25K. However, the payment was not processed until January 2022. The New Connections team was not notified of this payment until March 18, 2022 as the daily spreadsheet summary of payments processed was not received. This resulted in SilverBlaze being updated on March 18th, 2022, four months after the payment was received and the service upgrade being executed in the same month. It was confirmed with Management that one of the factors causing delays in processing results from the work order and the General Ledger string information not being communicated timely to the Payments team by the Design team. The delay in processing payments may result in the execution of the new connection requests being delayed as the New Connections team has to satisfy all service conditions before issuing a field activity for service connection to be completed. 2) **<u>Lack of notification of payments</u>** Six exceptions out of our sample of 25 (24%), were noted, where no daily spreadsheet summary was sent to the New Connections team, notifying them of the relevant customer payments processed in JDE. As a result, the New Connections team was unable to update the service condition for customer payment as "complete" in SilverBlaze, causing an unnecessary delay in processing the customer's request. The delay in processing payments may result in the execution of the new connection requests being delayed as the New Connections team has to satisfy all service conditions before issuing a field activity for service connection to be completed.

	3) <u>Receipt of deposit cheques by Design team</u> From the sample of 25, one exception was noted where a payment of $11K was processed on October 19, 2021 in JDE, however, no notification was sent to the New Connections team for SilverBlaze to be updated. As at the time of concluding the audit review, no updates had been made in the system. Management indicated that this deposit cheque for the project may have been mailed directly to the appropriate Design supervisor and then forwarded to the Payments team instead of to Payments directly. This became a recurrent practice during the pandemic and was not in accordance with procedures. The lack of harmonized procedures to receive customer payments may result in the misplacement of cheques, segregation of duties issues or delays in submission for processing in a timely manner.
Recommendation	We recommend that Management ensures that information required for processing of payments in JDE such as the work order and GL string be submitted to the Payments team in a timely manner to facilitate quick processing of customer requests. We recommend that Management ensures that a systematic automated approach be developed to notify the New Connections team of payments processed in JDE. We recommend that Management develops a uniformed process for receiving all payments by the Payments and Collections team, whether they are project fees or deposit cheques.
Response from Management	New Connections has developed an automated report which notifies the New Connections team each morning of any payments posted in JDE from the previous day. This achieves a portion of the recommendation above. Payments Management should work with the ICI & Layouts and New Connections Management teams to ensure communication to customers is consistent with respect to the payments process, and that downstream resources (i.e. ICI & Layouts Design Techs and New Connections Clerks) are aware of their roles in the process and follow it accordingly. Payments should be delivered to a single Alectra address, and consistent, detailed instructions should be provided to customers instructing them on how to make a payment. Future Opportunity: New Connections can explore the opportunity of an online payments feature for service requests through the discovery and development of the SilverBlaze Replacement Project (BC# 152361).
	Accountable Party: Linas Medelis VP, Customer Service
	Estimated implementation date: Q4, 2022 - Payment process improvement Q4, 2023 - Online payments

Observation #2 Priority: Medium	New connection requests monitoring (Design Effectiveness)
	Internal Audit noted six instances out of our sample of 45 new connection requests (13%) where the time taken to complete the request exceeded 90 days (Internal Audit's reasonableness measure) with the completion time ranging between 90 and 286 days. Four of these requests were related to new installations for subdivision housing developments, which, based on discussion with Management customarily take long periods of time, at times years to finalize, waiting on the last home(s) to be built within the subdivision. It was observed that no detailed notes providing status updates of the requests were documented in SilverBlaze. Management confirmed that a regular analysis is not performed to track/monitor requests or the time outstanding. Additionally, there is no existing standard to measure whether the time for the request processing may be deemed excessive. The absence of a monitoring process may result in undetected delays and customer complaints. Monitoring that is not performed does not allow for proper assessment of the efficiency of the new connections process.
Recommendation	We recommend that Management formalizes the monitoring process of customer new connections request and include an analysis on the status of the projects. Any long outstanding delays should be followed up on a timely basis. Management should consider performing an analysis of subdivision requests that are open for lengthy periods i.e. ten years and through communication with the respective builder determine whether these requests should be closed.
Response from Management	New Connections will be concluding the NCCP Phase 3B project in Q3, 2022, which includes the development of dashboards, illustrating the progress and status of various project types, including subdivision requests. New Connections and ICI & Layouts design teams will be able to utilize these dashboards to review the workload in their designated territories and determine how long service requests have been in a particular status for (e.g. Submitted, In Design, Waiting on Customer, etc.), enabling timely actioning of requests.
	Accountable Party: Michael Mees Director, Customer Care
	Estimated implementation date: Q4, 2022

Observation #3	Review of field activity completion time (Operating Effectiveness)
Priority: Medium	A sample of 45 new connection requests for installations and upgrades were reviewed by Internal Audit. We noted the following exceptions: **1) <u>Meter installation prior to field activity</u>** One exception, out of the sample of 45 was noted, where the work/meter installation was performed prior to the creation of the field activity in CC&B. The meter was installed on August 5, 2021, before the field activity was created on August 23, 2021. Non-compliance with established procedures which stipulates that a field activity must be created and dispatched to the appropriate teams prior to a meter installation, may result in unauthorized work being performed. **2) <u>Pending field activities</u>** We noted two instances where the status of the field activities in CC&B were stated as "Pending". The field activities for both requests were scheduled for July 2021 and related to the connection of streetlights. Based on further investigation by Management the field activities for these requests were dispatched to the Metering team and were completed and connection made. The field activity has subsequently been closed and instructions have been given to Billing to conduct the requisite back billing exercise. Long delays in completing field activities for service connection may result in delayed billing up to an allowable period of two years according to AUC's Conditions of Service.
Recommendation	We recommend that Management ensure that connections and installations are performed after a field activity is prepared, in accordance with the designed procedures. Logic or reasonability controls within the CC&B system could also ensure that a field activity is logged and initiated before the completion date of the installation/connection. We recommend that Management performs an analysis of the statuses of field activities on a regular basis specifically those in "pending" status and determine the stage of completion and reason for any delays and take any necessary corrective action. We recommend that Management ensures that the appropriate retroactive billing is performed for the customer accounts that were connected in 2021 and identified during the internal audit review.
Response from Management	Metering management regularly provides refresher training about FA management including the requirement that work cannot commence without a Field Activity, regardless of the scenario or urgency.

	Metering management supports the recommendation to build the tools to gain transparency about the status and aging of pending Field Activities. A Field Activities Dashboard is in development to provide reporting on FA aging and "time to serve". Process enhancements and training are planned to ensure that resources are appropriately prioritized and available to support time-sensitive field requests. The Dashboard will be in place by December 2022, with the continuous improvements and process enhancements beginning in 2023. New Connections can leverage CC&B reports in conjunction with PowerBI to review and assess FA statuses on a regular basis, providing greater visibility to the progress of FAs. The development of an FA report should enable responsible groups to understand their effectiveness related to timeliness of FA completion. New Connections will advise Billing once FAs are appropriately processed for accounts connected in 2021 (as identified during this internal audit review), to initiate the retroactive billing process.
	Accountable Party: Michael Mees Director, Customer Care Shelley Parker VP, Metering
	Estimated implementation date: Q4, 2022

Observation #4 **Priority: Medium**	**Inconsistent methods of distribution of field activities (Operating Effectiveness)**
	The Fieldworker software on tablets is utilized for the electronic distribution of field activities created in the CC&B system to the relevant dispatch groups. The dispatch groups use the application to note all documentation and relevant field activity comments, including the completion date. Some Operations teams are using the software while others are still paper based. It has been confirmed with Management that Metering is using the Fieldworker software for all territories, Lines is using the Fieldworker software for the West region and Mississauga. It was confirmed with Management and noted in our testing that the dispatch groups for Lines East Region and Lines for Brampton, do not utilize the Fieldworker software. As a result, the required field activity (FA) from the CC&B system must be physically printed for the work to be issued. Additionally, a written note must be entered in the comments section of the FA section in CC&B to document the actual date that the FA was completed in the field. Inconsistent methodologies and the use of manual methods for the distribution of field activities may lead to delays in execution times, lost or incomplete data and the inability to achieve the required greater efficiencies attainable by utilizing an automated process.
Recommendation	We recommend that Management ensures that all dispatch groups are using the Fieldworker application and that field activity processing is uniform across all service territories.
Response from Management	The Network Operations' Engineer in Training is currently working on the rollout of Fieldworker in both the Central-North and East Regions. In Central-North, the software is installed and supervisors, LTA's, and Leadhands are going to be trained on how to use Fieldworker, a brief quick orientation was held in March. The Leadhands in the ICI's and Trouble Department (Services) will receive the full software, and the LTA's and Supervisors will get access to a web portal. The team is still trying to figure out the best method for the contractors to gain access, however the solution looks like it will most likely be a VPN connection to the web portal. Central-South is only partially on Fieldworker and the team is working to obtain the licenses in bulk at the same time as the contractors. This would facilitate a rollout to the contractors, Trouble Truck, ICI's, and OH Maintenance in Central-South. This would ensure a consistent process.
	Accountable Party: Michael Wittemund VP, Lines
	Estimated implementation date: Q4, 2022

Observation #5 Priority: Medium	Draft procedure documentation (Design Effectiveness)
	A detailed procedure document is currently not in place for the new connections process. Management indicated that a procedure document is being developed with all the stakeholders involved in the various sub-processes. We have also reviewed existing process mapping, developed by Business Transformation, however, these were last updated in November 2019 and were not reflective of current practices. The lack of harmonized procedural documents increases the risk of non-compliance to processes and procedures and encourages staff to revert to prior practices. Without clear procedure documents in place, it may lead to knowledge of the processes being concentrated in specific individuals which pose a risk in the event of staff turnover and future training.
Recommendation	We recommend that Management takes the necessary steps to finalize the procedure document with the appropriate sign-off by authorized personnel and to ensure that staff are trained on all aspects of the process. While the procedure document is in draft status, the word “DRAFT” should be written in a watermark, to distinguish from finalized documents. The procedure document should be reviewed on a regular basis (at least annually) to ensure that they remain relevant and current and reflect any changes in current procedures.
Response from Management	New Connections is actively updating process maps through stakeholdering with departments including Subdivisions, ICI/Layouts, Lines, and Metering, to ensure the efficiency and relevance of existing processes and update them as necessary and/or where opportunities for improvement exist.
	Accountable Party: Michael Mees Director, Customer Care
	Estimated implementation date: Q1, 2023

Observation #6 Priority: Low	User access to SilverBlaze system (Operating Effectiveness)
	The system access to SilverBlaze is managed by the New Connections Team Lead. We noted 52 user accounts out of the total of 350 (15%) user accounts that were unable to be verified against the current employee listing and active directory for the audit period. Three of these unverified user accounts were also duplicate accounts. Without removing access of terminated users in a timely manner, the account could be used for unauthorized access to data or unauthorized activities in IT sub-systems, compromising data security and/or privacy.
Recommendation	We recommend that Management performs a clean-up exercise of the user accounts to the SilverBlaze system by obtaining an active directory listing from Information Technology to aid in this review. We recommend that responsibility for system access to SilverBlaze be transferred by Customer Service to Information Technology and follows the ongoing existing standard processes for system access and validation.
Response from Management	New Connections will review and update the current list of active SilverBlaze users to validate individuals within Alectra's active directory. Following this initial review and update of the list, New Connections will coordinate with IT (Security) to ensure the on-going and recurring review and updating of the list of active SilverBlaze users is maintained by IT.
	Accountable Party: Michael Mees Director, Customer Care
	Estimated implementation date: Q3, 2022

4. Acknowledgement of Review

Name and Title	Signature	Date
Michael Mees Director, Customer Care	Approved via Email	July 27, 2022
Linas Medelis VP, Finance	Approved via Email	July 25, 2022
James Douglas EVP, Customer Experience	Approved via Email	July 27, 2022
Michael Wittemund VP, Lines	Approved via Email	July 28, 2022
Shelley Parker VP, Metering	Approved via Email	July 27, 2022

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Productivity Reporting Framework Review

Internal Audit Department

January 2024

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1. Overview (Executive Summary)

As part of Alectra's 2023 Internal Audit Plan, the Internal Audit team conducted a review of the management of the productivity reporting framework for Alectra. The purpose of this audit review was to review the productivity benefits reporting framework and the process in place to develop, implement, monitor and measure productivity initiatives.

The Productivity Framework is a structured program developed by the Business Transformation department to identify, measure, and report increases in productivity and cost savings in both capital and operating, maintenance, and administration (OM&A) spending across Alectra. At its most detailed level, the Productivity Framework tracks "initiatives" that represent specific, calculable measurements of productivity. Proposed Alectra initiatives must meet certain criteria to be included in the Productivity Framework, ensuring that the initiative must be measurable, verifiable, and auditable. A sample of five project initiatives were selected to determine the application against the framework methodology for consistently, and not necessarily to assess each project for the productivity benefit type (expected reduction, avoided cost, and efficiency benefit) or category of savings ("hard" or "soft" cost savings).

The concept of the Productivity Framework was approved by the AFRM committee in 2022 and in Q4 2022, the Productivity Framework Governance document was completed and presented to the Senior Leadership Team. 2023 is the first year of the framework's rollout and has been integrated with the Corporate Planning process. As part of the business case submission, initiative owners must consider and include in their business cases any expected financial benefits or productivity benefits which will be generated from their projects.

Productivity Framework initiatives are identified and tracked for each of Alectra's lines of business, and incorporates productivity improvement resulting from the Productivity Framework in its budgets and forward-looking business plans. Furthermore, results from the Productivity Framework are included in Alectra's corporate scorecard upon which incentive compensation is based.

Internal Audit utilized best practices to define a set of criteria against which to evaluate initiatives within Alectra's Productivity Framework, drawing from industry research, Internal Audit's own experience, observations from a consultant who evaluated Hydro One's productivity program, and a review of Ontario Energy Board findings regarding productivity. These criteria indicate that an effective productivity program exhibits the following characteristics:

- Effective at identifying and quantifying sustainable productivity improvements and initiatives;
- Holistic in nature (i.e., targets all levels of the business);
- Promotes a corporate culture that embraces productivity and process improvement as a core value;
- Applies appropriate baseline data to measure productivity gains;
- Benefits are validated with an appropriate validation and audit process;
- Avoids contradictory incentives (i.e., does not sacrifice customer value, safety, and reliability for short term savings);
- Drives benefits that can be considered true productivity gains (i.e., more output for the same resources, or the same output using fewer inputs); and
- Integrates bottom-up business line initiatives with top-down planning, and considers productivity in the context of forward-looking planning.

These criteria provided Internal Audit with an objective basis for evaluating Alectra's Productivity Framework. These are not minimum criteria, as a productivity program can incorporate some of these elements and still be effective at delivering meaningful productivity gains and cost savings.

The audit approach was discussed with Management and testing was completed for the audit scope period October 1, 2022 to September 30, 2023, inclusive.

Productivity Reporting Framework Review

The scope of the review was as follows:

- Determine if sufficient written procedures exist for the Productivity Benefits process and are known and followed by staff;
- Review existing Framework and Governance documents;
- Review training provided on the Productivity Benefits process;
- Assess if the productivity benefits that have been reported are supported by relevant documentation;
- Review assumptions made by Management to ensure they are reasonable;
- Review any processes or changes made by Business Transformation for reasonability and accuracy;
- Determine, on a sample of reported projects:
    - uniformity and consistency of the methodology applied for the projects against the framework;
    - check that formulas were consistently used;
    - check completeness of the benefits reporting;
    - verify the reference material used;
    - verify the accuracy of the supporting calculations; and
    - agreement with the reported productivity benefits being reported;
- Performance of analytical procedures to understand any trends and anomalies that may indicate inconsistencies.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Performance of analytical procedures (if applicable) to understand trends and other anomalies using specialized audit software.

Our audit was conducted in conformance with professional standards established by the Institute of Internal Auditors. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

After a review of the process and supporting information, no material errors were noted. In general, there are controls in place to manage the productivity reporting framework process. Opportunities for improvement in the design, implementation and operating effectiveness of controls, were identified in the specific areas listed below:

1. Supporting back up of Productivity Benefits (Medium);
2. No formal approval of Productivity Benefits Framework (Medium);
3. Productivity Benefits Framework foundational documents to be finalized (Medium); and
4. Approvals of individual projects for Productivity Framework (Low)

Overall assessment: **Effective, with opportunity for improvement**

2. Good Client Practices

Overall, the Productivity Framework for Alectra is an effective productivity program. Specifically, the Productivity Framework is effective at identifying and quantifying sustainable productivity improvements and initiatives; is holistic and targets all levels of business; utilizes appropriate baselines to measure productivity gains; has an appropriate validation and audit process; avoids contradictory incentives; drives benefits that can be considered true productivity gains; and considers productivity in the context of forward-looking planning.

The Productivity Framework is also very detailed in nature and the Productivity Framework reference manual was noted as being very comprehensive. This level of detail is indicative of the robustness and rigor that has been built into the program by the Business Transformation Team.

The Productivity Framework is focused on cost savings. Internal Audit understands from our review of the Productivity Framework that Alectra has already achieved significant and material productivity savings, exceeding the target that has been set for 2023.

The Productivity Framework has support from the Board and the Senior Leadership Team, and due to the complexities of the program, the Business Transformation team educates senior leaders and other staff members on its structure and governance through effective training and ongoing communication. The training material reviewed was extensive and robust. Effective internal and external communications are integral to achieve the full potential of the program.

3. Key Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: Medium**	**Supporting back up of Productivity Benefits (Operating Effectiveness)**
	i) Internal Audit requested the back-up documentation for a sample of five projects included as part of the Q3, 2023 productivity reporting forecast. The Business Transformation team could not provide adequate back-up for one item in our sample. Business Transformation was in the process of confirming the savings methodology calculation, however the figure was included in the forecast report. No initiative brief was prepared for the project, with a productivity benefit value of $454K. Internal Audit therefore selected another project to complete the testing; ii) The initiative brief of one item in our sample had excluded the baseline values. Internal Audit followed this up and it was noted that because pilot initiatives were in-flight or recently completed projects, no original baselines had been determined for the financial benefits framework for projects commencing prior to 2023. However, we also noted that the baseline value for 2023 was also not provided for the same project. The Business Transformation team had difficulty assigning values to the baseline for the individual change requests as part of the “ERP Continuous Improvement project”; and iii) Internal Audit did not receive the necessary supporting documentation for one item out of our sample of five (20%) in a timely manner. The documents were in the process of being reviewed by the Business Unit owners, when the backup was requested by Internal Audit. Per discussion with Business Transformation, the business initiative brief and the approval from the BU owner, were received after the audit request was made and was only received in November 2023, despite the fact that productivity benefits for this project were reported since Q1 of 2023. There is a risk that the basis (baseline) for the Productivity Benefits or other support may have errors, resulting in inaccurate reporting if requested by the OEB. Even a low estimate, may be challenged and not be able to be defendable if questioned by the OEB if is not adequately supported. The validity of the Productivity Benefits reporting could thus be in question if the foundational documentation cannot be substantiated. There is also a secondary risk if the savings are not validated up front for accuracy, none of the other projections or actual benefits/savings achieved are valid.

Recommendation	The baseline values form the basis of the measurement for a project, as per the Productivity Benefits Framework methodology. Without that, it would be difficult to accurately measure the productivity gains of a project. Business Transformation should establish a baseline for the individual change requests, much like the value is determined for the efficiency gains, following the approach of the "cost of the status quo/ not doing anything" method. We recommend that all projects be reviewed to ensure that they have the necessary documentation to support their inclusion in the productivity benefits reporting and the supporting information to validate any proposed savings. This would include the initiative briefs, baseline values as well as the proper sign off from the Business Unit owners.
Response from Management	The Productivity Framework (PF) was implemented retroactively and in some cases, baselines were not created. Business Transformation has been working with the business on the transition to follow the PF and ensure the business will be creating the baselines. In future, the Business Transformation team will take the following approach: - Actuals to be only reported under the Productivity Framework once the Initiative Brief of the project is completed and approved. - Prior to the Initiative Brief approval, savings will be included as forecast opportunity only. For Observation (ii), the Business Transformation Team will update the Productivity Reference manual to state that program type initiatives are an exception to the rule, in that it is not possible to generate a single baseline value to capture on the Initiative Brief. Baseline will be calculated for each completed change request in the program.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: March 31, 2024

Observation #2 **Priority: Medium**	**No formal approval of Productivity Benefits Framework (Design Effectiveness)**
	i) Internal Audit reviewed the "Productivity Governance Framework" document. The summary of roles and responsibilities indicates that the overall approval of the productivity framework, including its implementation timelines, is the responsibility of the Executive Committee (EC). Internal Audit noted that no evidence of such approval was obtained during the review; only a redacted copy of the minutes to an AFRM committee meeting was noted, where the governance document was tabled for information; and ii) The document approval for the Productivity Framework reference guide was signed off by the VP of Business Transformation in November 2023. This was after evidence of the approval/Sign off was requested by Internal Audit as part of this audit review. The Business Transformation team had indicated that the document is a "live" document and that changes to the document can still be made. It was also mentioned that the document has been reviewed by senior management of Business Transformation, but not formally approved. The Productivity Governance Framework acts like a Policy document. Without the proper approval by the Executive Committee and the VP of Business Transformation, the productivity framework could lack overall vision, guidance and oversight to ensure that the delivery of cost efficiencies does not compromise Alectra's Strategy 2.0 objectives.
Recommendation	We recommend that a high-level overview of the workings of the Productivity Benefits Framework be provided to Alectra's Executive Committee, and approval obtained by them. Any major revisions to the methodology framework going forward, should also be reviewed and approved to ensure visibility and agreement by the Executive Committee.
Response from Management	Although the Productivity Framework was presented to the Executive Committee, no formal approval was documented. It will be presented for formal approval by the Executive Committee.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: March 31, 2024

Observation #3 **Priority: Medium**	**Productivity Benefits Framework foundational documents to be finalized (Design Effectiveness)**
	1) Productivity benefits reporting process documentation The Instruction Manual (procedure document) covers the operation, data validation, maintenance, process and revision of the Alectra Productivity Framework Model. i) The procedure document was in a draft stage and was not reviewed by Business Transformation Management, for finalization at the time of the audit review. During preliminary planning discussions with Internal Audit, to discuss what the audit requirements and the scope would be for this review, Business Transformation Management realized that they did not have process document in place and started drafting a document in September 2023; ii) The Productivity Model automates the process of consolidating the data, calculating the results and producing the reports using Power BI. Internal Audit noted that the manual process steps were missing from the document and still needed to be documented, as well as screenshots of process steps to be taken. The manual process is required, should the Productivity Model not be available to be run from the output files and integrated into Power BI; and iii) The process document also did not go into specific detail as to how the Productivity Framework model works, which would highlight the workings of the process to any new, or changing team members. Without clear procedure documents in place, it may lead to knowledge of the processes being concentrated in specific individuals which pose a risk in the event of staff turnover and future training. Because the process is consistently evolving as it matures, clear, documented guidelines are imperative and need to be updated regularly. **2) Productivity Framework governance documentation** i) The document labeled "Productivity Framework Governance Document" (policy document) was not in a finalized state. There were annotations on the version control cover sheet for the document being drafted and reviewed by the Business Transformation senior Management, but none were noted as being "published/final". ii) Although the “Productivity Framework reference manual” (procedure document) was comprehensive, Internal Audit noted that the document was not in a finalized state and had review comments and tracked changes for changes to be incorporated in the document by the reviewer. The version control table at the front of the document, indicated that the document had been drafted but not that it had been tabled/finalized yet.

	Without an approved and finalized framework document in place, it may lead to gaps in the process and or inconsistent application of the framework.
Recommendation	We recommend that the Productivity Benefits Framework and Reference manual documents be finalized by Business Transformation Management.
Response from Management	The Governance Document and the Reference Manual will be marked as Final. All other process documentation will be updated and marked as Final once completed.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: September 30, 2024

Observation #4 **Priority: Low**	**Approvals of individual projects for Productivity Framework (Operating Effectiveness)**
	Two items out of the sample of five items (40%) reviewed by Internal Audit had approvals for their initial business briefs signed off by the VPs of the respective Business Units, outside of the audit scope period. The approvals were obtained by the Business Transformation team, in October 2023 and November 2023, post audit period, respectively. Productivity Benefits projects that have not been approved by the BU owner/leaders are at risk of inaccuracies or being reported upon without proper Project Owner support.
Recommendation	We recommend that all projects receive the proper approvals for the initial business briefs sign off by Senior Leader/BU owner of the projects, before they are included and reported on for Productivity Benefits purposes.
Response from Management	The recommendation is accepted. Actuals to be only reported under the Productivity Framework once the Initiative Brief of the project is completed and approved. Prior to the Initiative Brief approval, savings will be included as forecast opportunity only
	Accountable Party: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: March 31, 2024

4. Additional Item(s) for Consideration

The point below was identified as a service to Management. It does not require a response and is provided to assist with building more effective and efficient processes.

Benchmarking and incorporation of KPIs

Internal Audit noted that Business Transformation had used the Pacific Economics Group (PEG report) for benchmarking analysis from other Canadian Utilities for the purposes of the OEB stretch target factor. However, there were no KPI (Key Performance Indicators) used i.e. targets such as cost performance results compared to other LDCs, cost efficiency assessments, etc. referenced within the Productivity Reporting Framework or reporting. We recommend that Business Transformation incorporate KPI's, possibly comparison to targets set by other LDC's and a need to look at the cost per effort basis of various projects. Incorporating KPI's from the benchmarking analysis will ensure that Alectra's productivity gains are tracked and targeted against our peers.

5. Acknowledgement of Review

Name and Title	Signature	Date
Nathalie McLauchlin VP, Business Transformation	Received via email	02/06/2024
Barb Gray EVP, People & Transformation	Received via email	02/06/2024

APPENDIX A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

Productivity Benefits - Selected Projects Review

Internal Audit Department

July 2024

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1. Overview (Executive Summary)

As part of Alectra's 2024 Internal Audit Plan, the Internal Audit team conducted a review of the total Productivity Benefits for selected projects reported as of December 2023 and Q1, 2024. The total Productivity Benefits reported for all projects as of December 2023 were $4.3M (YTD actual incremental) and $1.5M (Prior Year sustained) respectively. The total Productivity Benefits reported for all projects for Q1, 2024 were YTD Actual Incremental of $1.1M.

The purpose of this audit was to review the process and calculations of financial benefits reported under the Productivity Framework for selected projects, from the financial benefit estimation established baselines through to the final reported actual benefits in the Productivity Benefits Report. The Productivity Framework is a structured program developed by the Business Transformation department to identify, measure, and report increases in productivity and cost savings in both capital and operating, maintenance, and administration (OM&A) spending across Alectra. The Productivity Framework was developed and rolled out in 2023 and was based on projects that were planned in 2022. The Productivity Framework has been integrated with the Corporate Planning process.

The audit review focused on the following objectives:

1. Review the calculations and accuracy of productivity improvements reported.
2. Assess the methodologies for establishing baselines.
3. Assess the quality of data used for estimation of benefits and actuals calculation.
4. Review the allocation of year-to-date benefits between incremental and prior year sustained savings.

The audit approach was discussed with Management and testing was completed for the audit scope period from January 1, 2023, to March 31, 2024, inclusive.

The scope of the review was as follows:

- Assessed compliance with written procedures for the Productivity Benefits process;
- Assessed if the Productivity Benefits that have been reported are supported by relevant documentation;
- Assessed the Productivity Benefits that are being reported in comparison to the measurement methodology proposed in the initiative brief;
- Reviewed the calculations and accuracy of productivity improvements reported;
- Reviewed the allocation of year-to-date benefits between incremental and prior year sustained savings for select projects;
- Compared actual incremental benefits for Q1, 2024 to initial business case financial benefit estimate; and
- Determined, on a sample of reported projects:
    - reperformed the supporting calculations to verify accuracy;
    - reviewed supporting documentation, such as:
        - the initiative brief including the baseline values;
        - calculation model;
        - approval from business unit owner;
        - agreement with the reported Productivity Benefits;
    - checked that formulas were consistently used;
    - verified the reference material used; and
    - determined whether assumptions regarding savings types were adequately supported.

The **out-of-scope** areas for this review were as follows:

- The verification of the accuracy of inputs for projects in Copperleaf.

- Other non-financial benefits reported in Copperleaf not related to financial Productivity Benefits.

The audit methodology included:

- Examination of policies and procedures, standards, guidelines, and frameworks existing at the time of audit;
- Interviews and inquiries with key management and operational staff as well as process walk-throughs;
- Performance of detailed testing on selected samples; and
- Performance of analytical procedures (if applicable) to understand trends and other anomalies using specialized audit software.

Our audit was conducted in conformance with professional standards established by the Institute of Internal Auditors. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

After a review of the process and supporting information, no material errors were noted. In general, there are controls in place to manage the Productivity Benefits reporting process. Opportunities for improvement in the design and operating effectiveness of controls, were identified in the specific areas summarized below:

1. **Supporting back up within Efficiency Benefits category (Medium):**
   Four of the six (67%) projects reviewed had reported benefits within the Efficiency Benefits category. For these projects, baseline values were not available for the initiative briefs which did not allow for the calculation of actual efficiency benefits from inception. Additionally, for the ERP Continuous Improvements project with $903K reported benefits for 2023, a sample of change requests was reviewed and there were no baselines or original time for the tasks to perform an adequate assessment of the achieved efficiency benefits.

2. **Errors noted in reported Productivity Benefits calculations (Medium):**
   YTD actual incremental savings for the Locates project reported as $991K for 2023 was overstated by $26K (3%), due to errors discovered by Business Transformation (BT) team after the fact, during their preparation of the 2024 model. The quantification of the error was performed by Internal Audit. Internal Audit noted two manual errors in the calculation for the ServiceNow Expansion project where the 2023 Prior Year Sustained savings was understated by $29K (8%) and the Q1, 2024 YTD actual incremental savings had a small understatement of $4K.

3. **Lack of variance analysis to estimated savings and forecasts (Low):**
   It was noted that for the Productivity Benefits for 2023 and Q1, 2024, the BT Team did not perform variance analysis of the reported actual Productivity Benefits to the established estimated savings or forecasts.

Overall Assessment: Effective, with opportunity for improvement

2. Good Client Practices

At its most detailed level, the Productivity Framework tracks “initiatives” that represent specific, calculable measurements of productivity. Proposed Alectra initiatives must meet certain criteria to be included in the Productivity Framework, ensuring that the initiative must be measurable, verifiable, and auditable.

A sample of six project initiatives were selected and assessed for the productivity benefit type (expected reduction, avoided cost, and efficiency benefit) and it was noted that the calculation models for each were comprehensive with varying levels of complexities. This level of detail is indicative of the robustness and rigor that has been built into the program by the BT Team.

For the ERP Continuous Improvements project, the BT team implemented the requirement of a time study for each change request. This allows adequate assessment of the achieved efficiency benefits for each change request. This proactive approach reflects a strong commitment to continuous improvement and operational excellence.

Refer to Section 4 – for Detailed Observations and Recommendations.

3. Acknowledgement of Review

Name and Title	Signature	Date
Annabel King Director, Organizational Improvement	Provided via email	July 24, 2024
Nathalie McLauchlin VP, Business Transformation	Provided via email	July 23, 2024
Barb Gray EVP, People & Transformation	Provided via email	July 25, 2024

4. Detailed Observations and Recommendations

The following observations and recommendations were identified. The definitions for the ratings are provided in **Appendix A**.

Observation #1 **Priority: Medium**	**Supporting back up of Efficiency Benefits category (Operating Effectiveness)**
	Internal Audit requested the back-up documentation for a sample of six projects with Productivity Benefits reported in the year end 2023 report and Q1, 2024 report. Four of the six projects reviewed (67%) had reported benefits in the Efficiency Benefits category. For these projects, baseline values were not available for the initiative briefs. It was noted that the non-availability was due to pilot initiatives or recently completed projects, and no original baselines had been determined for the financial benefits framework for projects commencing prior to 2023. This issue was raised in Internal Audit's review of the Productivity Benefits Framework in 2023. The ERP Continuous Improvements project had the highest reported efficiency benefits of $903K for 2023, with 85% relating to 2022 change requests. Internal Audit selected a sample of five 2022 change requests with savings greater than 1000 hours, to perform additional testing of the underlying assumptions and calculations. The BT team was unable to provide further supporting documentation. The only information available were the time and human resources estimates provided by the business units. There were no baselines or original time for a task for each change request to perform an adequate assessment of the achieved efficiency benefits. There is a risk if the savings are not validated up front for accuracy, none of the other projections or actual benefits/savings achieved are valid. There is a risk that the basis (baseline) for the Productivity Benefits or other support may have errors, resulting in inaccurate reporting if requested by the OEB. Even a low estimate, which is not adequately supported, may be challenged and not be defendable if questioned by the OEB.
Recommendation	We recommend that Management requires that Business Unit owners provide a baseline for the projected savings in the Efficiency Benefits category. Additionally, for the ERP Continuous Improvement project, Management is to ensure that a baseline is calculated for each completed change request in the program. The baseline values form the basis of the measurement for a project, as per the Productivity Benefits Framework methodology. Without that, it would be difficult to accurately measure the productivity gains of a project.

Response from Management	Due to the timing of the launch of the Productivity Framework, efficiency benefits reported in 2023 related to projects and initiatives completed in prior years, where the establishment of baselines after the initiatives were implemented, were no longer available to the BT team. Furthermore, as noted in section 2, the BT team has worked with the business to implement the requirements of a time study for change request in the ERP and CC&B continuous improvement projects and is working with other areas of the business to do the same. The BT team has committed to continue measuring and reporting efficiency benefits, however as of 2024 efficiency benefits are no longer part of the Balance score card target, as the focus for the organization and likely the OEB is on Expected Reductions. The BT team will update the process and on a go-forward basis to only report Efficiency Benefits for projects where baselines have been established.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: December 31, 2024

Observation #2 **Priority: Medium**	**Errors noted in reported Productivity Benefits calculations (Operating Effectiveness)**
	The total Productivity Benefits reported as of December 2023 were $4.3M (actual incremental) and $1.5M (Prior Year sustained) respectively. Internal Audit reviewed the calculations for a sample of five projects and errors were noted in the calculation for two projects (40%) as follows: 1) Errors were noted in the recalculation of the 2023 actuals for the Locates project. The error was discovered by the Business Transformation (BT) team when they calculated the revised ratios after discovering errors in the source data and used the new ratios in the Q1, 2024 calculation model. However, the financial impact on the 2023 reported figures was not assessed nor restated by the BT team before this audit review. The YTD actual incremental savings for the Locates project reported as $991K, was overstated by $26K (3%). Internal Audit recalculated the Central North and Guelph regions' savings based on the BT team's revised 2023 Locates Service Providers (LSP) units per tickets ratios, applying the revised logic to the 2023 numbers to determine the financial impact. 2) The 2023 Prior Year Sustained savings for the ServiceNow Expansion project reported as $350K, was understated by $29K (8%), due to manual errors in the calculation when Internal Audit reperformed the calculation. 3) The total Productivity Benefits reported for Q1, 2024 were YTD Actual Incremental of $1.1M. Internal Audit reviewed the calculations for a sample of five projects and for the ServiceNow Expansion project reported as $181K. Manual errors in the calculation were noted, resulting in a small understatement of $4K. Inaccurate calculation of Productivity Benefits results in the misstatement of reported amounts and the value of the corporate scorecard metric being incorrect.
Recommendation	We recommend that Management develops a more detailed review process of the calculations for Productivity Benefits to ensure greater accuracy. This may include second-level review, peer reviews or spot checks. The calculation models used are highly manual and thus prone to human error. We recommend that Management develops a process to report significant errors identified in previously reported Productivity Benefits amounts. The process should include a materiality threshold and a sign off process by the VP/EVP.

Response from Management	The Productivity Framework aims to strike the right balance between the time and effort required by organization to measure and verify benefits and the total value of the benefits to the organization, limiting the investment to not more than 5% of the value of the Benefits. The BT will develop a process to perform secondary peer review within the BT team. The BT team will develop a process to report significant errors identified in previously reported Financial Benefits.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: March 31, 2025

Observation #3 **Priority: Low**	**Lack of variance analysis to estimated savings and forecasts (Design Effectiveness)**
	It was noted that for the Productivity Benefits for 2023 and Q1, 2024, the BT Team did not perform variance analysis of the reported actuals Productivity Benefits to the estimated projects' savings or forecasts. Based on discussions with the BT team, they have not performed a comparison to estimated savings versus actuals due to the projects being planned in 2022 and the Productivity Framework being developed in 2023. Additionally, based on inquiry, comparisons to forecast information were not performed by the BT team for the audit period. It was discussed that the BT Team plans to perform variance analyses in 2024 to improve the process. The absence of an efficient variance analyses process for projects' actuals vs. estimated savings and forecasts may result in undetected inefficiencies in the estimation process of savings being undetected.
Recommendation	We recommend that Management formalize the variance analysis process to ensure that materiality limits are defined and large deviations from projected savings are investigated. This variance analysis should ideally occur on a regular basis and be included in the reporting to the Executive Committee to ensure that Productivity Benefits are adequately tracked and monitored.
Response from Management	The BT team will formalize the variance analysis process to ensure that materiality limits are defined and large deviations from projected savings are investigated.
	Accountable Parties: Nathalie McLauchlin VP, Business Transformation
	Estimated implementation date: March 31, 2025

Appendix A:

Risk Rating Key

The following findings rating system has been established for evaluating the urgency of recommendations to be addressed:

Classification	Definition
High	• A significant breakdown in the control environment (i.e. process, controls), which should be corrected immediately to avoid possible financial or operational impact or reputational damage; or • An important issue is identified that could negatively impact the achievement of objectives; or • A legal non-compliance that could result in prosecution or significant penalty.
Medium	• A moderate breakdown in the control environment (i.e. process, controls) which should be corrected as soon as possible to avoid possible financial or operational impact or reputational damage; or • Issues are identified that could negatively impact the efficiency and effectiveness of operations; or • A legal non-compliance that could result in an order, fine or notice of violation.
Low	• A minor breakdown in the control environment (i.e. process, controls) that on its own may have minimal impact but combined with other findings or left unattended has the potential to escalate; or • The observation should be corrected in due course to avoid further repercussions or improve the current situation; or • Issues identified are less significant, but opportunities exist that could enhance operations; or • A legal non-compliance that is administrative in nature and unlikely to escalate to something more serious.

JT-3.8

Attachment 2
Status Full Internal Audit Reports

Report Issue Date	Internal Audit Report Name	Observ. #	Title of Observation	Due Date	Status Update
04/2019	22. Capital vs Operating cost review	1	Time billed to projects not captured or inconsistently captured.	31 Dec 2020	Completed
04/2019	22. Capital vs Operating cost review	2	No process owner to drive formalized procedure documents.	31 Dec 2020	Completed
04/2019	22. Capital vs Operating cost review	3	Inconsistency with set-up of capital work orders.	October 31, 2019	Completed
09/2019	26. Sustained Synergies	1	Duplicated Synergy savings	Sep-19	Completed
09/2019	26. Sustained Synergies	2	Discrepancies with reported values	Sep-19	Completed
01/2020	33. Synergy Savings & Transitional Costs 2019 Year End Review	1	Discrepancies with reported values	Mar-20	Completed
01/2020	33. Synergy Savings & Transitional Costs 2019 Year End Review	2	Classification of sustained synergies	Immediate	Completed
01/2020	33. Synergy Savings & Transitional Costs 2019 Year End Review	3	Discrepancies between severance liability worksheet and signed agreements	Immediate	Completed
06/2020	37. Economic Evaluation Model	1	Delay in status change after energization and settlement of project	Sep-20	Completed
06/2020	37. Economic Evaluation Model	2	Payment approval in JDE/TAP	Aug-20	Completed
06/2020	37. Economic Evaluation Model	3	Economic evaluation model for Guelph	Aug-20	Completed
06/2020	37. Economic Evaluation Model	4	Procedure documentation in Finance and Network Services	Mar-21	Completed
06/2020	37. Economic Evaluation Model	5	Customer input information	Sep-20	Completed
06/2020	37. Economic Evaluation Model	6	Approval of the economic evaluation model template and process manual	Mar-21	Completed
12/2020	41. Shared Services	1	Cost allocation model outdated	Sep-21	Completed
12/2020	41. Shared Services	2	Draft service level agreement	Sep-21	Completed
12/2020	41. Shared Services	3	Lack of process documentation	Mar-22	Completed
12/2020	41. Shared Services	4	Manual aspects of cost allocation process	Mar-22	Completed
05/2021	47. Budgeting	1	Budget process delays	Oct-21	Completed
05/2021	47. Budgeting	2	Headcount process delays	Sep-21	Completed
05/2021	47. Budgeting	3	Use of Asana tool in monitoring the budgeting process	Oct-21	Completed
05/2021	47. Budgeting	4	Documentary evidence of budget approval	Nov-21	Completed
05/2021	47. Budgeting	5	Cognos TM1 user termination not performed on a timely basis	Oct-21	Completed
05/2021	47. Budgeting	6	Draft budget process documents	Oct-21	Completed

Report Issue Date	Internal Audit Report Name	Observ. #	Title of Observation	Due Date	Status Update
07/2021	49. Fleet Services	1	Underutilization of light vehicles	Q4,2023	Completed
07/2021	49. Fleet Services	2	Funding from Fleet capital budget for net new headcount	Q1, 2022	Completed
07/2021	49. Fleet Services	3	Monitoring exceptions within the Fleet Processes	Q2, 2022	Completed
07/2021	49. Fleet Services	4	Accuracy of the fleet asset database	Q1, 2022	Completed
07/2021	49. Fleet Services	5	Formalized processes and documentation	Q2,2023	Completed
07/2021	49. Fleet Services	6	User access to Fleet IT sub-systems	Q1, 2022	Completed
01/2022	54. Software Asset Management (SAM) Assessment	1	Governance & Process	Q4,2022	Completed
01/2022	54. Software Asset Management (SAM) Assessment	2	Data Quality / Reporting Capabilities	Q4,2023	Completed
01/2022	54. Software Asset Management (SAM) Assessment	3	Publisher Onboarding & Data Connectors	Q4, 2024	Completed
01/2022	54. Software Asset Management (SAM) Assessment	4	Mitigate High Risk Compliance Areas	Q4, 2024	Completed
01/2022	54. Software Asset Management (SAM) Assessment	5	Organizational Integration	Q4, 2024	Completed
04/2022	59. Guelph Hydro ERP Integration "Project Harmony" Report #2	1	Testing documentation missing	Completed	Completed
04/2022	59. Guelph Hydro ERP Integration "Project Harmony" Report #2	2	Business requirements document	Completed	Completed
06/2022	61. New Connections	1	Inconsistencies in customer payments processing	Q4,2022 (Payment process improvement) Q4,2023 - Online Payments	Risk assumed
06/2022	61. New Connections	2	New connection requests monitoring	Q4,2022	Completed
06/2022	61. New Connections	3	Review of field activity completion time	Q4,2022	Completed
06/2022	61. New Connections	4	Inconsistent methods of distribution of field activities	Q4,2022	Risk assumed
06/2022	61. New Connections	5	Draft procedure documentation	Q1,2023	Risk assumed
06/2022	61. New Connections	6	User access to SilverBlaze system	Q3,2022	Completed

Report Issue Date	Internal Audit Report Name	Observ. #	Title of Observation	Due Date	Status Update
12/2022	64_Green Energy & Technology (GRE&T) Centre	1	Lack of process documentation	Q4,2023	Completed
12/2022	64_Green Energy & Technology (GRE&T) Centre	2	Timely review of quarterly reporting to external business partners	Q4,2023	Completed
12/2022	64_Green Energy & Technology (GRE&T) Centre	3	Confidentiality & intellectual property obligations for employees	Q1,2023	Completed
01/2024	77.Productivity Reporting Framework	1	Supporting back up of Productivity Benefits	Q1, 2024	Completed
01/2024	77.Productivity Reporting Framework	2	No formal approval of Productivity Benefits Framework	Q1, 2024	Completed
01/2024	77.Productivity Reporting Framework	3	Productivity Benefits Framework foundational documents to be finalized	Q3, 2024	Completed
01/2024	77.Productivity Reporting Framework	4	Approvals of individual projects for Productivity Framework	Q1, 2024	Completed
07/2024	84. Productivity Benefits - Selected Projects	1	Supporting back up of Efficiency Benefits category	Q4, 2024	Completed
07/2024	84. Productivity Benefits - Selected Projects	2	Errors noted in reported Productivity Benefits calculations	Q1, 2025	Completed
07/2024	84. Productivity Benefits - Selected Projects	3	Lack of variance analysis to estimated savings and forecasts	Q1, 2025	Completed
05/2025	94. Contact Centre Productivity and Efficiency	1	Non-compliance with OEB service standards and insufficient oversight of third-parties KPIs	Dec-25	Completed
05/2025	94. Contact Centre Productivity and Efficiency	2	The escalation resolution process requires strengthening	Dec-25	Completed
05/2025	94. Contact Centre Productivity and Efficiency	3	Inefficient After Call Work practices (ACW), elevated Average Handle Time (AHT), and high call Transfers impacting the Contact Centre performance	Dec-25	Completed
05/2025	94. Contact Centre Productivity and Efficiency	4	Inadequate monitoring of adherence to allocated schedules and idle time	Dec-25	Completed
05/2025	94. Contact Centre Productivity and Efficiency	5	IVR and website design require improvement	Dec-25	In Progress
05/2025	94. Contact Centre Productivity and Efficiency	6	Optimizing the Quality Assurance (QA) framework for improved oversight	Dec-25	Completed
05/2025	94. Contact Centre Productivity and Efficiency	7	Enhancing Quality Assurance (QA) coverage and call selection to strengthen customer experience monitoring	Dec-25	In Progress
05/2025	94. Contact Centre Productivity and Efficiency	8	Need for enhanced customer experience integration and technology enablement	Risk Assumed	Risk assumed
05/2025	94. Contact Centre Productivity and Efficiency	9	Shifting from reactive Work Force Management (WFM) forecasting model to predictive Planning	Dec-25	In Progress

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.9

Reference: 1-SEC-8 and 1-SEC-12

Reconcile the information in 2023, 2024, and 2025 to SEC-12.

RESPONSE:

The productivity improvement results reported on the Corporate Balanced Scorecard are reported on a different basis to the benefits presented in the pre-filed evidence and 1-SEC-12_Attachment 1_Framework Initiatives. The difference is primarily driven by the Scorecard results being measured against a year over year incremental target. For 2024 and 2025 it was for expected reduction only and incorporates an 8% capital revenue requirement factor applied to all capital benefits. A reconciliation is provided in Table 1 below.

Table 1 - Reconciliation between the Corporate Balanced Scorecard and savings shown in 1-SEC-12_Attachment 1_Framework Initiatives for 2023, 2024 and 2025.

		$M 2023	$M 2024	$M 2025
	Categories of Benefits included in the Scorecard Target	*Expected Reduction Avoided Costs Efficiency Benefits*	*Expected Reduction*	*Expected Reduction*
A	**Productivity Improvement results Corporate Balanced Scorecard (1-SEC-8)**	**4.3**	**5.3**	**3.7**
B	Add: Prior Year Sustained Savings	1.5	3.6	8.2
	Total Net savings	**5.8**	**8.9**	**11.9**
C	Add: capital savings equivalent for CRR factor	-	1.9	3.8
D	Other Adjustments	(0.5)	0.2	(0.4)
E	Add: Operating Costs included as offset in Scorecard results	0.6	0.8	1.2
	Gross Benefits for Framework Initiatives, Newly Added and Innovation (1-SEC-12)	**5.9**	**11.9**	**16.6**

Notes:

A: Incremental (year over year) savings reported in the Corporate Balanced Scorecard. For 2023, all categories were reported against the target and in 2024 and 2025, only the Expected Reduction savings were reported against the target.

B: 1-SEC-12 shows total savings, therefore for the purpose of this reconciliation prior year sustained savings are added back. Prior year sustained savings are explained in Exhibit 1, Tab 6, Sch 4, page 8.

C: For the Corporate Balanced Scorecard, capital savings are stated after the application of an 8% capital revenue requirement factor.

D: Other adjustments due to factors such as timing differences and materiality.

E: For the Corporate Balanced Scorecard, incremental ongoing operating costs are netted from the results as that is how our internal target was set to provide operational budget accountability.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.10

Reference: 1-SEC-15

Provide, for each function listed in Table 1-9-9 referenced in 1-SEC-15, the total number of positions at the time of the merger and the total number of positions proposed for 2027.

RESPONSE:

The table below displays the total number of budgeted positions by function at the time of the merger, as well as the positions proposed for 2027, following the same format as Table 1-9-9. This data has been compiled on a best-efforts basis, by mapping all positions within their respective program to the functions listed in table 1, which is consistent with the historical synergy reporting structure. The figures reflect permanent union and non-union positions, and do not include student or temporary positions.

Table 1 - Number of Positions at the Time of the Merger and Proposed for 2027 by Function

Function	Number of Positions at the Time of the Merger	Number of Positions Proposed for 2027
Network Operations	631	654
Network Services	151	228
Regulatory	28	25
Business Transformation	12	19
Customer Service	246	200
Finance	86	84
Legal	6	8
Metering	80	101
Government & Corporate Relations	15	12
Information Technology	109	119
Supply Chain	106	89
People & Safety	63	58
Executive Office	5	-
Internal Audit & Enterprise Risk Management	5	4
Total	**1,543**	**1,601**

Positions in the programs listed below have been mapped to the **Network Operations** function.

- Overhead Inspections and Maintenance
- System Control
- Stations
- Records and Mapping Services
- Cable Locates
- Program Delivery
- Vegetation Management
- Underground Inspections and Maintenance

Positions in the programs listed below have been mapped to the **Network Services** function.

- Distribution Design

- Asset Management

The overall growth in positions when comparing the number of positions proposed for 2027 to the number of positions at the time of the merger is largely concentrated in the Network Services, Network Operations, and Metering functions, partially offset by a reduction of positions in Customer Service and Supply Chain. The significant factors contributing to these fluctuations are outlined below, with relevant references to the Workforce Planning evidence where these drivers are discussed in greater detail.

Network Services

Growth in Distribution Design resources including Design Technologists, Leadership roles, and Analysts and Engineers are necessary to support increase in work volumes associated with capital programs and to enhance our ability to support customer service requirements and delivery. A portion of planned resources are being added in the bridge years, in order to allow for timely onboarding and training, so that new staff are ready and equipped to efficiently execute work in the next rate term. Please refer to Exhibit 4, Tab 3, Schedule 3, Page 9 for further elaboration.

Growth in Asset Management resources are necessary to support development of the 2027-2031 DSP and to support incremental workloads across grid modernization, system planning and electrification, capital investment planning and tracking, asset sustainment and standards, and leadership roles. Please refer to Exhibit 4, Tab 3, Schedule 3, Page 16 for further elaboration on the requirements for these positions.

Network Operations

Growth in Overhead Inspections and Maintenance, Underground Inspections and Maintenance, Cable Locates, and Vegetation Management are necessary to expand internal resource capacity to execute distribution capital and maintenance work relating to System Access, System Renewal, and System Service work. For more details, please refer to Exhibit 4, Tab 3, Schedule 3, Page 8.

Growth in System Control was necessary to address resource shortages and to stabilize the high attrition rate observed in this program historically. Over the bridge years and upcoming rate term, additional resources are necessary to manage increased volumes of field work resulting from the execution of Alectra Utilities' investments plans. For more details, please refer to Exhibit 4, Tab 3, Schedule 3, Page 14.

Network Metering

Growth in Network Metering resources are necessary, driven by the AMI renewal project, which is necessary to replace end-of-life AMI 1.0 meters. For more details, please refer to Exhibit 4, Tab 3, Schedule 3, Page.

Customer Service

Customer Service achieved significant headcount reductions as a result of the merger through eliminating duplicate or similar roles, process improvements and efficiencies, and IT systems consolidations. Customer Service partially offset these reductions with additional resources that were necessary to manage higher customer arrears, higher customer inquiries, supporting technology platforms to maintain regulatory compliance, revenue assurance, and cost-effective delivery, as well as resources to address projected increases in the volume of customer interactions over the forecast period. For more details, please refer to Exhibit 4, Tab 3, Schedule 3, Page 8.

Supply Chain

Supply Chain reductions achieved as a result of the merger were partially offset by projected increases that are required to accommodate increased workload related to sourcing materials and services for Alectra Utilities' capital and maintenance programs. Please refer to Exhibit 4, Tab 3, Schedule 3, Page 28 for further elaboration.

Executive Office

Please be advised that the Executive Office positions reported at the time of the merger include Alectra Inc. employees, unlike the 2027 projections, which exclude them.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.11

Reference: Updated Appendix 2K

On a best-efforts basis, provide a revised version of Appendix 2K. Can be provided showing all Alectra-related compensation costs paid by ratepayers including compensation for Alectra affiliates and holding company employees performing work for the utility.

RESPONSE:

Alectra completed Appendix 2K in accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications. The requested information entails producing a version of Appendix 2K that does not align with the OEB's Filing Requirements. As such, the utility is unable to provide the requested information.

To be helpful, the table below summarizes the labour-related net shared corporate services allocated to Alectra Utilities. These costs are presented on a net basis, which means that it is showing the costs allocated to Alectra Utilities less the costs that Alectra utilities allocates to other entities.

Table 1 – Net Labour-Related Shared Corporate Services

2027	2028	2029	2030	2031
$ 4,176,536	$ 4,189,426	$ 4,137,269	$ 4,213,566	$ 4,311,790

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-3.12

Reference: 4-CCC-42

Explain why the labour cost for the Business Transformation team is increasing by 11 percent between 2025 and 2027 despite the decrease in FTEs.

RESPONSE:

The Business Transformation labour costs are increasing primarily due to inflation and the addition of a resource to improve project outcomes, engagement and employee adoption of changes.

We also note that, based on Alectra's internal tracking methodology, FTEs associated with internal transfers are recorded in full within the organizational unit in which the employee resides at year-end (rather than being prorated), while labour costs are tracked and allocated to each business unit based on where the work was performed over the course of the year. As a result, in 2025 the Business Transformation reported FTE count reflects two employees who were part of that group for only a portion of the year and, accordingly, only a portion of their costs are reflected in the segment. Neither of those positions are included in the 2027 plan.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-3.13

Reference: Exhibit 4, Tab 3, Schedule 5, Attachment 4-7

To request that Mercer add a column to their table on page 5 of their study that links the position grades to union, non-union, management, and executive employees.

RESPONSE:

Response provided by Mercer

The methodology used in the Mercer study focused on assessing Alectra's market positioning for total remuneration across its non-executive workforce. To do this, a representative sample of non-executive benchmark jobs were selected across grades within the organization.

The methodology of the study did not focus on the employee categories in the manner being requested; as such, the request to link position grades to the requested employee categories would risk misinterpretation of the study results. Further, we specifically note the following:

1) As mentioned in the report, the study did not include executive jobs.
2) Alectra's union jobs do not have grades, and as such, a breakdown of results could not be provided on this basis.
3) The study's methodology does not separate the non-union and management workforce. Specifically, some grades are comprised of the two categories.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-3.14

Reference: 4-CCC-62 and Updated Appendix 2K

Provide a breakout of overtime between OM&A and Capital.

RESPONSE:

The breakdown of 2027-2031 Overtime between OM&A and Capital is presented in Table 1 below:

Table 1 - 2027-2031 Overtime

	2027	2028	2029	2030	2031
Operating	6,623,011	6,755,966	6,959,511	7,248,998	7,394,899
Capital	9,291,445	9,477,274	9,666,820	9,860,156	10,057,359
Total	15,914,456	16,233,241	16,626,330	17,109,154	17,452,258

In the course of preparing this undertaking response, Alectra became aware of an error in the "Less: Adjust for Overtime/Premiums" line in Interrogatory Response 4-CCC-62, Table 1, which had been inadvertently held flat across all years. A corrected version of the table is provided as Table 2 below and includes a separate breakout of the adjustments for Overtime and Premiums. This update has no impact on the effective vacancy rate reflected in the application.

Table 2 - 2027-2031 Vacancy Provision

Vacancy Provision Calculation (OM&A)	2027	2028	2029	2030	2031
Total Compensation - per Schedule 2-K (OM&A)	183,402,837	196,158,291	210,752,435	220,553,095	229,751,047
Add Back: Vacancy Provision - Other Recoveries	8,504,522	9,205,696	9,877,743	10,338,768	10,769,100
Less: Adjust for Overtime	(6,623,011)	(6,755,966)	(6,959,511)	(7,248,998)	(7,394,899)
Less: Adjust for Premiums	(2,057,450)	(2,108,623)	(2,161,333)	(2,215,622)	(2,269,543)
Compensation applicable for Provision (OM&A)	183,226,898	196,499,398	211,509,334	221,427,243	230,855,706
Vacancy Rate	**4.0%**	**4.0%**	**4.0%**	**4.0%**	**4.0%**
Vacancy Provision @ 4%	7,329,076	7,859,976	8,460,373	8,857,090	9,234,228
Vacancy Provision included in Other Recoveries	8,504,522	9,205,696	9,877,743	10,338,768	10,769,100
Difference	**1,175,446**	**1,345,720**	**1,417,369**	**1,481,679**	**1,534,872**
Effective Provision Rate embedded in Application	**4.6%**	**4.7%**	**4.7%**	**4.7%**	**4.7%**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.15

Reference: Appendix 2K, 4-Staff-171

Provide a reconciliation between the FTEs in Appendix 2K and the number of positions being added for 2025 to 2031 that shows a breakdown of the number of FTEs, the vacancy rates translated into FTEs, temporaries and part time, and any other FTE adjustments.

RESPONSE:

The table below provides a reconciliation between the FTE's in Appendix 2-K and the number of positions being added and removed from 2025 to 2031. In addition, the table provides the vacancy rate assumptions calculated into FTE and temp/student FTE for 2025 to 2031.

Table 1 – FTE and Positions Reconciliation

	Budget						
FTE	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Permanent[1]	1470.8	1523.2	1535.9	1592.3	1666.5	1736.0	1759.0
Temps and Students	112.4	104.8	87.1	87.0	83.0	80.0	80.0
Total FTE Added[2]	79.0	20.9	88.5	78.3	72.0	26.0	16.0
Total FTE Removed	-34.3	-25.8	-32.3	-8.1	-5.5	-3.0	0.0
Total FTE after Addition and Removal	**1627.9**	**1623.0**	**1679.2**	**1749.5**	**1816.0**	**1839.0**	**1855.0**
Vacancy Assumption %	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Vacancy Assumption FTE	76.5	76.3	78.9	82.2	85.4	86.4	87.2
Total FTE (Exclude Vacancy)	**1551.4**	**1546.8**	**1600.2**	**1667.2**	**1730.6**	**1752.5**	**1767.8**

Schedule 2-K FTE Total Before Vacancy	**1627.9**	**1623.0**	**1679.2**	**1749.5**	**1816.0**	**1839.0**	**1855.0**

1. This row translates existing permanent positions into an FTE figure. New roles are included in the Total FTE Added row.

2. This row provides the FTE figure for the new positions described in 4-Staff-171, Table 1.

With respect to 2025 actuals, the actual vacancy rate for 2025 was 7.6% as indicated in 4-Staff-169 and equates to approximately 124 FTE.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.16

Reference: 4-SEC-89, Table 1 and Exhibit 4, Tab 3, Schedule 3, page 2

Advise what happened to the 20 FTEs that were not filled in 2025 and advise whether Alectra plans to hire the FTEs in 2026 that were not filled in 2025.

RESPONSE:

To clarify, Table 1 in 4-SEC-89 reflects Alectra Utilities' FTE levels each year, rather than the number of positions. FTE levels are inclusive of full-time, part-time and temporary positions. Year-to-year fluctuations in FTE levels are normal and reflect ordinary churn due to employee retirements, departures, and maternity, paternity and medical leaves.

The following is a brief explanation of factors contributing to the variation in FTE levels seen in the Customer Service program:

- Hiring of 5 positions (equating to 5 FTEs) was deferred to align a training class with a seasonally slower period in the contact center. During this interim period, third party agents were utilized to supplement staffing levels and manage peak call volumes.
- Hiring of 6 positions (equating to 6 FTEs) was delayed due to cascading recruitment impacts related to lateral internal staff movement to back fill positions allocated to projects
- Hiring of 4 positions (equating to 4 FTEs) was delayed due to recruitment challenges, including a limited pool of qualified candidates at the established salary range and instances where newly hired employees resigned shortly after commencing employment.
- Hiring of 3 positions (equating to 3 FTEs) were related to normal churn to back fill employees who left the department or were on medical leaves.

Out of approximately 20 positions not filled in 2025, Customer Service has been able to fill 18 of the positions and is actively recruiting the remaining 2 vacancies. With these positions largely filled, Customer Service does not anticipate this level of staff lag to continue into future years.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.17

Reference: 2-Staff-156 page 3, part B

Atrium to advise what principle or criteria the statement on 2-Staff-156 page 3, part b regarding six weeks being consistent with common regulatory practice is based on and advise of what common regulatory practice is.

RESPONSE:

Response provided by Atrium Economics

Atrium's reference to common regulatory practice in response to 2-Staff-156 page 3, part b reflects the industry approach of using defined sampling time studies to estimate the proportion of employee time attributable to capital versus OM&A activities when developing labour capitalization factors. Utilities typically conduct these studies over a multi-week sampling period rather than tracking activities continuously over a full year in order to balance data quality, administrative burden, and participant compliance.

Regulatory review generally focuses on whether the selected study period is representative of normal operations, rather than prescribing a specific duration. The six-week period used in this study is consistent with that approach and was selected to provide a sufficient sample of work activities while maintaining manageable reporting requirements for participants.

Various approaches are used across the industry that in our view amount to common regulatory practice. For example, capitalization methodologies may be developed using combinations of historical accounting analysis, activity-based assessments, engineering judgment, or periodic time studies. For example, a review conducted by KPMG for Pacific Northern Gas Ltd. examining overhead capitalization practices across Canadian utilities

concluded that capitalization methodologies and cost components vary across utilities and jurisdictions, reflecting differences in organizational structure, accounting practices, and operational activities. The KPMG review concluded that there is no single prescribed methodology for determining capitalization rates; rather, utilities employ approaches that reasonably allocate labour between capital and OM&A activities based on available information and operational practices.

Accordingly, Atrium's reference to "common regulatory practice" reflects the established use of representative sampling studies, and an assessment that the time period is representative of normal operations to determine labour capitalization factors, rather than a single mandated study duration or specific approach across all utilities or jurisdictions.

This statement is informed by Atrium's experience supporting utilities across multiple jurisdictions, including work performed by Atrium's lead expert, John Taylor, in relation to labour capitalization, shared services, and cost allocation matters. Mr. Taylor has been involved in the development and review of capitalization rates and common cost allocation methodologies for multiple utilities in Ontario, including Hydro One (since 2016), Alectra (since 2019), Milton Hydro (2025), and another confidential Ontario utility (2018). Mr. Taylor has also conducted shared services and affiliate cost studies in the context of major utility transactions and integrations, including AGL Resources' acquisition of Nicor Inc., the divestiture of Bay State Gas by Northern Utilities, and the reorganization of Ameren's affiliated entities across Illinois and Missouri. In addition, Mr. Taylor was the lead expert supporting Dominion Energy Transmission Inc.'s evaluation of their FERC jurisdictional overhead capitalization rates, the review and audit of shared common administrative and operating costs allocated to jointly owned generating assets, including Palo Verde Nuclear Generating Facility and San Onofre Nuclear Generation Station. These engagements, as well as Mr. Taylor's work on revenue requirement and cost of service studies across multiple jurisdictions, where affiliate transactions are often involved, provide a broad basis for understanding common industry practices.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.18

Reference: Exhibit 2B, Tab 6, Schedule 2, Attachment 2B-13, page 1

Advise whether the specific methodology mentioned by legacy PowerStream in 2013 that was approved by OEB is the same one Alectra is using now for the DLC study.

RESPONSE:

The PowerStream DLC burden allocation process and procedure previously approved by the OEB is described in EB-2012-0161 Exhibit A3, Tab 1, Schedule 3, page 2, 6-7. Alectra notes that the PowerStream process was described at a very high level in EB-2012-0161.

Alectra can confirm that the process described in the updated DLC study is materially consistent with EB-2012-0161. The DLC Study completed by Atrium provides more detail than what was provided by PowerStream so it is difficult to provide a detailed comparison.

Minor differences are noted in two areas.

1. Alectra's allocation to capital for each DLC position was quantified and validated by a third party through the Atrium Study (time study, survey, interviews) vs. internal surveys and interviews used by PowerStream.

2. PowerSteam notes that the DLC rate was applied to 'overall capital work order costs' and Alectra is unable to determine if there were any exceptions that were applied by PowerStream in practice. The updated DLC study reflects Alectra's established practice of applying the DLC rate to applicable 'Distribution Capital' costs. As a result, Alectra's methodology more accurately distributes the DLC pool costs quantified through the Atrium Study to distribution capital projects that the impacted staff would

be working on by excluding ‘General Plant’ projects and material costs from the capital allocation pool.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.19

Reference: 2-Staff-156 page 7, part F

Atrium to advise how the methodology used to develop the DLC rate is common industry practice when no formal peer comparison was performed and advise of what the common industry practice is.

RESPONSE:

Response provided by Atrium Economics

Please see the response to JT-3.17. Please note that common industry practice is interchangeable with common regulatory practice as described in JT-3.17.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

JT-3.20.1

CCMBC-1

References: Interrogatory response to 1-CCMBC-1; Exhibit 1, Tab 6, Schedule 2, Attachment 1-3, Clearspring Report, Page 16, 6 Table 2 Total Cost Benchmarking Sample

Questions:

a) How many utilities in your sample are electricity distributors?
b) How many utilities are electricity transmitters?
c) How many utilities are gas distributors?
d) How many utilities are electricity generators?
e) How many utilities are there with a combination of the above categories?
f) As far as utility business is concerned, did Clearspring make any adjustments to make utilities in the sample comparable to Alectra?

RESPONSE:

Response provided by Clearspring

a) All 82 utilities in the sample are electricity distributors.

b) Out of the 82 electric utilities in the sample, 76 of them have some transmission plant in service in the last year that they are included in the sample. A handful of these only have a small proportion of plant designated as transmission but we counted them in the number.

c) Out of the 82 utilities in the sample, 29 serve both electric and gas customers.

d) Out of the 82 electric utilities in the sample, 58 of them have some production plant in service in the last year that they are included in the sample. A handful of these only have a small proportion of plant designated as production.

e) All 82 utilities in the sample have some combination of the above categories.

f) Yes, we have made several adjustments to assure data comparability between utilities with different operational scopes. The study and the cost definition used in the study only compares electric distribution expenses plus customer care and administration and general expenses allocated to the electric distribution functions of each utility in the sample. These functions are performed by Alectra and every utility in the sample. This separation of expenses is based on the Uniform System of Accounts and the cost definition and categories that comprise Alectra's costs match those of the rest of the sample. Therefore, the cost definition for all the utilities, regardless of their functions, is based on only using electric distribution (plus customer care) expenses of each utility. To be clear, Clearspring does not include transmission, generation, or gas utility capital costs or expenses into the cost definition of the sample to assure an "apples to apples" comparison for a distribution-only utility like Alectra.

Beyond matching the cost definition and operation function of electric distribution to only those that Alectra engages in, Clearspring's model also adjusts for the potential cost-saving advantages of economies of scope that U.S. utilities may have access to because of their added functions beyond electric distribution. Clearspring's model includes a percent electric variable that adjusts the model for utilities that serve both electric and gas customers. Clearspring's model also includes an electric scope variable that adjusts the model for utilities that have transmission and/or generation expenses, in addition to electric distribution expenses.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO
COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

JT-3.20.2

CCMBC-2

According to the U.S. Energy Information Administration, there are 1,958 publicly owned electric utilities in the US, 812 electric co-operatives but only 168 investor-owned electric utilities.

a) Why did Clearspring not include any publicly owned utilities in the sample?
b) Regarding accounting standards, is Clearspring aware that distributors in Ontario are required to follow MIFRS?
c) Can Clearspring confirm that in the US utilities are required to follow US GAAP?
d) What are the main differences between MIFRS and USGAAP?
e) Is the financial data reported to FERC in USGAAP?
f) Did Clearspring make any adjustments to make the data of US utilities comparable to data of Ontario utilities?

RESPONSE:

Response provided by Clearspring

a) The publicly owned utilities are not required to report Form 1 information to the U.S. Federal Energy Regulatory Commission (FERC). Investor-owned utilities are required to make these annual filings. FERC Form 1's assure data consistency amongst the sample and when comparing cost data to Alectra. FERC Form 1 filings follow the Uniform System of Accounts. This provides a long series of robust data for the investor-owned utility dataset. This is essential, especially in the case of total cost benchmarking where estimating capital costs requires decades of continuous and reliable data for each utility in the sample. Clearspring's capital data for the dataset begins in 1947. Our capital dataset has continuous data for the entire sample spanning a 70-year time horizon. There

is no comparable dataset or possibility to construct one with the publicly owned utilities. Furthermore, most of the publicly owned utilities in the U.S. are relatively small, with a handful of exceptions. The investor-owned utilities tend to be larger in size and more comparable to Alectra Utilities (Alectra).

b) Yes.

c) U.S. FERC Form 1 filers, which is the cost data relied upon in Clearspring's study, are required to follow FERC's Uniform System of Accounts ("USofA"). It is Clearspring's understanding that the USofA generally follows US GAAP accounting standards. On the FERC's website in the "Accounting Matters" section, the Readme file states, "Jurisdictional companies are required to maintain their books and records in accordance with the Commission's Uniform System of Accounts (USofA). The USofA provides basic account descriptions and accounting definitions that are useful in understanding the information reported in the Form Nos. 1, 1-F, 2, 2A, 3Q, 6, 6Q and 60."

d) In regard to how the accounting standards may impact a benchmarking study, Clearspring understands that the move to MIFRS accounting will tend to increase OM&A somewhat and decrease capitalization of expenses. Since the benchmarking study is a total cost study and is a sum of OM&A and capital costs, this will tend to balance out and have a minimal impact on the study results. However, this does illustrate one of the reasons why a total cost study is more robust and reliable than disaggregated benchmarking which will be impacted far more by accounting changes and differences.

We also note that, while the impacts on a total cost study are minimal, from a directional perspective, the move to MIFRS accounting is likely slightly raising the calculated total costs of the company and, thus, harming Alectra's benchmark score relative to what it would otherwise be if Alectra had a consistent accounting standard across the study time period. This is because OM&A expenses are annual but capital costs are calculated using a series of plant additions going back to the early 2000's. During those early years, Alectra's predecessor utilities would have reported higher plant additions due to GAAP, which would still be raising capital costs in future years (albeit by a very small amount).

Especially since this change occurred around 15 years ago, these are minimal impacts but are serving to slightly worsen Alectra's benchmark score relative to what it would be if the data had been either consistently MIFRS or GAAP throughout time.

e) Please see the response to part (c).

f) Yes. Please see the response to JT-3.20.1, part (f) for a detailed explanation.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO
COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

JT-3.20.3

CCMBC-3

Using Wisconsin as an example, there are four Wisconsin utilities in the sample: Madison Gas and Electric Company, Wisconsin Electric Power Company, Wisconsin Power and Light Company and Wisconsin Public Service Corporation.

a) Are they all regulated utilities?
b) What is the name of the state regulator?
a) Does the Wisconsin state regulator use the same method of regulation as the OEB? If the answer is no, did Clearspring make any adjustments to make the data of Wisconsin utilities comparable to data for Ontario utilities?
b) Is Clearspring aware that electricity distributors in Ontario are required by the OEB to follow the OEB Distribution System Code?
c) Does the Wisconsin regulator have its own distribution system code? Is it the same as the OEB Distribution System Code? If the answer is no, did Clearspring make any adjustments to make the data of Wisconsin utilities comparable to data of Ontario utilities?

RESPONSE:

Response provided by Clearspring

a) Yes, they all are regulated utilities. Additionally, Northern States Power – WI also serves in Wisconsin and is in our sample.

b) The Public Service Commission of Wisconsin is the name of the state regulator.

c) No. There are differences in the methods of regulation between Wisconsin and Ontario. The comparability adjustments made to the data are described in Clearspring's response to JT-3.20.1, part (f). No other adjustments for regulatory differences between jurisdictions are made.

d) Yes, we are aware in a general sense.

e) We would assume Wisconsin has a code but have not investigated it. We do not know if it is the same as Ontario's or not. Please see our response to part (c) of this response and our response to JT-3.20.1, part (f) in regard to the adjustments made.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.1

1.0 Reference: SEC 69 b) Exhibit 3, Attachment 3-2, Tables 1, 7, and 8

Preamble:

The response to SEC 69 b) states: "Alectra Utilities confirms that it re-ran the load forecast, based on the updated historical data up to December 2025 and the most recent Conference Board of Canada economic forecast."

1.1 Please update Tables 1, 7 and 8 in Attachment 3-2 based on the Conference Board of Canada economic forecasts used to re-run the load forecast models in response to SEC 69 b).

RESPONSE:

Response provided by Itron

1.1 Please see Tables 1 to 3 below, respectively, to Tables 1, 7, and 8 in Attachment 3-2.

Table 1 – Toronto CMA Economic Outlook

Year	Population	Chg_Pop	Real GDP	Chg_GDP	Employment	Chg_Emp
	(1000's)		(millions)		(1000's)	
2017	6,256.23		383,902.77		3,187.10	
2018	6,372.55	1.9%	396,275.48	3.2%	3,253.95	2.1%
2019	6,466.90	1.5%	405,936.15	2.4%	3,359.20	3.2%
2020	6,478.77	0.2%	388,195.87	-4.4%	3,179.10	-5.4%
2021	6,514.17	0.5%	412,552.30	6.3%	3,360.58	5.7%
2022	6,700.23	2.9%	429,536.91	4.1%	3,519.91	4.7%
2023	6,969.08	4.0%	436,597.30	1.6%	3,619.05	2.8%
2024	7,213.48	3.5%	442,180.23	1.3%	3,670.63	1.4%
2025	7,249.56	0.5%	445,551.11	0.8%	3,720.04	1.3%
2026	7,234.43	-0.2%	451,727.45	1.4%	3,731.32	0.3%
2027	7,239.41	0.1%	464,054.50	2.7%	3,757.70	0.7%
2028	7,307.87	0.9%	476,684.91	2.7%	3,807.68	1.3%
2029	7,400.82	1.3%	489,718.49	2.7%	3,856.97	1.3%
2030	7,486.05	1.2%	503,190.13	2.8%	3,905.13	1.2%
2031	7,573.66	1.2%	517,061.20	2.8%	3,953.06	1.2%
Average Annual Growth						
2017 - 2024		2.1%		2.1%		2.1%
2024 - 2031		0.7%		2.3%		1.1%

Table 2 – Guelph CMA Economic Forecast

Year	Population	Chg_Pop	Real GDP	Chg_GDP	Employment	Chg_Emp
	(1000's)		(millions)		(1000's)	
2017	162.36		10,492.99		94.35	
2018	165.61	2.0%	10,883.11	3.7%	92.40	-2.1%
2019	168.91	2.0%	11,054.06	1.6%	94.54	2.3%
2020	171.66	1.6%	10,441.10	-5.5%	88.09	-6.8%
2021	174.67	1.8%	11,052.22	5.9%	96.09	9.1%
2022	178.20	2.0%	11,429.17	3.4%	100.23	4.3%
2023	181.62	1.9%	11,483.30	0.5%	103.85	3.6%
2024	184.73	1.7%	11,383.39	-0.9%	103.01	-0.8%
2025	186.89	1.2%	11,364.87	-0.2%	99.34	-3.6%
2026	187.87	0.5%	11,522.92	1.4%	102.01	2.7%
2027	189.16	0.7%	11,818.28	2.6%	102.44	0.4%
2028	191.39	1.2%	12,152.91	2.8%	103.84	1.4%
2029	194.10	1.4%	12,497.29	2.8%	105.25	1.4%
2030	196.82	1.4%	12,851.12	2.8%	106.66	1.3%
2031	199.58	1.4%	13,214.96	2.8%	108.10	1.4%
Average Annual Growth						
2017 - 2024		1.9%		1.2%		1.4%
2024 - 2031		1.1%		2.2%		0.7%

Table 3 – Hamilton Economic Forecast

Year	Population	Chg_Pop	Real GDP	Chg_GDP	Employment	Chg_Emp
	(1000's)		(millions)		(1000's)	
2017	783.89		35,866.56		421.57	
2018	793.75	1.3%	37,008.07	3.2%	418.46	-0.7%
2019	805.98	1.5%	37,581.68	1.5%	425.36	1.6%
2020	814.77	1.1%	35,563.27	-5.4%	394.98	-7.1%
2021	822.38	0.9%	37,213.30	4.6%	420.34	6.4%
2022	834.69	1.5%	38,161.29	2.5%	429.55	2.2%
2023	851.42	2.0%	38,364.11	0.5%	425.46	-1.0%
2024	868.85	2.0%	38,445.31	0.2%	433.04	1.8%
2025	876.45	0.9%	38,529.47	0.2%	440.87	1.8%
2026	876.70	0.0%	38,985.89	1.2%	440.64	-0.1%
2027	878.18	0.2%	39,862.19	2.2%	444.54	0.9%
2028	883.57	0.6%	40,777.09	2.3%	448.92	1.0%
2029	891.21	0.9%	41,711.91	2.3%	452.26	0.7%
2030	898.84	0.9%	42,687.32	2.3%	455.57	0.7%
2031	906.48	0.8%	43,692.81	2.4%	458.82	0.7%
Average Annual Growth						
2017 - 2024		1.5%		1.0%		0.5%
2024 - 2031		0.6%		1.8%		0.8%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.2

2.0 Reference: VECC 21 a), Attachment 4_HRZ Residential Class – Coef Tab

2.1 For the HRZ Residential Customer Count model, the mEcon.Cust_Var variable has a T-stat of 1.75. Does Itron consider this result to be statistically significant and why?

2.2 What is Itron's practice with respect to including variables that are not statistically significant in the models it develops for forecasting purposes?

RESPONSE:

Response provided by Itron

2.1 While not at the 95% level of confidence, the T-Statistic of 1.75 indicates the customer model variable is still statistically significant at the 90% confidence level. The corresponding *P-value* is 8.22%, indicating that there is just an 8.22% probability that the customer variable is not contributing to the forecast. The *mEcon.Cust_Var* model variable is consistent with that constructed across the other rate zones and contributes to a reasonable customer forecast.

2.2 There is no hard-set rule as to the required level of significance for a model variable. Generally, we like to see model variables at higher levels of statistical significance (95% plus), but if a model variable should be included on a theoretical basis, we will often let the variable flow through even if it doesn't meet the 95% level of confidence, as it will provide some contribution to the forecast. Coefficients that are not highly statistically significant will have a small coefficient relative to their standard error and have just a small impact on the forecast.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.3

3.0 Reference: VECC 24 a)

Preamble:

For the GS<50 class' BRZ and ERZ customer count models the primary variable used is mEcon.Cust_Var. However for the GS<50 class' HRZ, PRZ and GRZ customer count model the primary variable used is ResCust.Predicted.

3.1 Why were different variables used in the various models?

3.2 Were both variables tested for inclusion in all five models?

RESPONSE:

Response provided by Itron

3.1 The basis of the GS<50 customer count was to tie the forecast to regional economic activity. We started with the *Cust_Var* variable (which combines population and gross regional output) in all five rate zone customer models. Through the analysis, we found that we could get a small improvement in the model fit for HRZ, PRZ, and GRZ by using the predicted residential customers that are also based on the *Cust_Var* variable.

3.2 Yes. Both variables were tested in each of the models.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.4

4.0 Reference: Exhibit 3, Tab 1, Schedule 4 SEC 69 b)

4.1 Please update Tables 3-1-6 and 3-1-7 based on the updated baseline forecast per SEC 69 b).

RESPONSE:

4.1 Please see Table 1 for updated Table 3-1-6 and Table 2 for updated Table 3-1-7 based on the updated baseline forecast per SEC 69 b).

Table 1 - Updated 2025-2031 Baseline Consumption Forecast by Rate Class (MWh)

	2025	2026	2027	2028	2029	2030	2031
Residential	8,739,403	8,403,986	8,471,631	8,553,527	8,583,758	8,632,056	8,682,229
GS<50 kW	2,870,975	2,802,874	2,808,283	2,829,797	2,839,703	2,850,643	2,862,703
GS>50 kW, Regular	10,326,791	10,076,031	10,084,596	10,158,194	10,179,520	10,204,258	10,234,424
GS>50 kW, Intermediate	2,955,086	3,052,629	3,043,610	3,047,974	3,051,928	3,055,911	3,059,933
Large User	2,028,497	2,136,881	2,136,881	2,137,102	2,161,935	2,219,212	2,219,212
LUDA	842,989	852,840	852,840	852,840	852,840	852,840	852,840
Street Lighting	92,002	93,602	94,572	94,837	94,932	94,967	94,980
Sentinel Lighting	654	601	586	571	556	541	526
USL	46,675	47,082	47,437	47,801	48,166	48,531	48,897
Total Baseline Consumption (MWh)	**27,903,072**	**27,466,526**	**27,540,435**	**27,722,642**	**27,813,338**	**27,958,959**	**28,055,743**

Table 2 – Updated 2025-2031 Baseline Billed Demand Forecast by Rate Class (MW)

	2025	2026	2027	2028	2029	2030	2031
GS>50 kW, Regular	27,433	27,133	27,155	27,278	27,410	27,477	27,557
GS>50 kW, Intermediate	6,674	6,838	6,818	6,810	6,836	6,845	6,854
Large User	3,806	3,980	3,980	3,971	4,058	4,236	4,236
LUDA	1,620	1,584	1,584	1,581	1,584	1,584	1,584
Street Lighting	259	261	264	264	265	265	265
Sentinel Lighting	2	2	2	2	1	1	1
Total Baseline Billed Demand (MW)	**39,795**	**39,798**	**39,803**	**39,904**	**40,155**	**40,409**	**40,499**

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JT-3.21.5

5.0 Reference: VECC 31 – Attachment 3, Coef Tab
VECC 33 – Attachment 1, Coef Tab

5.1 Please explain how the LoadLoss-type variables used in Itron's models were constructed.

RESPONSE:

Response provided by Itron

5.1 The load loss variables were developed by Alectra Utilities in earlier sales forecast models. The variables were retained in several of the models as they helped explain large sales variation during the COVID-19 period. Residuals in these periods appear to have been used in constructing the model variables. The impacts are small and help generate strong model coefficients for the primary model variables. Figures 1 to 3 below show the impact of these variables in the historical data period.

Figure 1 - ERZ Residential

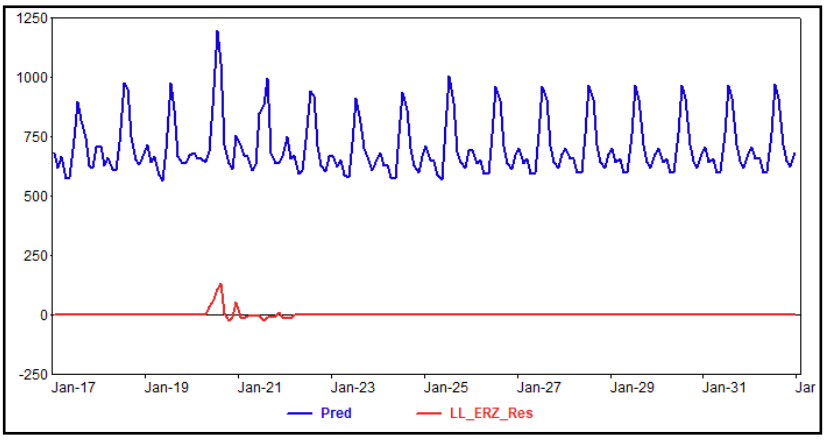


Figure 2 - BRZ GSP 50

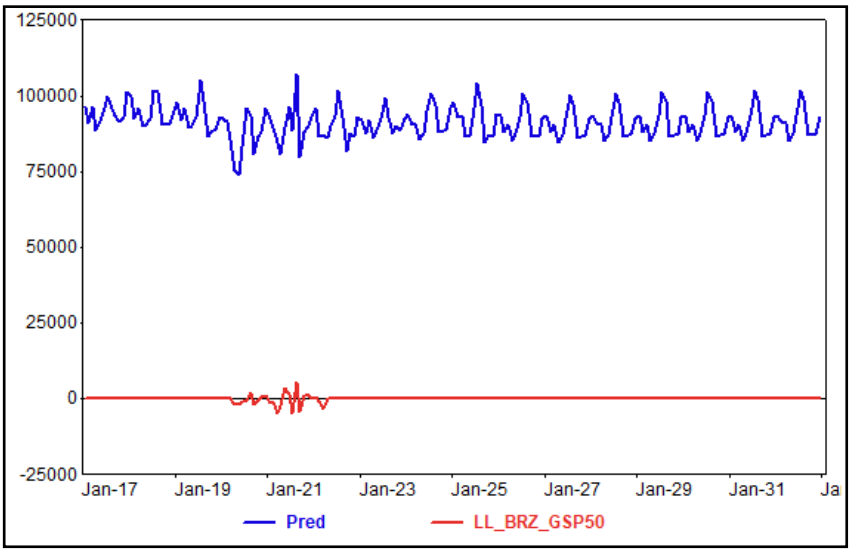
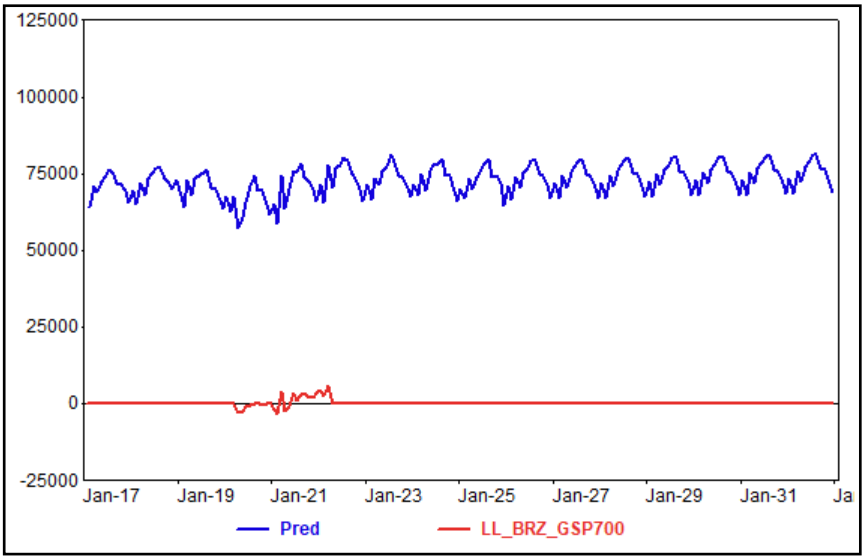


Figure 3 - BRZ GSP700



TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.6

6.0 Reference: VECC 31 b)

Preamble:

The response states: “Model variables to specifically account for the impact of COVID-19 on electricity sales were used when other explanatory variables used in the model either did not or did not fully account for the change in usage due to COVID-19. In the case of residential models, it was found that the 2020 increase in per capita real personal income had mostly accounted for the corresponding increase in energy usage due to people staying/working from home. Per capita income is used in all residential use per customer models as part of the constructed XHeat, XCool, and XOther SAE variables (please refer to section ii. above)”. (emphasis added)

6.1 Please explain how (i.e., intuitively from a cause and effect perspective) COVID-19 would lead to higher per capita real income. If there was a cause and effect relationship wouldn’t it be more reasonable to expect the opposite?

6.2 Were COVID-19 related variables (e.g. LoadLoss variables and GMR variables) both explicitly tested for inclusion in the updated (per SEC 69 b)) Residential Average Use models for each of thel five rate zones?

6.2.1 If not, why not?

6.2.2 If yes, on basis were they excluded?

RESPONSE:

Response provided by Itron

6.1 The Government of Canada introduced multiple temporary financial aid programs in response to the economic impacts of the COVID-19 pandemic in Canada. This had an impact on real per capita income (i.e., Toronto CMA - 6.6% increase in 2020, Hamilton CMA – 3.8% increase, Guelph CMA – 4.1% increase). The increase in income was correlated with an increase in residential electricity use and accounted for much of the increase in sales.

6.2 COVID-19-related variables were not explicitly tested for inclusion in the updated (per SEC 69 (b)) Residential Average Use models for each of the five rate zones.

6.2.1 COVID variables that were in the original models were left in the updated models. There was no need to further test for COVID impact, as the updated models only incorporated new sales and customer data starting May 2025. The COVID variables do not impact the forecast.

6.2.2 Not applicable.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.7

7.0 Reference: Exhibit 3, Attachment 3-2, Appendix C, page 59 VECC 32, Attachment 1, BRZ GS<50 kW Class Sales Model

Preamble:

VECC 32 b) states:"GMR variables are used to account for the impact of COVID-19 on electricity sales in those cases where other variables used (such as economic projections) either do not or do not fully account for this impact."

7.1 Were COVID-19 related variables (e.g. GMR variables) explicitly tested for inclusion in the updated (per SEC 69 b)) GS<50 sales models for all five rate zones?

7.1.1 If not, why not?

7.1.2 If yes, on basis were they excluded?

7.2 Please explain why a GMR variable was included the original BRZ GS<50 model but not in the updated BRZ GS<50 model.

RESPONSE:

Response provided by Itron

7.1.1 COVID-19-related variables (incl. GMR variable) were not explicitly tested for inclusion in the updated (per SEC 69 (b)) GS<50 kW sales models. COVID variables that were in the original models were left in the updated models. There was no need to further test for COVID impact, as the updated models only incorporated new sales

and customer data starting May 2025. The COVID variables do not impact the forecast.

7.2 GMR variable 'Peel_Retail_Rec' is included in both the originally submitted forecast and the Update forecast. The updated model statistics for the BRZ GSL50 model provided in response to 3-VECC-32 include the GMR variable.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.8

8.0 Reference: VECC 37 c) Exhibit 3, Attachment 3-2, page 34

Preamble:

The response to VECC 37 c) states: "The process for the derivation of demand was as follows:

1. Developed energy by electrification type (com buildings, EV) and rate class.
2. Aggregated energy by class.
3. Converted energy to demand using load factors based on historical relationship between energy and billing demand for each relevant class."

Attachment 3-2 states:
"Commercial electrification sales are based on system planning's expected case. System planning provided MW estimates for both new construction and retrofit by rate zone. The MW forecast is translated to energy using an average annual load factor based on an estimated commercial electric heat load factor of 0.20."

8.1 The response to VECC 37 c) indicates that, for the relevant customer classes, the impact of EVs on billing demand was determined based on the customer class' load factor. Please confirm that this is the case and, if so, explain why this is a reasonable assumption.

8.1.1 If not confirmed, please explain how the impact of EVs on billing demand was determined

8.2 With respect to commercial electrification, VECC 37 c) indicates that the MWh impacts were developed first and used to calculate the MW impacts. However, Attachment 3-2

indicates that the MW estimates were developed first and use to calculate the MWh impacts. Please reconcile.

RESPONSE:

Response provided by Itron

8.1 For demand-billed classes, the impact of EVs on billed demand was determined based on the customer's rate class load factor.

Billed demand represents the sum of individual customers' maximum demands recorded over the monthly billing period. These customer-specific maximum demands may occur at varying times throughout the day. While we recognize that an average commercial EV charging profile may be useful for understanding distribution load impacts, it cannot be reliably translated to individual customers' maximum monthly billed demands. Therefore, for revenue forecasting purposes, commercial building electrification and EV energy sales are added to the baseline commercial energy sales. Billed demand is derived by applying the rate class load factor to all energy sales within that rate class, including EV and building electrification.

8.2 The forecast flows from a building MW electrification forecast (re: Alectra Utilities System Planning forecast) to a monthly billed demand MW forecast for the demand-billed rate classes.

For each rate zone, we start with a building MW electrification forecast. We assume building electrification sales are primarily from heating; therefore, the building MW electrification forecast is converted to energy sales (MWH) using a 0.20 commercial electric heat load factor. Electrification sales MWH are then allocated to the commercial rate classes based on each class's share of 2025 billed sales, followed by allocation to baseline monthly sales based on monthly normal heating-degree-days within each rate class. Monthly billed MW demand within each rate class is estimated by applying a

billed demand load factor to total rate class energy sales, which include the EV and building electrification sales forecast.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.9

9.0 Reference: Exhibit 3, Attachment 3-2, pages 31-32 VECC 37 c)
Government of Canada's new EV Strategy https://www.canada.ca/en/innovation-science-economic-development/news/2026/02/prime-minister-carney-unveils-canadas-new-automotive-strategy-to-protect-jobs-and-position-our-country-as-a-global-leader-in-next-generation-vehicl.html

Preamble:

VECC 37 c) states: "Alectra Utilities updated the load forecast in response to 3-SEC-69. Please refer to the tables below for 2026-2031 EV and Building Electrification consumption and EV and Building Electrification billed demand based on the results of the updated load forecast. 2025 volumes are included in the historical actuals."

9.1 Is the only difference between the forecast for incremental EV MWh included in VECC 37 c) - Table 3 and the original forecast in Attachment 3-2 the fact that incremental 2025 volumes are now included in the historical data?

9.1.1 If so, please confirm that the incremental 2025 sales are assumed to be 24 GWh (i.e., the difference between the 1724 GWh for 2031 shown in VECC 37 b) – Table 3 and the 1,748 GWH referenced on page 32 of Attachment 3-2). If not confirmed, please explain why and what the assumed incremental 2025 sales included in the historical data are.

9.1.2 If not, what else accounts for the difference?

9.2 What impact does the Government of Canada's recently announced new EV strategy, which is expected to drive a 75% EV adoption rate by 2035 (as opposed to the 100%

adoption by 2035 set out in the previous Electric Vehicle Availability Standard) have on the EV MWh/MW forecast provided in VECC 37 c)?

RESPONSE:

Response provided by Itron

9.1 Confirmed. The only difference in the forecast is that the 2025 sales are now included in the starting actual sales.

9.1.1 Confirmed

9.2 Please see Alectra's response to 2-Staff-137 which is reproduced below.

As the Government of Canada's announcement to reduce import tariffs on affordable EVs was made on January 16th 2026 and the announcement indicating the launch of the Electric Vehicle Affordability Program (EVAP) and funding for charging infrastructure was made on February 5th, 2026, the specifics and details related to these government announcements are not yet available. Further, as the government's announcements identify the policy objectives to accelerate EV uptake by increasing customer options for lower-priced EVs, providing incentives and improving charging infrastructure to reduce customer concerns of range anxiety, the announcements demonstrate a commitment to EV uptake. Alectra Utilities does not expect material changes to its EV projections over the 2027-2031 planning period.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.10

10.0 Reference: VECC 39 Exhibit 3, Attachment 3-2, page 36

Preamble:

Attachment 3-2 states: “Commercial electrification sales are allocated to zones based on the rate zone’s relative share of commercial sales and residential electrification sales are allocated based on the zone’s share of residential customers.”

10.1 Since Alectra’s non-residential rate classes include both commercial and industrial customers, how were the commercial sales by rate zone determined?

10.2 How were the commercial electrification sales allocated to the customer rate classes? (Note: As Itron prepared the commercial electrification forecast but the response to VECC 39 c) was provided by Alectra it was not clear which party would be responsible for responding to this question. Please re-direct to Alectra as appropriate.)

RESPONSE:

Response provided by Itron

10.1 Upon review of the referenced material, Itron identified that the reference was incorrect. The corrected reference should read: “Alectra Utilities System Planning provided demand projections for each municipality, which were then mapped to the corresponding rate zones”.

10.2 Once converted from MW to MWH, commercial electrification sales are allocated to the General Service rate classes within each rate zone based on each class's share of the

2025 total General Service sales. The General Service electrification MWh allocation factors are shown in Table 1 below. As the rates are determined by customer demand level, we have no means to determine pure commercial from industrial sales.

Table 1 – Rate Class Allocation Factors

	Class Allocations			
%	GSL50	GSP50	GSP500/700/1000	Total
BRZ	15.742%	47.448%	36.810%	100.00%
ERZ	16.267%	48.129%	35.604%	100.00%
GRZ	14.630%	37.265%	48.105%	100.00%
HRZ	25.744%	74.256%	0.000%	100.00%
PRZ	17.090%	82.910%	0.000%	100.00%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.11

11.0 Reference: Staff 161

Preamble:

The response states: “To test whether we have missed additional CDM efficiency gains, we include a trend variable in the initial models. A negative coefficient on the trend variable would indicate that there are additional CDM savings above that captured in the SAE model variables. In every model the trend variable was either statistically insignificant or positive as it was correlated with the XOther variable. There is no indication that the model is missing the impact of CDM.”

11.1 Was the described test performed for just the Residential Average Use models or for the sales models for all customer classes?

11.1.1 If just for Residential, please provide the results of a similar test for each of the GS<50, GS>50 Regular and GS>50 Intermediate sales models.

11.2 For those models where the trend variable was positive (including any of the additional models provided in the previous question), were there any instances where the trend variable was statistically significant?

11.2.1 If yes, why wasn’t the trend variable retained in the final model used for the load forecast?

11.2.2 If yes, please provide the model (i.e., variable coefficients and related statistics) as well as the resulting 2026-2031 baseline MWh forecast for the customer class.

RESPONSE:

Response provided by Itron

11.1 and 11.2

We tested all models using a trend variable. Some of the models had a statistically significant positive trend. But in general, that trend was displacing the impact of the XOther variable, as there is a strong correlation between the two. Adding the trend variable also did little to improve the model fit statistics. But the most significant issue is that carrying the trend through the forecast reduces the impact of XOther, which is the primary forecast driver, and it captures most of the economic growth and energy efficiency.

The GSL50 sales forecast for BRZ is a good example. Figure 1 below shows the coefficient with and without the trend variable.

Figure 1 – Variable Coefficients Comparison

BRZ Sales with Trend

Variable	Coefficient	StdErr	T-Stat	P-Value	Elasticities
mStructGSL50.XOther	0.201	0.022	9.038	0.00%	0.654
mStructGSL50.XHeat	0.143	0.018	8.111	0.00%	0.078
mStructGSL50.XCool	0.053	0.005	11.150	0.00%	0.063
GMRVariables.Peel_Retail_Rec	3855.571	1541.357	2.501	1.40%	
mBin.Feb	1513.438	652.607	2.319	2.24%	
mBin.Apr	1381.828	605.569	2.282	2.46%	
mBin.Oct	-1230.552	636.665	-1.933	5.61%	
mBin.Jan19	9056.903	1718.682	5.270	0.00%	
mBin.TrendVar	128.255	68.864	1.862	6.55%	

BRZ Sales Without Trend

Variable	Coefficient	StdErr	T-Stat	P-Value	Elasticities
mStructGSL50.XOther	0.228	0.017	13.484	0.00%	0.743
mStructGSL50.XHeat	0.140	0.018	7.877	0.00%	0.077
mStructGSL50.XCool	0.052	0.005	10.963	0.00%	0.063
GMRVariables.Peel_Retail_Rec	3328.793	1533.771	2.170	3.23%	
mBin.Feb	1700.569	652.737	2.605	1.06%	
mBin.Apr	1391.225	612.977	2.270	2.54%	
mBin.Oct	-1276.011	644.002	-1.981	5.03%	
mBin.Jan19	8839.022	1735.731	5.092	0.00%	

The trend variable is statistically significant, but it reduces the power of the explanatory variable XOther. The elasticity (which gives the percentage change in sales given a percent change in XOther) drops from 0.743 to 0.654. The model fit is about the same.

Figure 2 – Model Statistics Comparison

BRZ Sales with Trend

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	99
R-Squared	0.733
Adjusted R-Squared	0.711
AIC	14.896
BIC	15.119
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-948.60
Model Sum of Squares	737,301,488.21
Sum of Squared Errors	269,211,259.17
Mean Squared Error	2,719,305.65
Std. Error of Regression	1,649.03
Mean Abs. Dev. (MAD)	1,275.31
Mean Abs. % Err. (MAPE)	4.49%
Durbin-Watson Statistic	2.147

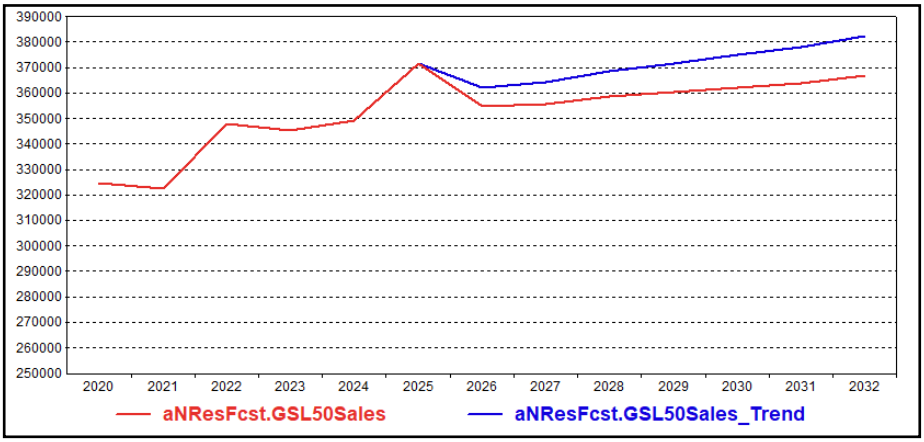
BRZ Sales Without Trend

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	100
R-Squared	0.723
Adjusted R-Squared	0.704
AIC	14.911
BIC	15.110
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-950.46
Model Sum of Squares	727,869,280.89
Sum of Squared Errors	278,643,466.49
Mean Squared Error	2,786,434.66
Std. Error of Regression	1,669.26
Mean Abs. Dev. (MAD)	1,273.52
Mean Abs. % Err. (MAPE)	4.47%
Durbin-Watson Statistic	2.091

The adjusted R-Squared with the trend is 0.711 vs 0.704 without the trend and the MAPE with the trend is 4.49% vs 4.47% without the trend.

The forecast with a positive trend variable will always be greater than the model without the trend, as the impact of XOther (which includes efficiency impacts) is reduced. Figure 3 below compares the forecast with and without the trend. The trend variable has too much of an impact and mitigates the efficiency and appropriate impact of economic activity that is incorporated in the XOther variable.

Figure 3 – GS<50 kW Energy Sales



11.2.1 We would generally not include a linear trend variable in sales forecast models unless there is no meaningful alternative.

11.2.2 It would be an onerous task to re-estimate all the forecasts with added trend variables and, for the reason discussed above, generate a forecast not tied to the economic and efficiency assumptions embedded in the forecast – a forecast that Itron would not support.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.12

12.0 Reference: Staff 158

12.1 Please reconcile or explain the following inconsistencies in the Street Lighting rate zone forecast for connection/device count and MWh for the 2026-2031 period:

- For BRZ there is a decrease in the connection count but an increase in the MWh forecast.
- For ERZ there is an increase in the device count but a decrease in the MWh.
- For PRZ there is an increase of more than 3% in devices but less than a 1% increase in MWh.

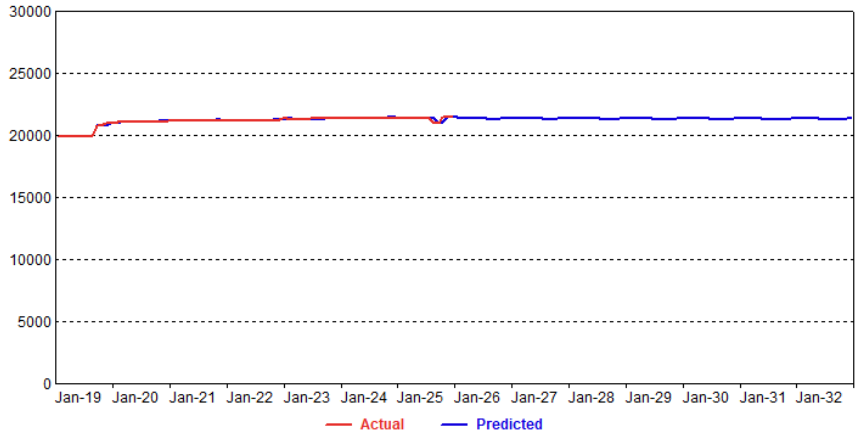
RESPONSE:

Response provided by Itron

12.1 The sales and connection/device (re: unit) count models are estimated separately, based on the historical monthly billing data. Units and sales do not always move in the same direction, as reflected in the estimated models. For ERZ and PRZ, the opposite trends are reasonable because of gains in lighting efficiency. Lighting-related energy sales are often decreasing faster than the increase in the number of units.

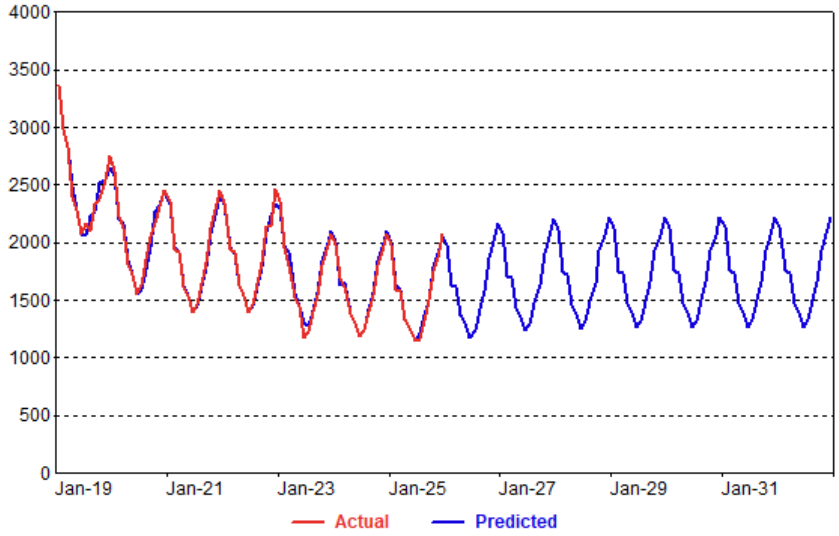
For BRZ, the decrease in customer count is minimal. Our model only includes variables to account for variation in bills over the estimation period and an autoregressive variable. It is the autoregressive term (AR term) that contributes to a small increase in the number of units in the early years. Figure 1 below shows the BRZ Street Lighting customer count forecast.

Figure 1 – BRZ Street Lighting Customer Count



Similarly, BRZ Street Lighting energy sales are effectively flat. Any growth is due to the inclusion of an AR term, which generates the current month's forecast from the prior month's sales. The impact fades out over time. In retrospect, the AR terms are contributing to a forecast that looks slightly too high, as depicted in Figure 2 below.

Figure 2 – BRZ Street Lighting Energy Sales



TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.13

13.0 Reference: VECC 40 – Table 1 Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-14

13.1 Table 1 in the response to VECC 40 provides the updated 2026-2031 impact of customer reclassification on the customer counts for the GS<50 and GS>50 customer classes. The response states that "the 2025 actual reclassifications are excluded from the tables because they are already incorporated in the total actual 2025 baseline figures". However, the 2026-2031 net impacts on the GS<50 and GS>50 customer classes are the same as in the original Application (Table 3-1-14), which included the 2025 reclassifications. Please reconcile and update the response to VECC 40 as required.

RESPONSE:

13.1 Alectra Utilities clarifies that Tables 1 to 3 provided in its response to 3-VECC-40 were based on the cumulative customer reclassifications forecast from May 2025 onwards, which aligns with Alectra Utilities' customer and load forecast from its filed application.

Tables 1 to 3 below summarize the impacts on customer count, sales (MWh), and billing demand (MW), respectively, of the rate reclassifications between the general service customer classes in 2026-2031, which align with Alectra Utilities' updated customer and load forecast in response to 3-SEC-69. As such, the 2025 actual reclassifications and their impact in 2026-2031 are excluded from the tables because they are already incorporated in the total actual 2025 baseline figures.

Table 1 – Impact on Customers

		2026	2027	2028	2029	2030	2031
i	From GS<50 to GS>50	48	94	132	168	197	225
ii.	From GS>50 to GS<50	284	541	768	969	1,141	1,293
iii.	From GS>50, Regular to GS>50 Intermediate	4	8	11	14	17	20
	From GS>50, Intermediate to GS>50, Regular	26	50	71	89	104	117

Table 2 – Impact on Sales (MWh)

		2026	2027	2028	2029	2030	2031
i	From GS<50 to GS>50	397	1,176	1,871	2,484	3,022	3,494
ii.	From GS>50 to GS<50	1,738	5,049	8,011	10,630	12,913	14,896
iii.	From GS>50, Regular to GS>50 Intermediate	364	1,093	1,739	2,302	2,865	3,428
	From GS>50, Intermediate to GS>50, Regular	1,591	4,651	7,405	9,792	11,812	13,525

Table 3 – Impact on Billing Demand (MW)

		2026	2027	2028	2029	2030	2031
i	From GS<50 to GS>50	17	49	78	104	126	146
ii.	From GS>50 to GS<50	(72)	(210)	(334)	(443)	(538)	(621)
iii.	From GS>50, Regular to GS>50 Intermediate	15	46	72	96	119	143
	From GS>50, Intermediate to GS>50, Regular	66	194	309	408	492	564

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JT-3.21.14

14.0 Reference: VECC 26 b) and 63 a), VECC 40
Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-23
SEC 69 – Updated Appendix 2-IB
Staff 1, Attachments 1-5

14.1 It is understood that adjustments were made to the GS<50 baseline customer count forecast (per VECC 26 b)) to account for: i) reclassification (per VECC 40 – subject to any corrections) and ii) distributed generation customers (Table 3-1-23). Please provide a schedule that for each of the years 2026-2031 sets out: i) the GS<50 forecast baseline customer count; ii) the GS<50/GS>50 customer reclassification adjustment, iii) the distributed generation reclassification adjustment, and iv) sum of (i) to (iii). If other adjustments were made please include them in the schedule and provide the relevant evidence references.

14.2 Please reconcile sum in (iv) with the values in SEC 69 – Updated Appendix 2-IB.

14.3 It is understood (per VECC 63 a)) that the GS<50 customer counts used the RRWF and the Cost Allocation models are the average of that year and the previous year's year-end forecast values. Please reconcile the 2027 to 2031 GS<50 customer count values used in the updated RRWFs (per Staff 1) with the results from part 1 of this question.

RESPONSE:

14.1 Table 1 below presents the GS<50 kW customer count related to the: i) baseline customer forecast, ii) reclassification adjustments, iii) Distribution Generation ("DGEN")

and FIT adjustments, and iv) sum of the baseline customer forecast and all adjustments.

Table 1 – GS<50 kW Baseline + Adjustments

GS<50 kW Adjustments	2026	2027	2028	2029	2030	2031
i) Baseline	88,949	89,379	89,902	90,434	90,971	91,512
ii) Reclassification	236	447	636	801	944	1,068
iii) DGEN/FIT	426	557	557	557	557	557
iv) Sum of (i) to (iii)	**89,611**	**90,383**	**91,095**	**91,792**	**92,472**	**93,137**

14.2 Table 2 below presents row (iv) from Table 1 and the GS<50 kW customer count values in 3-SEC-69 – Updated Appendix 2-IB.

Table 2 – Reconciliation between Table 1 (iv) and Updated Appendix 2-IB

	15.2 (iv)	Updated Appendix 2-IB
2026	89,611	89,611
2027	90,383	90,383
2028	91,095	91,095
2029	91,792	91,792
2030	92,472	92,472
2031	93,137	93,137

14.3 Tables 3 to 7 present the year-end GS<50 kW customer count values in 3-SEC-69 – Updated Appendix 2-IB and the two-year average year-end GS<50 kW customer count values included in the updated Revenue Requirement Workforms ("RRWFs") from 1-Staff-1.

Please note that a minor adjustment was made to the 2026 customer count prior to calculating the average customer count for the 2027 RRWF, consistent with the 2027 rate design. Specifically, the 131 DGEN customers proposed to be reclassified to GS<50 kW in 2027 (and added to 2027 for the GS<50 kW rate design) were also added to the 2026 GS<50 kW customer count prior to calculating the average customer count, to provide a more accurate representation of the two-year average customer count.

This adjustment is not made to the 2026 year-end (emphasis added) GS<50 kW customer count in Appendix 2-IB, as the DGEN reclass, if approved, would not occur until 2027.

Please also note that the customer count average used in the RRWFs is built up by summing the rounded average from each rate zone ("RZ average customer count"), which may cause minor discrepancies when comparing the RZ average customer count and the Alectra Utilities total average customer count, but it does not affect year-end values.[1]

Table 3 – Reconciliation between Year-End GS<50 kW Customer Counts in Updated Appendix 2-IB and Updated 2027 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2026	**Year-End 2027**	**2026-2027 Average** ***(a)***	**2027** ***(b)***	***(c)=(b)-(a)***
89,611	90,383	89,997	90,063	66
Year-End 2026 with DGEN Adjustment	**Year-End 2027**	**2026-2027 Average** ***(a)***	**2027** ***(b)***	***(c)=(b)-(a)***
89,742	90,383	90,063	90,063	-

Table 4 – Reconciliation between Year-End GS<50 kW Customer Counts in Updated Appendix 2-IB and Updated 2028 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2027	**Year-End 2028**	**2027-2028 Average** ***(a)***	**2028** ***(b)***	***(c)=(b)-(a)***
90,383	91,095	90,739	90,740	1

[1] For example, assuming all 5 rate zones have year-end customer counts of 2 and 3, respectively, the average customer count for each rate zone equal 2.5, rounded to 3, and then the sum of these customer counts equal 15 (3 x 5). Alternatively, if the year-end customer counts were summed up first and then averaged, the year-end customer counts equal 10 (2 x 5) and 15 (3 x 5), respectively, the average of which equal 12.5, rounded to 13. The total year-end customer counts are the same, however, the two-year average experiences a minor difference.

Table 5 – Reconciliation between Year-End GS<50 kW Customer Counts in Updated Appendix 2-IB and Updated 2029 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2028	Year-End 2029	2028-2029 Average *(a)*	2029 *(b)*	*(c)=(b)-(a)*
91,095	91,792	91,444	91,444	-

Table 6 – Reconciliation between Year-End GS<50 kW Customer Counts in Updated Appendix 2-IB and Updated 2030 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2029	Year-End 2030	2029-2030 Average *(a)*	2030 *(b)*	*(c)=(b)-(a)*
91,792	92,472	92,132	92,133	1

Table 7 – Reconciliation between Year-End GS<50 kW Customer Counts in Updated Appendix 2-IB and Updated 2031 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2030	Year-End 2031	2030-2031 Average *(a)*	2031 *(b)*	*(c)=(b)-(a)*
92,472	93,137	92,805	92,806	1

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JT-3.21.15

15.0 Reference: VECC 26 b), VECC 40, VECC 42 – Table 1, SEC 75 – Table 3
Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-23
SEC 69 – Updated Appendix 2-IB
Staff 1, Attachments 1-5

15.1 The GS>50 customer count adjustments provided in SEC 75 do not match those set out in VECC 42. Please reconcile.

15.2 It is understood that adjustments were made to the GS>50 baseline customer count forecast (per VECC 26 b)) to account for: i) reclassification (per VECC 40 – subject to corrections) and ii) large customer additions (SEC 75/VECC 42 – subject to correction per part 1). Please provide a schedule that for each of the years 2026-2031 sets out: i) the GS>50 forecast baseline customer count; ii) the GS<50/GS>50 customer reclassification adjustment, iii) the large customer addition adjustment and iv) sum of (i) to (iii). If other adjustments were made please include them in the schedule and provide the relevant evidence references.

15.3 Please reconcile the sum in (iv) with the values in SEC 69 – Updated Appendix 2-IB.

15.4 It is understood (per VECC 63 a)) that the GS>50 customer counts used the RRWF and the Cost Allocation models are the average of that year and the previous year's year-end forecast values. Please reconcile the 2027 to 2031 GS>50 customer count values used in the updated RRWFs (per Staff 1) with the results from part 1 of this question.

RESPONSE:

15.1 The two tables are not the same. Table 3 in 3-SEC-75 shows the number of GS>50 kW and Large Use customers that were included (re: from Alectra Utilities' System Planning data centre load forecast) in the data centre load forecast adjustments. The purpose of this table is to reconcile the data centre projects included in the rate-setting load forecast against data centre projects reported in Table 1 of 2A-SEC-36. Table 1 in 3-VECC-42 illustrates actual adjustments that were required to be made to the baseline customer forecast as a result of the "qualified" (re: 3-SEC-75) projects.

These two sets of data may not appear to match because multiple adjustments may be embedded within a single cell of Table 1 of 3-VECC-42, as described in the footnote of 3-VECC-42. Further, two of the data centre customers are pre-existing (current) customers, so no adjustment would be made for these customers in the GS>50 customer class cells of Table 1 of 3-VECC-42. Table 1 below illustrates how each data centre customer reconciles to 3-SEC-75 and 3-VECC-42.[1]

Table 1 – Data Centre Customer Count Reconciliation

	Year 1		2026	2027	2028	2029	2030	2031
Application 3 (Pre-Existing Customer)	2027	GS>50 kW	-	(1)	(1)	(1)	(1)	(1)
		Large Use	-	1	1	1	1	1
Application 6 (New Customer)	2027	GS>50 kW	-	1	1	1	-	-
		Large Use	-	-	-	-	1	1
Application 7 (New Customer)	2026	GS>50 kW	1	1	1	1	1	1
		Large Use	-	-	-	-	-	-
Application 8 (Pre-Existing Customer)	2026	GS>50 kW	1	1	1	(1)	(1)	(1)
		Large Use	-	-	-	1	1	1
Application 9 (New Customer)	2026	GS>50 kW	1	1	1	1	1	-
		Large Use	-	-	-	-	-	1
Net Total		**GS>50 kW**	**3**	**3**	**3**	**1**	**-**	**(1)**
		Large Use	**-**	**1**	**1**	**2**	**3**	**4**
Net Total Excluding Subtractions due to Reclasses (3-SEC-75)		**GS>50 kW**	**3**	**4**	**4**	**3**	**2**	**1**
		Large Use	**-**	**1**	**1**	**2**	**3**	**4**
Net Total Excluding Additions due to Pre-Existing Customers (3-VECC-42)		**GS>50 kW**	**2**	**2**	**2**	**1**	**-**	**(1)**
		Large Use	**-**	**1**	**1**	**2**	**3**	**4**

[1] Year 1 in Table 1 of this undertaking response represents the first year of new load that is not considered in the baseline forecast.

15.2 Table 2 below presents the GS>50 kW customer count related to the: i) baseline customer forecast, ii) reclassification adjustments, iii) large customer (data centre) adjustments, and iv) sum of the baseline customer forecast and all adjustments.

Table 2 – GS>50 kW Baseline + Adjustments

GS>50 kW Adjustments	2026	2027	2028	2029	2030	2031
i) Baseline	12,581	12,580	12,581	12,582	12,582	12,583
ii) Reclassification	(236)	(447)	(636)	(801)	(944)	(1,068)
iii) Large Customer (Data Centre)	2	2	2	1	-	(1)
iv) Sum of (i) to (iii)	**12,347**	**12,135**	**11,947**	**11,782**	**11,638**	**11,514**

15.3 Table 3 below presents row (iv) from Table 2 and the GS>50 kW customer count values in 3-SEC-69 – Updated Appendix 2-IB. Please note that the Appendix 2-IB presents the GS>50 KW class as two classes: GS>50 kW, Regular, and GS>50 kW, Intermediate, to provide a sufficient breakdown for the historical data. For Table 3 below, these two classes are combined into one GS>50 kW class.

Table 3 – Reconciliation between Table 2 (iv) and Updated Appendix 2-IB

	15.2 (iv)	Updated Appendix 2-IB
2026	12,347	12,347
2027	12,135	12,135
2028	11,947	11,947
2029	11,782	11,782
2030	11,638	11,638
2031	11,514	11,514

15.4 Tables 4 to 8 present the year-end GS>50 kW customer count values in 3-SEC-69 – Updated Appendix 2-IB and the two-year average year-end GS>50 kW customer count values included in the updated Revenue Requirement Workforms ("RRWFs") from 1-Staff-1.

Please note, that the customer count average used in the RRWFs is built up by summing the two-year rounded average from each rate zone ("RZ average customer count"), which may cause minor discrepancies when comparing the RZ average

customer count and the Alectra Utilities total average customer count, but it does not affect year-end values.[2]

Table 4 – Reconciliation between Year-End GS>50 kW Customer Counts in Updated Appendix 2-IB and Updated 2027 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2026	Year-End 2027	2026-2027 Average (a)	2027 (b)	(c)=(b)-(a)
12,347	12,135	12,241	12,243	2

Table 5 – Reconciliation between Year-End GS>50 kW Customer Counts in Updated Appendix 2-IB and Updated 2028 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2027	Year-End 2028	2027-2028 Average *(a)*	2028 *(b)*	*(c)=(b)-(a)*
12,135	11,947	12,041	12,043	2

Table 6 – Reconciliation between Year-End GS>50 kW Customer Counts in Updated Appendix 2-IB and Updated 2029 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2028	Year-End 2029	2028-2029 Average *(a)*	2029 *(b)*	*(c)=(b)-(a)*
11,947	11,782	11,865	11,865	-

Table 7 – Reconciliation between Year-End GS>50 kW Customer Counts in Updated Appendix 2-IB and Updated 2030 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2029	Year-End 2030	2029-2030 Average *(a)*	2030 *(b)*	*(c)=(b)-(a)*
11,782	11,638	11,710	11,711	1

[2] For example, assuming all 5 rate zones have year-end customer counts of 2 and 3, respectively, the average customer count for each rate zone equal 2.5, rounded to 3, and then the sum of these customer counts equal 15 (3 x 5). Alternatively, if the year-end customer counts were summed up first and then averaged, the year-end customer counts equal 10 (2 x 5) and 15 (3 x 5), respectively, the average of which equal 12.5, rounded to 13. The total year-end customer counts are the same, however, the two-year average experiences a minor difference.

Table 8 – Reconciliation between Year-End GS>50 kW Customer Counts in Updated Appendix 2-IB and Updated 2031 RRWF

Updated Appendix 2-IB			RRWF	Difference
Year-End 2030	Year-End 2031	2030-2031 Average *(a)*	2031 *(b)*	*(c)=(b)-(a)*
11,638	11,514	11,576	11,578	2

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JT-3.21.16

16.0 Reference: VECC 26 c) SEC 75 – Table 3

16.1 The response to VECC 26 c) confirms that the Large Use class' baseline customer count increases by one between 2025 and 2031. Staff 75 identifies additional large loads that increase the Large Use class' customer count. Please explain how Alectra determines whether a new Large Use customer is to be considered an increase in the baseline customer count forecast or is to be included as an additional large load adjustment?

RESPONSE:

16.1 Additional large load adjustments are informed by Alectra Utilities' System Planning forecast of data centre loads.

This customer is not a data centre customer. While initially energized in 2023 as a GS>50 kW customer, the customer expects to ramp up their load and reach the 5,000 kW threshold required for Large Use classification starting in 2029.

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JT-3.21.17

17.0 Reference: SEC 69 – Updated Appendix 2-IB Staff 158 VECC 37

17.1 It is understood that adjustments were made to the Residential baseline MWh forecast (per Staff 158) to account for: i) EVs (per VECC 37) and ii) building electrification (VECC 37). Please provide a schedule that for each of the years 2026-2031 sets out: i) the Residential forecast baseline MWh; ii) the EV adjustment, iii) the building electrification adjustment and iv) sum of (i) to (iii). If other adjustments were made please include them in the schedule and provide the relevant evidence references.

17.2 Please reconcile the sum in (iv) with the values in SEC 69 – Updated Appendix 2-IB.

RESPONSE:

17.1 Please see Table 1 for Residential consumption forecast breakdown.

Table 1 – Residential Forecast Breakdown (MWh)

	i) Baseline	ii) EV	iii) Building Electrification	iv) Sum of i) to iii)
2026	8,403,986	50,866	35,688	8,490,541
2027	8,471,631	196,740	57,915	8,726,286
2028	8,553,527	394,366	91,848	9,039,741
2029	8,583,758	655,305	128,411	9,367,474
2030	8,632,056	979,608	175,800	9,787,463
2031	8,682,229	1,272,529	225,870	10,180,628

17.2 Please see Table 2 for Reconciliation between sum in 17.1 (iv) and SEC 69 – Updated Appendix 2-IB residential class consumption forecast.

Table 2 - Reconciliation between Sum in 17.1 (iv) and SEC 69 – Updated Appendix 2-IB Residential Class Consumption Forecast (MWh)

	17.1 (iv)	Updated Appendix 2-IB
2026	8,490,541	8,490,541
2027	8,726,286	8,726,286
2028	9,039,741	9,039,741
2029	9,367,474	9,367,474
2030	9,787,463	9,787,463
2031	10,180,628	10,180,628

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JT-3.21.18

18.0 Reference: VECC 40 – Tables 2 and 3 Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-14

18.1 Tables 2 and 3 in the response to VECC 40 provide the 2026-2031 impact of customer reclassification on the customer class MWh and MW (where applicable) for the GS<50 and GS>50 customer classes. The response states that "the 2025 actual reclassifications are excluded from the tables because they are already incorporated in the total actual 2025 baseline figures". However, the 2026-2031 net MWh and MW impacts on the GS<50 and GS>50 customer classes are the same as in the original Application (Table 3-1-14), which included the 2025 reclassifications. Please reconcile and update the response to VECC 40 as required.

RESPONSE:

18.1 Please see JT-3.21.13.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.19

19.0 Reference: Staff 158 VECC 40 VECC 37 Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-24 SEC 69 – Updated Appendix 2-IB

19.1 It is understood that adjustments were made to the GS<50 baseline MWh forecast (per Staff 158) to account for: i) reclassification (per VECC 40 – subject to corrections), ii) EV adjustments (per VECC 37); iii) building electrification (per VECC 37) and iv) distributed generation customers (Table 3-1-24). Please provide a schedules that for each of the years 2026-2031 sets out: i) the GS<50 forecast baseline MWh; ii) the GS<50/GS>50 customer reclassification MWh adjustment, iii) the EV MWh adjustment; iv) the building electrification MWh adjustment, v) the distributed generation reclassification MWh adjustment, and vi) sum of (i) to (v). If other adjustments were made please include them in the schedule and provide the relevant evidence references.

19.2 Please reconcile sum in (vi) with the values in SEC 69 – Updated Appendix 2-IB.

RESPONSE:

19.1 Please see Table 1 below for GS<50 kW consumption forecast breakdown.

Table 1 – GS<50 kW Consumption Forecast Breakdown (MWh)

	i) Baseline	ii) GS<50/GS>50 Reclassification Adjustment	iii) EV	iv) Building Electrification	v) Distributed Generation Reclassification Adjustment	vi) Sum of (i) to (v).
2026	2,802,874	1,341	14,429	3,650	294	2,822,588
2027	2,808,283	3,873	55,989	7,029	588	2,875,761
2028	2,829,797	6,140	110,892	12,114	588	2,959,530
2029	2,839,703	8,146	182,069	18,139	588	3,048,645
2030	2,850,643	9,891	269,633	25,706	588	3,156,460
2031	2,862,703	11,402	350,760	34,033	588	3,259,486

19.2 Table 2 below presents row (iv) from Table 1 and the GS<50 kW consumption forecast values in 3-SEC-69 – Updated Appendix 2-IB.

Table 2 – Reconciliation between Table 1 (vi) and Updated Appendix 2-IB

	19.1 (vi)	Updated Appendix 2-IB
2026	2,822,588	2,822,588
2027	2,875,761	2,875,761
2028	2,959,530	2,959,530
2029	3,048,645	3,048,645
2030	3,156,460	3,156,460
2031	3,259,486	3,259,486

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.20

20.0 Reference: Staff 158 VECC 40 VECC 37 SEC 75 – Table 3 Exhibit 3, Tab 1, Schedule 4, page 9, Table 3-1-17 SEC 69 – Updated Appendix 2-IB

20.1 It is understood that adjustments were made to the GS>50 baseline MWh and MW forecasts (per Staff 158) to account for: i) reclassification (per VECC 40 – subject to corrections), ii) EV adjustments (per VECC 37); iii) building electrification (per VECC 37); iv). Standby adjustments (Table 3-1-17) and v) large load addition (SEC 75 – Table 3). Please provide schedules that for each of the years 2026-2031 sets out for GS>50 MWhs and MW respectively: i) the GS>50 forecast baseline ii) the GS<50/GS>50 customer reclassification adjustment, iii) the EV MWh adjustment; iv) the building electrification MWh adjustment, v) the Standby adjustment, vi) the large load adjustment and vii) sum of (i) to (vi). If other adjustments were made please include them in the schedule and provide the relevant evidence references.

20.2 Please reconcile sum in (vii) with the values in SEC 69 – Updated Appendix 2-IB.

RESPONSE:

20.1 Please see Tables 1 and 2 for the requested GS>50 kW rate class consumption forecast breakdown and demand forecast breakdown, respectively. In addition to the adjustments described in the question, Tables 1 and 2 also includes adjustments (vii) due to the reclassification of FIT customers from GS>50 kW to GS<50 kW, as described in Exhibit 3, Tab 1, Schedule 4, pp. 15-17 (PDF pp. 98-100). Subsequently, an additional row was added to the table (viii) to sum adjustments (i) to (vii).

Table 1 – GS>50 kW Consumption Forecast Breakdown (MWh)

	i) Baseline	ii) GS<50/GS>50 Reclassification Adjustment	iii) EV	iv) Building Electrification	v) Standby Adjustment	vi) Large Load Adjustment	vii) FIT Adjustment	viii) Sum of (i) to (vii).
2026	13,128,660	(1,341)	3,793	16,326	(11)	1,026	(217)	13,148,236
2027	13,128,206	(3,873)	15,794	31,481	9,691	1,284	(217)	13,182,366
2028	13,206,168	(6,140)	29,063	54,294	9,691	2,817	(217)	13,295,677
2029	13,231,448	(8,146)	43,916	81,335	9,691	2,682	(217)	13,360,708
2030	13,260,169	(9,891)	60,955	115,292	9,691	2,158	(217)	13,438,156
2031	13,294,357	(11,402)	80,412	152,661	9,691	1,152	(217)	13,526,653

Table 2 - GS>50 kW Billed Demand Forecast Breakdown (MW)

	i) Baseline	ii) GS<50/GS>50 Reclassification Adjustment	iii) EV	iv) Building Electrification	v) Standby Adjustment	vi) Large Load Adjustment	vii) FIT Adjustment	viii) Sum of (i) to (vii).
2026	33,971	(56)	10	42	(0)	43	(1)	34,008
2027	33,973	(161)	40	81	404	54	(1)	34,388
2028	34,087	(256)	73	138	404	117	(1)	34,563
2029	34,246	(339)	111	209	404	112	(1)	34,741
2030	34,322	(412)	153	296	404	90	(1)	34,851
2031	34,411	(475)	202	392	404	48	(1)	34,981

20.2 Tables 3 and 4 below present row (viii) from Tables 1 and 2 and the GS>50 kW consumption forecast and billed demand forecast values in 3-SEC-69 – Updated Appendix 2-IB, respectively.

Table 3 – Reconciliation between Table 1 (viii) and Updated Appendix 2-IB Consumption Forecast (MWh)

	20.1 Table 1 (viii)	Updated Appendix 2-IB
2026	13,148,236	13,148,236
2027	13,182,366	13,182,366
2028	13,295,677	13,295,677
2029	13,360,708	13,360,708
2030	13,438,156	13,438,156
2031	13,526,653	13,526,653

Table 4 – Reconciliation between Table 2 (viii) and Updated Appendix 2-IB Billed Demand Forecast (MW)

	20.1 Table 2 (viii)	Updated Appendix 2-IB
2026	34,008	34,008
2027	34,388	34,388
2028	34,563	34,563
2029	34,741	34,741
2030	34,851	34,851
2031	34,981	34,981

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.21

21.0 Reference: CCC 71 c) SEC 98 b)

21.1 With respect to SEC 98 b), please explain why the pole count is constant for the years 2025-2029 and the basis for the increase to 139,310 in 2030 and 2031.

RESPONSE:

In preparing this undertaking response Alectra Utilities became aware of an error in the number of pole attachments and associated revenue provided in Interrogatory Response SEC 98 Table 1. A corrected version of the table is provided below.

This correction results in an increase of the Pole Attachment revenue by $4,171 in 2027.

Table 1 – Pole Attachments

Description	2024A	2025A	2025	2026	2027
Pole Attachment Rate	$ 37.78	$ 39.14	$ 38.54	$ 39.31	$40.10
# Pole Attachments	140,532	144,814	139,310	139,310	139,310
Pole Attachment Revenue	$5,307,005	$5,664,207	$5,369,007	$5,476,276	$5,586,331
Other Rentals	$ 838,829	$ 914,488	$ 765,754	$1,008,157	$1,012,240
Total Pole attachments	**$ 6,145,834**	**$6,578,695**	**$6,134,761**	**$6,484,433**	**$6,598,571**
Pole Attachment Revenue Deferral 1508 A/C	$(2,171,459)	$(2,425,876)	$(2,251,457)	$(2,527,020)	$ -
Toal Pole Revenue 4210 Account	**$3,974,375**	**$4,152,819**	**$3,879,296**	**$3,957,413**	**$6,594,400**
	2028	**2029**	**2030**	**2031**	
Pole Attachment Rate	$40.90	$ 41.72	$ 42.55	$ 43.40	
# Pole Attachments	139,310	139,310	139,310	139,310	
Pole Attachment Revenue	$5,697,779	$5,812,013	$5,927,641	$6,046,054	
Other Rentals	$1,017,212	$1,021,726	$1,022,818	$1,027,863	
Total Pole attachments	**$6,714,991**	**$6,833,739**	**$6,950,459**	**$7,073,917**	
Pole Attachment Revenue Deferral 1508 A/C	$ -	$ -	$ -	$ -	
Toal Pole Revenue 4210 Account	**$6,714,991**	**$6,833,739**	**$6,950,459**	**$7,073,917**	

The forecast of pole attachments for 2025-2031 is equal to the 2023 actual pole attachments.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.22

22.0 Reference: Staff 212

22.1 With respect to USoA 4225, please provide the actual monthly arrears balances for 2024 and 2025.

22.2 Please provide the forecast monthly arrears values for 2026-2031, explain how they were derived and how they are then use to forecast late payment revenues.

RESPONSE:

22.1 Please see Table 1

Table 1 - Actual Monthly Arrears ($ Million)

	Jan	Feb	March	April	May	June	July	August	Sept	Oct	Nov	Dec
2024	61.5	64.7	67.6	65.3	61.7	57.6	56.5	59.0	61.1	55.6	59.4	91.9
2025	60.7	65.9	67.5	66.4	59.2	52.0	48.7	57.5	69.8	61.7	57.7	61.5

22.2 Please see Table 2

Table 2 - Monthly Arrears for Calculation of Late Payment Charges ($ Million)

	Jan	Feb	March	April	May	June	July	August	Sept	Oct	Nov	Dec
2026	54.2	54.9	56.0	54.1	56.3	54.9	55.6	60.8	59.8	62.6	54.5	55.9
2027	57.2	58.0	59.1	57.2	59.4	57.9	58.6	63.9	62.9	65.8	57.4	58.8
2028	59.6	60.4	61.6	59.6	61.9	60.4	61.1	66.6	65.6	68.6	59.8	61.3
2029	62.3	63.2	64.5	62.4	64.9	63.4	64.2	70.1	69.0	72.2	63.1	64.8
2030	65.8	66.7	68.1	65.9	68.5	67.0	67.8	74.0	72.9	76.2	66.7	68.5
2031	69.5	70.5	71.9	69.6	72.4	70.7	71.6	78.1	76.9	80.5	70.5	72.3

Table 2 represents the combined forecast arrears in each month from 2026-2031 for purposes of calculation of Late Payment Charges ("LPC"). This table includes a forecast of arrears for all rate classes in the 31-60, 60-90 and >90-day categories for both active and final accounts. In addition, 50% of the forecasted arrears in the 1–30-day category,

are also included, reflecting that LPC charges are applied 27 days after the bill due date. Interrogatory response 4-CCC-46 describes Alectra's forecast methodology for arrears. The forecast of LPC takes the forecast of these monthly arrears and multiplies the values by 1.5%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.23

23.0 Reference: Staff 212, SEC 98 d)

23.1 With respect to USoA 4355 and 4360, please provide schedules that set out for each of the years 2022-2025: i) the actual values, ii) the one-time adjustments made (with explanations as to why) and iii) the resulting averages used for purposes of forecasting (per Staff 212).

23.2 Please provide any adjustments (and supporting explanations) made to the historical averages for purposes of forecasting 2026-2031 values (per SEC 98 d)).

RESPONSE:

23.1

i) Please see the table below.

Table 1 – 2022-2025 Actuals (Account 4355 and 4360)

(Loss) / Gain on disposition	2022A	2023A	2024A	2025A
Account 4355/4360	(8.5)	(2.6)	(9.6)	(6.1)
Adjustments:				
Add: Derecognition of customer contributions (Note 1)	0.7	0.0	0.0	0.0
Remove: OMS impairment (Note 2)	3.2	0.0	0.0	0.0
Remove: One-time gain on sales (Note 3)	0.0	(2.8)	0.0	0.0
Remove: Derecognition of meters (Note 4)	0.0	0.0	1.7	0.0
Total Derecognition	**(4.5)**	**(5.4)**	**(7.9)**	**(6.1)**
3-Year Average			(6.0)	

ii) One-time adjustments shown in Table 1 above were made to the historical averages to normalize for events that were not expected to reoccur, as described below:

Note 1: In 2022, the derecognition of capital contributions ($0.7MM) were reported in Account 5705, instead of Account 4360. This adjustment aligns the presentation on the same basis.

Note 2: In 2022, Alectra recorded a one-time impairment of the OMS project ($3.2MM).

Note 3: Adjusted for one-time gains related to the sale of land ($2.0MM), furniture ($0.5MM) and software ($0.3MM).

Note 4: In 2024, Alectra derecognized a net book value of $1.7MM related to meters removed from service from 2022-2024.

iii) Per the table above, the three-year average of derecognition activities was calculated as $6.0MM which was used as the basis for budgeted derecognition for 2025-2031.

23.2 Please see Table 2 below.

Table 2 – Budgeted Derecognition

(Loss) / Gain on disposition	2025B	2026B	2027B	2028B	2029B	2030B	2031B
3-Year Average	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)
Derecognition of Meters	(0.6)	(0.4)	0.0	0.0	0.0	0.0	0.0
Total Derecognition	**(6.6)**	**(6.4)**	**(6.0)**	**(6.0)**	**(6.0)**	**(6.0)**	**(6.0)**

The budget for 2025 and 2026 includes an estimated derecognition loss on AMI 1.0 meters removed from service of $0.6MM and $0.4MM, respectively.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.24

24.0 Reference: Exhibit 8, Tab 1, Schedule 1, Tables 8-1-6 to 8-1-13 SEC 69 – Updated Appendix 2-IB

24.1 Please update the notional rate derivation provided in Tables 8-1-6 to 8-1-13 using the updated 2026 load forecast and actual 2026 rates.

RESPONSE:

24.1 The tables below provide the notional rate derivation of notional harmonized 2026 rates using the updated 2026 load forecast and actual 2026 rates.

Table 1 - Updated Table 8-1-6: 2026 Notional Rates - Residential Rate Class

	Fixed			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*
BRZ	$29.93	161,985	$58.18	--
ERZ	$29.86	185,485	$66.46	--
GRZ	$35.99	52,930	$22.86	--
HRZ	$32.90	236,609	$93.41	--
PRZ	$34.43	356,459	$147.27	--
Total		**993,468**	**$388.19**	**$32.56**

Table 2 - Updated Table 8-1-7: 2026 Notional Rates - GS<50 kW Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Consumption (kWh)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ	$31.61	10,557	$4.00	--	$0.0209	357,880,444	$7.48	--
ERZ	$54.84	20,119	$13.24	--	$0.0160	706,906,716	$11.31	--
GRZ	$20.89	4,356	$1.09	--	$0.0174	142,858,449	$2.49	--
HRZ	$52.09	19,559	$12.23	--	$0.0133	582,755,209	$7.75	--
PRZ	$36.17	35,151	$15.26	--	$0.0231	1,032,481,255	$23.85	--
Total		**89,742**	**$45.82**	**$42.55**		**2,822,882,072**	**$52.88**	**$0.0187**

Table 3 - Updated Table 8-1-8: 2026 Notional Rates - GS>50 kW Rate Class[1]

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ	$244.92	1,667	$4.90	--	$3.7965	5,061,902	$19.22	--
ERZ	$268.39	3,734	$12.03	--	$4.7034	9,613,132	$45.21	--
GRZ	$259.78	584	$1.82	--	$3.6377	2,110,690	$7.68	--
HRZ	$479.71	1,900	$10.94	--	$3.2215	5,170,863	$16.66	--
PRZ	$177.34	4,462	$9.50	--	$5.2880	12,455,251	$65.86	--
Total		**12,347**	**$39.18**	**$264.43**		**34,411,838**	**$154.63**	**$4.4936**

Table 4 - Updated Table 8-1-9: 2026 Notional Rates - Large Use Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ	$5,919.46	6	$0.43	--	$3.1385	565,836	$1.78	--
ERZ	$17,344.09	11	$2.29	--	$3.7129	1,800,021	$6.68	--
GRZ	$1,375.87	4	$0.07	--	$3.4381	457,380	$1.57	--
HRZ	$29,910.77	7	$2.51	--	$1.7647	542,879	$0.96	--
PRZ	$7,640.35	3	$0.28	--	$2.8203	615,333	$1.74	--
Total		**31**	**$5.57**	**$14,971.02**		**3,981,449**	**$12.73**	**$3.1961**

Table 5 - Updated Table 8-1-10: 2026 Notional Rates - Large Use with Dedicated Assets Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ								
ERZ								
GRZ								
HRZ	$7,090.86	6	$0.51	--	$0.4185	1,605,512	$0.67	--
PRZ								
Total		**6**	**$0.51**	**$7,090.86**		**1,605,512**	**$0.67**	**$0.4185**

[1] Table 8-1-8 in the Application incorrectly referenced Forecasted kWh instead of Forecasted Demand kW, which in turn impacted the Variable Revenue ($M) column. The correct total values should read: Column "Forecasted Demand (kW)" – 34,607,532; Column "Variable Revenue ($M)" - $155.68; Column "Alectra 2026 Notional Variable Rate" - $4.4984.

Table 6 - Updated Table 8-1-11: 2026 Notional Rates - Street Lighting Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ	$0.86	51,809	$0.53	--	$18.4274	54,710	$1.01	--
ERZ	$1.91	50,930	$1.17	--	$14.5249	37,640	$0.55	--
GRZ	$0.55	14,478	$0.10	--	$12.8219	9,870	$0.13	--
HRZ	$2.40	52,482	$1.51	--	$6.3755	46,890	$0.30	--
PRZ	$1.49	103,466	$1.85	--	$7.9528	112,160	$0.89	--
Total		**273,165**	**$5.16**	**$1.57**		**261,270**	**$2.87**	**$10.9939**

Table 7 - Updated Table 8-1-12: 2026 Notional Rates - Sentinel Lighting Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ								
ERZ								
GRZ	$9.45	20	$0.00	--	$10.4582	29	$0.00	--
HRZ	$6.94	259	$0.02	--	$19.0231	1,010	$0.02	--
PRZ	$5.26	133	$0.01	--	$12.4150	590	$0.01	--
Total		**412**	**$0.03**	**$6.52**		**1,629**	**$0.03**	**$16.4776**

Table 8 - Updated Table 8-1-13: 2026 Notional Rates - Unmetered Scattered Load Rate Class

	Fixed				Variable			
Rate Zone	2026 Forecasted Fixed Charge	2026 Forecasted Customers	Fixed Revenue ($MM)	Alectra 2026 Notional Fixed Charge	2026 Forecasted Variable Rate	Forecasted Consumption (kWh)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A	*B*	*C = A x B x 12*	*Total C / Total B / 12 months*	*A*	*B*	*C = A x B*	*Total C / Total B*
BRZ	$1.35	1,735	$0.03	--	$0.0248	6,144,780	$0.15	--
ERZ	$11.33	3,185	$0.43	--	$0.0205	11,843,580	$0.24	--
GRZ	$6.11	584	$0.04	--	$0.0278	1,953,150	$0.05	--
HRZ	$10.64	2,750	$0.35	--	$0.0165	11,409,760	$0.19	--
PRZ	$10.82	3,346	$0.43	--	$0.0245	15,730,270	$0.39	--
Total		**11,600**	**$1.29**	**$9.26**		**47,081,540**	**$1.02**	**$0.0217**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.25

25.0 Reference: Staff 1 – Attachment 6 (Cost Allocation Model) – Tab I6.1

25.1 It is noted that in the updated Cost Allocation model the harmonized 2026 Transformation Ownership Allowances (TOA) for the GS>50 and Large Use classes are unchanged from those in the original Application. Were the notional 2026 TOA's used in the original Application updated based on the updated 2026 load forecast for purposes of Staff 1 – Attachment 6?

RESPONSE:

25.1 The notional 2026 TOAs used in the original Application were not updated based on the 2026 load forecast for purposes of Staff 1 – Attachment 6.

Tables 1 and 2 below, which are presented solely to illustrate the potential impact, show the derivation of the notional GS>50 kW and Large Use 2026 TOA rate based on the updated 2026 load forecast.

Table 1 – GS>50 kW

	Variable			
Rate Zone	**2026 Forecasted Variable Rate**	**Forecasted Demand (kW)**	**Variable Revenue ($MM)**	**Alectra 2026 Notional Variable Rate**
	A3 = C3 / B3	***B3 = B1 + B2***	***C3 = C1 + C2***	***Total C3 / Total B3***
BRZ	-$0.8175	2,010,746	($1.64)	--
ERZ	-$0.4000	2,432,641	($0.97)	--
GRZ	-$0.7200	255,316	($0.18)	--
HRZ	-$0.7300	2,021,194	($1.48)	--
PRZ	-$0.6000	4,188,933	($2.51)	--
Total		**10,908,830**	**($6.79)**	**-$0.6224**

Table 2 – Large Use

Rate Zone	Variable			
	2026 Forecasted Variable Rate	Forecasted Demand (kW)	Variable Revenue ($MM)	Alectra 2026 Notional Variable Rate
	A4	*B4*	*C4 = A4 x B4*	*Total C4 / Total B4*
BRZ	-	-	$0.00	--
ERZ	-$0.4000	1,797,017	($0.72)	--
GRZ	-	-	$0.00	--
HRZ	-	-	$0.00	--
PRZ	-$0.6000	319,073	($0.19)	--
Total		**2,116,090**	**($0.91)**	**-$0.4302**

The recalculated rates for GS>50 kW and Large Use rate classes differ from the corresponding 2026 proposed notional rates [1] by 0.6% and 0.9%, respectively, reflecting a minor variance between the values.

[1] GS>50 kW TOA rate is ($.6189) and Large Use TOA rate is ($0.4264), as per the 2027 Cost Allocation Model, Tab I6.1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.26

26.0 Reference: Staff 232 Staff 1 – Attachment 6 (Cost Allocation Model) – Tab I3 (BO-ASSETS)

26.1 In Staff 232 the overall customer class weights for billing and collecting are determined by weighting the Billing weights (Column D) and the Collection Weights (Column E) by the proportion of FTE resources for Billing (60.8%) and Collecting (39.2%) respectively. In Tab I3 the total costs for Billing (USoA 5315) and Collecting (USoA 5320) are $16,663,459 and $7,368,112 respectively. Why weren't the relative total costs for Billing and Collecting used to weight Columns D and E?

RESPONSE:

26.1 The customer allocation weighting factors for billing and collections represent the level of effort needed to issue, administer and collect a single bill in each rate class, relative to a residential bill. As discussed in 7-Staff-232, the relative number of FTE's are considered to be reasonable proxies to allocate level of effort.

Alectra did not use USoA Accounts 5315 (Billing) and 5320 (Collections) to weight Columns D and E, as this approach would not appropriately reflect the underlying cost drivers. As an example, billing costs (USoA 5315) include postage and printing costs ($11.3 million in 2025), or 68% of the USoA total. These costs are incurred on a per-bill basis and do not vary materially by rate class. As such, they are not a driver of differences in billing effort across customer classes.

Including these costs in the weighting factor calculation would therefore distort the results by overstating the importance of billing activities relative to collections and by masking the true differences in effort between rate classes. In contrast, the use of

relative FTEs better captures the operational effort required to support billing and collections activities and, therefore, provides a more appropriate basis for determining the weighting factors.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT-3.21.27

27.0 Reference: Exhibit 8, Tab 1, Schedule 1, Tables 8-2-12 to 8-2-13 SEC 69 – Updated Appendix 2-IB Staff 158 a) – Table 1 VECC 26 b)

27.1 Please provide updated versions of Tables 8-2-12 and 8-2-13 based on the updated BRZ Streetlight forecast (per Staff 158 a) – Table 1) and explain the basis for converting the BRZ Streetlight forecast connections to devices for purposes of updated Table 8-2-13.

RESPONSE:

27.1 As described in Exhibit 8, Tab 2, Schedule 2, pp. 10 (pdf pp. 40), Alectra Utilities used the historical 5-year (2020-2024) average number of devices provided by the City of Brampton as a basis for a growth rate to derive its 2026-2031 quantity of devices for the Street Lighting rate class. Therefore, Table 8-2-12 remains unchanged, as the number of forecasted BRZ Street Lighting devices is based on the number of historical devices provided by the City of Brampton, not by the baseline connection forecast.

Please refer to the updated Table 8-2-13 below (Table 1), where only the Connections column is updated based on the revised forecast.

Table 1 – Proposed BRZ Devices and Connections

Billing Period	Devices	Connections
2019	50,756	20,988
2020	50,800	21,169
2021	51,010	21,254
2022	51,301	21,377
2023	51,401	21,398
2024	51,505	21,461
2025	51,657	21,486
2026	51,809	21,424
2027	51,962	21,399
2028	52,116	21,389
2029	52,270	21,385
2030	52,425	21,384
2031	52,581	21,383

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

JT-3.22

BOMA-1

References:

1. Interrogatory Response 2A-SEC-26 Table 1

Table 1 - Comparison of System Peak Demand to Customer, Consumption and Billing Determinant Forecast Methodologies

Aspect	System Peak Demand Forecast (Capital and Regional Planning)	Customer, Consumption, Billing Demand Forecast
Forecast Model	End-Use	Statistically Adjusted End-Use and Regression
Purpose	Station and Feeder Capacity Adequacy	Customer Count Growth and Billing Determinants
Weather Scenario	Normal Weather (1 in 2) Extreme Weather (1 in 10)	Normal Weather
Zones	6 System Planning Zones	5 Rate Zones
Granularity	Station and Feeder	Rate Class
EV Uptake	Included	Included
Decarbonization Scenario	Medium	Medium

2. Pre-filed Evidence Exhibit 3, Tab 1, Schedule 1, Attachment 3-1, OEB Appendix 2-IB

Consumption (Weather Normalized)

Rate Class	Historical 2024	Bridge Year 2025	Bridge Year 2026	Test Year 2027	Test Year 2028	Test Year 2029	Test Year 2030	Test Year 2031
Residential	8,511,337	8,420,148	8,556,582	8,833,994	9,184,006	9,550,659	10,000,906	10,421,040
General Service < 50 kW	2,854,840	2,794,906	2,830,938	2,873,274	2,956,719	3,045,931	3,154,197	3,257,990
General Service > 50 kW, Regular	10,237,327	10,188,310	10,184,084	10,175,775	10,276,208	10,336,638	10,406,727	10,488,921
General Service > 50 kW, Intermediate	3,039,667	3,050,990	3,100,028	3,080,270	3,091,115	3,103,801	3,119,048	3,135,977
Large Use	1,941,696	2,030,408	2,124,065	2,129,485	2,135,914	2,164,532	2,227,767	2,232,718
Large Use with Dedicated Assets	864,720	852,476	855,328	855,838	855,838	855,838	855,838	855,838
Street Lighting	93,691	93,208	94,717	95,130	95,262	95,308	95,324	95,330
Sentinel Lighting	587	629	590	574	557	541	524	508
Unmetered Scattered Load	47,636	46,271	47,095	47,482	47,870	48,258	48,646	49,034
Embedded Distributor	17,012	17,012	17,012	17,012	17,012	17,012	17,012	17,012
	27,608,514	27,494,358	27,810,439	28,108,835	28,660,499	29,218,516	29,925,989	30,554,366

Demand (Weather Normalized)

Rate Class	Historical 2024	Bridge Year 2025	Bridge Year 2026	Test Year 2027	Test Year 2028	Test Year 2029	Test Year 2030	Test Year 2031
Residential								
General Service < 50 kW								
General Service > 50 kW, Regular	27,470	27,435	27,406	27,755	27,942	28,173	28,294	28,500
General Service > 50 kW, Intermediate	6,794	6,804	6,797	6,604	6,526	6,499	6,475	6,466
Large Use	3,857	3,799	3,926	4,034	4,151	4,245	4,492	4,501
Large Use with Dedicated Assets	1,590	1,593	1,599	1,620	1,616	1,620	1,620	1,620
Street Lighting	260	260	265	266	265	266	266	266
Sentinel Lighting	2	2	2	2	1	1	1	1
Unmetered Scattered Load								
Embedded Distributor								
	39,972	39,894	39,994	40,281	40,503	40,806	41,148	41,354

3. Pre-filed Evidence Exhibit 2A, Tab 1, Schedule 1, Appendix J, Figure 19.
4. Pre-filed Evidence Exhibit 2A, Tab 1, Schedule 1, Appendix J, Figure 22.

Preamble:

In Reference #2, the Compound Annual Growth Rate (CAGR) of the total demand (weather normalized) between 2024 and 2031 is estimated at about 0.5%. The CAGR of the total consumption (weather normalized) between 2024 and 2031 is estimated at about 1.5%.

In Reference #3, the total 1-in-2 summer peak load has a 2024-2031 CAGR of approximately 3.2%. In Reference #4, the total 1-in-2 medium decarbonization scenario winter peak load has a 2024-2031 CAGR of approximately 4.5%.

During BOMA Toronto's cross-examination on March 5, 2026, we asked Panel 1 to provide comments on why the CAGR values estimated in reference 2 (between 0.5% to 1.5%) are so different when compared to the CAGR values estimated in references 3 and 4 (3.2% for summer peak and 4.5% for winter peak).

Questions:

Please expand the table listed in reference 1 (2A-SEC-26 Table 1) to include:

a) Additional rows of forecast drivers: (see illustrative table in part c below)

- CDM activities
- AI/Data centres
- Demographic and forecast (e.g. population, income, GDP….)

b) Additional columns that explain the differences (in magnitude and growth rates) between the system peak demand forecast and the customer/consumption/billing demand forecast. (see illustrative table in part c below)

c)

Aspect	(1) System Peak Demand Forecast (Capital and Regional Planning)	(2) Customer, Consumption, Billing Demand Forecast	Impact on 2024-2031 forecast (kWh/kW/customer counts)	Impact on 2024-2031 forecast (%)	Please explain if there is a material difference between (1) and (2)
Forecast Model	End-Use	Statistically Adjusted End-Use and Regression	N/A	N/A	N/A
Purpose	Station and Feeder Capacity Adequacy	Customer Count Growth and Billing Determinants	N/A	N/A	N/A
Weather Scenario	Normal Weather (1 in 2) Extreme Weather (1 in 10)	Normal Weather	N/A	N/A	N/A
Zones	6 System Planning Zones	5 Rate Zones	N/A	N/A	N/A
Granularity	Station and Feeder	Rate Class	N/A	N/A	N/A
EV Uptake	Included in End-Use Model	Included as add-on			
Decarbonization Scenario	Medium	Medium			
	Included in End-Use Model	Included as add-on			
CDM activities	Included in End-Use Model	Not explicitly modelled in regression analysis			
AI/Data Centres	Included in End-Use Model	Not explicitly modelled in regression analysis			
Demographic and Economic Forecast	Higher drivers e.g. see 3.0-VECC-22/23	Lower Drivers e.g. see 3.0-VECC-22/23			

Please confirm
Please fill out

RESPONSE:

Please see the expanded table below for 2A-SEC-26 in response to parts a), b) and c).

Table 1 – Expanded Table 2A-SEC-26

Aspect	System Peak Demand Forecast (Capital and Regional Planning)	Customer, Consumption, Billing Demand Forecast
Forecast Model	End-Use	Statistically Adjusted End-Use, Multivariate Regression
Purpose	Station and Feeder Capacity Adequacy	Customer Count and Customer-level Consumption and Demand within billing
Weather Scenario	Normal Weather (1 in 2) Extreme Weather (1 in 10)	Normal HDD and CDD (average of the past 10 years)
Zones	6 System Planning Zones	5 Rate Zones
Granularity	Station and Feeder	Rate Class
EV Uptake	Included (2.0-VECC-13(d))	Included (JT-3.35 Attach 1)
Decarbonization Scenario	Medium Exhibit 2A, Tab 1, Schedule 1, Appendix J	Medium (JT-3.35 Attach 1)
Data Center	2A-SEC-38	JT-3.35 Attach 1
CDM Activities	2.0-VECC-13(a)	JT-1.34
Organic Growth	Included Exhibit 2A, Tab 1, Schedule 1, Appendix J	JT-3.35 Attach 1

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.23

Reference: 1-AMPCO-13

Provide the 2017 to 2026 savings already achieved through the merger on a revenue requirement basis including the supporting calculation.

RESPONSE:

The table below presents the estimated revenue requirement reductions achieved through merger synergies from 2017 to 2026. Operating synergies are converted into revenue requirement assuming a one-to-one relationship. Capital synergies are converted into revenue requirements using a ~7% assumption, derived from a detailed bottom-up assessment of capital cost drivers – including return and depreciation – on the overall revenue requirement.

By way of this response, Alectra Utilities would also like to correct the previously reported average annual (2027-2031) revenue requirement reduction due to synergies from $40.7 to $38.2 million.[1]

[1] In 1-AMPCO-13, accumulated depreciation was used in place of depreciation expense, resulting in an overstatement of the impact on revenue requirement.

Table 1 - Derivation of 2017-2026 Revenue Requirement Reduction[2]

Net Synergies ($MM)		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026 Total**
Operating		($0.8)	$24.0	$25.4	$31.9	$32.2	$35.4	$35.8	$35.9	$35.9	$37.8	$293.6
Capital		($3.3)	$0.1	$3.8	$8.2	$15.4	$7.6	$4.7	$5.3	$0.9	$4.6	$47.2
Total		($4.1)	$24.1	$29.2	$40.1	$47.6	$43.0	$40.5	$41.2	$36.8	$42.4	$340.7
Revenue Requirement Reduction ($MM)	**Ratio**											
Operating	100.0%	($0.8)	$24.0	$25.4	$31.9	$32.2	$35.4	$35.8	$35.9	$35.9	$37.8	$293.6
Capital	7.1%	($0.2)	$0.0	$0.3	$0.6	$1.1	$0.5	$0.3	$0.4	$0.1	$0.3	$3.3
Total Revenue Requirement Reduction		**($1.0)**	**$24.0**	**$25.7**	**$32.5**	**$33.3**	**$35.9**	**$36.1**	**$36.3**	**$36.0**	**$38.1**	**$296.9**

[2] Minor differences could exist due to rounding.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.24

Reference: 1-SEC-2 and 1-SEC-4

To consider the request to provide the documents identified on page 80 of the record from the list provided in response to SEC-4, and advise accordingly of Alectra's position.

RESPONSE:

Alectra Utilities has included a compendium of documents that are responsive to this request as Attachment 1 ("Consolidated Reports") to this undertaking. Additionally, a table has been provided in this response which points the reader to where each document requested on Transcript Day 3, Page 80 can be found on the public record:

Table 1 – Summary of Responses to SEC Document Request

Document Requested	Response
Alectra Utilities 2020–2024 Capital Plan Assurance Review	The requested document has been filed by Alectra Utilities in past OEB proceedings but is provided as an attachment to this undertaking response for ease of access.
Canadian Power Sector Cybersecurity – Budget & Headcount Benchmarking Report	Alectra Utilities is currently unable to produce this report. PwC has informed the utility that the information within the Responsive Document is protected under contractual arrangements signed by the participants in the study. Alectra is actively working with the consultant to resolve the issue, and an update will be filed on this matter at a later date.
Executive Pension Benchmarking Report	The requested document is provided as an attachment to this undertaking response.
Executive Compensation Analysis (only if covering levels beyond EVP)	This request by SEC is only to provide this Executive Compensation Analysis report if its content goes beyond addressing the EVP level, since a more recent EVP benchmarking analysis (from 2025) has already been produced. This

Document Requested	Response
	Executive Compensation Analysis report, by Meridian dated January 2022, only addresses EVP levels and not any levels below this. Accordingly, and consistent with the limitation in the request, it is not being provided.
Review of Target Market Positioning and Peer Group for Executive Compensation Benchmarking	This is a May 2021 slide deck prepared by Meridian regarding target market positioning approach and peer group in preparation for, and in connection with Meridian conducting, the above-referenced Executive Compensation Analysis in January 2022. This 2021 slide deck is not relevant to the matters at issue in this application. As SEC's counsel noted, a more recent (2025) executive compensation benchmarking report has already been produced addressing executive compensation. The earlier 2022 analysis and related preparatory 2021 slide deck have no bearing on the issues to be decided in the application. On this basis, it is not being provided.
Deep-dive Electricity Utility Customer Survey (Commercial) – 2025	The requested document is provided as an attachment to this undertaking response.
National Electric Customer Survey – 2025	The requested document is provided as an attachment to this undertaking response.
Continuous Improvement Framework Review	The requested document is provided as an attachment to this undertaking response.
Building Condition Assessment	The requested documents were filed by Alectra Utilities in Appendix N of its Distribution System Plan (Exhibit 2A).
ARI Vehicle Health Report	As indicated in Alectra's response to IR 2-AMPCO-46, The work product prepared by Holman (ARI) consisted of hundreds of detailed assessments of individual fleet assets providing condition and demographic information of each, along with multiple photos and videos of each asset. The assessments were hosted on an online portal operated by Holman (ARI), Alectra Utilities did not receive a singular report or other document setting out the assessments. Alectra Utilities confirms that this statement remains true at the time of filing this undertaking response.
Digital and Innovation Target Operating Model Report	The requested document is provided as an attachment to this undertaking response.
Software Asset Management Review	The requested document is filed in Attachment 1 to JT-3.8.

Document Requested	Response
Hardware Asset Management Review	The requested document is provided as an attachment to this undertaking response.
Alectra DERMS Assessment	The requested document is provided as an attachment to this undertaking response.
Alectra DSO Research Study	The requested document is provided as an attachment to this undertaking response.
Determination of Asset Utilization Report	The requested document is provided as an attachment to this undertaking response.

JT-3.24

Attachment 1
Consolidated Reports

Alectra DERMS Assessment

Alectra DERMS Needs Assessment

June 2020

alectra
GRE&T Centre
Green Energy & Technology

Executive Summary

The future speed and magnitude of Distributed Energy Resources (DERs) proliferation is beyond what we might be able to foresee today, but it's expected to be great. Alectra already has nearly 200MW of DERs connected through past FIT and microFIT programs. While these do not currently pose an operational problem, as we enter this coming decade, there will be a growth in both the type and the number of different DERs connecting into the distribution system. While this creates some operational risk for Alectra's grid, it also creates customer service and stakeholder relations risks if not properly managed. As customers look to install DERs, it will be important for Alectra to be an enabler and trusted energy advisor, as opposed to a barrier, in order to maintain its focus on customers.

Alectra is facing the need to understand, mitigate and reduce the risks DERs pose on capacity constraints, power quality, and reliability, and ready the distribution system to accept and support DERs, from residential and/or commercial generation and storage to electric fleet trucks and vehicles. As DER penetration in the distribution system increases, equipment rating capability and coordination of protection systems will require closer investigation or more failures will occur. This may result in expensive upgrades to distribution infrastructure to manage these power quality risks. On the other hand, using internet-of-things enabled technologies, Alectra has the opportunity to leverage customer-owned DERs, in harmony with traditional grid assets, to improve the operation and efficiency of the grid even while it is becoming more complex.

Alectra will evolve from just distributing electricity to providing an electricity exchange platform for its customers. In a recent consultation, initiated by the Ontario Energy Board (OEB), both Local Distribution Companies (LDCs) and DER owners have emphasized a need for solutions to standardize and streamline the process of DER connections and integration into the distribution system. As more of Alectra's customers start adopting various forms of DERs, having the LDC's processes and technologies in place to reduce the time and cost of DER connections and integration will be important to maintaining good customer satisfaction and stakeholder relationships. This should proceed in parallel while the OEB is developing a comprehensive regulatory framework that facilitates investment and operation of DERs based on value to consumers and effective DER integration. The OEB is also looking for Alectra to consider employing Non-Wires Alternatives (NWA) to traditional grid investments to utilize these DERs to potentially reduces rates.

Looking forward, Alectra has recently developed a five-year strategic plan, Strategy 2.0, focused on establishing the "grid of the future". The three pillars of this strategy are Grid, Customer Experience, and Growth. It sets out how Alectra can innovate, transform and grow into an integrated energy services company. As Alectra will evolve into this vision, in the presence of an increasing number of customer-owned DERs connected to its distribution system, the Strategy 2.0 identified a need to develop and integrate an enterprise-level Distributed Energy Resource Management System (DERMS).

An enterprise-level DERMS platform will enable Alectra to monitor, control, and optimize the integration of DERs into its distribution system (Grid), to offer real-time and transparent operation of DERs in various energy services (Growth), and to serve the increasing number of customers that already are and will continue to adopt DERs and demand for more energy services choices (Customer Experience).

As both Alectra's most recent Distribution System Plan and Alectra's Strategy 2.0 have identified the need

for DERs management and integration, this DERMS Needs Assessment project was initiated and mandated by the Non-Wires Alternative (NWA) Pilot Steering Committee, in late January 2020. This project's objective is to take a holistic approach and identify the DER-related needs of the entire Alectra organization and evaluate the necessity of implementing a DERMS, beyond what may be required for the NWA pilot project.

Following the direction of the NWA steering committee, a working group was established with representatives from operational and non-operational business units. Headed by the Grid Innovation team at GRE&T Centre, Elletrica was engaged to facilitate the workshops, interview business units and deliver an assessment on the need for an enterprise-level DERMS. This document represents the results of the DERMS Needs Assessment.

This DERMS Needs Assessment (the Assessment) outlines the need for a DERMS to monitor, control and optimize these distributed resources in the coming years to maintain a safe, reliable and cost-effective electricity grid for its customers. It is best to manage the impacts of DERs ahead of time, then to be reactive.

The recommendation of this Assessment is to take a forward-looking approach to prepare Alectra for the possible future scenarios by starting the DERMS journey now, by taking slow yet calculated steps. The Assessment recommends Alectra's DERMS team to start the process of Execution Framework development in 2020. The goal is for the Request for Proposal (RFP) to be released in early 2021 with a target to start the pilot phase in the last quarter of 2021, to run the DERMS proof of concept as the first phase. This will enable Alectra to conduct the proper execution framework validation and run a robust procurement process in advance of significant investments. The next phases will then be implementing the identified use-cases through development sprints, upon the success of the pilot phase. Using this approach, all the identified short-term use cases can be completed by mid 2023.

As part of this DERMS Needs Assessment, candidate use cases related to DER management were gathered. A use case is a system engineering term that describes how a user can use a system to accomplish a particular goal. It is a business-oriented view of what a system can do. These use cases were reviewed with each business unit to determine if they had a need for that use case and the timing of that need. The results of the assessment are provided in Table 1.

Table 1: DERMS Needs Assessment Use Case Analysis

<table>
<tr><th>Total Use Cases Identified</th><th>Use Cases Deemed Needed</th><th>Short Term (2021/2022)</th><th>Medium Term (2023/2024)</th><th>Long Term (2025+)</th></tr>
<tr><td rowspan="3">56
Identified</td><td rowspan="2">48
Needed</td><td>9
Operational</td><td>1
Operational</td><td>9
Operational</td></tr>
<tr><td>14
Non-Operational</td><td>9
Non-Operational</td><td>6
Non-Operational</td></tr>
<tr><td colspan="4">8
2025+ consideration</td></tr>
</table>

Note: Operational Units: System Control, OT, IT, P&C, Stations, & Planning.
Non-Operational Units: CDM, CIA, Customer Service, Key Accounts, GRE&T Centre, & Distributed Energy Solutions.

The Needs Assessment points to a short-term need for a DERMS to provide operational business units with the DER management capabilities required for the continued safe and reliable operation and planning of Alectra's distribution system. These are needed to establish a more robust compliance management and control capability as well as enable better forecasting and planning. This will establish a foundational capability as DERs grow on Alectra's distribution system.

Outside of the operational use cases, the DERMS can provide a valuable platform to better leverage grid assets, improve customer experience, and provide a platform for revenue growth. While not immediately required for the Non-Wires Alternative (NWA) Pilot, should a DERMS become available it could be leveraged to perform many NWA use cases.

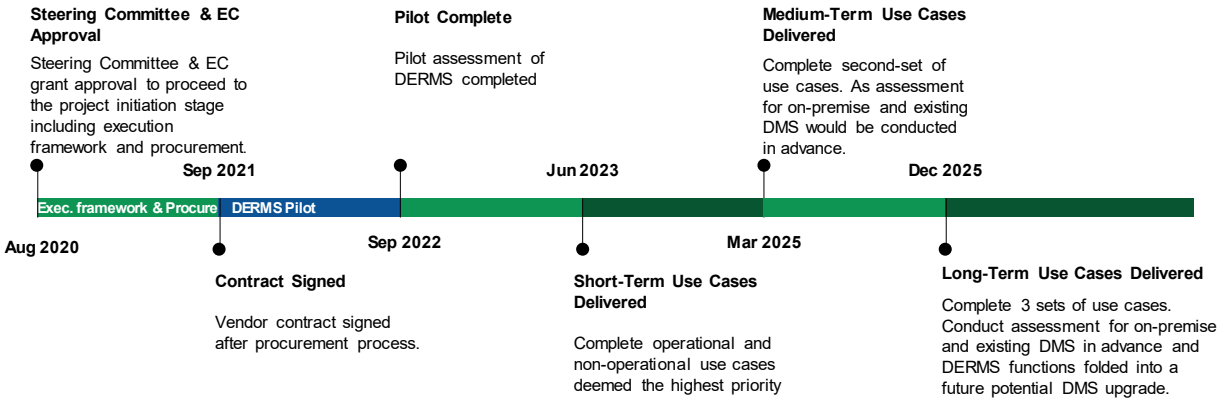
All the identified use cases were then mapped against an industry-benchmark for DERMS capabilities and requirements. It identified which capabilities are needed to support each use case. Based on the use case to capability mapping, Alectra requires 10 of the 11 identified DERMS functional capabilities (e.g., user interface, controls, energy business rules, etc.) to meet its short-term operational use case needs.

As a DERMS requires both a network model and inputs from the current SCADA system, the existing Distribution Management System (DMS) is the natural fit to provide DERMS capabilities. The working team reviewed the DER-related functionalities of the existing DMS and met with Survalent (Alectra's current DMS provider) to understand their future DERMS roadmap. Upon discussion with the Operational Technology team, it was collectively concluded that the DMS will not have the requisite capabilities in the short or medium term. As such a new DERMS should be procured and integrated to Alectra's DMS.

By understanding the capabilities along with Alectra's current operating technology landscape, a high-level conceptual solution architecture was created that identifies which systems the DERMS will need to interact with for it to perform its function. As DERMS will become more functional over the next five years, Alectra should ensure that its investment can benefit from these improvements. It would be prudent for Alectra to employ a cloud based DERMS. This will allow Alectra to enjoy the benefits of advancing technology while minimizing the costs and risks associated with implementing an on-premise DERMS. While the DERMS will need to interface with Alectra's DMS to obtain real-time SCADA data, it should be possible to secure the connection just as current connections to the IESO and Hydro One are secured. This will be subject to a security review by Alectra's Cyber Security team. To enable Alectra's system controllers to attain a "single-pane-of-glass" to operate the distribution system with its traditional assets as well as DERs, system-to-system integration efforts should be undertaken.

The recommended timeline for a DERMS implementation would be to start drafting execution framework this year with RFP documents to be designed and released by mid 2021. This will enable procurement by Q3 2021 with a goal to launch a pilot project in the last quarter of 2021. Once the pilot use cases were ready, there would be a six-month pilot assessment period to evaluate on vendor capabilities, execution framework validation, and Alectra's needs. Should the pilot prove successful, then additional use cases would be implemented quarter-by-quarter through to June 2023, to complete the identified short-term use cases. This would provide the requisite functionality for the Business Units about a year later than the timelines they have requested. Additional releases of DERMS functionality would be made in future updates.

Diagram 1: Alectra's Five-Year DERMS Timeline



As this project will be occurring at the same time as other projects, it is important to take into account constraints on key resources as well as the change management capacity of the organization. Multiple Operational Technology (OT) resources will be required in the last half of 2021 to establish infrastructure connectivity and interfaces. The control room will need to train some of its system controllers in the use of the new pilot system in early 2022 and the entire control room staff will need to be trained by mid 2023.

Using this cloud based DERMS approach to first pilot, and if successful, implement, the pilot is estimated to cost $960K with the additional short-term use cases estimated to cost $1.7M. These costs will be incurred from 2021 to 2023. Once the platform is established, subsequent upgrades are estimated to cost $1M for medium-term and long-term use cases. The ongoing cost to support the infrastructure, license the software and provide maintenance will grow to $261K per year by 2024, starting from 2022.

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Introduction

Alectra Utilities Corporation's distribution system will need to adapt to accommodate increasing levels of DERs. As the electric grid begins to shift from a primarily centralized generation platform to a more decentralized distribution generation platform, a utility's ability to integrate, control and optimize DERs becomes paramount - to be able to maintain a safe and reliable electricity grid and satisfy consumers' needs for grid services.

While development of renewable energy projects (i.e., rooftop solar) will remain slow over the medium term, Alectra's customers are already undertaking behind-the-meter generation and energy storage projects mainly to reduce their Global Adjustment commodity costs. Also, we already have nearly 15,000 EV drivers in Alectra service territory. EV charging demand, either light-, medium-, or heavy-duty electric vehicles is expected to grow much faster than other load impacting DERs in the coming decade. This growth in DERs, combined with nearly 200MW fleet of DERs already connected, requires Alectra to establish better monitoring and compliance management of these resources as they grow in the coming years.

Beyond the changing electricity supply mix, there are multiple driving forces for grid modernization. With the advancement in information and control technologies there are new opportunities to bring intelligence to both the central grid control systems as well as the grid-edge. Using internet-of-things enabled technologies, Alectra has the opportunity to leverage customer-owned DERs and other grid assets to improve the operation and efficiency of the grid even while it is becoming more complex.

Connected DERs will increasingly come in the form of connected electric vehicles (EVs). While we have seen a slow acceleration of passenger EV adoption, there are compelling economic and environmental forces that will see the electrification of transit, delivery and trucking fleets. With these large concentrated mobile loads connecting into the system, it will be imperative for Alectra to have the capabilities to monitor and optimize the loads for both the benefit of the customer (lower electricity and connection costs) and the grid (avoid grid upgrades and increase capacity utilization).

Customers are starting to look for, and will soon start demanding, ways to participate in new energy market opportunities. As more and more customers install DERs, we will see both residential and commercial customers seek to maximize the economic value of their investments. It's important to support Alectra in its vision of evolving from a company that distributes electricity to one that provides a platform for energy market participants. Alectra will need to provide customers with alternative energy choices to the traditional electricity supply model, including the DER technologies. This could involve novel ownership structure that allows customer participation in grid-benefiting services

The need for systems and capabilities that can manage DER Integration are driven by the need to understand, mitigate and reduce the risks DERs pose. It will be important for Alectra to ready its distribution system to accept and support DERs. Not only will Alectra need to connect DERs, but it will need to establish the systems and processes that allow it to do so cost-efficiently. It's important to improve efficiencies around managing and settling with DERs on Alectra's distribution grid.

At the heart of Alectra is a desire to ensure electricity is affordable for its customers. As DERs become an increasing reality on the distribution system, it is important for Alectra to avoid rate increases associated with the operational issues that could come with growing amounts of unmanaged DERs. By undertaking investments now, Alectra can prepare the distribution system to safely and reliably respond to the expected uptake of DERs with a coordinated architecture that balances the benefits of DERs to their owners, with the costs they potentially pose on all of Alectra's customer base.

Without the proposed investments, Alectra faces the risk of power quality and reliability issues that arise from unmonitored and unmanaged DERs. This could result in the increasing frequency of power quality issues and outages. Already, there will likely be outages due to adverse weather conditions. It will be important for Alectra to manage DERs and the grid in this new more complex operating paradigm.

There is also a missed opportunity cost. Alectra is still in a period of expansion, with many of its municipalities still experiencing population growth. The regulator is looking for Alectra to consider non-wires alternatives to traditional grid investments. A DERMS provides Alectra the platform to get away from traditional thinking. Without the investment in DERMS required to manage DERs, there could be asset expansions that could potentially be deferred or avoided through the intelligent use of embedded DERs.

Alectra has recently developed a five-year strategic plan which is focused on the "grid of the future". This strategy consists of three pillars: Grid, Customer Experience, and Growth. Alectra's strategy is focused on innovation, transformation and growth; evolving Alectra into an integrated energy services company while having all elements - customer, grid, and growth - working in collaboration on an enterprise-wide basis.

To fully position Alectra for being the "grid of the future" in the presence of the ever-increasing penetration of utility and customer-owned DERs, the need to develop and integrate an enterprise-level DERMS is present and has been identified in Alectra's Strategy.

Alectra's GRE&T Centre is currently piloting an NWA project. The NWA Pilot, Canada's first-in-its kind, will establish a distribution-level DERs market that is interoperable with the IESO wholesale market. This market will utilize distributed energy resources (DERs) in the demonstration areas to reduce load, absorb excess power, and improve power quality, with the goal to defer or avoid the need for traditional infrastructure investment in wires solutions. In order for the NWA Pilot to accomplish this, a DERMS was being considered and proposed the NWA Pilot Steering Committee, in January 2020.

The NWA Pilot Steering Committee mandated GRE&T Centre to take a holistic approach and determine if the broader Alectra organization could also benefit from a DERMS. Hence, this DERMS Needs Assessment (the Assessment) project was initiated. This Assessment is to evaluate and to provide recommendations to the NWA Steering Committee and Alectra's Executive Committee so they can make an informed decision about investing in a DERMS.

Methodology

Identify Stakeholders

The DERMS Needs Assessment Working Group that was initially identified by the NWA Steering Committee includes team members from System Control, Planning, Stations, Protection & Control (P&C), IT/OT, and the Grid Innovation group at the GRE&T Centre. In addition to those identified by the NWA Steering Committee, the Needs Assessment team felt that additional input from the CDM, CIA, Distributed Energy Solutions, Key Accounts, and Smart Cities group at the GRE&T Centre would be prudent as they also have a need for DER related use cases. The Regulatory Policy & Strategy, Customer Systems, and Customer Service Excellence teams were also consulted.

Table 2: DERMS Needs Assessment Working Group

Jack Jacoby Manager, **Control Room**	Jordan Snooks Specialist, **OT Application Services**	Piyush Patel Manager, **Distributed Energy Solution**
Keith Hemingway Manager, **OT Services**	Ralph Williams Manager, **Connections&Key Accounts**	Daniel Carr Head, **Smart Cities**
Bob Braletic Manager, **Station Design**	James Ilari Director, **IT Innovation & Governance**	Hamza Mortage Project Lead, **Grid Innovation**
Philip Haid Manager, **Protection & Control**	Ken Craft, Director, **IT Security & Risk**	**Needs Assessment Team**
David Burns Engineer, **Stations& New Connections**	Gia DeJulio VP, **CDM**	Fahimeh Kazempour Technical Manager, **Grid Innovation**
Riaz Shaikh Manager, **Distribution System Planning**	Michael Pardal Manager, **CIA**	Geri Yin Head, **Grid Innovation**
	Ammar Nawaz VP, **Distributed Energy Solutions**	Alex Bettencourt **Consultant**, Elletrica

Identify Use Cases

The Needs Assessment team went through an extensive process of identifying use cases based on detailed research of DERMS vendor offerings, industry association publications and the team's knowledge and experience. In total, 56 use cases were identified. A traditional approach would have been to identify

requirements - the specific details of what the system needs to perform. However, the new approach favored by technology companies and system design engineers is to identify use cases - the business outcome a user is looking to achieve.

This enables a business-driven approach to determine the need for the system. It also makes the business case justification more compelling. The advantage is that it enables the business to clearly communicate an objective to a technology developer, so they can engineer a solution. The list of these 56 use cases along with their description, benefits, and the identified business units can be found in Appendix A.

Determine Need by Business Unit

The Needs Assessment team then met with each business unit individually to review the use cases and identify which use cases, in particular, would be useful for them. The use cases were also placed on a timeline to determine when the business unit forecasted its need. Afterwards, these were distilled into a centralized DERMS Use Case repository and summarized for the business units.

Business units were then asked to review and confirm the use cases and the timing of the need captured. As a result, some business units added some additional needs after review or moved the identified timelines.

Map Capabilities for Use Cases

With the final use cases identified by the business units along with their associated timing, the next step was to identify the capabilities of a DERMS necessary to meet the requirement of these use cases. To establish the framework, we consulted a common industry source. The Smart Energy Power Alliance (SEPA) is an industry association based in the US that is working to advance many energy technologies including DERMS. They have published a SEPA DERMS Requirements 2.0 document that identifies the common set of DERMS requirements.

This has become a touchstone in the industry as it was developed by many utilities, in concert with DERMS providers, to provide a set of common requirements that could be used by utility companies looking to implement a DERMS.

This document identifies 17 major capability areas that are broken down into 95 sub-capabilities and about 650 requirements. This constituted the core of capability mapping. There was one set of capabilities around market functions that were not in the SEPA document that was added into Alectra’s assessment. The list of these capabilities can be found in Appendix B.

Assess Current & Future DMS Capabilities

In assessing DMS capabilities, we want to acknowledge that Alectra already has operating technology and ensure that we are not duplicating functionality that is already available. The long-term need will likely be a DMS with sufficient DER management capabilities to enable continued operation of the system when there will be high penetration of DERs.

As a result, the Needs Assessment team along with the OT and System Control groups met with Survalent, Alectra's current DMS and OMS provider. The meeting was to assess the current DMS to understand its capabilities and to determine if it could meet some of the DERMS Use Cases. Also, the team was interested to understand Survalent's future roadmap of the DMS product to determine what future capabilities will be available and when.

Propose Solution Architecture

Based on the understanding of the current OT environment, the required capabilities and the current/future capabilities of Survalent's DMS, this assessment develops a target solution architecture that could be used to provide a basis for design and cost estimation. It identifies the interface systems and how the system should be positioned relative to other systems.

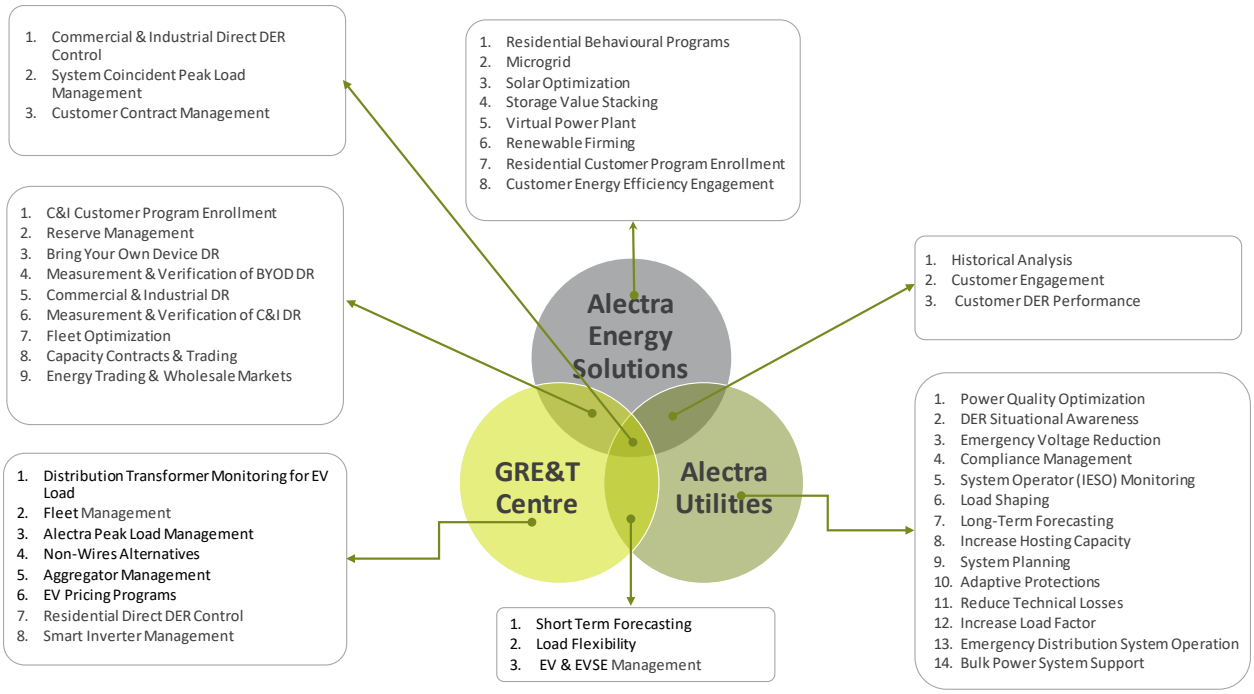
Develop Cost Estimate

Based on the solution architecture, the objective is to develop a high-level cost estimate that can be used for decision and investment planning purposes. To do so, we would use the information available from DERMS vendors working with GRE&T Centre on the current projects, information available from OT for similar projects, and the Needs Assessment team's knowledge and experience.

Alectra Identified Use Cases

During the business unit review sessions, the Working Group identified which use cases would be needed by their business unit. In Diagram 2, you can see the mapping of use cases to business units. Some use cases were deemed necessary by multiple business units. The diagram below presented the business organization (GRE&T Centre, Alectra Utilities and Alectra Energy Solutions) that identified the need for use cases.

Diagram 2: Use Case Mapping by Alectra Business Organization



In order to align the use cases with Alectra's strategic plan, the use cases were also categorized into the three strategic objectives of focus: grid, customer and growth. In Diagram 3, it outlines the mapping. Some use cases can meet more than one strategic objective.

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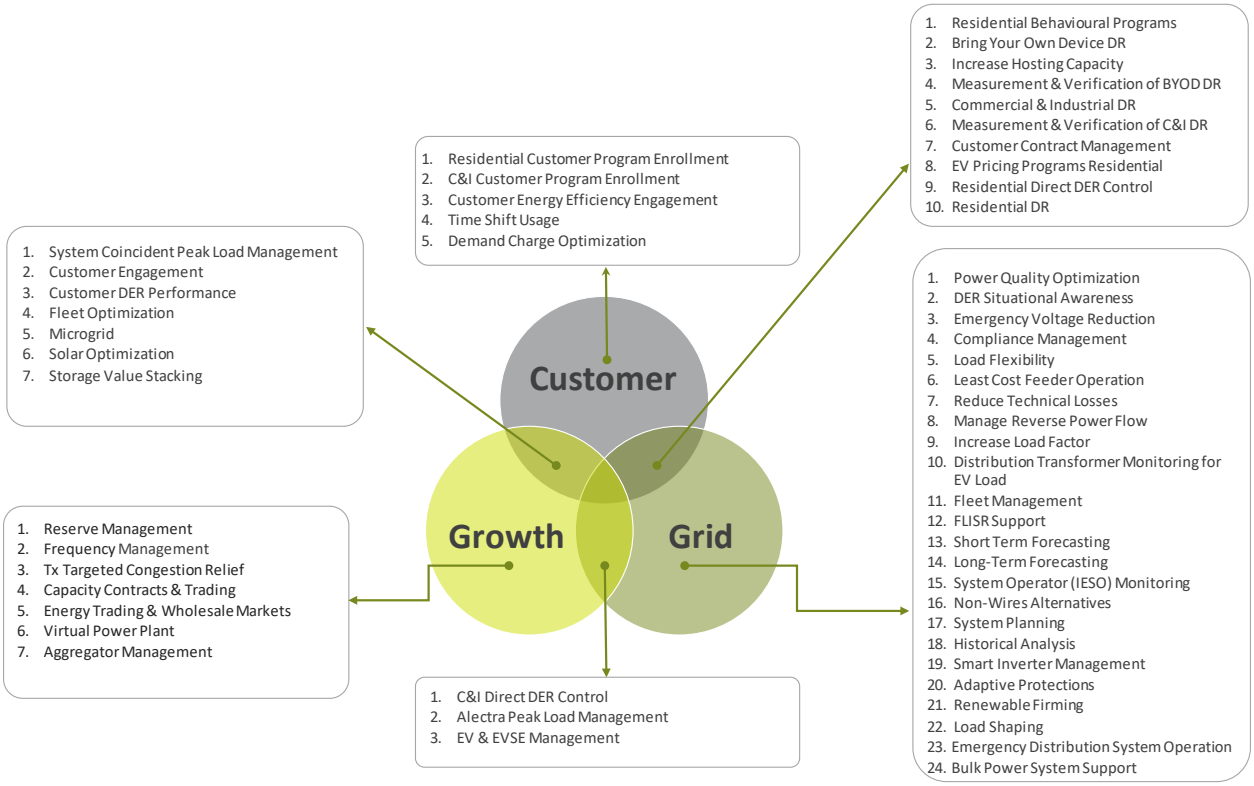
Diagram 3: Use Case Mapping by Alectra Strategy Area



Each business unit not only identified their need for a use case but also provided the timing of that need. The use cases were further categorized into Operational and Non-operational business units; their use case need, and timing as shown in Diagram 4 and Diagram 5 below:

Diagram 4: Use Case Timeline for Operational Use Case

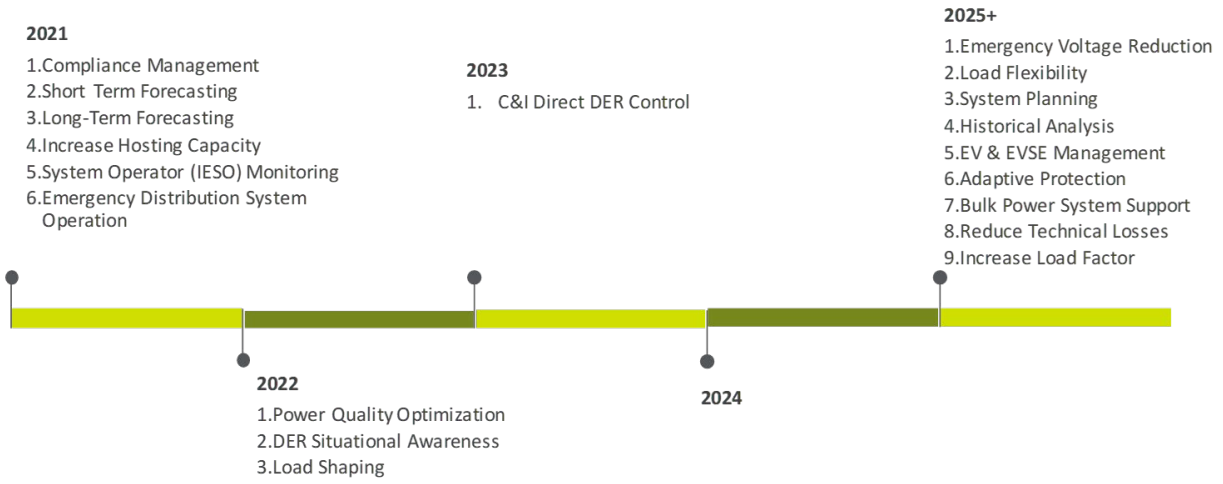


Diagram 5: Use Case Timeline for Non-Operational Use Case

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The use cases were also categorized into their DER management function in Diagram 6.

Diagram 6: Use Case by DER Management Stage

There was a set of 8 identified use cases that no business unit believed they would have a need for in the short or long term. These use cases are recommended to be re-considered in 2025+ timeframe.

Frequency Management	FLISR Support	Time Shift Usage
Least Cost Feeder Operation	Targeted Tx Congestion Relief	Demand Charge Optimization
Manage Reverse Power Flow	Residential DR	

Needed DERMS Capabilities

A DERMS is a broad collection of capabilities used to manage DERs. These capabilities range from user interfaces to SCADA functionality and system maintenance. Not all capabilities may be needed by Alectra initially. This Needs Assessment Study also examined how use cases (something that a person wants to perform) translate into capabilities (something the systems can do).

The Smart Energy Power Alliance (SEPA) is an industry association based in the United States. It has had a project over the last couple of years to create a common set of DERMS requirements that can be used by utilities. It gathers all sizes of the industry (utilities, DERMS providers, DER companies) to think through and compile a list of all the potential requirements of a DERMS. The purpose is so it can be used by any utility companies looking to procure a DERMS to jump-start their procurement process with a set of requirements that are known to the industry. The SEPA DERMS Requirements is now in its second release. In the document, they outline 17 high-level capabilities required of DERMS. These are broken down into 95 mid-level capabilities which are further broken down into about 650 requirements.

This Needs Assessment Study utilized SEPA DERMS Requirements as a Capability Model so Alectra can leverage an industry-wide accepted set of requirements for any potential future procurements and projects. These requirements will form the basis of any RFP, design, and testing for future DERMS projects.

A detailed assessment was completed to determine which capabilities would be needed to meet each of the Alectra identified use cases. This was done across the 95 mid-level capabilities. We have rolled up that assessment to the high-level capabilities below to show which capabilities are required. In addition to the functional capabilities, a set of non-functional capabilities are also required for the efficient and secure operation of a DERMS. The non-functional capabilities are considered essential in any DERMS implementation.

Table 3: Capabilities Needed

Functional Capabilities		**Non-Functional Capabilities**
Operational Use Cases	**Non-Operational Use Cases**	
- User Interface - Reporting - Configuration - Controls - Dynamic Topology Changes - Contract Management - Energy Business Rules - Historian - Constraint Management - Forecasting	- User Interface - Reporting - Configuration - Controls - Dynamic Topology Changes - Contract Management - Energy Business Rules - Historian - Constraint Management - Forecasting - Market Functions	- Testing - System-to-System Integration - Cybersecurity - High Resilient Design - Scalability - Maintainability - Common Information Technology Services

Note: A full detailed listing of use cases to mid-level capabilities can be found in Appendix B.

The assessment points to Alectra requiring a DERMS with a broad set of capabilities in the short-term. The key operational use cases require capabilities that can serve both the operator function in the control room as well as the planner function in the back office. As such, in order to perform the short-term operational use cases, there is a need for a full set of capabilities that range from User Interface to Controls.

Current & Future DMS Capabilities

The stated goal of Alectra's Operational Technology and System Control business units is to provide system controllers with a "single pane of glass" to manage Alectra's distribution system penetrated by DERs. This means providing all the capabilities an operator would need within a single system. Alectra is currently in the process of consolidating all legacy utility control systems into a single DMS platform, provided by Survalent. The last legacy control system to be consolidated will be Guelph in 2021. Alectra is also currently upgrading its DMS with the latest Outage Management System (OMS) functionality with the intent to complete this upgrade by the end of 2020.

This Needs Assessment Study reviewed Survalent's existing DERMS capabilities to determine if Alectra already has sufficient existing technology to meet the identified use cases. As the DERMS functionality will be needed in stages, this initiative also reviewed what was Survalent's roadmap for future DERMS functionality. This allows us to assess if a future upgrade of the DMS would provide the required capabilities that could avoid the implementation of a separate purpose-built DERMS.

Survalent currently has limited DER-related functionality. While the Survalent system is not currently performing a formal Compliance Management function, their SCADA system can be configured with alarm rules that could provide some functionality. Survalent's primary development focus related to DERMS is ensuring their ADMS functions can continue to work when there are higher penetrations of DERs on the system.

Survalent is looking to build a DER Management engine (DERMe) into their Survalent.One platform instead of providing a standalone DERMS. Survalent sees adding DER engineering/planning, increased hosting capacity and DER data management functionality as a secondary priority. Currently, Survalent is not focused on the customer-facing elements of a DERMS (e.g., customer enrollment, residential CDM programs).

While Survalent is currently capable of providing the required data export to third-party DERMS, they are interested in building new DERMS functionality if a utility was willing to pay and if it was aligned with their roadmap. To co-develop Survalent's DERMS capabilities, Alectra would have to play the role of requirement creator as well as system tester for Survalent DERMS functionality. Survalent is currently working with the National Renewable Energy Laboratory (NREL) on an ADMS+DER interoperability pilot. Their goal is to set the first multispeak standard for ADMS-DER integration and are examining how they can pass their load flow results to third-party DERMS. In addition, they are looking to determine how they can export the as-operated network model to a third-party system by Q1 2021.

In consultation with the Operational Technology team and the above understanding of Survalent's current and future DERMS functionality, it was determined that the existing Survalent DMS would not be able to provide the required use cases in the short or medium term. They will provide data central to any DERMS Alectra chooses to procure (e.g., network mode, SCADA, load flow).

DERMS Recommendation

Through this DERMS Needs Assessment Study, the working team sought to understand the needs of Alectra when it comes to DER management, how those needs translate into system capabilities, and how the current DMS capabilities stack up against those needs. The overall results from this assessment are:

1. There is a strategic mandate to both standardize and speed the process of DER interconnection and lower the costs to maintain customer satisfaction and meet Alectra's strategic mandate of improving the customer experience.
2. There are 48 needed use cases from both operational and non-operational business units, in short-, mid-, and long-term.
3. There are 9 use cases needed in the short-term (2021/2022) to meet operational needs.
4. These use cases require 10 of 11 DERMS capabilities to be operational.
5. The review of the existing Alectra DMS identified that it does not currently have the capabilities required to meet the needed use cases.

Based on this assessment, the recommendation is to implement a DERMS, though a phased approach starting with a pilot by 2022 and a full basis by 2023.

With a foundational DERMS established for operational use cases, it can be leveraged by other non-operational business units to meet the grid, customer experience and growth objectives set out in Alectra's Strategy 2.0.

DERMS as a system is relatively new in the marketplace. As DERMSs are not as mature as other control systems (i.e., DMS), we recommend that Alectra not proceed with a large on-premise implementation to make the upgrades and maintenance a less-labor intense on Alectra. As such, the recommendation is to find a vendor-hosted, cloud-based DERMS to enable a quicker and cost-efficient approach. This would reduce the risk of the up-front investment and ensure that Alectra has the opportunity to adjust as both the DER and DERMS market develop over the next five years.

The strategic goal would be to utilize a new DERMS as a platform Alectra can use over the coming decade to connect with customer-owned DERs. The platform would enable Alectra to intermediate between its critical control systems and customer-owned DERs to maintain security while also enabling those same DERs to be optimized for the benefit of the grid and customers. The new DERMS capabilities can standardize the process of DER connection and maintain the compliance management and contract management functions. It can also be used as a customer opportunity to provide additional value to customers in the form of ancillary service market participation and asset optimization.

To enable Alectra to achieve its goal of a "single pane of glass", it is recommended to undertake system-to-system integration efforts. This involves collaboration between Survalent, the DERMS vendor, and

Alectra's internal resources but it will provide Alectra's system controllers with display and control of traditional system assets as well as DERs, all through a single dashboard.

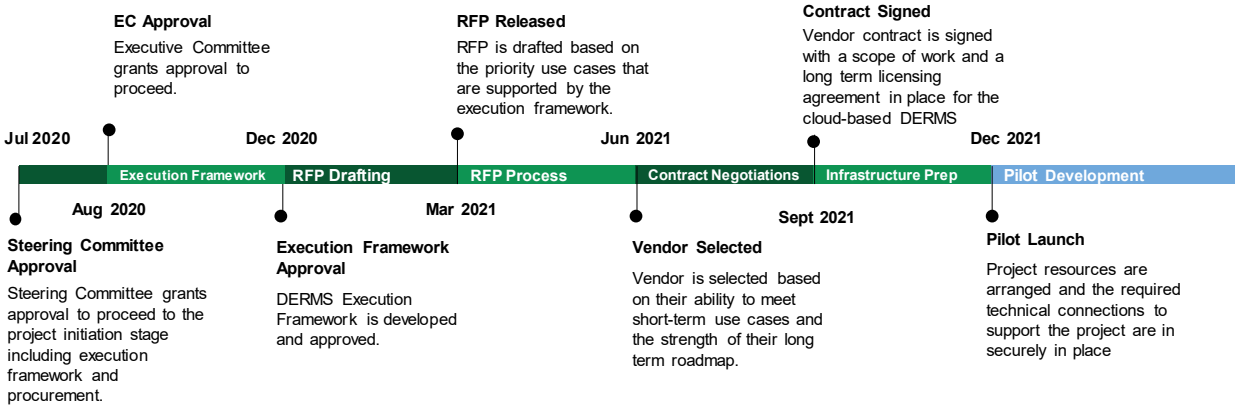
Recommended Timeline

The timeline to implement a DERMS for Alectra will take two years in total. Upon approval by the Steering Committee and the Executive Committee, the next step will be to proceed with an execution framework development. Once use cases are evaluated and prioritized through a quantitative approach based on value, risk, and alignment to strategy in the execution framework, Alectra will draft and issue an RFP and select and negotiate with the winning vendor. This whole project initiation process will take 15 months and go through Q3 2021.

The project should start with a pilot where Alectra can assess both the features of the vendor DERMS and their delivery capability. The vendor will implement five pilot use cases. Alectra will then assess the vendor technology over a six-month period. If the pilot goes well, then the project can continue to implement additional use cases.

To accommodate other Operating Technology work that will be going on concurrently to this initiative (i.e., OMS project, GIS project), the initial geographies for the pilot could be Central South and East region of Alectra's service territory. This will ensure that the validated GIS data is available for the DERMS in Q4 2021 for implementation.

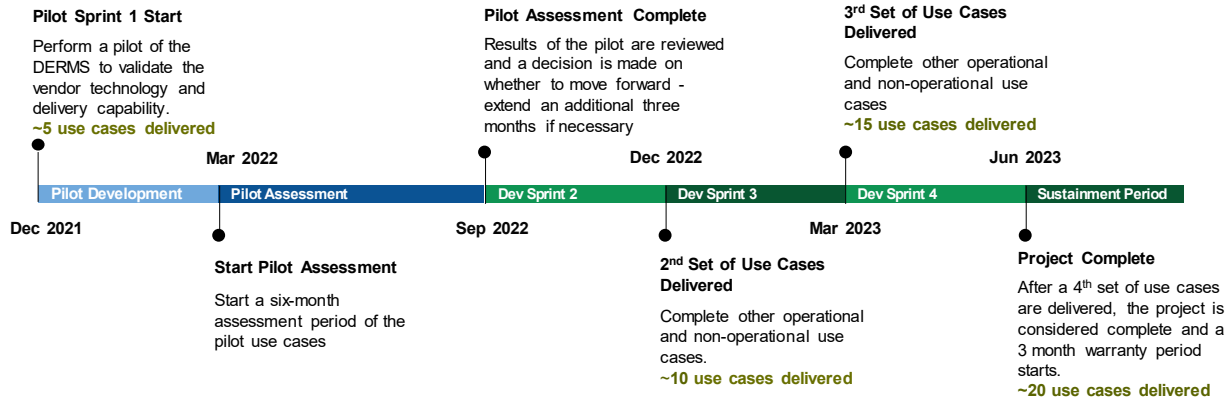
Diagram 7: Project Initiation Timeline



The first implementation of DERMS should take place also over a 12-month period starting in Q3 2021. The recommendation is for the project methodology to use a vendor to provide cloud based DERMS that will

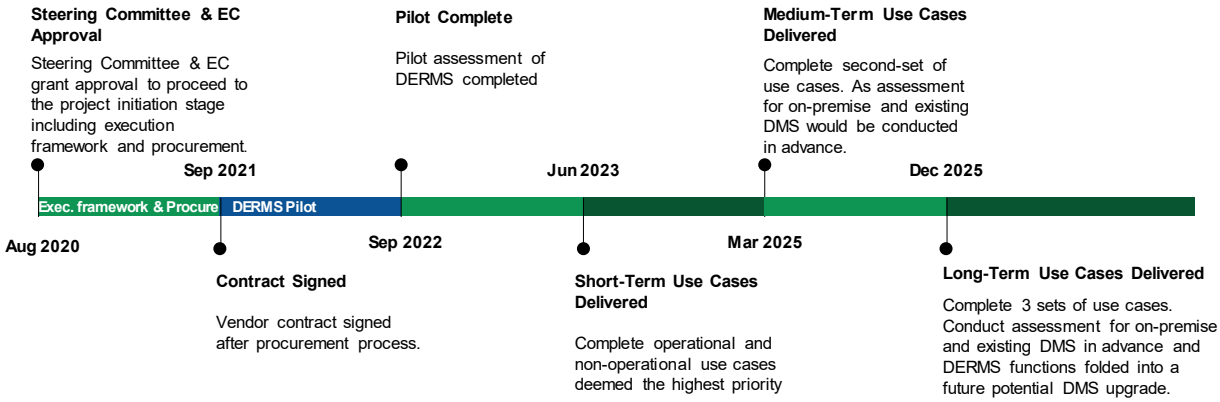
enable a more agile project implementation. The goal is to have four development sprints that will release functionality to the business in four stages based on use case prioritization. it is estimated each 5 use-cases are developed and tested in one quarter (development sprint). The goal is to complete the implementation of DERMS short-term use cases by Q2 2023. A warranty period of 3 months will follow the implementation.

Diagram 8: DERMS Implementation Timeline



Future implementation of DERMS use cases will occur in future development sprints with the DERMS vendor. The target is to have two additional implementations to enable medium-term and long-term use cases. An assessment of the Survalent DERMS functionality should be made before proceeding with the expansion of the existing DERMS platform three months in advance of any project implementation.

Diagram 9: Five-Year DERMS Timeline



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Proposed High-Level Solution Architecture

In order to reduce the risks of the project and speed the implementation Alectra should implement a pilot DERMS on a vendor-hosted cloud infrastructure. Once the pilot DERMS has proven both its functionality (ability to meet the use cases) as well as its infrastructure (security and stability of the solution), Alectra can build upon this platform. By using a vendor-hosted cloud-based infrastructure, many of the complexities associated with a DERMS can be ignored by Alectra. It will be the DERMS vendors' responsibility to provide a stable and workable solution.

Diagram 10: Proposed High-Level Solution Architecture

This architecture enables Alectra to intermediate between its control system and customer-owned DERs. The DERMS would handle the complexities of different communication protocols. We expect these protocols to evolve over the coming years. With the responsibility on the DERMS vendors for ensuring that

they keep up with evolving protocols, it will reduce the risk on Alectra. This approach also enables Alectra to securely connect to customer-owned DERs through a trusted intermediary, the DERMS.

Diagram 11: Proposed DERMS Model Maintenance Architecture

Diagram 12: Proposed DERMS Quality Assurance Architecture

With a vendor-hosted DERMS, much of the complexities associated with production systems and quality assurance systems are transparent to Alectra. Alectra users will test the DERMS system through their QA machines. The DERMS QA should be able to test against the DERMS QA to enable point to point testing

of new DERs. This recommended cloud-based solution is pending a full security assessment to determine if it meets Alectra security standards

Estimated Cost

The cost of a DERMS is dependent on the number of capabilities and use-cases being implemented and the approach for procurement. Based on the recommendation, the DERMS to be implemented will be hosted by the vendor on a secure cloud infrastructure. It requires an upfront investment to configure and customize the DERMS for Alectra needs for the short-term use cases.

The project approach will be phased to reduce risk. The first phase will pilot the first five use cases. This will provide the vendor with the opportunity to demonstrate their technology and delivery capability. The capital at risk by the end of the pilot phase will be about $960K. This covers the execution framework, procurement and pilot phase of the project. The pilot approach will add 6 months to the project timeline.

Subsequent implementation for the medium- and long-term use cases will be smaller implementation as there will already be a working platform. The addition of new capabilities will be shorter projects.

Ongoing operational expenses will be required to provide both internal resources to maintain the security of the connections to the cloud based DERMS as well as provide for software maintenance and cloud computing services.

Table 4: Investment Plan for DERMS ($K)

	2020	2021	2022	2023	2024	2025	TOTAL
Capex	$109	$783	$1,112	$937	$881	$974	$4,796
Opex	$0	$0	$0	$94	$261	$261	$615

A detailed cost estimate is available in Appendix C.

Next Steps

This assessment marks the beginning of the journey for Alectra as it makes plans to manage and take advantage of the DERs in the coming years. The next steps required for the DERMS are:

1- **Make Decision**
   The Steering Committee and the Executive Committee need to make a decision on whether to proceed with a DERMS initiative as recommended for implementation by Q3 2022.

2- **Gather and Quantify Benefits**

Once the approval to proceed is given, the 56 identified use cases need to be quantitatively evaluated and prioritized. While this assessment identified use cases that were of value to the business unit, a further step is required to quantify the benefits in terms of value, risk reduction, and alignment to strategy. A cost estimate has been included here but should be refined with any new information that comes available. Full cost certainty will only come once the procurement process is completed.

3- **Draft and Gain Approval for Execution Framework**

Based on the use cases' finalized score, estimated benefits and implantation timeline per their priority group, draft a formal Execution Framework that can be taken for approval.

4- **Draft RFP**

Using the use cases identified and supported by the execution framework and the capability mapping in this assessment, draft an RFP. The RFP should list the target use cases Alectra is looking to pursue as well as the SEPA DERMS Requirements that Alectra believes are required to implement those use cases. Include the target timelines from this assessment as well as a clear set of security requirements.

5- **Run Procurement**

Run the procurement process for the DERMS. With the SEPA DERMS Requirements being the basis of the RFP as well as clear use cases, it may be possible to have the RFP be open for only 3 weeks with a 1-week extension to provide DERMS vendors enough time to respond.

Contract negotiations with the DERMS vendor should focus on ensuring that there is an open-enough structure to enable changes in scope as the DER market develops as well as a full security assessment to determine if their cloud-based DERMS will meet Alectra security standards.

6- **Initiate Project**

Before the project is launched and the vendor and internal resources are on the ground working, it will be important to ensure that the correct connectivity and security considerations are in place to enable project work to commence. [redacted]

Appendix A - DERMS Use Cases

1	Power Quality Optimization	Operator would be able to optimize the power quality for a feeder using the volt/var support from embedded DERs. Planner would be able to maintain power quality for a non-normal feeder configuration using volt/var support from embedded DERs.	Customer receive consistent power quality that is within the target range at a lower cost than utility-procured devices (i.e. line regulators and capacitor banks). Utility is able to perform load transfers that it was unable to before due to power quality issues in the non-normal feeder configuration.	Key Accounts (2021) System Control (2022) Planning (2025+)
2	Reserve Management	Energy Marketer would be able to sell operating reserve (spinning and 30-minute) into the IESO market.	Provides additional revenue for utility.	NWA Pilot (2022) Energy Solutions (2022)
3	Frequency Management	Energy Marketer would be able to sell frequency regulation into the IESO market.	Provides additional revenue for utility.	NONE
4	DER Situational Awareness	Operator would know the real-time status (switch status, amp, volts, vars) of connected DERs.	Provide situational awareness for operating decisions. Enable efficient operation of the grid in the presence of DERs. Improved safety by understanding which downstream DERs are inputting into system.	System Control (2022)
5	Residential Behavioural Programs	Utility is able to send out communiques to customers that change their usage as required by the grid conditions. Utility is able to verify through measurement and verification (M&V) which customers changed behaviour and provide incentive based on action.	Provides a no/low cost opportunity to procure demand response capacity. Reduces the cost of M&V for residential behavioural programs. Provides value to the customer.	Energy Solutions (2023) CDM (2025+)

6	Bring Your Own Device DR	Customers are able to enroll their devices (e.g. smart thermostats, home energy storage, water heaters, etc) into a utility-controlled demand response program. Utility is able to call upon these BYOD resources for both conservation and emergency demand response events. Utility is able to predict the decay curve of BYOD DR as an event goes one.	Reduces the cost of demand response assets. Provides value to the customer.	Energy Solutions (2023)
7	Measurement & Verification of BYOD DR	Conservation Analyst able to measure and verify the demand response magnitude of participating customers to ensure compliance.	Ensures BYOD resources are providing the expected resources. Reduces the cost of contracting third-party M&V firms.	Energy Solutions (2023)
8	Commercial & Industrial Direct DER Control	Operator is able to reduce or increase load from DERs using C&I customer facilities as required for economic, capacity or emergency operations. Customer is able to enroll their assets into the utility Direct DER Control program.	Provide Operator with control over some of the load on the system for emergency and capacity operations. Provides Short-term Planner with the ability to perform load transfers on feeders where they otherwise would have been unable. Provides Distribution Planner with a potential non-wires alternative to feeder/station upgrades. Provides revenue stream to customer.	NWA Pilot (2022) System Control (2023) Energy Solutions (2025+)
9	Alectra Peak Load Management	Conservation Analyst is able to call on all available and economic DER facilities to reduce the Alectra peak load.	Provides demand response capacity for the IESO in times of peak load management.	NWA Pilot (2021)
10	System Coincident Peak Load Management	Alectra is able to forecast and avoid coincident peaks with the bulk electric system.	Reduces customer cost of electricity.	NWA Pilot (2021) Key Accounts (2021) Energy Solutions (2024)
11	Emergency Voltage Reduction	Utilize embedded DER resources to provide emergency voltage reduction resources.	Provides voltage reduction capability at low cost.	System Control (2025+)

12	Commercial & Industrial DR	Conservation Analyst is able to manage demand response program using C&I resources. C&I customers are able to enroll different load devices into a DR plan.	Provides considerable demand response resources from C&I customers.	NWA Pilot (2021) Energy Solutions (2021)
13	Measurement & Verification of C&I DR	Conservation Analyst is able to measure and verify the demand response magnitude of participating customers to ensure compliance.	Ensures C&I resources are providing the expected resources. Reduces the cost of contracting third-party M&V firms.	NWA Pilot (2021) Energy Solutions (2021)
14	Compliance Management	Operator is able to receive an alarm whenever is DER is outside of its contractual compliance (e.g. output, voltage, etc). Account Manager is able to view a historical report of the compliance of all DERs over a certain threshold along with an event report for each non-compliance incident.	Enables operator to decide whether to take action on the non-compliance of the DER. Enables Account Manager to follow up with DER owner on non-compliance events to ensure that they do not occur again as well as provide the evidence of non-compliance for a fine or disconnection order.	System Control (2021)
15	Customer Engagement	Marketing Analyst and Account Manager is able to engage and communicate with DER customers. Marketing Analyst is able to understand customers with DERs and use the data from the DERs to engage and sell other services. Customer (residential and key accounts) is able to access the programs of the utility through the Customer Engagement portal.	Reduces cost of engagement with DER customers. Improves customer satisfaction with DER customers. Increases the amount of DERs enrolled in utility programs and reduces the cost of acquisition. Provides a Customer Relationship Management for DERs. Use information to better market productions and solutions.	CIA (2021) CDM (2021) Key Accounts (2021)

16	Customer Contract Management	Account Manager and Conservation Analysts are able to initiate and manage and put contracts in place with DER customers.	Reduces the cost of managing DER customers. Improves the compliance of DER customers by having robust contract management. Provides the legal backing for any disagreement with DER customers.	NWA Pilot (2021)* CDM (2021) Key Accounts (2021) *Could be provided by UtilAssist
17	Residential Customer Program Enrollment	Conservation Analyst is able to manage the enrollment of residential customers in various programs. Customer is able understand the available programs, enroll themselves and manage their enrollment through an online portal.	Reduces cost of residential customer enrollment. Improves customer satisfaction. Increases the amount of enrolled resources.	CDM (2021)
18	C&I Customer Program Enrollment	Conservation Analyst is able to manage the enrollment of C&I customers in various programs. Customer is able understand the available programs, enroll themselves and manage their enrollment through an online portal as well as through an Account Manager.	Reduces cost of residential customer enrollment. Improves C&I customer satisfaction. Increases the amount of enrolled C&I resources.	NWA Pilot (2021)* CIA (2021) CDM (2021) Energy Solutions (2023) *Could be provided by UtiliAssist
19	Customer DER Performance	Conservation and Settlements Analysts are able to understand if the DER performed as expected/contracted in order to process any payments/penalties. Customer is able to understand their performance relative to the contractual obligations and track their payment/penalties.	Reduces the cost of managing DER customers. Improves customer satisfaction. Improves compliance of DERs.	Energy Solutions (2021) CIA (2021) CDM (2021) Key Accounts (2021)
20	Customer Energy Efficiency Engagement	Conservation Analyst is able to provide energy saving tips to customers based on their actual historical load and generation profiles. Account Manager is able to provide energy efficiency advice to C&I customers based on their actual historical load and generation profiles.	Improve customer energy efficiency. Improve customer satisfaction. Reduce the cost of providing energy efficiency programs.	CDM (2025+)

21	Load Flexibility	Operator and Planner are able to understand in both the real and planning timeframe what load could become available from DERs for them to make operational decisions. Distribution Planner is able to understand what non-firm load would be available from DERs in the system planning timeframe.	Increases the operational flexibility of the current distribution systems. Enables system configurations that were not possible before. Avoids/defers investments in distribution systems by using DER resources.	System Control (2025+)
22	Least Cost Feeder Operation	Operator is able to leverage DERs to reduce operations of devices.	Reduces wear and tear on voltage regulating (i.e. cap banks, line regulators, ULTC) and switching devices (i.e. break-current operations).	NONE
23	Reduce Technical Losses	Utility is able to utilize DERs to balance load across phases and optimize voltage for the purpose of reducing losses.	Reduce line losses. Lower customer utility bills.	Planning 2025+
24	Manage Reverse Power Flow	Operators are able to monitor in real-time and control DERs to maintain reverse power flow under a configurable limit.	Reduce risk on assets of reverse power flow.	NONE
25	Increase Load Factor	Utility is able to utilize DERs to increase average distribution load factor.	Better utilization of assets. Reduce risk of stranded assets.	Planning 2025+
26	EV & EVSE Management	Operator is able to understand the real-time status of connected EV and EVSE and is able to effect the charging rates as required by the grid. Distribution Planner is able to understand the charging patterns of EVs and usage of EVSEs in order to inform system planning decisions. Innovation Manager is able to understand the charging patterns of EVs and usage of EVSEs in order to inform potential for EV related businesses.	Manage the risk of EV and EVSE on the distribution grid. Provides information on EV and EVSE usage patterns that informs planning and business decisions.	Innovation EV (2023) System Control (2025+)
27	EV Pricing Programs	Alectra is able to provide differentied pricing for EV owner as well as EVSE providers that encourages EVs while also minimizing coincident peak load at a local level and system-wide level.		Innovation EV (2023)
28	Distribution Transformer Monitoring for EV Load	Alectra is able to manage the EV charging so that local distribution transformer is not overloaded by all of the downstream connected EVs.	Avoid/defer the upgrade of distribution transformers.	Innovation EV (2023)

29	Fleet Management	Operator is able to understand the real-time status of connected electric fleets and is able to affect the charging rates as required by the grid. Distribution Planner is able to understand the charging patterns of electric fleets in order to inform system planning decisions.	Manage the risk of electric fleets on the distribution grid. Provides information on EV and EVSE usage patterns that informs planning and business decisions.	Innovation EV (2023)
30	Fleet Optimization	Innovation Manager is able to understand the charging patterns of electric fleets in order to maximize value from electrification for customers.		CIA (2024)
31	FLISR Support	Operator and Short-term Planner are able to configure FLISR with any necessary DER actions that could make a non-normal configuration possible.	Increases the combination of FLISR configurations improving reliability.	NONE
32	Short Term Forecasting	Operator and Short-Term Planner are able to forecast the DER inputs and outputs and their potential impact to the grid between 15 minutes - 1 month out using historical, nameplate and weather data.	Provides forecasts of DERs for operational decision making.	Planning (2021) NWA Pilot (2021)
33	Long-Term Forecasting	Operator and Short-Term Planner are able to forecast the DER inputs and outputs and their potential impact to the grid between 1 month to 5 years out using historical, nameplate and weather data.	Provides forecast of DERs for system planning decision making.	Planning (2021)
34	Increase Hosting Capacity	Distribution Planner is able to offer capacity to DERs on feeders and substations that had reached their operating limits by using controls over DERs.	Avoids/defers costs of upgrading the system to accommodate DERs. Improves customer satisfaction by speeding the time for DERs to connect.	Planning (2021)
35	System Operator (IESO) Monitoring	IESO and Operator are able to understand the total aggregate impact of DERs from the utility on the overall bulk electric system and input that data into their control systems.	Improves operational decision making on the bulk electric system. Improves system planning on the bulk electric system.	System Control (2021)

36	Microgrid	Utility is able to operate a DER enabled microgrid on a customer site to improve reliability and sustainability.	Improves reliability for microgrid connected customers. Improves public relations.	Energy Solutions (2025+)
37	Non-Wires Alternatives	Utility is able to utilize non-wire alternatives for some customer connections/grid improvements by utilizing DER resources. (Similar to Increase Hosting Capacity)	Meet regulatory mandate. Avoid/defer investments in distribution upgrades. Speed the connection tie for customers.	NWA Pilot (2021)
38	Targeted Tx Congestion Relief	Utility is able to provide congestion relief on elements of the transmission system using utility-embedded DERs.	Improve reliability of transmission system. Potential for new revenue stream.	NONE
39	System Planning	Distribution Planner is able to understand impact of DERs and model its growth on the system to make system planning investments. This includes the ability to scale the amount of DERs on a given part of the system and understand the localized impact.	Improves system planning. Reduces cost of system modeling.	Planning (2025+)
40	Historical Analysis	Distribution Planner is able to understand impact of DERs using historical analysis.	Improves system planning. Reduces cost of system modeling.	Planning (2025+)
41	Residential Direct DER Control	Conservational Analysts is able to manage a direct DER control program. Customer is able to automatically have their DER controlled to minimize their utility bill. Operator is able to understand the amount of direct DER available and call upon that load in emergencies.	Provides control for emergency load reductions. Reduce customers utility bill.	GRE&T Centre (2025+)
42	Load Shaping	Utility is able to use DERs to optimize the load curve through the day using all of the resources at a feeder/substation/utility level.	Improves reliability of the system. Avoids/defers grid upgrades. Improves power quality.	System Control (2022)
43	Residential DR	Conservation Analyst is able to manage demand response program using residential resources. Residential customers are able to enroll different load devices into a DR plan.	Provides demand response resources from Residential customers.	NONE

44	Time Shift Usage	Utility is able to shift load for customers to times that are better for the bulk electric system and lower costs. (Similar to Load Shaping)	Reduces customer utility bill. Reduce investment on bulk electric system.	NONE
45	Demand Charge Optimization	Customer is able to manage its DERs in a manner that optimizes their demand chargers.	Reduces customer demand charges.	NONE
46	Solar Optimization	Utility is able to help customers determine if their solar resources are optimized relative to other customers.	Maximizing solar revenues.	CIA (2021) Energy Solutions (2023)
47	Smart Inverter Management	Operator and Short-Term Planner are able to call upon DERs with smart inverters to provide local volt/var support as required.	Improves power quality.	GRE&T Centre (2025+)
48	Storage Value Stacking	Utility is able to co-optimize utility-owned storage for maximum benefits.	Maximizing value from storage.	Energy Solutions (2021)
49	Capacity Contracts & Trading	Energy Marketer is able to understand its current capacity contracts and trade those capacity contracts on the market.	Provides additional revenue for utility.	NWA (2023) Energy Solutions (2025+)
50	Energy Trading & Wholesale Markets	Energy Marketer is able to understand its current energy needs of the utility. They are able to aggregate a mix of customer-owned and utility-owned DERs and dispatching them automatically based on wholesale market signal.	Manage energy needs of utility. Provide additional revenue for utility.	NWA (2023) Energy Solutions (2025+)
51	Virtual Power Plant	Utility is able to aggregate the resources of many DERs into a single virtual power plant and operator those resources as required for economic or emergency events.	Provides additional revenue for utility.	Energy Solutions (2025+)
52	Aggregator Management	Conservation Analyst is able to aggregate many smaller DER resources into a single aggregated product for use in conservation programs. Conservation Analyst is able to manage the contracts and performance of third-party aggregators.	Provides a lower cost demand response resource that can be bid into the market. Provides additional utility revenue.	NWA (2023)
53	Renewable Firming	Utility is able to manage renewable intermittency by using other embedded DERs to optimize the gap between solar production and station peak.	Improves reliability. Avoids/defers grid upgrades.	Energy Solutions (2025+)

54	Adaptive Protections	Utility is able to dynamically adjust the protection group settings based on the DERs operating state and the grid configuration.	Increases uptime of DERs Reduces labour associated new protection studies.	P&C (2025+)
55	Bulk Power System Support	to help IESO restore the bulk power system and mitigate the emergency in the event of a partial or complete blackout using DERs.	Mitigating the risk of bulk system blackout event, increasing reliability, TSO-DSO Interoperability,	System Control (2025+)
56	Emergency Distribution System Operation	During blackouts, form islands within the distribution grid to pick up a portion of loads especially for the mission-critical facilities such as hospitals, etc	with the increasing number of weather-related outages such as storms and outage-related restoration activities, DERs could be operated by System controllers to form islands within the Dx to pick up partial or full loads within the islands	System Control (2021)

Appendix B - DERMS Capabilities

The DERMS Capabilities were mostly derived from the SEPA DERMS Requirements 2.0 document. This did not cover the full set of capabilities required to meet Alectra's use cases. Additional capabilities were added to create a complete set.
The capabilities are divided between functional and non-functional.

High-Level Capability	Capability Cross Reference to SEPA	Mid-Level Capability
User Interface	DER-UI-001	General User Interface
	DER-UI-002	Operational User Interface
	DER-UI-003	Non-Operational User Interface
	DER-UI-004	Dashboards Displays
	DER-UI-005	Energy Usage Real-Time Display
	DER-UI-006	Display of SCADA Data Processing Functions
Reporting	DER-REP-001	Reporting DER Capacity at various levels of the system
	DER-REP-002	Reporting Contractual Compliance
	DER-REP-003	Reporting for Official Documentation
	DER-REP-004	Report Configuration Parameter Compliance
	DER-REP-005	Ad Hoc Reporting
Configuration	DER-CFG-001	Discovery of Individual DERs
	DER-CFG-002	Configuration of Individual DERs

	DER-CFG-003	Support of Industry DER standards
	DER-CFG-004	Configuration of New Aggregators
	DER-CFG-005	Schedule Modes of Operations
	DER-CFG-006	Import Information from External Systems.
	DER-CFG-007	DER Model Consumption and Storage Information
Controls	DER-CON-001	Control and Monitoring of DERs
	DER-CON-002	Immediate Control and Mode Management of DER controllers
	DER-CON-003	Communication Standards for DER Monitoring and Control
	DER-CON-004	DERMS General Control Functions
	DER-CON-005	Supervisory Data Acquisition Services
	DER-CON-006	Tags, Memos and Service Notes
	DER-CON-007	Supervisory Control Services
	DER-CON-008	DER Control Services
Dynamic Topology Changes	DER-DTC-001	Awareness of DER Real-Time Circuit Topology Connections
	DER-DTC-002	Automatically Drop Group DER Based Upon Real-Time Topology
Contract Management	DER-DCM-001	Interconnection Agreements Contractual Awareness
	DER-DCM-002	Interconnection Summary of Generation Facility

	DER-DCM-003	Operating Requirements for Energy Storage Devices
Energy Business Rules	DER-EBR-001	Business Rules for Integration
	DER-EBR-002	Support Real Power Operating Modes
	DER-EBR-003	Support Reactive Power Operating Modes
	DER-EBR-004	Define Application Configuration Parameters
Historian	DER-HST-001	Local System Storage for DERMS Operations
	DER-HST-002	Customizable Rules for Data Archival
	DER-HST-003	Time-Oriented Data Histories
	DER-HST-004	Data Access to DERMS Users and Utility Corporate Network Users
	DER-HST-005	DERMS Historian User Interface
	DER-HST-006	Adequate Data Storage and Retention
	DER-HST-007	Export Data to Other Applications
	DER-HST-008	Integration with External Historian
	DER-HST-009	Long-Term Archival Capabilities
Constraint Management	DER-CMS-001	DER Constraint Management Based on Business Rules
	DER-CMS-002	DER Constraint Management Based on Contract Awareness
	DER-CMS-003	DER Constraint Management Based on Dynamic Topology Changes

	DER-CMS-004	DER Non-Compliance Disconnect
	DER-CMS-005	DER Constraint Management Communications Monitoring & Processing
	DER-CMS-006	DER Charging Limit Calculation
	DER-CMS-007	DER Compliance Reconnect
Forecasting	DER-FOR-001	Manage DER Profiles
	DER-FOR-002	Manage Aggregated Forecasts
Markets (not in SEPA DERMS Requirements Document)	DER-MKT-001	Market User Interface
	DER-MKT-002	Market Clearing
	DER-MKT-003	Import and Export Data from Markets in Real Time
	DER-MKT-004	Report for Market Audit
	DER-MKT-005	Market Settlements
NON-FUNCTIONAL CAPABILITIES		
Testing	SYS-TST-001	General DERMS Testing
	SYS-TST-002	Factory Testing
	SYS-TST-003	Head-end Testing
	SYS-TST-004	Field Testing
System-to-System Integration	SYS-SSI-001	Interface Technology Support

	SYS-SSI-002	Interface with Other Utility Systems
Cybersecurity	SYS-SEC-001	Supporting Access Controls
	SYS-SEC-002	Support-System Level Controls for Malware Protection
	SYS-SEC-003	Support-System Level Controls for Vulnerability Management
	SYS-SEC-004	Data Protection Services
	SYS-SEC-005	System Monitoring and Management Services
	SYS-SEC-006	Managing Grid Data Integrity
	SYS-SEC-007	Security Implementation Requirements
	SYS-SEC-008	Security Standards Compliance
	SYS-SEC-009	Documentation of DERMS Cybersecurity Risks and Responses
High Resilient Design Scalability	SYS-HRD-001	Support a resilient design
	SYS-SCL-001	Direct Connect DER Scalability
	SYS-SCL-002	Scalability for Aggregated DERs
Maintainability	SYS-MNT-001	Development and Quality Assurance Environments
	SYS-MNT-002	System Performance and Monitoring
	SYS-MNT-003	Software Update Management
	SYS-MNT-004	Database Management

	SYS-MNT-005	Configuration of User Roles and Responsibilities
Common Information Technology Services	SYS-CIT-001	Access Control and Account Management
	SYS-CIT-002	Patch and Configuration Management
	SYS-CIT-003	Event Monitoring and Reporting
	SYS-CIT-004	Malware Protection and Anti-virus
	SYS-CIT-005	Network Services
	SYS-CIT-006	Time Protocols
	SYS-CIT-007	Back-up
	SYS-CIT-008	Vulnerability Scanning
	SYS-CIT-009	SMTP Mail Relay
	SYS-CIT-010	Storage Utilization and Reporting
	SYS-CIT-011	Network Analytics and Visualization
	SYS-CIT-012	Boundary Defense and Management
	SYS-CIT-013	Database
	SYS-CIT-014	Performance
	SYS-CIT-015	Development and Quality Assurance Environments
	SYS-CIT-016	System Performance and Monitoring

	SYS-CIT-017	Software Update Management
	SYS-CIT-018	Database Management
	SYS-CIT-019	Configuration of User Roles and Responsibilities

Appendix C - Detailed Cost Estimate

The cost estimate is made using a bottom-up resource model. It allocates costs by resource and over time to develop a model of costs.

Investment Plan for DERMS

	2020	2021	2022	2023	2024	2025	TOTAL
Capex	$108,575	$782,813	$1,112,200	$936,600	$881,400	$974,200	$4,795,788
Opex	$0	$0	$0	$93,750	$260,600	$260,600	$614,950

Capex Detail for DERMS

Capex Requirement	2020	2021	2022	2023	2024	2025	Total
DERMS	**$108,575**	**$782,813**	**$1,112,200**	**$936,600**	**$881,400**	**$974,200**	**$4,795,788**
Alectra (Payroll)	$36,575	$274,313	$319,200	$226,100	$296,400	$281,200	$1,433,788
Project Manager (Contract)	$72,000	$216,000	$180,000	$72,000	$0	$0	$540,000
Vendor Software Platform	$0	$292,500	$613,000	$638,500	$585,000	$693,000	$2,822,000

Opex Detail for DERMS

Opex Requirement	2020	2021	2022	2023	2024	2025	Total
DERMS	**$0**	**$0**	**$0**	**$93,750**	**$260,600**	**$260,600**	**$614,950**
Operating Technology	$0	$0	$0	$0	$45,600	$45,600	$91,200
Vendor Software Platform	$0	$0	$0	$93,750	$215,000	$215,000	$523,750

Estimating Assumptions

- For the short and medium-term, Alectra uses elects to use an off-premise DERMS that is hosted by the DERMS vendor (cloud-based DERMS) to reduce upfront infrastructure costs and speed project timeline.
- Discovery capital costs
    - In 2020, discovery capital costs would be for drafting the execution framework
    - In 2021, discovery capital costs would be for running the RFP (Q1) and negotiating the contract (Q3) and launching the DERMS pilot project (Q4)
    - If the project is approved, this investment can be capitalized as it is front end work to a capital project.
- The initial project will be executed in an agile manner.
- The project would be broken into one pilot sprint followed by three developmentary sprints, each lasting one quarter.
    - Each sprint will target to implement 5 use cases.
    - Pilot sprint will be followed by a 6-month pilot assessment period.
- Each sprint will consist of a design phase, configuration and coding phase, and a testing phase each taking one month.
    - Vendor resources will be utilized with all phases with 1 FTE on design, 3 on configuration and coding, and 2 FTEs on testing.
    - Internal resources will be utilized for the design and testing phases with 2 half-time FTEs on design and 2 FTEs on testing.
- For subsequent upgrades to the DERMS, there will be two sprints required with the same resource structure.
- Vendor rate of [redacted] work week
- Internal rate of $95 per hour with a 35 hour work week
- A contract project manager and vendor project manager will be needed for the initial implementation as it is larger and the first time Alectra and Vendor will be working together - subsequent implementations can rely on Vendor project manager alone
- An upfront software license fee of [redacted]
    - Assume that [redacted] is due upon delivery of the pilot use cases.
    - The remaining [redacted] will be due upon delivery of the remaining use cases.
- Ongoing annual software license fee of [redacted]
- Ongoing cloud infrastructure fee of [redacted]
- Ongoing infrastructure maintenance required of internal resources of 40 hours per month to maintain and monitor connections and firewalls.

Alectra DSO Research Study

alectra
GRE&T Centre

DSO Research Study – Final Report

DSO Overview, Jurisdictional Scan, and Value Propositioning

February 3rd, 2022

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Document Purpose

This research report was developed in collaboration with EY and Alectra to provide **foundational knowledge** of the emerging Distribution System Operator (**DSO**) **landscape across leading markets, and key considerations for Ontario**. The gathered information aims to help **inform Alectra's next steps** regarding its own DSO vision within the local context.

Meeting Defined Requests

As defined in the Statement of Work (SoW), the following pages summarize each of the required questions. In some cases, those questions were answered in more than one part of this document, which have been indicated accordingly.

Research Question	Location
Phase 1: DSO Overview (Appendix A)	
What is a DSO? Provide top industry standard definitions.	22-25
What are the drivers for DNO>DSO transformations in leading markets?	17-20
What types of DSO's exist in other markets – what countries are leading DSO transitions?	23, 26-27
Compare and contrast the identified DSO models to other market structures (e.g. LSE, RTO).	28-29
What are the roles/responsibilities of different players under these models?	26
What are the benefits and shortcomings of becoming a DSO for each of the models identified in this phase?	49
Phase 1: Jurisdictional Scan (Appendix B)	Appendix B
What are the unique attributes and characteristics (functions), differences, and specific value proposition to the market/policy environment which they serve?	31-34
If available, what roadmap or implementation plans are these companies following?	37-41
What type of regulatory environment do they operate in?	35-36
What are lessons learned from DSO implementations to date (provide examples where available)?	37-41
Phase 2: DSO Value Proposition and Shortlist	
Clarify the business value of a DSO based on outputs of Phase 1.	44-46

Research Question (Continued)	Location
What are the regulatory requirements for enabling each type of DSO model identified in previous phase? How do these requirements transcend to Ontario's market?	47
Outline asset/DER ownership optionality for each model.	49
What are the renumeration options for these models?	38
Lay out business model optionality of most viable DSO models.	48
Provide overview of longer-term value of each model given ecosystem changes.	26, 49
Contrast/compare benefits/disadvantages to various options using EY's DSO of the Future Framework.	48-49
Phase 2: Workshop 2 (Appendix D)	
Outline the most viable DSO options for Ontario and create a shortlist.	48-49
Why have the selected distribution companies chosen different DSO approaches and why? Provide examples with a focus on technology, analytics, process, and people.	37-38, Appendix B
What are the technological, processes, and people changes required to enable these transitions (focusing on shortlisted DSOs)?	55-56, Appendix B
What is the roadmap for DNO>DSO for shortlisted case studies? Provide detailed overviews where possible.	58, Appendix B
Align on 1-2 case studies to use as benchmark for roadmap/future state operationalizing.	Appendix D
What are EY's high-level capabilities roadmap considerations for DSO (e.g. organizational structure, system planning, technology, regulatory, etc.).	55-58

Glossary of Terms

Distributed Energy Resources (DERs): Small, modular, energy generation and storage technologies that provide electric capacity or energy, including electric vehicles, wind turbines, photovoltaics (PV), fuel cells, microturbines, and more.

Distribution Network Operator (DNO): An entity that owns an electric distribution grid in a defined franchise service area. Coordinates outages/de-rates with and receives control signals from LDC operations. As a Local Distribution Company (LDC), Alectra is considered a DNO.

Distribution System Operator (DSO): DSO definitions vary across markets. However, broadly, a DSO is a real-time system operator for an active distribution network which manages, and coordinates distributed generation at a local level, acts as a neutral facilitator to open markets, and enables easy access to T&D networks.

Transmission System Operator (TSO): An entity is responsible for the operation of the transmission system (the assets that transmit power between bulk resources and the distribution system). Coordinates outages/de-rates with and receives control signals from the ISO balancing authority.

Flexibility: Flexibility is the ability of a power system to maintain stability in the face of swings in supply or demand. Traditionally, flexibility was provided in power systems almost entirely by controlling the supply side at large power stations. The energy system has seen increasing shares of intermittent renewable generation requiring additional flexibility to maintain system reliability. Customer connected flexibility can help alleviate both transmission and distribution constraints and contribute to releasing additional capacity on both the transmission and distribution networks.

Independent System Operator (ISO): Independent DSO work with distribution utilities to optimize the dispatch of the DER based upon local system constraints that are provided by the network business. The latter provide the aggregated bids to ISO for incorporation into the larger dispatch.

Total TSO Model: Total TSO model has visibility over the entire transmission and distribution system and is responsible for real time, reliable operation of the transmission-distribution system, interconnection, and planning for the combined system infrastructure.

Hybrid DSO Model: Hybrid DSO is a model where TSO and DSO take shared responsibility of the network and work together to resolve system issues. It requires complex communication between transmission and distribution system operators, and 3rd party DER aggregators.

Total DSO Model: Total DSO model is an approach, where all, or a subset of resources, e.g., 10MW, are connected to the distribution level, participate in transmission markets, and orchestrated via a DSO to enable interactions between DERs and TSOs.

Independent DSO (IDSO): A conceptual approach to a DSO model. The UK is currently exploring the IDSO structure. In this model, the IDSO work with distribution utilities to optimize the dispatch of the DER based upon local system constraints that are provided by the network business, provide the aggregated bids to ISO for incorporation into the larger dispatch.

T&D: Transmission and Distribution; T = Transmission and D = Distribution;

ETNO: Energy Transformation Network of Ontario

OEB: Ontario Energy Board

IESO: Independent Electricity System Operator

Ofgem: Office of Gas and Electricity Markets

FSO: Future System Operator

EV: Electric Vehicle

ICE: Internal Combustion Engine

LMP: Locational Marginal Pricing

DER: Distributed Energy Resources

VPP: Virtual Power Plant

Note: this report provides a total project overview and key takeaways. There is additional information for Sections 3, 4, and 5 that is **available as separate appendices**.

The report was intentionally separated from the appendices to avoid a compilation of 200+ pages in a single file. For additional details, refer to the appendices as needed.

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01

Executive Summary

Engagement summary and key takeaways from the project.

Alectra DSO Research Study Overview

In 2022, Alectra's GRE&T Centre engaged EY to perform a research study to explore Distribution System Operator (DSO) models and best practices in leading jurisdictions around the world to help inform Alectra's future DSO vision.

Overall Project Objective

EY provided research support to Alectra to better understand emerging DSO definitions, models, examples, and lessons learned from leading markets. The project involved a phased approach with iterative deliverables and interactive workshops covering DSO case studies around the world. This final output provides real-world insights of DSO journeys across the UK, Australia, US, and EU states, and key considerations for Alectra's own DSO journey in Ontario.

Deliverable Scope

1. DSO Overview Report: a description of the DSO landscape, including definitions and models.

2. Jurisdictional Scan Report: 3-5 DSO case studies in leading markets with relevant considerations and key takeaways.

3. Workshop 1 – DSO of the Future (SCAN): an interactive workshop with EY Subject Matter Advisors (SMAs) and Q&A from Alectra stakeholders

4. Workshop 2 – DSO of the Future (FOCUS): a follow-up workshop with EY SMAs and Q&A from Alectra stakeholders on the shortlisted DSOs

5. Final DSO Research Report: an overarching PowerPoint report summarizing all outputs above.

Additional Value: Upon request, EY expanded the scope of work **to deliver 8 case studies (vs. 3-5) to the Jurisdictional Scan Report** and leveraged the firm's global network to **connect Alectra with 3 DSOs** in private discussions to facilitate further learning and collaboration.

Research Questions*

The research deliverables sought to address

1. How do leading jurisdictions define "a DSO"
2. What are the key drivers, models, and lessons learned in DSO transitions around the world?
3. What are the unique characteristics, functions, and approaches taken in leading DSO markets?
4. What existing roadmaps or implementation plans are leading DNOs developing?
5. What type of regulatory environment do transitioning DSOs operate in and how are market and policy regimes reforming to support these transitions?

*Questions listed are summarized to reflect the overarching research objectives of the project. A detailed scope of questions is included in the SOW.

Milestones

Project Kick-Off
October 17, 2022

1 **DSO Overview Report**
November 9, 2022

2 **Jurisdictional Scan + SCAN Workshop**
December 9, 2022

3 **DSO Shortlist + FOCUS Workshop**
January 19, 2022

Final DSO Report Submission
February 3, 2023

Deliverable Purpose and Value

The enclosed report is the final milestone in EY's DSO Research Study for Alectra. This deliverable builds on the previous chapters of our DSO research, and synthesizes key learnings from our exploration of 10 DSOs around the world.

[redacted]

"*This document summarizes insights from our research activities over the course of the **DSO Research Study**, including our **two previous chapters, workshop activities, and DSO 1-on-1 discussions** to provide an overview of the DSO for Alectra.*"

1. DSO Overview Chapter

2. Jurisdictional Scan Chapter

3.A Workshop 1 – "DSO Around the World" (SCAN)

3.B Workshop 2 – "DSO Around the World" (FOCUS)

4. Final DSO Research Study Report

Project Outcomes

1. The report was developed in collaboration with EY to provide Alectra with foundational knowledge of the Distribution System Operator (DSO) space and its implications in other jurisdictions outside of Ontario.
2. The research aimed to inform Alectra's next steps on addressing and exploring the DSO concepts by providing examples of leading DSO transformations/roadmaps/regulatory enablement in other jurisdictions.
3. Wavespace workshops helped socialize and explain the DSO data to various levels of the organization, including SVPs, VPs, and Directors, to gain an aligned perspective on Alectra's future DSO roadmap and strategy.

Note: Alectra's preferred or specific roadmap forward were out of scope of this study.

Key Project Takeaways

Underpinned by the energy transition, the DSO construct is rapidly evolving across the globe. Yet, in many instances, the DSO is still conceptual given that definitions, market roles, and functions vary from market to market.

01

Similar drivers for various DSOs, but no playbook

While there are common drivers for DSOs around the world, each jurisdiction is influenced by its own policies, dynamics, regulations, and technologies that drive respective developments.

There is no one-size fits all model for a DSO and Alectra will need to develop its own vision for Ontario.

02

A DSO is a journey, not a destination, and the end-state is undefined

The DSO journey can take decades, where the end state is not well defined.

Tackling the transition challenge begins with no-regret moves.

Successful DSOs start with aligning on vision, building business cases, investing in digital grid technologies, campaigning to stakeholders, and demonstrating new capabilities with partners.

03

Regulators may not have the answers, but utilities can help shape the future

Regulatory barriers undoubtedly exist, but the risk of inaction threatens operational control over utilities' own networks.

Utilities drive DSO development and advocacy through pilots to test key DSO functionalities and build quantitative business cases.

Regulators often reciprocate with public consultations and utility advisory to shape the DSO space and future.

04

Utility mindset must shift to become more proactive

Traditional utilities respond to market changes and regulatory directives. However, conventional planning will be insufficient.

Now, aspiring DSOs must proactively anticipate and manage the system.

In other jurisdictions, a high DER adoption uptake occurred much faster than expected, for example 1/3 of residential properties in Western Australia are already equipped with solar PVs in contrast to a minimal adoption rate just five years ago.

05

Alectra is beginning to recognize DSO as an imperative for its future business

The team witnessed a gradual change in stakeholder perspectives on the DSO subject.

During the workshops, Alectra representatives became more engaged, interactive, and aligned on the potential DSO value for Alectra.

Afterwards, they gained a consensus that a DSO is an important model that will shape the future business.

However, a quantitative business case and clear vision are still required.

06

The customer is at the core of the DSO transition

Despite tendencies to view DSO as a technical pursuit, customers are the driving force for change.

Other DSOs are trying to better understand future customer needs through consultations and engagements.

The data is used to more accurately plan for the future and appropriately address customer concerns in a DSO.

Global DSO Snapshot

There are markets that are on route to adopting a DSO model, including UK, USA, Australia, Ireland, Germany, and Holland. This research study covers eight detailed case studies and two additional utilities that EY introduced to Alectra.

[redacted]

National Grid

NG views Distribution System Operations (vs Operator) as a future model, whereby industry participants will need a more whole systems approach to network ops. NG ESO believes that utilities are suited for DSO transition and work on enabling them.

Western Power

Western Australia is testing a Hybrid DSO Model through Virtual Power Plant (VPP) demonstrations, which involve a close coordination between WP and its ISO, to deliver required functions most suitable for the South West Interconnected System.

Netze BW

Germany is positioned with a high private DER ownership and a significant number of utilities (700+) and municipalities (12,000+). Secure grid operation and system stability are seen as new core tasks of the DSO – best fulfilled by local network operators.

PG&E

PG&E is investigating the potential to manage distribution grids as open-access platforms for local energy markets. Its pilot approach has brought about many lessons regarding customer participation, T&D coordination, and the importance of data and system integration.

Stedin Group

Stedin has demonstrated ownership and accountability over the energy transition with priorities of improved grid management and sustainable business operations. The DSO has leveraged an energy trading platform to demonstrate active load management for improved system performance.

[redacted]

UKPN

UKPN aims to establish the first-ever Independent DSO model by April 2023 and is also the first network operator in the UK to pledge to a 'Flexibility First' approach. The utility began their DSO journey in 2010 by engaging with customers on their needs and DER interests.

ENWL

ENWL is an active participant in the shaping of the DSO environment in the UK. However, the utility does not necessarily drive the market definition and instead focuses on satisfying/enabling customer needs via meaningful pilots.

ESB

The Irish DSO is preparing for unprecedented DER penetration through a focus on scaling flexibility services and pilots that are designed to build the DERMS/ADMS capabilities ESBN requires between 2022-2025.

ConEd

ConEd has developed a Distributed System Platform that will forecast, plan, interconnect, monitor, control, and effectively manage the integration of DERs, and continues to invest in demonstration projects to build its case in assuming DSO functions.

SPEN

SPEN published a Distribution System Operation Vision in October 2016, where the utility described the whole system operating model that SPEN considered to be best suited in addressing the DER future. Since then, SPEN made several investments and conducted many DSO pilots.

Legend Detailed Case Studies Available | Additional EY Connections

EY x Alectra DSO Research Study Snapshot

The DSO Research Study was the first step in tackling this ambiguous topic for Alectra. It was facilitated by interactive workshop sessions and individual discussions with three other DSOs. Now Alectra needs to focus on the following steps:

1. DSO Research Study Kick-Off

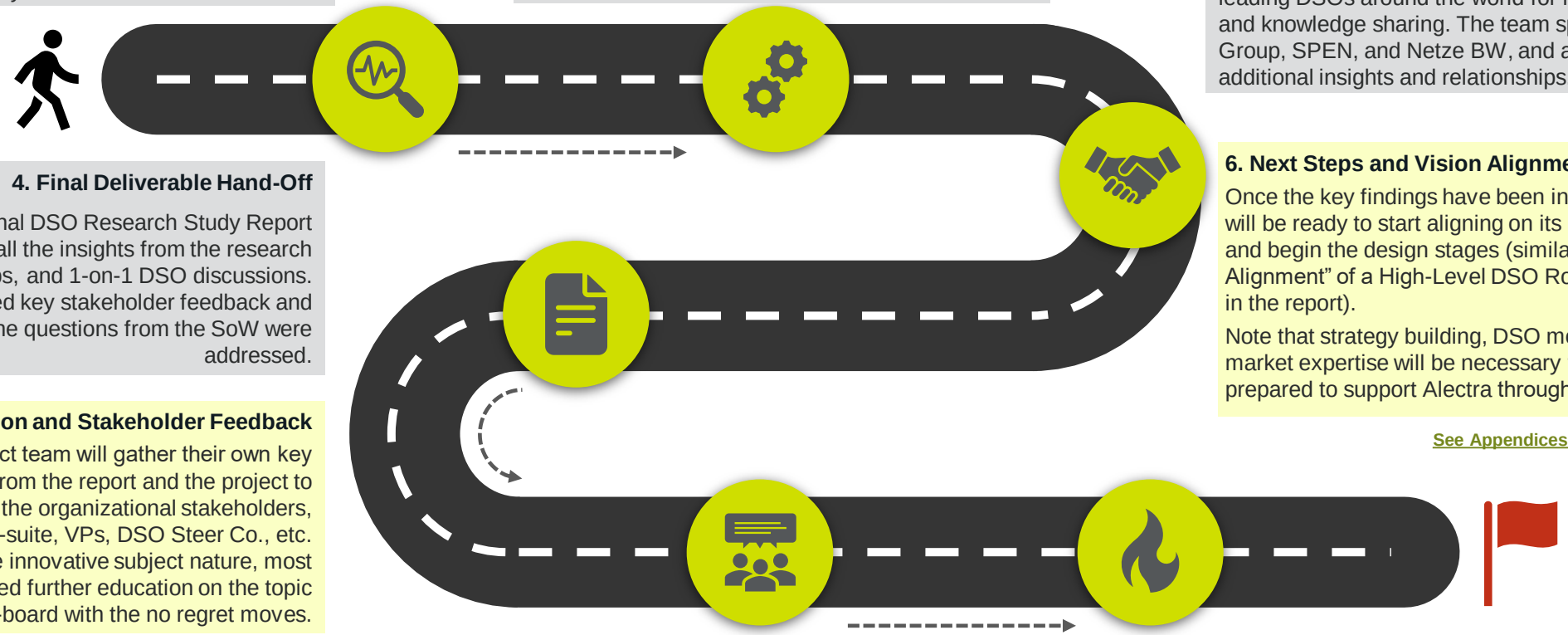
EY and Alectra undertook a 15-week project to research the DSO subject, develop 8 detailed case studies on leading DSOs around the world, and synthesize the value propositioning for Alectra in Ontario. Throughout the study, both parties provided inputs to foster a truly collaborative effort.

2. Wavespace Workshops (SCAN +FOCUS)

EY hosted 25+ Alectra stakeholders at two interactive workshops to educate the attendees on the DSO subject through eight speaker series and group activities. EY witnessed a change in the attendee perspectives by becoming more open to DSO models and aligning in their perceptions.

3. 1-on-1 DSO Discussions

As an extra addition to the scope, EY leveraged its global network to connect Alectra's project team with leading DSOs around the world for further collaboration and knowledge sharing. The team spoke to Stedin Group, SPEN, and Netze BW, and as a result gained additional insights and relationships.



4. Final Deliverable Hand-Off

EY prepared a final DSO Research Study Report that amalgamated all the insights from the research phases, workshops, and 1-on-1 DSO discussions. The team integrated key stakeholder feedback and made sure all the questions from the SoW were addressed.

5. Socialization and Stakeholder Feedback

Alectra's project team will gather their own key takeaways from the report and the project to socialize them with the organizational stakeholders, including the C-suite, VPs, DSO Steer Co., etc. Given the innovative subject nature, most stakeholders will need further education on the topic to be fully on-board with the no regret moves.

6. Next Steps and Vision Alignment

Once the key findings have been internalized, Alectra will be ready to start aligning on its DSO vision/strategy and begin the design stages (similar to "Phase 1: DSO Alignment" of a High-Level DSO Roadmap mentioned in the report).

Note that strategy building, DSO model, and Ontario market expertise will be necessary for this step. EY is prepared to support Alectra through this phase ("ACT")

See Appendices for further ACT details.

Legend Completed SCAN + Focus Activities | Outstanding ACT Future Activities

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02

Methodology and Approach

An overview of the research scope, timeline, and key steps undertaken to complete the project.

Project Summary

EY provided an in-depth research competency to enhance Alectra's understanding of the innovative and evolving DSO space. The project was conducted over a 15-week period (including the Christmas break) with two interactive workshop sessions.

EY Team

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Note: the EY team was supported by global Subject Matter Advisors, including **Paul Micallef, Andre Winarto, Andrew Horstead, Marc Coltelli,** and others.

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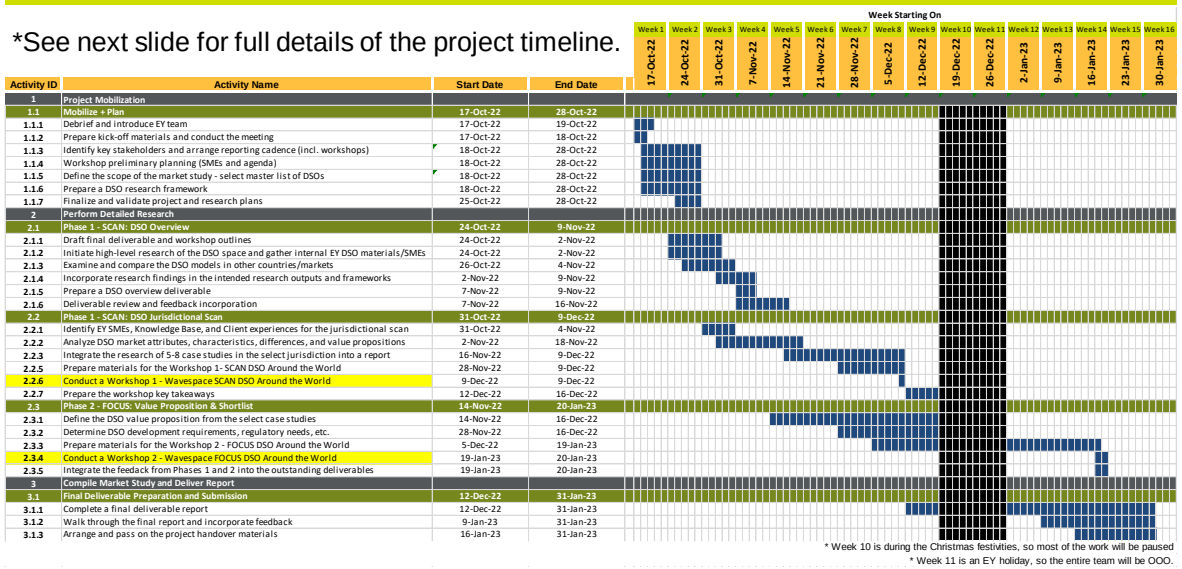
Collaborative Effort

The combined EY and Alectra team co-developed the DSO Research Study report. EY led the research and analysis competencies, and Alectra provided direction and validated outputs. The teams also engaged in a weekly cadence to follow the appropriate project management practices.

Project Details

*See next slide for full details of the project timeline.



Activity ID	Activity Name	Start Date	End Date
1	Project Mobilization		
1.1	Mobilize + Plan	17-Oct-22	28-Oct-22
1.1.1	Debrief and introduce EY team	17-Oct-22	19-Oct-22
1.1.2	Prepare kick-off materials and conduct the meeting	17-Oct-22	18-Oct-22
1.1.3	Identify key stakeholders and arrange reporting cadence (incl. workshops)	18-Oct-22	28-Oct-22
1.1.4	Workshop preliminary planning (SMEs and agenda)	18-Oct-22	28-Oct-22
1.1.5	Define the scope of the market study - select master list of DSOs	18-Oct-22	28-Oct-22
1.1.6	Prepare a DSO research framework	18-Oct-22	28-Oct-22
1.1.7	Finalize and validate project and research plans	25-Oct-22	28-Oct-22
2	Perform Detailed Research		
2.1	Phase 1 - SCAN: DSO Overview	24-Oct-22	9-Nov-22
2.1.1	Draft final deliverable and workshop outlines	24-Oct-22	2-Nov-22
2.1.2	Initiate high-level research of the DSO space and gather internal EY DSO materials/SMEs	24-Oct-22	2-Nov-22
2.1.3	Examine and compare the DSO models in other countries/markets	26-Oct-22	4-Nov-22
2.1.4	Incorporate research findings in the intended research outputs and frameworks	2-Nov-22	9-Nov-22
2.1.5	Prepare a DSO overview deliverable	7-Nov-22	9-Nov-22
2.1.6	Deliverable review and feedback incorporation	7-Nov-22	16-Nov-22
2.2	Phase 1 - SCAN: DSO Jurisdictional Scan	31-Oct-22	9-Dec-22
2.2.1	Identify EY SMEs, Knowledge Base, and Client experiences for the jurisdictional scan	31-Oct-22	4-Nov-22
2.2.2	Analyze DSO market attributes, characteristics, differences, and value propositions	2-Nov-22	18-Nov-22
2.2.3	Integrate the research of 5-8 case studies in the select jurisdiction into a report	16-Nov-22	9-Dec-22
2.2.5	Prepare materials for the Workshop 1- SCAN DSO Around the World	28-Nov-22	9-Dec-22
2.2.6	Conduct a Workshop 1 - Wavespace SCAN DSO Around the World	9-Dec-22	9-Dec-22
2.2.7	Prepare the workshop key takeaways	12-Dec-22	16-Dec-22
2.3	Phase 2 - FOCUS: Value Proposition & Shortlist	14-Nov-22	20-Jan-23
2.3.1	Define the DSO value proposition from the select case studies	14-Nov-22	16-Dec-22
2.3.2	Determine DSO development requirements, regulatory needs, etc.	28-Nov-22	16-Dec-22
2.3.3	Prepare materials for the Workshop 2 - FOCUS DSO Around the World	5-Dec-22	19-Jan-23
2.3.4	Conduct a Workshop 2 - Wavespace FOCUS DSO Around the World	19-Jan-23	20-Jan-23
2.3.5	Integrate the feedback from Phases 1 and 2 into the outstanding deliverables	19-Jan-23	20-Jan-23
3	Compile Market Study and Deliver Report		
3.1	Final Deliverable Preparation and Submission	12-Dec-22	31-Jan-23
3.1.1	Complete a final deliverable report	12-Dec-22	31-Jan-23
3.1.2	Walk through the final report and incorporate feedback	9-Jan-23	31-Jan-23
3.1.3	Arrange and pass on the project handover materials	16-Jan-23	31-Jan-23

Week Starting On: 17-Oct-22, 24-Oct-22, 31-Oct-22, 7-Nov-22, 14-Nov-22, 21-Nov-22, 28-Nov-22, 5-Dec-22, 12-Dec-22, 19-Dec-22, 26-Dec-22, 2-Jan-23, 9-Jan-23, 16-Jan-23, 23-Jan-23, 30-Jan-23

* Week 10 is during the Christmas festivities, so most of the work will be paused
* Week 11 is an EY holiday, so the entire team will be OOO.

Purpose

Provide research support to Alectra's GR&T Centre project team and enhance their understanding of DSO model definitions, examples, and lessons learned from other jurisdictions.

The report serves to inform Alectra's future strategy by providing external insights and leading industry knowledge on the DSO market space.

Timeline

The DSO Research Study was conducted between October 17th and February 3rd. The project was split into two phases: **SCAN DSO Overview** and **Jurisdictional Scan**, **FOCUS Value Proposition** and **Shortlist** (see next slide for more details). **Note**: the original project timeline was extended until the end of January to avoid the Christmas break scheduling issues.

See Appendices for further ACT details.

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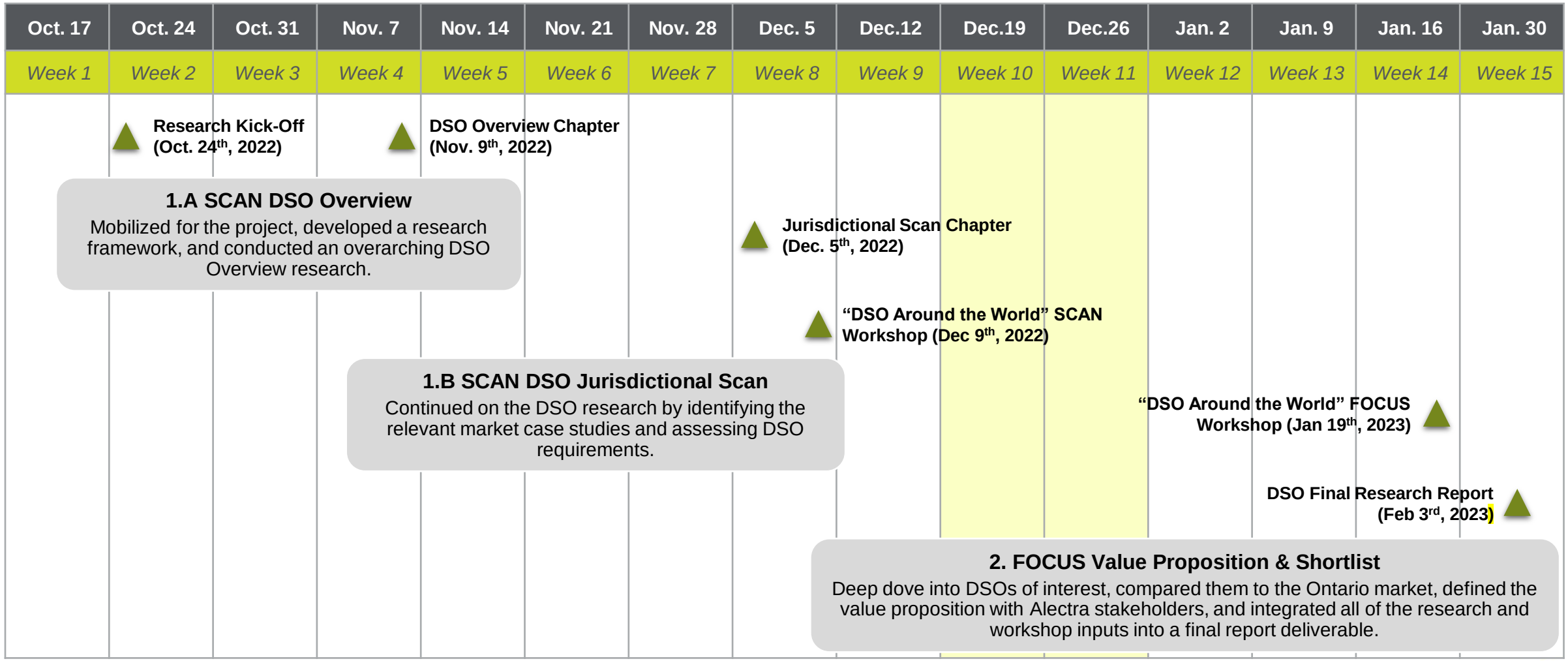
Project Methodology

Overall, the project had six major milestones, including two interim chapters (DSO Overview and Jurisdictional Scan) and two wavespace workshops (SCAN and FOCUS), that were critical to aligning on the engagement outputs.



Project Approach

EY followed a structured approach to conduct the engagement, which included numerous sequential undertakings. Overall, the project adhered to the project timeline, while answering the key research questions within and beyond the original scope.

***15 weeks total** – October 17th, 2022 and February 3rd, 2023*

~ Weeks 1-2

- ✓ Debriefed and introduced the EY team
- ✓ Prepared kick-off materials and conducted the meeting
- ✓ Identified key stakeholders and arranged reporting cadence
- ✓ Defined the scope of the research study
- ✓ Prepared a research framework
- ✓ Finalized and validated project and research plans with the Alectra team and proceeded with gathering data

~ Weeks 2-5

- ✓ Initiated high-level scoping of EY materials, Subject Matter Advisors (SMAs), and other sources
- ✓ Gathered EY DSO materials and engaged EY SMAs on data gathering sources and materials
- ✓ Consolidated research findings in a centralized document to define the DSO space, key drivers, and jurisdictional market examples
- ✓ Drafted a deliverable outline
- ✓ Designed and updated interim chapter slides
- ✓ Worked with the Alectra team to refine the structure of the interim chapter according to their needs
- ✓ Shared a draft chapter with EY SMAs for validation
- ✓ Integrated and shared the final changes with the Alectra team

~ Weeks 5-8

- ✓ Defined further scope of research on the case studies
- ✓ Identified key DSOs in applicable jurisdictions to study (UK, USA, Australia, and Europe)
- ✓ Conducted preliminary research on potential entities to validate relevance and availability of data
- ✓ Validated the shortlist and key questions with the Alectra team
- ✓ Conducted detailed research of the select eight DSOs, including UKPN, National Grid, ENWL, Western Power, Con Ed, PG&E, ESB, and Netze BW
- ✓ Consolidated the research findings in a case study format, including key takeaways, DSO strategies, roadmaps, priorities, etc.
- ✓ Shared the chapter with Alectra

~ Weeks 7-14

- ✓ Shortlisted and confirmed EY and external utility speakers for the workshops
- ✓ Prepared detailed workshop agendas in collaboration with the Alectra team
- ✓ Developed the workshop materials, including speaker slides, breakout activities, etc.
- ✓ Integrated key case study findings into the session materials
- ✓ Hosted the workshop sessions and gathered feedback on the DSO perceptions around the organization
- ✓ Drafted and shared workshop retrospective materials, including key notes and outputs
- ✓ Arranged and hosted additional DSO 1-on-1 sessions

~ Weeks 9-15

- ✓ Defined the DSO value proposition for Ontario and Alectra
- ✓ Identified key research takeaways
- ✓ Determined the DSO regulatory requirements, needs, etc.
- ✓ Integrated previous chapters and workshop retrospective materials into the final deliverable outline
- ✓ Completed and shared a draft final deliverable report
- ✓ Incorporated final changes to the deliverable
- ✓ Arranged and passed on the project handover materials

Project Mobilization → **SCAN: DSO Overview** → **SCAN: Jurisdictional Scan** → **Workshops DSO Around the World (SCAN + FOCUS)** → **Final Deliverable Preparation**

Research Outline

EY and Alectra defined the key DSO research objectives and questions into a research outline to streamline the study and ensure a full scope coverage, which included SoW stated and newly identified questions throughout the engagement itself.

#	Objective	Key Question	Related Research & Analysis	Intended Outputs
1	**Define the industry standard of a "DSO", including the various drivers, models, player roles/responsibilities, and benefits/shortcomings of DSOs across relevant markets.**	**What is a DSO?**	What is a DSO? Provide top industry standard definitions (from ISOs or Regulators)	Context Around the Rise of the DSO General DSO Definitions Around the World Descriptions of DSO Models and Other Market Structures
			What are the drivers for DNO>DSO transformations in leading markets?	
			What types of DSO's exist in other markets – what countries are leading DSO transitionsf?	
			What are the focus functions?	
			Compare and contrast the identified DSO models to other market structures (e.g. LSE, RTO).	
			What are the roles/responsibilities of different players under the identified DSO models?	
			What are the benefits and shortcomings of becoming a DSO for each of the models identified in this phase?	
2	**Provide an overview of 8 DSO case studies, including unique attributes, characteristics, regulatory frameworks, and market contexts.**	**What are the relevant lessons learned from the other DSO markets?**	What jurisdictions/case studies should be researched?	8 Global DSO Case Studies
			What framework/assessment variables should be researched for each jurisdiction? (e.g., regulatory, economic, etc.)	
			If available, what roadmap or implementation plan are these companies following?	
			What are their unique attributes and characteristics (functions), differences, and specific value proposition to the market/policy environment which they serve?	
			What are the DSO enablers in each jurisdiction?	
			What are the key lessons learned for each case study? How are the key lessons relevant for Ontario/Alectra?	
			How should the lessons be grouped? (e.g., technology, process, people, regulatory, etc.)	
3	**Determine the potential Ontario/Alectra DSO value proposition, including a viable DSO model shortlist with key regulatory requirements, characteristics, and needs.**	**What are the optimal DSO models for Ontario/Alectra?**	Based on the earlier research, what are the different jurisdictional models?	EY Wavespace Workshop Retrospective Materials A DSO Value Proposition Analysis in Ontario Next Steps
			Based the research and workshops, what DSO models would fit Ontario/Alectra?	
			What are the long-term benefits/value of those shortlisted models based on the EY DSO of the Future Framework?	
			What are the disadvantages of those options based on the EY DSO of the Future Framework?	
			What is the asset/DER ownership optionality for each shortlisted model?	
			What are the renumeration options for the shortlisted models?	

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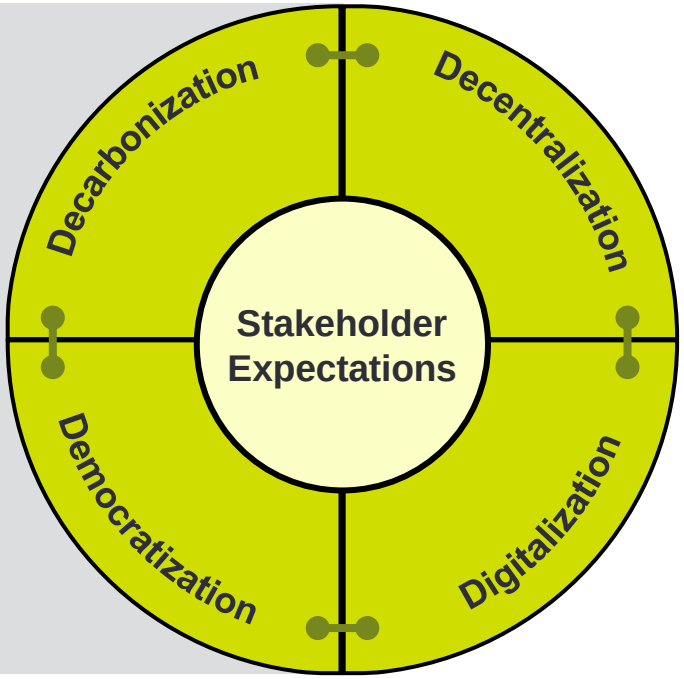
03

Why DSO in the New Energy Era

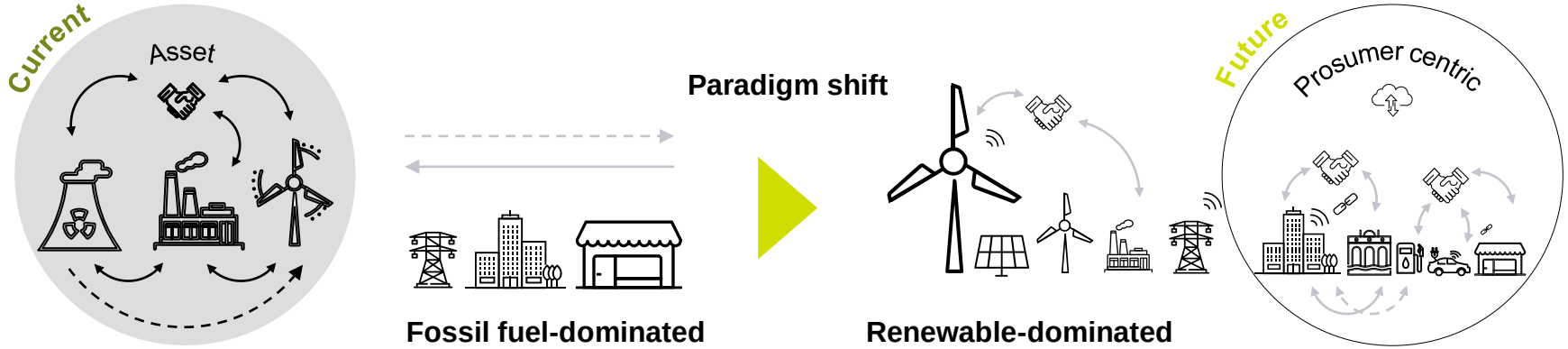
A description of the drivers behind utility business model transformations.

The Evolving Energy System

The global energy system is undergoing a major shift, and the **4Ds — decarbonization, decentralization, digitalization, and democratization** — will continue to disrupt power system markets and the traditional utility business model.



Interconnected by digital technologies … with a two-way flow of energy and information … driving new business models



Fossil fuel-dominated centralized generation

Renewable-dominated decentralized generation

Decarbonization | **Decentralization** | **Digitalization** | **Democratization**

Generation follows demand

Demand follows generation

Source: EY Knowledge, EY Countdown Clock Model, EY Navigating the Energy Transition Research

4Ds are Accelerating the Energy Transition

Driven by net-zero goals, innovation, and evolving customer expectations, the 4Ds are no longer conceptual, but are creating real-world technology, business, and policy transformation in the energy sector globally and in Canada.

Decarbonization

Net-zero mandates are driving electrification. For example, Canada's Fall Economic Statement **proposed a refundable tax credit equal to 30% of the capital cost of investments** in electricity generation systems, including solar PV, SMRs, concentrated solar, wind, and water.

Decentralization

Declining costs in DERs and net-zero targets are leading to a more distributed grid. Estimates predict that new **solar & battery storage projects will make up 60% of new generating capacity by 2025.** These advances will require utility grids to accommodate the resulting increase in two-way energy flows.

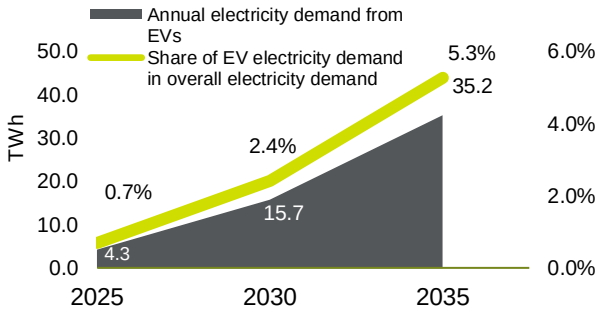
Digitalization

As technology and customer needs evolve, utilities will need to invest in digital technologies to improve their asset performance and operations. The US Inflation Reduction Act allocated nearly **$3 billion towards transmission systems development and improvement**, including modification of facilities.

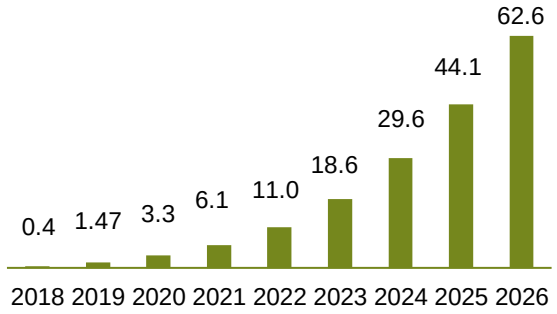
Democratization

Customers are now actively engaging with the grid – **seeking low-cost and flexible ways to participate in the energy transition**. In 2022, Canada adopted the **Clean Fuel Regulations**, which increase incentives for the development and adoption of clean fuels, technologies, and processes, such as eMobility.

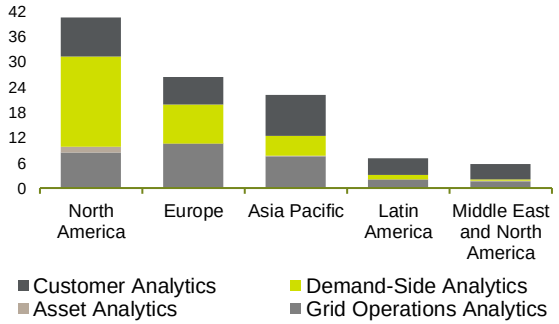
Rise in Adoption of Electric Vehicles in Canada



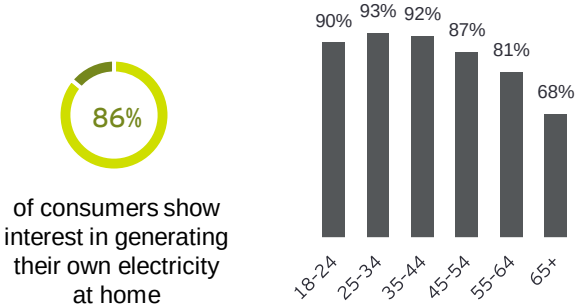
Global Rise in Residential Solar PV Plus Energy Storage Market (US$b)



North American Market Size of Advanced Grid Analytics (US$m) – 2020



Global Customer Interest in Self-Generation of Electricity by Age Groups



Source: EY Analysis, EY Countdown Clock Model, EY Navigating the Energy Transition Research, IEA

Electricity System's Three Tipping Points

EY research identified three tipping points that will drive transformation in the Power and Utilities sector around the world. More specifically, the transformation will be driven by the cost competitiveness of new vs traditional energy solutions.

Tipping point 1 (T1 Global example):

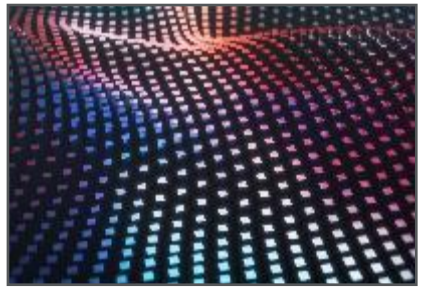
Electricity and mobility convergence

Where the price of battery electric vehicles (EVs) reaches cost and performance parity with internal combustion engine (ICE) vehicles

Tipping point 2 (T2 Oceania example):

Birth of the new energy system

Where the cost of distributed solar generation - plus storage - reaches parity with the full retail price of grid-supplied electricity

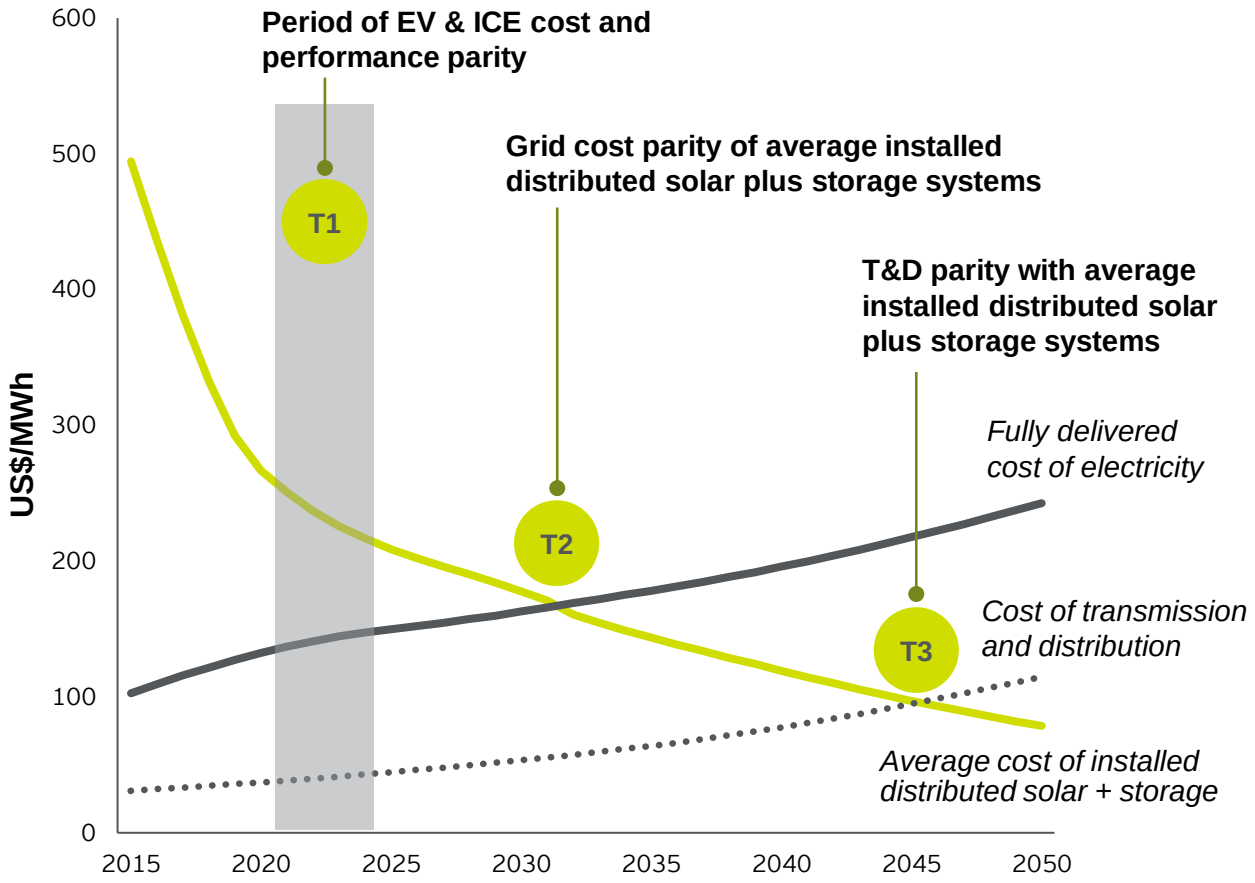


Tipping point 3 (T3 NE US example):

Digital energy marketplace

Where the cost of distributed solar generation plus storage falls below the transmission and distribution (T&D) costs of grid-supplied electricity

Comparative costs



 Source: EY Countdown Clock model – Central Scenario

The DER Future and Its Implications for DNOs

Distribution Network Operators (DNOs) are at the heart of the transition to a high-DER future. Distribution networks will need to accommodate empowered customer demands and a digital grid where power and information flow bi-directionally.

The industry says…

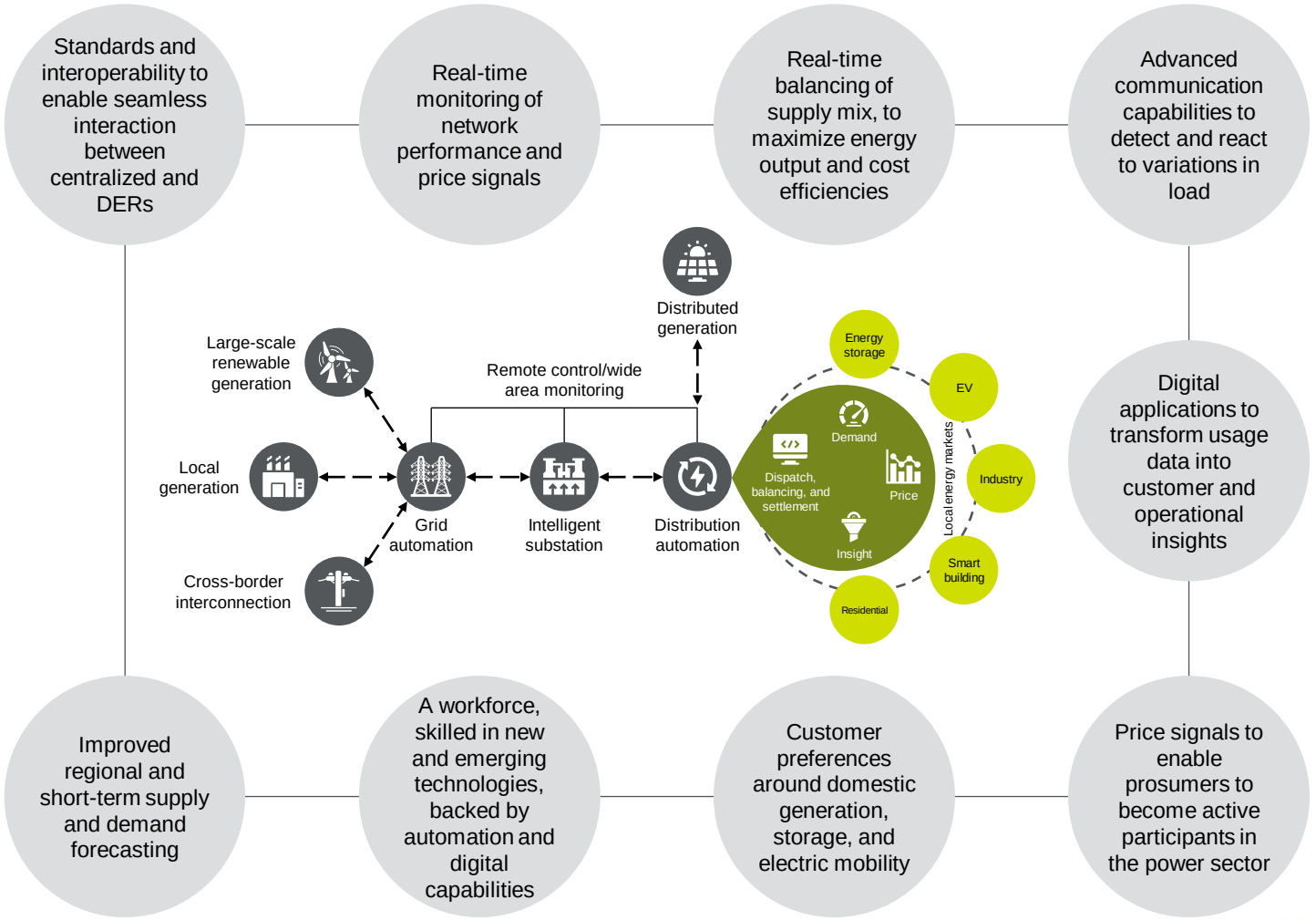
93% of network leadership say DNOs will need to take on a more active role in the management of DERs at local levels.

Source: DSO Survey, EY, 2019.

The call for DNOs to design and operate active distribution systems, comprising networks, demand, generation and other flexible DER is **leading to utility business model transformations across the globe.**

Network operations will need to change, requiring new capabilities and enhanced functions that enable the network to be more dynamic and flexible to cope with multidirectional power flows and new customer connections.

Current ways of working will therefore need to be modified, with new investments prioritized. The current model of 'connect and reinforce' will need to overcome the passive relationship between the DSO and network customers.



 Source: EY Analysis, EY Report Future of DSOs

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04

DSO Definitions and Models

An overview of the DSO concept and model variations, as well as a comparison to other structures.

DSO Model in a Nutshell

The solution championed by leading DNOs around the world is to change the role of the utility itself, moving from a cost-of-service electric utility role to that of a DSO.

New System Management Tasks

The DSO model pushes local distribution companies of today to take on more real-time “system operator” roles, adding management tasks like those performed by independent system operators (ISOs) on transmission systems.

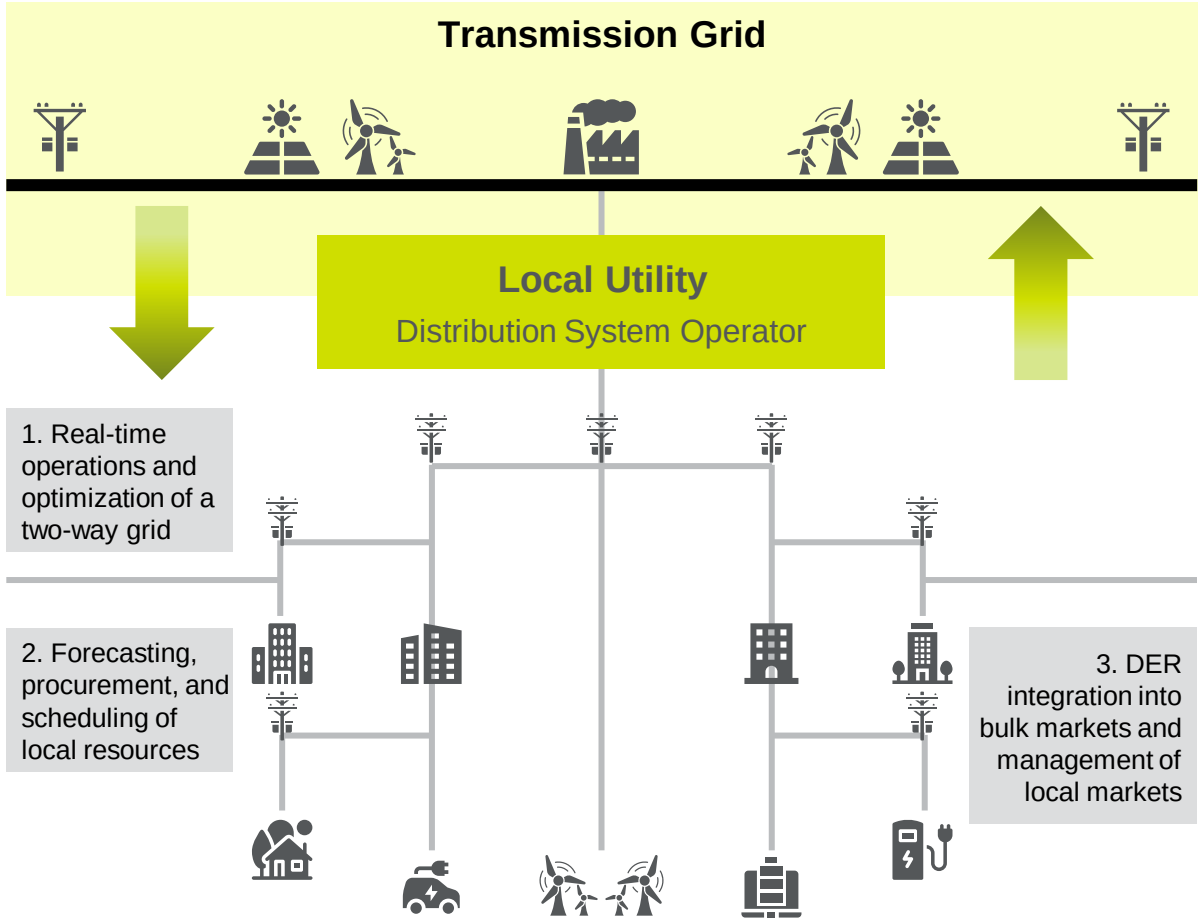
Varying DSO Model Applications

Each market is applying its own version of the DSO model, whereby system operations range from highly centralized to decentralized standards.

For example, the UK concept includes a stand-up of a separate public corporation to oversee the DSO functions, while the US model sees a DSO operating the grid like a marketplace via Distributed System Platforms (DSPs) that will serve as neutral gatekeepers between energy providers and buyers.

Grid Management is at the Centre of DSOs

Irrespective of model designs, a DSO is responsible for managing local grid conditions, while enabling complex interactions to occur among grid-connected energy resources, including interactions between distribution-connected devices and bulk (transmission-level) power systems.



Key DSO Responsibilities

 Source: EY Analysis, EY Report Future of DSOs

EY's DSO Definition

The term "DSO" invited numerous definitions and thus, confusions in the industry. It is often used to describe either a set of actors, roles, and responsibilities, or a single entity. From an entity perspective, EY views the DSO broadly as:

> ***"A real-time system operator for an active distribution network which manages and coordinates distributed generation at a local level, acts as a neutral facilitator to open markets, and enables easy access to T&D networks."***

Every market defines DSO differently, with some key similarities…

United Kingdom DSO

A DSO securely operates and develops an active distribution system comprising of networks, demand, generation and other flexibly distributed energy resources.

California, USA DSO

DSO is the entity responsible for planning and operational functions associated with a distribution system that is modernized for high levels of DERs.

New York, USA DSO

Distributed System Platforms (DSPs) are comprised of the people, processes, and systems that allow utilities to provide three core services: (1) facilitating expanded DER integration, (2) sharing information that helps third parties identify and evaluate business opportunities and energy use, and (3) expanding market services.

Australia DSO

A DSO is an entity that is responsible for planning and operating functions associated with coordinating DER services for distribution networks and/or DER participation in wholesale markets in coordination with the TSO, aggregators, and other relevant parties.

Europe DSO

A DSO is a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.

Source: EY Knowledge, EY Report Future of DSOs, ENA DSO Transition, various articles from market operators and regulators

EY's View on the DSO of the Future

Today's DNOs are responsible primarily for timely connections of new capacity to the grid and improving system resilience. Tomorrow's DSOs will be required to help transform energy systems by accelerating innovation and digitalization.

Today's DNO*	Maintains a safe and reliable grid	Enables the energy transition	Identifies the most cost-effective solutions
Tomorrow's DSO	Securely develops and operates an active distribution system comprising networks, demand, generation and other flexible DER.	Creates a level playing field for new and existing flexible technologies, providers and solutions and access to a wide range of revenue streams.	Contributes to the design of markets that combine local, regional, national and international solutions which offer 'whole system outcomes' that are best for customers.
	Takes into account two-way energy flows and greater supply intermittency.	Integrates all types of generation and prepares and facilitates the uptake of EVs.	Enables new local markets for peer-to-peer trading, giving all participants - whether prosumers, aggregators, traditional players or third parties - equal access to the energy market, without jeopardizing the resilience of the network or security of supply.
	Coordinates information exchange between the DSO and TSO to balance the whole system.	Optimizes network investment decisions using alternative flexible solutions.	
	Procures, uses and coordinates flexibility services to balance the local grid.		
	+	+	+
	Promotes innovation, flexibility and non-network solutions	Improves the resilience and security of the electricity system at a local level	Facilitates neutral markets for more efficient whole system outcomes

 Source: EY Report Future of DSOs

Core Capabilities of Tomorrow's DSO

Transitioning to a DSO will require policymaker and regulatory engagements to define new DSO roles and functions. These new functional areas call for new approaches to traditional applications and capabilities.

Distribution System Operations and Management

Managing variable power on the network to maintain equal distribution and ensure that the demand is met

System Operations

- Collection and analysis of data to understand the network power distribution in real time
- Enhanced modelling for real-time network solutions and system flexibility
- Real-time DER dispatch to meet a wide range of system operational requirements
- Coordination of network configuration and system support with TSO
- Advanced network automation and control for performance optimization
- Real-time state estimation and load flow analysis
- Coordination of outage and constraint management
- Facilitation of system defence and restoration

Network Planning

- Identify capacity requirements and cost-effective capacity provision on the distribution network
- Ensure T&D collaboration on investment and operational decisions
- Forecast demand, generation, network power flows and the requirements for DSR and flexibility
- Firm and un-firm connection agreements

Asset Management

- Facilitate the information and data exchanges required to plan and operate as a DSO
- Assess risk base management using multi-data analytics
- Increase scope/ penetration of intelligent electronic devices
- Assess and mitigate cybersecurity risks

Systems Management

- Upskill workforce to be able to install new network assets (E.G. EV Connections)
- Facilitate workflow management

Market Management

Supporting and facilitating trading within localized markets

Flexibility Management

- Establish and run LMP/nodal pricing models
- Establish customer charges and generate customer bills
- Manage peer-to-peer or peer-to-market platform infrastructure
- Settle DSO/ TSO/DER/customer trading interactions
- Support interactions through the creation, development, admin and management of contractual arrangements

Commercial Operations

Establish customer charges and generate customer bills

- Manage DER and the demand side of customer management
- Manage system support product portfolio
- Manage, analyse and optimise customer consumption and generation data
- Manage and settle customer trading interactions

New Function | Enhanced Function

 Source: EY Knowledge, EY Report Future of DSOs

DSO Market Models Overview

DSO market models are still highly conceptual and configurations depend on market and regulatory dynamics. Currently, there are four primary models under consideration, which explore “who” should serve the DSO function and “how”.

Total TSO Model

Definition

Total TSO model has visibility over the entire transmission and distribution system and is responsible for real time, reliable operation of the transmission-distribution system, interconnection, and planning for the combined system infrastructure.

DER Ownership Model

In principle, DERs can be utility owned, customer owned or third party owned.

However, TSOs optimize the whole system, with visibility of distribution grid conditions and all DER above a low size threshold.

Jurisdictional Application

California’s current coordination structure is closer to a Total TSO model. The current structure is a continuation of the California ISO (CAISO) and distribution utility roles.

Ontario Market Relevance

This model is relevant up to some extent where IESO or TSO can manage the DER integration at wholesale levels.

Hybrid DSO Model

Definition

Hybrid DSO is a model where TSO and DSO take shared responsibility of the network and work together to resolve system issues. It requires complex communication between transmission and distribution system operators, and 3rd party DER aggregators.

DER Ownership Model

In a Hybrid DSO model, both DSOs and TSOs play a role in coordinating DER services and operations. DERs can be utility owned, customer or third party owned; however, if a local market platform is operated by a DSO, then utility owned DERs will not be allowed to participate.

Jurisdictional Application

Western Australia initially trialed the hybrid approach, and NYISO is likely to implement a variation of it, which will be based on tiered optimization.

Ontario Market Relevance

This model, or variations thereof, could be relevant to Ontario. LDCs will need to tackle scalability challenges to successfully operate in the Ontario market structure.

Total DSO Model

Definition

Total DSO model is an approach, where all, or a subset of resources, e.g., 10MW, are connected to the distribution level, participate in transmission markets, and orchestrated via a DSO to enable interactions between DERs and TSOs.

DER Ownership Model

In principle, DERs can be utility owned, customer owned or third party owned.

However, DSO controls the whole system and secures system security by directly controlling the resources of an aggregator.

Jurisdictional Application

Germany pursues a total DSO model. Trading on the liberalized wholesale market is either carried out over the counter or via the European Energy Exchange (EEX).

Ontario Market Relevance

Total DSO approach, though possible, would be complex to implement at scale in Ontario, as currently there are 63 local distribution companies.

Independent DSO Model

Definition

Independent DSO work with distribution utilities to optimize the dispatch of the DER based upon local system constraints that are provided by the network business. The latter provide the aggregated bids to ISO for incorporation into the larger dispatch.

DER Ownership Model

Ownership can lay with customers, third party aggregators or utilities depending on the policies of a jurisdiction.

Jurisdictional Application

UKPN has laid out its plans to establish the first ever independent DSO by the start of ED2 in April 2023.

Ontario Market Relevance

This model is less relevant to the current Ontario structure given the UK’s TOTEX model. However, IDSO dynamics and future implications highlight it as a suitable option.

Source: EY Analysis, Gridworks (2022) Evaluating Alternative Distribution System Operator Models for California

Comparison of DSO Market Models

DSO is a fairly-new concept that can take many forms, while fundamentally challenging existing transmission and distribution network operation models. The following three messages are the key observations from the DSO market model comparison:

01

There is a spectrum of DSO model options, but all remain nascent.

DSO market models range from highly-centralized transmission wholesale models (top-down approach), to distribution nodal models, to highly-decentralized peer-to-peer (PtP) models (bottom-up).

Choosing the right model will require consideration of how best to perform secure, efficient key market processes for vast numbers of assets at the grid edge.

02

Despite its many forms, DSO will serve to operate a highly-distributed distribution marketplace.

Broadly, DSO would have two responsibilities: operate the distribution system marketplace and manage DERs in coordination with other distribution grid assets, regardless of who owns them.

This will require effective TSO-DSO coordination schemes to address new two-way energy and information flows while meeting regulatory and customer expectations.

03

DSO implementation will take time – starting strategic discussions today is critical.

Utilities, ISO/TSOs, and regulatory organizations should begin DSO discussions today.

DNOs should consider how a DSO model can help manage DERs within their territories, and which roles they want to assume.

Focus should be placed on developing organizational and regulatory strategies, and coordinating with key market players to determine the most appropriate models.

Note: regardless of a DSO model choice, Alectra's foundational approach should also consider pivoting away from traditional worst case scenario planning to a more stochastic techno-economic modelling. In addition, Alectra needs to determine economic values of each non-traditional service and animate them in terms of prices.

Today's Power Market Roles and Emerging Variations

Our team reviewed today's three key power market roles and emerging variations to help contextualize how the role of the DSO can be fulfilled. In sum, the ISO, TSO, and DNO can assume the DSO role or a variation thereof.

	Today's Key Power Market Roles			Emerging Roles			
	Independent System Operator (ISO)	Transmission System Operator (TSO)	Distribution Network Operator (DNO)	Distribution System Operator (DSO)	Load Serving Entity (LSE)	Community Choice Aggregator (CCA)	Fully Integrated Network Orchestrator (FINO)
Definition	An entity responsible for real-time operations of the bulk transmission system and/or operation of a competitive wholesale power market within its jurisdiction. Operates the wholesale electricity market and bulk electricity system independently.	An entity responsible for the operation of the transmission system (the assets that transmit power between bulk resources and the distribution system). Coordinates outages/de-rates with and receives control signals from the ISO balancing authority.	An entity that owns an electric distribution grid in a defined franchise service area. Coordinates outages/de-rates with and receives control signals from LDC operations.	Encompasses various conceptual models of operating distribution systems with high numbers of DERs. Broadly, it refers to a real-time system operator of an active distribution network comprising networks, demand, generation and high levels of DERs.	An entity that secures energy and transmission service (and related interconnected operations) to serve the electrical demand and energy requirements of customers. Many variants exist, including those that own/operate distribution systems.	CCAs are local, not-for-profit, public agencies that take on the decision-making role about sources of energy for electricity generation. Once established, CCAs become the default service provider for the power mix delivered to customers.	FINO is a single entity that performs the roles of a distribution system owner and those that relate to effectively integrating DERs within a service territory.
Core Function	Serve regional planning functions, including intra- and interregional infrastructure expansion for reliability and economic improvement. Coordinate generation and transmission across a wide geographic area, matching generation instantaneously to the market demand for electricity.	Responsible for controlling and operating the transmission grid. This includes monitoring and controlling the current grid topology (position of breakers and switches within the grid) and the voltage in all parts of the transmission grid. A TSO maintains coordination with LDC operations to fulfill much of this function.	Responsible for the operation of the distribution system and secures distribution-level services from DERs in a non-discriminatory, open-access manner. Today's DNOs maintain a safe and reliable grid, connecting new generation and identifying the most cost-effective solutions for energy customers.	Serves as a neutral facilitator of an open and accessible market, enabling competitive access to markets and the optimal use of DERs on distribution networks to deliver security, sustainability and affordability in the support of whole system optimization.	Aggregates end-use customers for procuring and supplying energy from the grid. LSEs procure energy and capacity on behalf of the customers (loads) they serve.	CCAs achieve environmental and social objectives for customers, providing them with more choices. They are mainly responsible for procuring wholesale electricity on behalf of retail electricity customers, within a defined geographic area, or through bi-lateral contracts with resources and re-sell these services.	Takes on an integrated role of a DER aggregator, owner, and operator and of an LSE – demonstrating a DSO function, including ability to direct the operations of DERs.
Variants / Alternatives	**TSO:** In some jurisdictions, also considered the TSO. **FSO**: The Future System Operator in Great Britain is being considered as a public body to oversee the energy system with a boosting of security of supply and support for the transition to net zero in the country.	**RTO**: A Regional Transmission Operator operates the power system over large regions, allowing for improved reliability and efficient use of system resources (e.g., US market).	**LDC:** A Local Distribution Company owns and operates a distribution system, but is not commercially responsible for the differences between the wholesale price it pays for electricity and retail price at which it is sold to retail customers.	**Fully independent DSO**: Similar to an ISO, a fully independent DSO conducts physical dispatch of the distribution system to facilitate market access for DERs. **FINO:** Can have combined responsibilities of an LDC and a DSO, and may be involved in commercial DER activities.	**DSO**: In some cases, LSEs may also encompass the duties of a DSO and/or a DO entity.	**Aggregator**: Aggregates and transacts bundled energy services for delivery to the DSO, Utility, or ISO/TSO. **Retailer**: Private companies that purchase wholesale electricity from power generating companies and then sell it to customers.	*The FINO structure could serve many of the same distribution-level functions that DSOs and LSEs serve.

 Source: EY Analysis, ETNO (2019-2021): Distribution System Structures for a High Distributed Energy Resource Future; ETNO-Structural Options High DER Future

DSO Comparison to the Other Market Roles

The DSO as a market role can be considered against a backdrop of traditional and other newly emerging market structures. The following three messages are the key observations from this section:

01

An increased sense of urgency to evolve market structures.

Large scale penetration of DERs, accompanied by heat and transport electrification, is changing the way jurisdictions operate their power markets.

There are various ongoing discussions around what system structure is best suited to support a highly distributed, decarbonized, and digitalized energy future.

02

Conventional market players can assume new roles and responsibilities to drive transition.

The various market structures under current consideration demonstrate both a naturally iterative and transformational approach to electricity market reform.

In some cases, entirely new entities such as the UK's FSO will form to oversee the evolution of T&D systems, while in others, traditional players such as the TSO, DNO and ISO can assume new responsibilities to enable electricity system transitions.

03

Unique market conditions dictate the market structure choices.

As the myriad of models explored here shows, there is no one-size-fits-all solution and each jurisdictions' structure of choice depends on local regulatory frameworks, policy drivers, customer behaviour, as well as players in the power market.

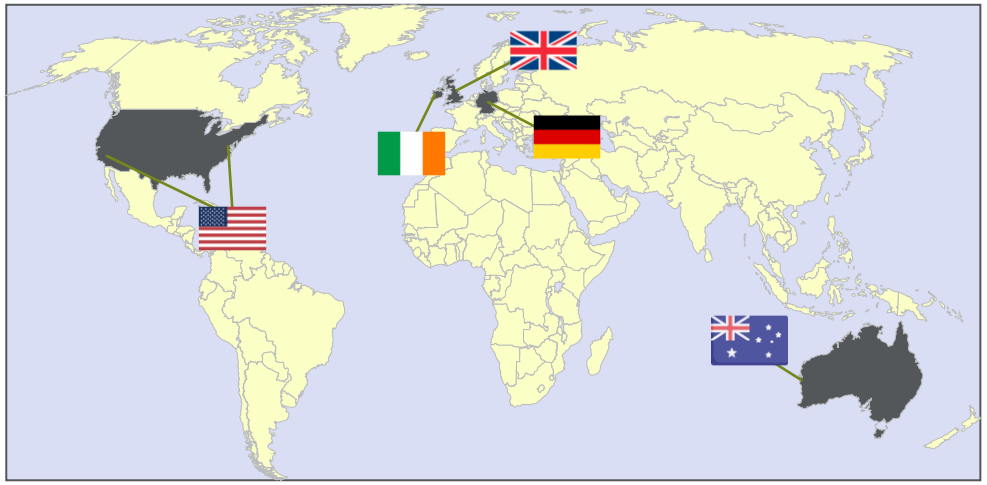
05

DSO Case Studies Around the World

Key takeaways from the eight DSO case studies and their regulatory environments.

Market and Case Study Summary

The utilities and markets selected for this research study are considered to be leaders in the DSO transition landscape. Each example provides key insights on how various jurisdictions are navigating through their respective journeys.



United Kingdom
Australia
Ireland
Germany
USA (New York)
USA (California)

The DSO transition from a Distribution Network Operator (DNO) or a Local Distribution Company (LDC) model is an emerging business and regulatory transformation that is currently being explored and tested around the world in response to a shifting energy system landscape.

Despite the widespread push towards more sustainable, equitable, and accessible energy systems (the energy trilemma), DSO transitions have been limited, inconsistent, and complex across various markets. The following DSOs were selected to provide Alectra with an introduction to tangible case studies based on the following elements:

DSO Progress to Date

The following DSOs and markets are considered to be “leaders” in utility transformation, whereby the advanced nature of their respective system characteristics, e.g., a high penetration rate of electric vehicles in the UK or solar PV adoption in Australia, are pushing respective network operators to adopt DSO models faster than other jurisdictions.

DSO Data Availability

For many utilities, DSO is a critical and strategic - yet still conceptual - journey that is driven by evolving stakeholder needs, system demands, and decarbonization goals. While some utilities are actively lobbying for regulatory allowance and market evolution to enable DSO models, other utilities have put forward high-level DSO strategies without meaningful action.

Thus, the case studies here have been compiled on entities that have made more tangible steps to pursue a DSO transition and those that EY has information on from past engagements, stakeholder contributions, and desktop research.

Alectra’s DSOs/Markets of Interest

Lastly, our team ensured that the markets/case studies were of interest to Alectra. Such utilities were shortlisted and discussed with the project sponsor team before EY’s detailed research to ensure selection alignment.

DSO Models – Jurisdictions Exploring Different Approaches

Considering the four conceptual models outlined in the DSO Overview, the studied jurisdictions are exploring their own approaches to applying Total TSO, Total DSO, IDSO, and Hybrid models with core variations between them.

Total TSO

- A top-down approach in which TSOs extend their current responsibilities to operate markets and balance the grid all the way to devices at the distribution level (either directly or via aggregators) – i.e., the TSO serves the DSO function.
- Requires substantial functional enhancements by TSO.

California

Hybrid DSO

Australia

New York

- Can take various forms, generally, TSO models DERs at T-D interfaces, but dispatches individual DER aggregations.
- DSO manages DER activities on D system & impacts of/on D grid conditions.
- Most common trajectory of DER integration being considered in the US today.

Important Areas of TSO-DSO Coordination

- Definition of data that need to be exchanged
- Data on DER type, characteristics, capacity
- Exchange of system planning information
- Development of simplified system models
- Coordinated technical studies to assess system constraints
- Co-ordination on congestion management
- Definition of grid connection requirements
- Exchange of information on available network capacity
- Definition of system operation network codes
- Co-ordination on protection and restoration schemes

Total DSO

- A bottom-up approach featuring balancing responsibilities and/or markets nested below the T&D interface.
- More proactive role for DNOs, requiring them to build and maintain the D grid and perform many of the functions traditionally reserved for TSOs, including operating capacity and energy markets (or procuring services) – i.e., the DNO serves the DSO function.

Ireland

Germany

Independent DSO

United Kingdom

- IDSO is similar to the Total DSO, but IDSO separates the profit-making opportunities of distribution system ownership from distribution system market operations by tasking an independent organization with distribution system market operations.

Most markets are currently developing either a Total TSO or a Hybrid DSO model. However, all DSO models depicted here are still under consideration and have not yet been fully defined, determined, or scaled as of today.

Source: EY Knowledge, Gridworks (2022) Evaluating Alternative Distribution System Operator Models for California, IRENA (2020) - The Future Role of DSOs.

Overview of Jurisdictions

Each jurisdiction has its own characteristics, development stages, and drivers. However, the selected markets are all trying to pursue DSO models in their own space. Below is a high-level description of those market structures.

	United Kingdom	Australia	Ireland	Germany	USA (New York)	USA (California)
System Operator	National Grid Electricity System Operator (ESO)	Australian Energy Market Operator (AEMO)	Single Electricity Market Operator (SEMO)	Bundesnetzagentur (BNetzA)	New York Independent System Operator (NYISO)	California Independent System Operator (CAISO)
Role	ISOs run the transmission system but do not own the transmission network. They manage the wholesale trading of power as well.					
Markets Operated by ISOs	• Bilateral Market • Spot Market • Ancillary Market • Capacity Market • Balancing Market	• Bilateral Market • Spot Market • Ancillary Market	• Day-ahead Market • Real-time Market	• Over The Counter Trading • Mandatory Pool Or Power Exchange • European Energy Exchange (EEX) And European Power Exchange (EPEX)	• Day-ahead Market • Real-time Market • Demand Response Program • Capacity Markets • Ancillary Markets • T Congestion Contracts	• Day-ahead Market • Real-time Market • Ancillary Markets • Congestion Revenue Rights
Major Regulations/ Policy	The Office of Gas and Electricity Markets (Ofgem) performance-based RIIO model rewards utilities for innovation while ensuring consumers get the necessary investment in Britain's energy networks at a fair price. In July 2020, Ofgem published the smart system flexibility plan with a focus on removing barriers to flexibility markets in order to enable net-zero.	In 2020, Australian Energy Market Commission (AEMC) allowed consumers to sell demand response in the wholesale market. In December 2017, Australia issued the guidelines for DER connection to the grid.	In 2018, the Ireland energy market transformed from a single energy market to an integrated single energy market. Ireland has to comply with the targets published in Clean Energy for all European package by 2030. In addition, Ireland follows the Climate Action Plan 2023 (CAP23) that sets economy-wide carbon budgets and sectoral GHG ceilings.	The Energy Act assigned the task of regulating Germany's electricity and gas markets to the Bundesnetzagentur. The EU Commission approved three measures to support electricity production from renewables in Germany. Germany also needs to comply with the EU Clean Energy Package by 2030.	FERC allowed the participation of DERs in wholesale and retail level.	
Major Roadmaps	Distribution utilities have to submit the business plan for revenues, whereas every DNO has also prepared the DNO to DSO transition plans.	In April 2017 Energy Networks Australia and The Commonwealth Scientific and Industrial Research Organization (CSIRO) developed an electricity network transformation roadmap (2017-2027) to build the future energy market.	Renewable Energy Directive sets a common target – currently 32% – for amount of RE in EU's energy consumption by 2030. Ireland has to comply with the targets published in Clean Energy for all European package by 2030:	Germany's federal parliament passed an energy legislation, designed to accelerate the expansion of the power grid and protect consumers from rising energy prices when a supplier leaves the market.	NYISO directed utilities to submit plans to become distribution system platform providers. NYISO, under its 2018-22 Strategic Plan, aims to make electric grid smarter, greener and more efficient.	CAISO directed DNOs to submit distribution resources plans (DRPs) to better integrate DERs onto the grid. Under the 2021-three year initiative, CAISO is planned to ensure resource adequacy and power reliability.

 Source: EY Analysis, DSO Reports and Websites.

Overview of Jurisdictions (Cont'd)

Each market provides different and interesting insights for Alectra to consider. Most interestingly, each jurisdiction has different approaches to addressing DER participation, ownership, and dispatch.

	United Kingdom	Australia	Ireland	Germany	USA (New York)	USA (California)
Local Power Dispatch	ISOs release power through a centrally-coordinated dispatch process that pools generation from producers, and deliver required quantities of electricity from the pool to wholesale consumers.					
Utility DER Participation	DNOs can sell DERs in the wholesale market. If over 1 MW DERs can participate via the wide access agreements.	Interim arrangements have been made for DERs to provide ancillary services.	According to ESB's National Network, Local Connections Programme, DERs are owned by a range of entities (from a household to a large utility), each with unique objectives/priorities.	Not seen in Germany yet. For now, DER participation is only for customers.	Allowed as per FERC order 2222.	
Incentives for DSO / Innovation Activities	Under the RIIO-2 network price control, Ofgem introduced the Strategic Innovation Fund - DNO's receive £150,000 from the £450m Strategic Innovation Fund.	DNOs receive incentives for investing in various measures to support net-zero and renewable integration target . They are compensated by the ISOs for providing DERs at the market clearing price.	PR5 regulation, which is an incentive-based regulation that allows the pursuit of net-zero initiatives.	Germany introduced an incentive based regulation to encourage utilities to invest in energy efficiency measures	Distribution utilities receive incentives for investing in energy efficiency measures to reduce carbon footprint. They are compensated by the ISOs for providing DERs at the market clearing price.	
Retailer DER Participation	Retailers can sell the electricity at wholesale market.	Retailers are conducting trials to aggregate DERs at a local level.	Retailers are conducting trials to aggregate DERs at a local level.	No retailer DER participation yet.	Retailers can aggregate DERs at the retail level, but currently there is minimal activity in this space.	
Congestion Management	System optimization, reactive power control, and demand response are some of the mechanisms used to control congestion at the distribution level.					
Why this Market?	The UK is one of the most advanced DSO markets, expedited by net-zero targets, innovative regulatory allowances, and electricity market reform, including entity separation. It is a unique environment that the rest of the world is watching closely.	With the highest per capita penetration of solar PV in the world, a mature storage market, strong EV incentives, and expanding demand-side market participation, Australia is on pace to get nearly half of its electricity from DERs by 2040 – driving DSO transitions faster.	Ireland is approaching DSO from a T&D coordination and innovation incentive approach. The Hybrid DSO Irish market describes TSO and DSO-led relationships and engagements that can be considered in Ontario.	Germany is as one of the world's energy transition leaders. As a highly distributed, municipally-led market, Germany is of interest to the Ontario context. DNOs are investing in innovation, digitization and flexibility services to achieve net-zero by 2035.	NYISO established a Distributed System Platform definition and plan to carefully enable the transition to clean energy resources. A more defined ISO stance provides several benefits to utilities, including a degree of certainty in future investments.	The California market is known for its innovative response to managing high-DER penetration, and is somewhat similar to Ontario, whereby regulation is heavy. Hence, DSO pursuit in this operating environment faces several regulatory hurdles.

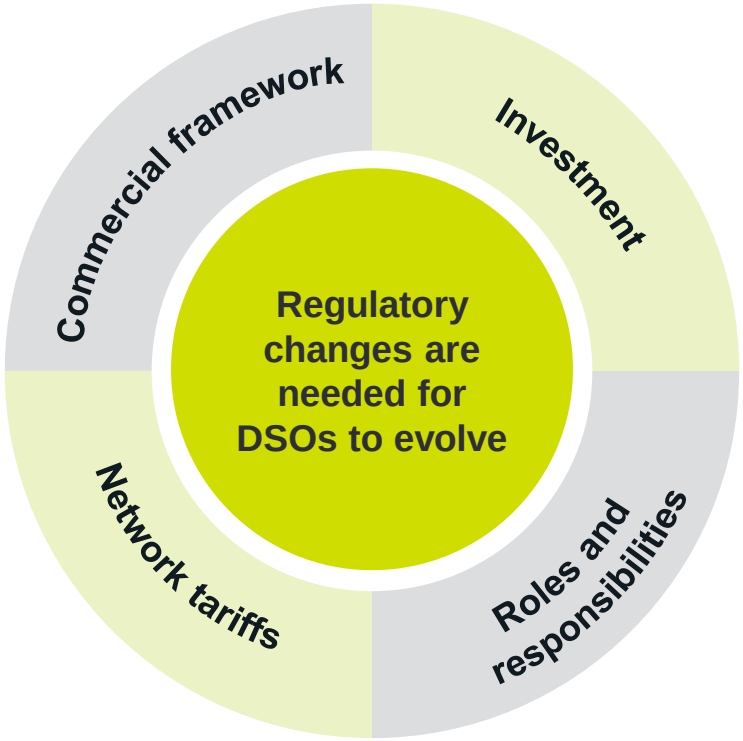
 Source: EY Analysis, DSO Reports and Websites.

The Importance of Regulatory and Public Policy Support

Regulation and policy are key to DSO transformations. Based on research (see Appendix B), progressive DSOs undertake proactive and engaged regulatory approaches to create more open environments, i.e., consultations, testing, etc.

New market frameworks for ancillary services are needed that encourage participation from DER owners and aggregators.

Network tariffs do not adequately reflect the changing use of the network across different customer groups.



Substantial investment is needed to reinforce and smarten the network but investment in R&D and innovation is being discouraged.

The **roles and responsibilities of new players**, including distributed generators, flexibility providers and communities needs to be recognized.

The traditional cost-of-service regulation is ill-equipped to foster a rapid modernization and expansion of capabilities needed for the future grid.

Utilities require incentives to pursue a wider range of alternative options to traditional wire investments, e.g., performance-based regulations.

Hence, **utilities need to reconsider their roles, collaborate with regulators on new reforms, and invest heavily in innovation.**

Source: EY Analysis, EY DSO Survey

Regulatory Scan Key Takeaways

Regulatory environments are complex in each market and have their unique attributes. Alectra's DSO journey should consider the following four key lessons from the regulatory scan (**note**: detailed regulatory overviews are included in the appendices):

01	**Leading DSOs are taking accountability and shaping their future**	Every leading jurisdiction has its own understanding of the DSO model – and regulators seldom take a leading role. Its up to the DSOs themselves to define future and work with respective stakeholders to enable it. Starting with an aligned vision allows utilities to have a more confident outlook on the future market conditions and plan accordingly, e.g., New York's Reforming of the Energy Vision.
02	**Regulatory support is critical to the DSO pursuit**	Regulatory support is necessary for DSO model enablement, due to financial and risk mitigation-related reasons. Regulation can constrain proposed DSO activities if not embedded into DSO planning. Engaging regulators early can help elicit buy-in, financial incentives, research support, achievable targets, etc., e.g., Irish PR5 Regulatory Framework Support and Reporting.
03	**Unlocking DER barriers will be key**	DSO models assume their relevance and utility based on high future DER adoption and penetration rates, including EVs, storage, solar PV, etc. Thus, successful DSOs will operate in environments where DERs are market-based activities encouraged via regulatory boundaries and grid-scale services are procured by system operators with technical capabilities, e.g., California's DER Adoption Plan.
04	**Regulators should be guided by utilities on DSO**	Again, DSO is a novel concept that has not been fully explored. Utilities are able to collaborate with regulators and educate them based on their experience to avoid information siloes. For example, an "Open Energy Networks" project in Australia and a "Call for Input" in the UK, highlight the ability of utilities to influence regulators and propose adjustments in consideration of grid and customer needs.

Wavespace attendee: "*We need to be careful on when the regulator is ready to make decisions. They've been asking us about addressing four concerns: 1. alignment across 60 LDCs; 2. potential conflict of interest in owning and managing demand; 3. stranded assets; and 4. infrastructure planning and cost. Perhaps it is our job to answer these concerns. Without regulatory support, we will not be able to progress.*"

Case Study Overview

The team researched eight utilities in the jurisdictions of DSO interest, including UKPN, National Grid, ENWL, Western Power, ESB, Netze BW, ConEd, and PG&E (**note**: detailed utility case studies are included in the appendices):

UKPN

Overview

UK Power Networks is a distribution network operator for electricity. It manages three licensed distribution networks (Eastern Power, London Power, and South-eastern power networks) covering 30,000 square kilometers.

DSO Type: Independent DSO

DSO Strategy: RIIO-ED2 Business Plan (Chapter 12)

DER Role: DERs owned and controlled by customers.

Key Learnings

- UKPN began their DSO journey in 2010 by engaging with customers on their needs and DER interests (e.g., 2017 Future Smart Consultation)
- UKPN has a goal to establish a separate legal entity to provide an open market place for flexibility services by April, 2023

National Grid

Overview

National Grid is a British multinational utility that owns an electricity distribution and high-voltage transmission network in England and Wales; they also operate in the US. Electricity Transmission (ET) and Electricity System Operator (ESO) are separate businesses under Group.

DSO Type: Total TSO

DSO Strategy: NG Electricity Distributions DSO Strategy 2021

DER Role: DERs owned and controlled by customers.

Key Learnings

- NG views Distribution System Operations (vs Operator) as a future model, whereby industry participants will need a more whole systems approach to network ops
- NG Electric System Operator believes that utilities are suited for DSO transition and work on enabling them

ENWL

Overview

Electricity North West Limited (ENWL) is responsible for maintaining and upgrading a large network and nearly 500 major substations across the communities in the North-West of England, which extend from Macclesfield all the way up to Carlisle.

DSO Type: Independent DSO

DSO Strategy: ENWL DSO Strategy 2021

DER Role: DERs owned and controlled by customers.

Key Learnings

- As a smaller DNO (e.g., in contrast to UKPN), ENWL has a moderately less active ambition to become a DSO
- ENWL still aspires to become a DSO, but within the direct purview of the outlined Ofgem DSO functions
- Primary focus is on customer enablement and ops improvement

Western Power

Overview

Western Power is a State Government owned corporation, having a vast transmission and distribution network with seamless connects to a renewable energy mix, also leveraging new technologies, including integrating microgrid and battery storage solutions

DSO Type: Hybrid DSO

DSO Strategy: Energy Transformation Strategy 2022

DER Role: DERs owned and controlled by customers.

Key Learnings

- WP responded to the rapidly changing current state (system reliability issues) by collaborating and consulting with regulators and governments on the DSO future
- WP involved policymakers at a project level to align on tactical and strategic directions for the system development

 Source: EY Analysis, DSO Reports and Websites.

Case Study Overview (Cont'd)

Given the publicly available information and EY data on the selected utilities, UKPN can be considered as the most advanced DSO to date. However, Western Power and Netze BW are also DSOs who have made significant progress in the past decade.

ESB

Overview

Electricity Supply Board is a diversified utility, operating in generation, transmission distribution and supply. It also works in other related sectors including telecommunications, electric vehicle charging, home retrofits and DERs.

DSO Type: Total DSO

DSO Strategy: National Network, Local Connections Program (NNLCP)

DER Role: DERs owned and controlled by customers and utilities.

Key Learnings

- Irish utility landscape requires a strong transmission and distribution coordination, as well as governance and independence
- ESB identified its role in the DSO future and began investing in pilots to develop an overarching system infrastructure/operating model

Netze BW

Overview

NBW is the largest DSO in the EnBW Group (Energie Baden-Württemberg AG). It focuses on electricity T and D, renewable energies, electricity grids, telecom network, e-mobility and smart, sustainable energy solutions. NBW has some municipal shareholder ownership.

DSO Type: Total DSO

DSO Strategy: EnBW Corporate Strategy 2025

DER Role: DERs owned and controlled by customers.

Key Learnings

- Since Germany has several hundred DSOs/distribution utilities, a Total DSO model to manage flexibility services at local levels is considered to be a suitable solution
- NBW has a Network Development Plan for the transmission system operators to align with DSO needs

ConEd

Overview

ConEdison provides electricity and gas services, develops, owns and operates renewable and sustainable energy infrastructure projects and provides energy-related products and services to wholesale and retail customers while investing in transmission projects.

DSO Type: Hybrid DSO

DSO Strategy: Distributed System Implementation Plan (DSIP)

DER Role: DERs owned and controlled by customers.

Key Learnings

- New York State has seen a wide range of opinions on the DER future, ownerships, aggregations, etc.
- ConEd's DERMS implementation showed that business leadership should be enabled to drive the design and not the IT organization
- ConEd recognized the need for reform

PG&E

Overview

Pacific Gas and Electric Company (PG&E), incorporated in California in 1905 and headquartered in San Francisco, is one of the largest combined natural gas and electric energy companies in the US.

DSO Type: Total TSO

DSO Strategy: Electric Program Investment Charge (EPIC)

DER Role: DERs owned and controlled by customers.

Key Learnings

- PG&E is able to test and pilot various DER adoption and grid control/market operations projects through EPIC
- The fundings was established by CPUC to serve the public interest via innovative investments
- Regulators pushed PG&E to act on DSO after recognizing system issues

 Source: EY Analysis, DSO Reports and Websites.

Additional DSO Case Studies and 1-on-1 Connections

As part of our scan, EY also leveraged the firm's global network to connect Alectra with three additional DSOs in private discussions to facilitate further learning and collaboration. We heard from SMAs at SPEN, Stedin, and Netze BW.

[redacted]

"Asset management needs to be treated side by side. How you manage or replace assets will affect the system. You need have solid asset management decisions and system operations as you transition to a DSO" – **SPEN Discussion**

"It is the DSO's responsibility as asset custodians to engage the regulators and educate market stakeholders on your needs and system needs in the evolving sector" – **SPEN Discussion**

"It's important to see the DSO as not just a technical game, but a customer and regulator game also. Today we see Dutch people as active energy traders in our market – something we'd never imagine years ago" – **Stedin Discussion**

Key Learnings – SPEN

- SPEN's DSO vision began in 2016 with a whole system operating model. In 2019, it was presented to the regulator
- DSO guiding principles: transparency, structure, responsibility
- SPEN is building new capabilities in control room, soft network management and enhanced planning using new tools, such us SPEN's connectivity platform ("NAVI")
- Achieved regulatory support by taking accountability, bringing stakeholders along, and assuming the role of a trusted adviser

Key Learnings – Stedin Group

- Netherlands has passed the tipping point, seeing grid congestion from EV / solar PV
- Stedin has taken strong ownership over energy transition, prioritizing improved grid management and sustainable business operation
- Launched an extensive change office (150 employees) and actively engaging regulators to shift from a CAPEX to TOTEX model
- Stedin is focused on active system management, pricing and billing mechanisms and scaling a trading platform

Key Learnings – Netze BW

- Since Germany has several hundred DSOs/distribution utilities, a Total DSO model to manage flexibility services at local levels is considered to be a suitable solution
- NBW has a Network Development Plan for the transmission system operators to align with DSO needs
- NBW is planning to make its grid future-proof with intelligent solutions and expand its electricity grid. NBW uses a scenario framework of the overarching network development plan of the transmission system operators (NEP) to identify trends and forecasts for customer needs.

The quotes were taken directly from the DSO meetings

Wavespace Workshops “DSO Around the World” Purpose

EY facilitated wavespace workshops to share the research findings, educate 25+ Alectra stakeholders, and incite a meaningful conversation around the organizational DSO future. The sessions had a common key question, but unique objectives:

Key Workshop Question:

*“**How might we think** about a potential DSO model, based on what leading jurisdictions are doing in light of the energy transition, **so that we can** position ourselves as a leader in Ontario?”*

December 9th, 2022

SCAN

- ✓ Expanded our thinking and understood evolving DSO models, functions, and attributes in other jurisdictions across the globe
- ✓ Discovered what other jurisdictions and utilities are doing to prepare for the changing energy ecosystem
- ✓ Gained perspectives on DSOs of interest to help drive the next phase of the research study and wavespace FOCUS workshop

January 19th, 2023

FOCUS

- ✓ Reflected on DSOs around the world covered during the SCAN session
- ✓ Focused on DSO shortlist (top three case studies) to better understand their journeys, market and regulatory backdrops, capabilities and operational elements
- ✓ Unpacked shortlisted DSOs for Alectra against Ontario market, regulatory, and technical contexts to begin alignment with Alectra’s future DSO vision

Potential Future Scope TBD

ACT

- ✓ Leverage SCAN+FOCUS findings and EY’s DSO framework to assess Alectra’s current state, strategic alignment, and feasibility for a DSO model
- ✓ Explore viability for Alectra to pursue a DSO model
- ✓ Assess key capabilities needed for DSO implementations
- ✓ Understand investment levels and timelines required to reach a DSO future

Legend Completed SCAN + Focus Activities | Outstanding ACT Future Activities

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Wavespace Workshops “DSO Around the World” Key Learnings

During the sessions, the attendees listened to six different Subject Matter Advisors (SMAs) across the globe to further their understanding of the select DSOs covered in the research phase and yielded the following key learnings:

Workshop 1: SCAN (Wide Review of DSOs)

[redacted]

DSO Definition and a Point of View on the “Case for Change”

Australia’s DSO Journey: Western Power Case Study

Irish DSO Journey: ESB Network Case Study

California’s DSO Transition: PG&E Case Study

UKPN DSO Journey

Key Learnings

1. **There is no blueprint or one-size fits all mode**: each jurisdiction is influenced by its own policies, dynamics, regulations, and technologies that drive DSO model development.
2. **DSO development is still nascent**: even the most advanced utilities are still facing T&D coordination, commercial framework, regulatory allowance, and pricing issues.
3. **Pilot studies are critical to the DSO pursuit**: utilities are driving DSO development and advocacy through pilots to test key DSO functionalities, which are often funded via mixed sources (e.g., innovation allowances, grants, etc.)
4. **Regulation is both an opportunity and a barrier**: DSOs engage regulators to create favourable conditions and funding opportunities, while avoiding risks and policy barriers.
5. **DSO pursuit is a marathon, not a sprint**: DSO journey can take years to decades. For instance, UKPN started their journey in 2010 and are still in the process of a creating an established DSO.

Workshop 2: FOCUS (Shortlisted DSOs)

WP’s DSO Journey, ‘Climate Wars’, and Hybrid DSO

Irish DSO Preparing for Unprecedented DER Penetration

UKPN Journey to Become a World Leading DSO

Key Learnings

1. **The customer is at the DSO core**: despite tendencies to view DSO as a technical pursuit, customer is the driving force.
2. **Expect transformational challenges**: Alectra will need to tackle a fragmented Ontario market and low alignment for the transition.
3. **Focus on “no-regret moves”:** align on vision, build business cases, demonstrate capabilities, and collaborate with partners.
4. **Build quantifiable, yet iterative evidence**: risk is inherent and advocacy efforts based on evolving evidence are needed.
5. **A DSO is a journey, not a destination**: DSOs must navigate through complexity and ambiguity with an innovative mindset.

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06

DSO Considerations in Ontario

DSO model relevance to the provincial context, including value propositioning and regulatory.

Ontario Electricity Market Snapshot

The provincial electricity market is a centrally planned and highly complex environment with fragmented distribution systems. The IESO has proposed some DSO consideration, but clear regulatory direction on the topic is still absent.

Highly fragmented distribution market with **57 Limited Distribution Companies (LDCs)**

Diverse electricity generation **59% Nuclear, 24% Hydro, 8% Wind, 7% Natural Gas, 1% Solar, 1% Biomass, and 0.3% Petroleum**

With an expected high degree of electrification and nuclear refurbishment, **potential supply shortfall is anticipated by 2026**

Central	Eastern	Western	Northern
Hydro One	Hydro Ottawa	Bluewater Power Distribution Corporation	Greater Sudbury Hydro
Alectra Utilities	Kingston Hydro	London Hydro	Fort Frances Power Corporation
Toronto Hydro	Hydro 2000 Inc.	E.L.K. Energy Inc.	Hearst Power Distribution Company Ltd.

Note: this is an illustrative list of sample utilities in Ontario showcased by approximate geographies.

MARKET CHANGES & REGULATORY TRENDS

Net-Zero Aspirations
The provincial and federal governments have both made commitments to achieve net-zero emissions by 2050.

Clean Electricity System and Vehicle Sales by 2035
The federal government (Clean Electricity Regulations) and IESO (Pathways to Decarbonization) have proposed policies and approaches to develop a decarbonized electricity system in Ontario by 2035. Similarly, Canada will require 100% of car and passenger truck sales to be zero-emissions by the same year.

Electricity Generation Uncertainty
The Ontario government has announced plans to refurbish and extend the life of some of the province's nuclear power plants in order to ensure the continuity of supply, while also addressing expiring generation contracts.

High DER Future Prediction
In June 2019, IESO published the Structural Options for Ontario's Electricity System in a High-DER Future report, recognizing the electricity market disruption caused by current and future DER adoption rates in the province.

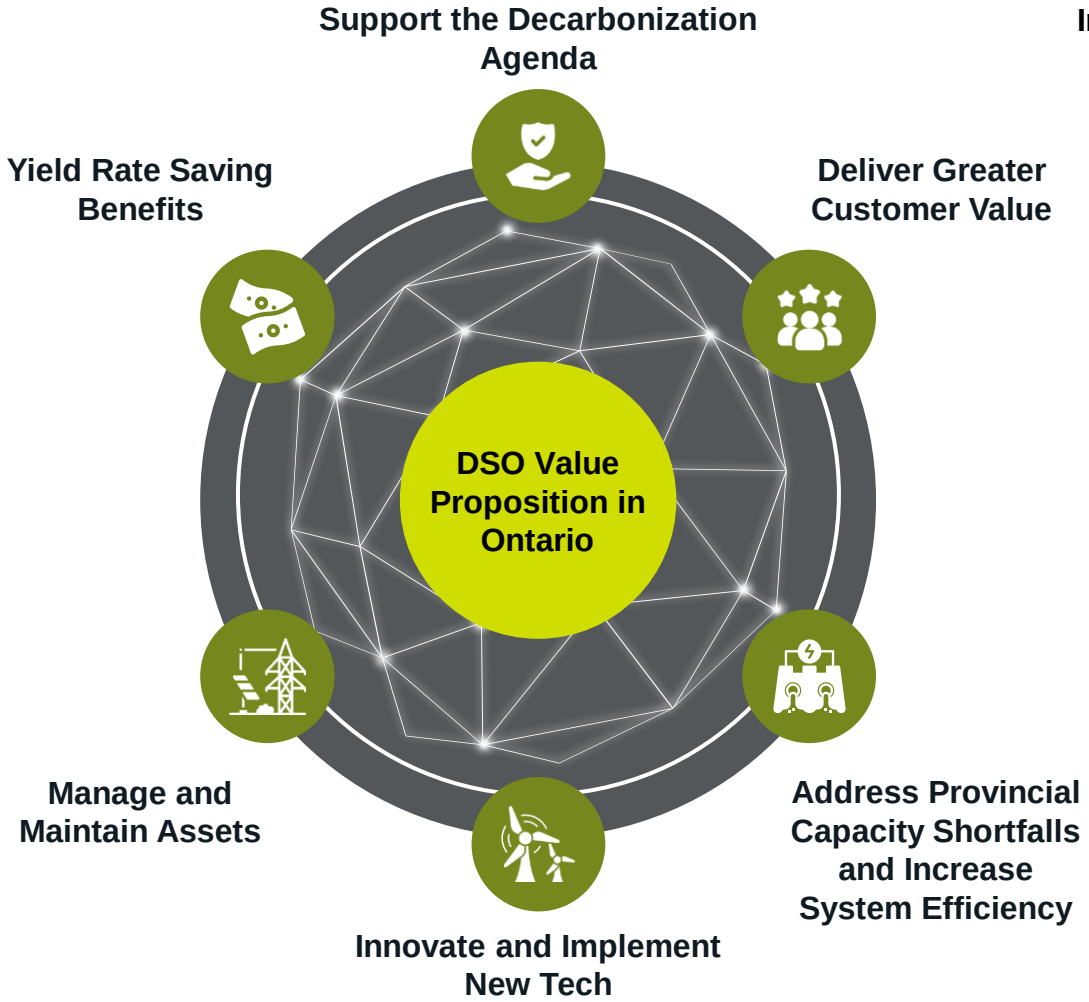
DSO Model Consideration in Ontario
In December 2021, ETNO identified the DSO structure as suitable to directly address the near-term challenges of effectively integrating high volumes of DERs at the distribution level via a creation of local markets (energy, capacity, ancillary).

Limited DSO Model Direction or Clarity
Although OEB helped utilities invest in transmission and distribution system upgrades via rate applications to accommodate the increased use of renewable energy, the regulator is yet to publish its stance on the DSO model pursuit.

1 **Source:** EY Knowledge, EY Report Future of DSOs, ENA DSO Transition, EDA, NRCan Provincial and Territorial Energy Profiles - Ontario, IESO APO, various articles from market operators and regulators

DSO Value Proposition in Ontario

Based on the current state of the Ontario electricity market, a DSO model consideration would bring the following value proposition to system stakeholders. The six proposed benefits could lay the foundation of a future business case.



Important

Support the Decarbonization Agenda

Play a key role in supporting the provincial drive to achieve a cleaner, more sustainable energy system by 2050 through addressing operational challenges of electrification and DER adoption.

Deliver Greater Customer Value

Support customers by improving behind-the-meter, DER, and other services to help them proactively participate in the energy market and manage their assets more effectively.

Address Provincial Capacity Shortfalls and Increase System Efficiency

Increase the share of renewable electricity generation by residential and commercial customers to address the incoming electricity generation shortfalls, while enhancing productivity of asset use.

Innovate and Implement New Tech

Design, build, and pilot new technologies to enable the grid of the future in the digital age.

Manage and Maintain Assets

Continue operating a reliable distribution system by making proactive and planned investments into the grid of the future.

Yield Rate Saving Benefits

Potentially save capital from rate applications by avoiding large distribution infrastructure upgrades via more cost-effective DER asset integrations and technologies.

Tertiary

 Source: EY Report Future of DSOs, EDA The Power to Connect

DSO Value Proposition for Alectra

In addition to the system wide DSO value proposition, Alectra could also yield four specific benefits to its business. The following insights were collected at EY wavespace workshops: “DSO Around the World”.

01 Facilitate the Prosumer Market

The value lies in…

- Enabling consumer’s ability to proactively participate in the energy market and manage their assets more effectively
- Providing consumers with energy options and choices
- Providing DSO services for other LDCs

02 Transform & Stay Relevant

The value lies in…

- Reinventing our value proposition to our customers
- Proactively morphing our business to stay relevant for our customers
- Aligning customer needs to Alectra’s overall strategy

03 Maintain Operational Effectiveness

The value lies in…

- The ability to continue operating a reliable distribution system
- Managing the changing landscape at the lowest cost for customers while maintaining viability of the LDC
- Maximizing DER value to provide grid services

04 Generate New Revenue

The value lies in…

- Accelerating the energy transition and generating new revenue streams
- Generating new revenue, while adapting to a changing landscape to stay relevant

“We can help the economic outlook and development. ***We can really set the next generation for success and shape the future***”

“This is not a risk free investment. Given that this is innovation-related, we need to ***accept that a certain level of risk is unavoidable***”

Note: from an EY perspective, “Maintaining Operational Effectiveness” is also about ensuring resiliency in the system and security of supply. Alectra could also consider three additional value propositions:

1. **Provide Cost Effective Solutions to Customers**
2. **Enhance Brand Perception**
3. **Facilitate Net-Zero and ESG Goal Achievement**

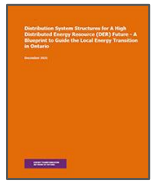
EY wavespace workshop participant quotes: “DSO Around the World”

The DSO Position in Ontario To Date

While Ontario does not have a clear DSO direction yet, recent thought leadership from government and market stakeholders is showing signs of a stronger sector alignment and a ripening environment for LDCs to take a more definitive DSO position.

01 ETNO High DER Future Report #1 Jun., 2019

ETNO identified four model options for enabling high-DER integration whilst maximizing technical and economic value: CCA, FINO, DSO and LSE. Both LSE and DSO were selected for further analysis.

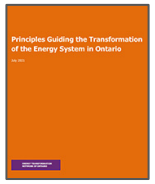


02 OEB IESO Grid Innovation Fund Jun. 22, 2021

OEB and IESO launched a partnership between the IESO's Grid Innovation Fund and OEB's Innovation Sandbox to support pilot projects seeking to test how to derive value from distributed energy resources.

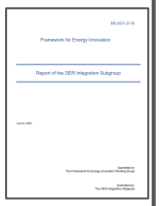
03 ETNO High DER Future Report #2 Jul., 2021

ETNO assessed various models for Ontario's high-DER future, recommending that DSO models could enable an integration of DERs to maximize their values to ratepayers. ETNO viewed LDCs as well positioned to take on the DSO roles.



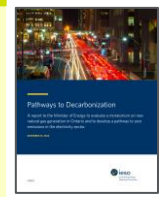
04 OEB DER Integration Subgroup Report Jun. 8, 2022

The Framework for Energy Innovation Working Group (FEIWG) established the DER Integration (DERI) Subgroup to identify how DER distributors could plan and operate their systems more effectively.



05 IESO Pathways to Decarbonization Dec. 15, 2022

IESO published a report to respond to the Minister of Energy's request to evaluate the moratorium on new generation fueled by natural gas, and to develop a pathway to decarbonization. DSO was not mentioned, but the focus was placed on innovation and breaking regulatory barriers.

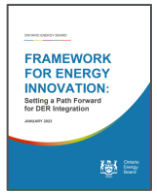


06 NRCan RFI Canada's Electricity Grid Modernization, 2023

NRCan is seeking input regarding the regulatory, policy, and market barriers and opportunities for accelerating the pace of electrification and electricity grid modernization to meet the net-zero goals.

07 OEB Framework for Energy Innovation Jan. 30, 2023

OEB issued a report to "Set a Path Froward for DER Integration" in Ontario by describing policy determinations and next steps. OEB expects LDCs to begin evolving planning and operations to cost-effectively integrate DERs, and use them to meet system meets.



Note: each report image has a hyperlink.

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DSO Regulatory Requirements for Ontario

A supportive regulatory environment is critical to materializing the DSO transformation. There are five primary regulatory requirements that could help the Ontario electricity market adopt DSO market models.

Based on the key learnings from other jurisdictions, EY DSO perspectives, and wavespace workshops, the **following five regulatory requirements are necessary for DSO advancement in Ontario:**

Req. I: Recognition of the DSO Application in Ontario

The regulator must have a clear commitment to pursuing a DSO model. OEB should be able to explain the DSO role, application, model evolution, and alignment with TSO to express its certainty over the electricity market model future.

For example, Ofgem's DSO: Our Approach and Regulatory Priorities.

Req. II: Identification of Wider Stakeholder Roles

The regulator needs to define the roles played by the various stakeholders and develop an environment where all users could contribute to the network development and cost sharing fairly.

For example, US Federal Energy Regulatory Commission's (FERC) Order 2222.

Req. III: Provision of Incentives for Innovation

The regulator should support LDCs' investments in emerging technologies and solutions that deploy DERs, batteries, EVs, etc. Those incentives should apply to both CAPEX and OPEX, acknowledging the spending requirements.

For example, Irish Better Energy Communities Scheme.

Req. IV: Optimization of Risk Allocation

The regulator must recognize that inherent risks in emerging technologies, should be accepted. However, those risks should not cause unreasonable doubt of innovation initiatives, as some costs will be innately irrecoverable and valuable over the long-term.

For example, Western Australia's Cost-Benefit Analysis that included public inputs and consultations.

Req. V: Enablement of Standards and Models

The regulator needs to encourage customers and market participants to collaborate and apply consistent techniques, mechanisms, and data applications to fully engage in new market activities, and avoid information siloes.

For example, Joint Utilities of New York initiative to collaborate and coordinate efforts on achieving DSP models.

"There is some talk from the government and IESO on the DSO space. Maybe we can influence them to find a slice of spending on DERs and other related technologies."

Wavespace Workshop Participant

 Source: EY Report Future of DSOs and EY wavespace workshops

DSO Market Model Considerations for Ontario

Ontario's unique market environment could accommodate and integrate most of the DSO market models, including a Total TSO, Hybrid DSO, or a Total DSO. Alectra will need to assess and pursue a select model in the future if desired.

Total TSO

Definition

Total TSO model has visibility over the entire transmission and distribution system and is responsible for real time, reliable operation of the transmission-distribution system, interconnection, and planning for the combined system infrastructure.

PG&E in California, USA

California's current coordination structure is closer to a Total TSO model, whereby CAISO oversees the market and distribution utilities play a minimal role. California is framing rules and regulations to connect DERs at the distribution level, while PG&E is responsible for managing local energy markets.

Ontario Relevance – Possible

This model could be possible in Ontario, whereby Hydro One has a natural monopoly over the transmission business and are most suitable for this role. IESO will need to manage DER integration at wholesale levels.

Hybrid DSO

Definition

Hybrid DSO is a model where TSO and DSO take shared responsibility of the network and work together to resolve system issues. It requires complex communication between transmission and distribution system operators, and 3rd party DER aggregators.

Western Power in Australia

Western Australia decided to pursue a Hybrid DSO model on the basis of the results from the Open Energy Networks Project. Western Power is piloting Project Symphony to test capabilities of a Virtual Power Plan (VPP) and feeding the data to AEMO (market operator) for further bulk power market management.

Ontario Relevance – Possible

This model is possible in Ontario, due to the current structure and the importance of IESO and Hydro One. However, the Hybrid approach would require significantly more T&D coordination and investment, due to the current IESO constraints. LDCs will need to tackle scalability challenges to successfully operate in the Ontario market structure.

Total DSO

Definition

Total DSO model is an approach, where all, or a subset of resources, e.g., 10MW, are connected to the distribution level, participate in transmission markets, and orchestrated via a DSO to enable interactions between DERs and TSOs.

Netze BW in Germany

Germany pursues a Total DSO model. Trading on the liberalized wholesale market is either carried out over the counter or via the European Energy Exchange (EEX). NBW is able to manage and aggregate DERs, plan and dispatch the gathered bulk power within its territory.

Ontario Relevance – Possible

Total DSO approach, though possible, would be complex to implement at scale in Ontario as currently there are 60+ LDCs. Not every LDC will be equipped to conduct the relevant infrastructure upgrades and handle the burden of whole system coordination at scale. However, it could offer a more straightforward path to a DSO than Hybrid (NWA Alectra pilot).

Independent DSO

Definition

Independent DSO work with distribution utilities to optimize the dispatch of the DER based upon local system constraints that are provided by the network business. The latter provide the aggregated bids to ISO for incorporation into the larger dispatch.

UKPN in the UK

UKPN has laid out its plans to establish the first ever independent DSO by the start of ED2 in April 2023. An independent market platform could ultimately simplify participation for Flexibility Service Providers (FSPs) and enable joint procurement. Such approach should improve transparency and coordination.

Ontario Relevance – Not Applicable

This model is less relevant to the current Ontario structure. An establishment of a new independent legal entity from an existing LDC and for DER aggregation and dispatch purposes could be overly costly and operationally challenging.

Note: EY and Alectra haven't conducted a full assessment on specifying which DSO model is most feasible in Ontario (out of scope). These are initial considerations.

DSO Market Model Ontario Relevance Explained

The relevance showcased on the previous slide was evaluated based on the market dynamics and inherent model benefits and shortcomings, as well as DER ownership and dispatch.

Criteria	Total TSO	Hybrid DSO	Total DSO	Independent DSO
Model Benefits	Total TSO entails a TSO being able to use systems modelling on distribution circuits and DER mappings at their actual locations on the distribution system. This model is most suitable for jurisdictions with a strong TSO/ISO backbone.	Hybrid DSO removes hidden coupling by permitting both DSO and TSO to share coordination and control signals through a new TSO/DSO interface. Both transmission and distribution operators synchronize and take on a shared active role in operating the grid.	Responsibilities of DSO align with asset ownership boundary, leading to reduced resource contention and ambiguity of control. Could drive different approaches and innovation across DSOs. DSOs are more responsive with locally specific solutions and provide innovative localized customer value propositions from local suppliers.	IDSO coordinates closely with the T&D system, potentially better managing infrastructure losses and voltage controls. IDSO easily aggregates information to ensure better visibility of the entire grid in system operations. Potentially increased visibility regarding conditions of the system and DER use to enhance market efficiency and reliability.
Model Shortcomings	Total TSO could be challenging to implement. The model ignores the physical power flow over the distribution system and tries to manage everything centrally. This model creates scalability concerns for replicating the coordination framework between the TSO and DSO at the T-D interface to other levels of the system	Hybrid DSO is complex in structure. The model creates a delineation of roles/responsibilities, which is manageable at lower levels of DER markets and network services, but also faces scalability issues as DER participation grows. The presence of the direct aggregator-to-TSO connection presents a moderate cyber security vulnerability to the bulk energy system.	As in the UK (although the country does not follow a Total DSO model), regulation will be required to standardize the approach across DSOs, so that national customers and retailers can operate fairly across the market. DNOs would need to adapt their roles to market facilitators on a real-time basis. Cyber vulnerability of the bulk energy system, due to DER connectivity, is relatively small.	IDSO is complex and costly to establish (each DSO as IDSO). Similarly, defining roles and responsibilities is also a challenge. Seamless interfaces between the IDSO and DNSP for exchanging network status and distribution network constraints for co-optimization of resources can be complex and investment intensive to achieve.
DER Ownership & Dispatch	In principle, DERs can be utility owned, customer owned or third-party owned. However, a TSO will optimize the whole system, with visibility of distribution grid conditions and all DERs above a low size threshold.	Both DSOs/TSOs play a role in coordinating DER services and operations. TSO dispatches wholesale DERs, while the DSO dispatches DERs at the distribution level and coordinates with TSO on all DER dispatch. Customers or third-parties can own them.	In principle, DERs can be utility owned, customer owned or third party owned. However, DSO controls the whole system and ensures system security by directly controlling the resources of the aggregator. The DSO will be dispatching DERs.	Ownership can lay with customers, third party aggregators or utilities depending on local regulatory frameworks. A DSO will dispatch DERs based on local network constraints and provide aggregated bids to the centralized markets operated by ISO.

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07

Getting to a Viable DSO

Understanding the potential future journey for Alectra and a high-level DSO roadmap.

Transformational Challenge Ahead

The DNO to DSO transition is a significant transformation that requires several enhanced and novel capabilities. Our global DSO scan illustrated a high-level DSO capabilities framework and roadmap for Alectra to consider on their own journey.

Integrated Planning

Identification and planning of capacity requirements, coordinating decisions with RTOs/ISOs, granular DER forecasting

- Develop better tools for identifying & planning capacity requirements
- Ensure T&D coordination
- Forecast bottom-up to account for tech diffusion and customer adoption

Asset Management

Real-time monitoring of network performance, predictive maintenance analytics

- Manage assets in real time with remotely sensed data, weather analytics & drones
- Monitor remotely and apply weather analytics for more accurate forecasting

System Management

Greater data and analytics to study and control system configuration in real time, remote sensing and drone technologies

- Upskill the workforce to install new network assets (e.g., EV connections)
- Facilitate work flow management
- Use automation to improve supply chain and contract management, and vendor selection

Systems Operations

Visibility and control of power flows, loads and connections at the distribution level, integration of full DERMS/ADMS

- Integrate demand response (DR) and DERMS with ADMS
- Roll out ADMS, whereby DR and DERMS (need a phased approach for regulatory compliance) are implemented over time

Flexibility Management

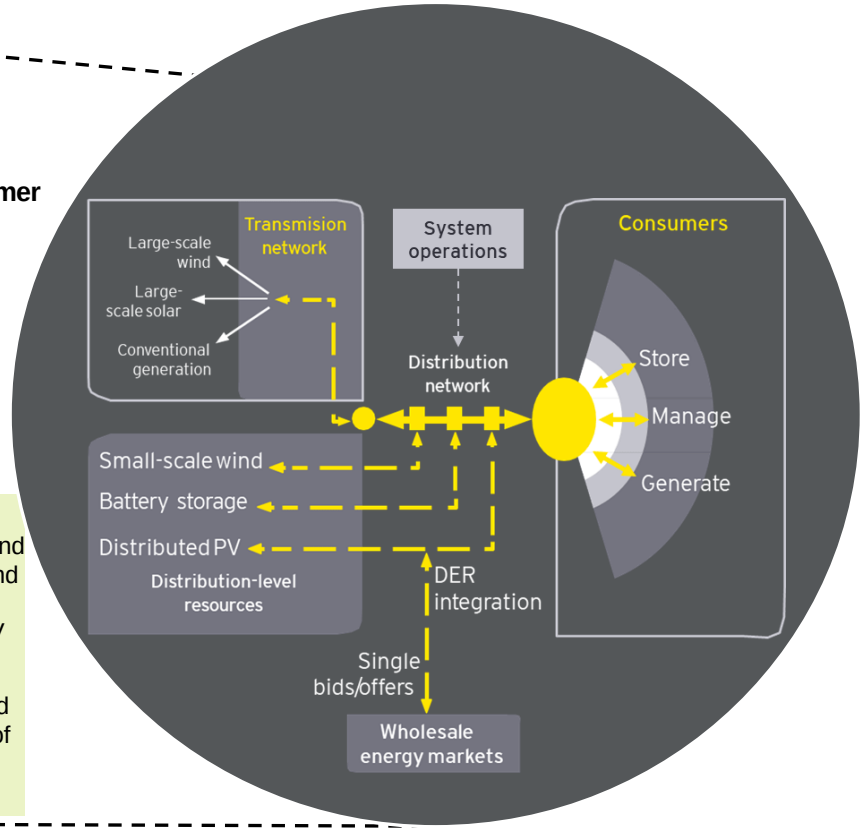
Platforms for procuring flexibility services, dynamic market pricing, incentives for non-wires solutions

- Introduce new market frameworks for ancillary services in coordination with TSOs
- Provide independent market facilitation services (e.g., platforms)

Commercial Operations/Customer Management

Commercial frameworks and digital information channels for flexibility services and new behind-the-meter services

- Develop go-to-market products and services that extend beyond the meter (e.g., batteries, EV infrastructure)
- Manage DERs and the demand side of customer management



Source: EY Knowledge. EY Report Future of DSOs

Legend Enhanced Capabilities | New Capabilities | Examples

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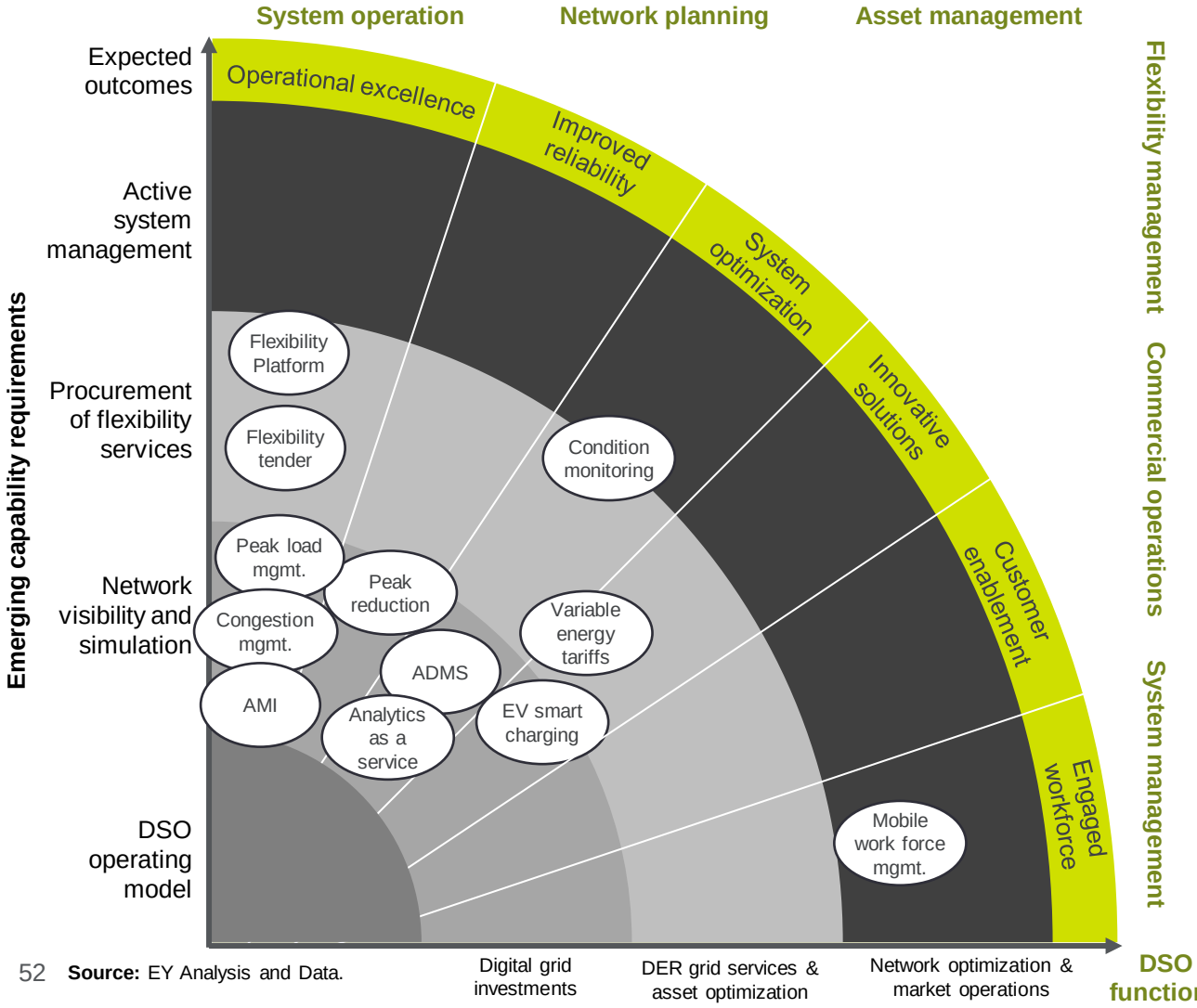
Sample Initiatives from Aspiring DSOs

DNOs across the globe have begun to invest in these capabilities and initiatives with focus on making the grid robust, resilient, and intelligent to accommodate DER increases and leveraging digital grid solutions for network automation and control.



Flexibility tender	UK	UK's first open tender for flexibility services to deliver net reduction in load or increase in export
Flexibility Platform	UK	Piclo Flex online platform for all types of DSO flexibility tenders
Congestion mgmt.	Germany	EPEX SPOT local flexibility market, an open and voluntary market-based congestion management platform
Congestion mgmt.	Netherlands	Electricity Trading Platform Amsterdam (ETPA) congestion management platform
Condition monitoring	US	System-wide Asset Health Centre (AHC). An analytics platform that predicts asset performance and determines action to extend asset lifetime
ADMS	US	Integrates outage management, distribution management system, the SCADA system and GIS to "a single truth"
Smart EV charging	Netherlands	ICT application, enables consumers to charge their batteries at any time, without overloading the grid
Analytics as a service	Italy	Smart grid analytics solution that enables predictive grid maintenance and advanced power fraud detection
Mobile work force mgmt.	Italy	Redesigning operations of field engineers leveraging mobile technology and processes automation
Peak reduction	Australia	Manage peak demand as an alternative solution to build generation and network infrastructure
Peak load mgmt.	Norway	NODES initiative is being implemented in Norway for peak load management
Variable energy tariffs	Netherlands	Consumers use a smart energy contract to pay hourly prices for their electricity and daily prices for their gas

Source: EY Analysis and Data.

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Conceptual Example of a DSO Grid Architecture

From a grid architecture approach, DNOs can drive a bottom-up system redesign to build a technology-enabled distributed grid with capabilities to support a growing number of DERs and variable loads, reduce risks, and capture more opportunities.

The evolution will enable whole system benefits, including:

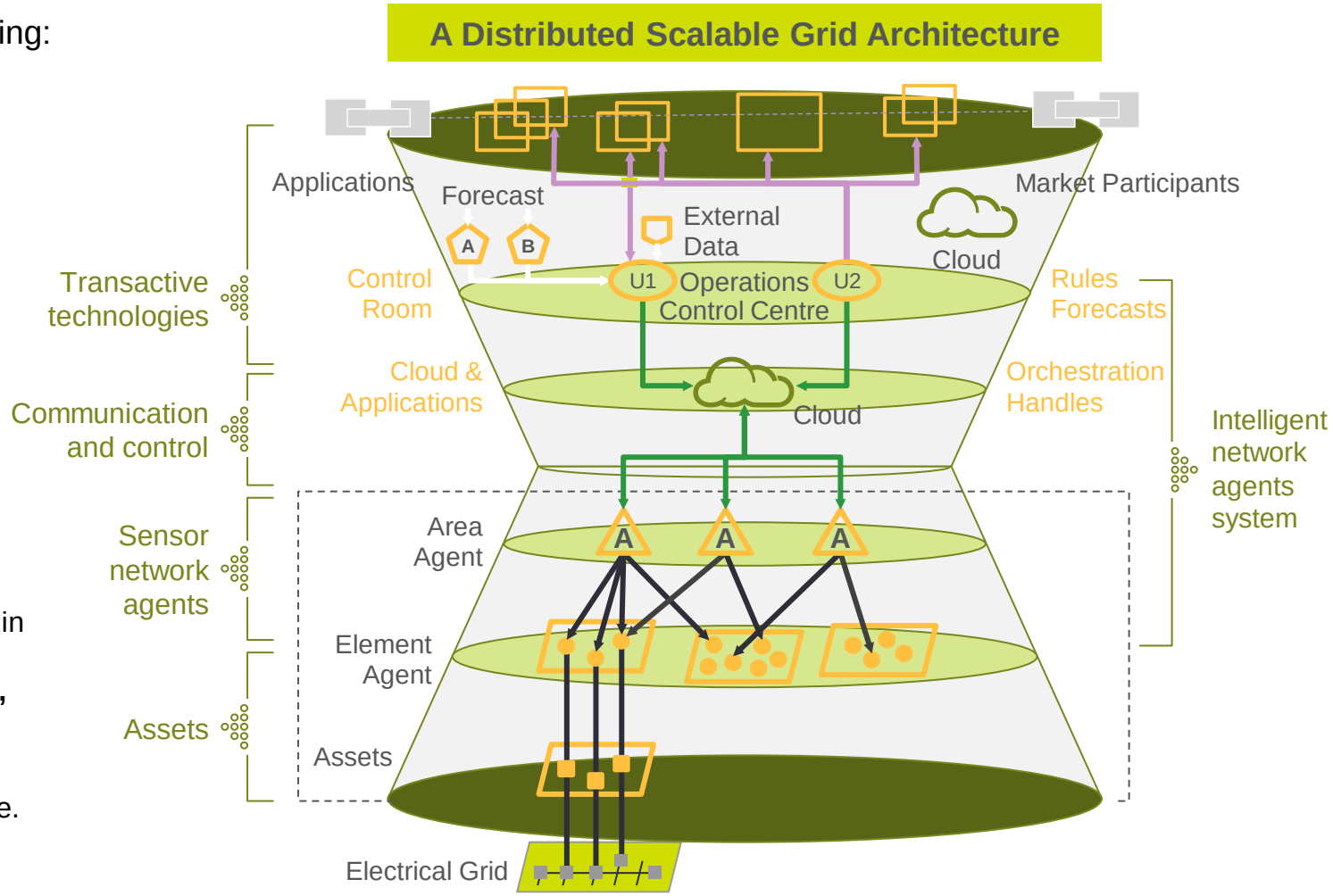
Achieve power reliability at the distribution level by managing the optimization and aggregation of local DERs.

Streamline DER participation in wholesale markets, by aggregating excess supply or demand into single bids, to balance local reliability needs.

Provide visibility and guidance to DER owners on how to avoid conflicts with local reliability needs when providing services.

The proactive approach to designing the future grid helps DNOs in not only planning for the required transformation, but also in ultimately **shaping the market according to their preferences, priorities, and capabilities** in light of the energy transition.

The early steps include **pilots and the identification of key building blocks** to accomplish a clear vision of the final outcome. As such, utilities **reduce transformational risks and have a greater chance at capturing key DSO opportunities.**



 Source: EY Knowledge

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DSO Grid Architecture at a Platform Level

By taking a closer look at a platform level, aspiring DSOs need to make proactive investments in innovative technologies and system designs to establish new operating markets and build operational controls, as well as transformational capabilities.

From an EY perspective, an **integrated operational platform** (real-time network model, single database, and central OT/IT integration point) is going to be needed by utilities to handle the DSO future.

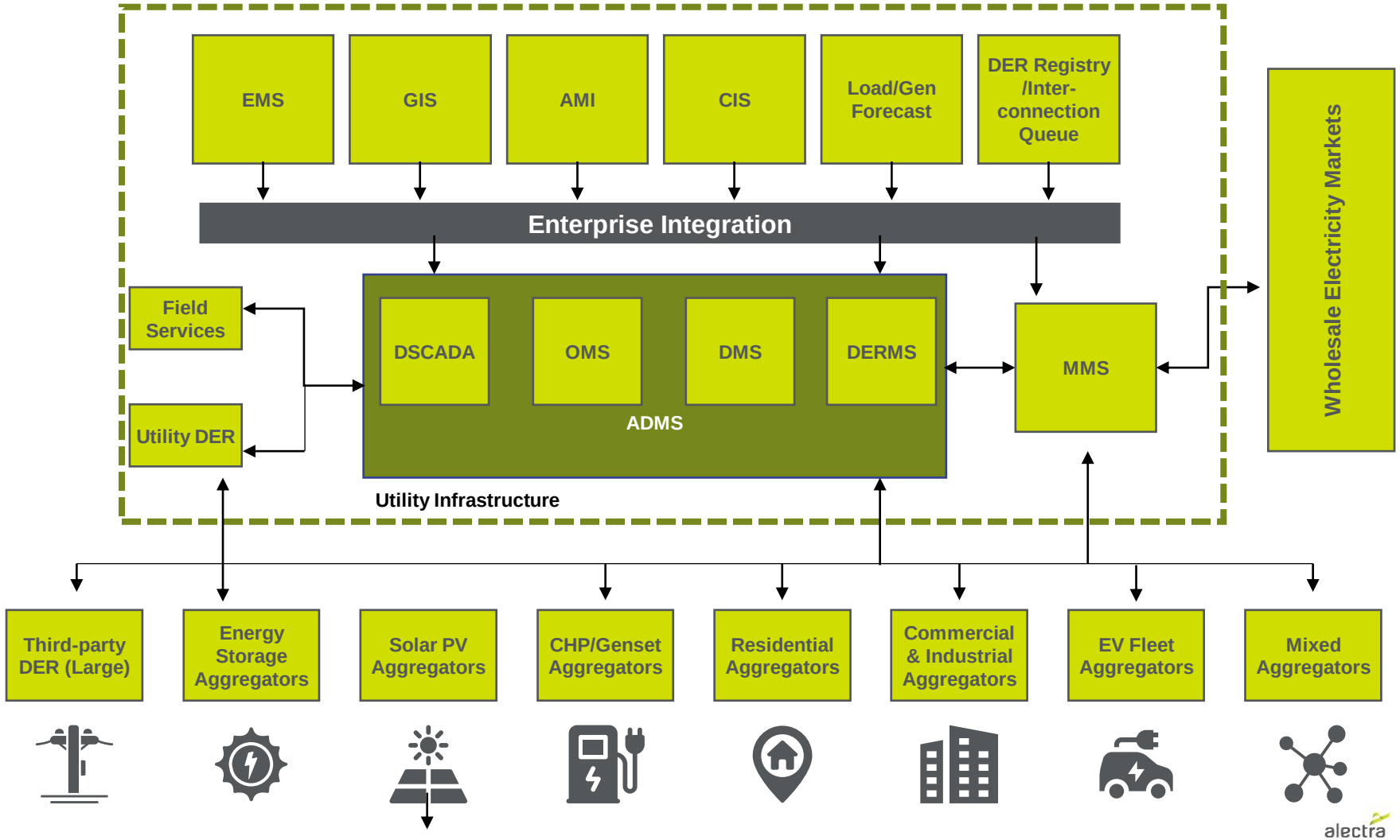
This is a sample DSO grid architecture that highlights the **complexity of the future system and the need for innovation investments**.

Some of the key objectives of this platform are to ensure a high degree of **usability, efficiency, and safety**.

The platform covers:

- Existing, traditional core operational capabilities (SCADA, OMS)
- Additions of new mature capabilities (DMS)
- Innovative product capabilities (DERMS)
- Ancillary benefits (FLISR, etc.,)

Similar grid architecture designs are **stable foundations** to innovation and future DSO developments in any jurisdiction.



 Source: EY Knowledge. EY Report Future of DSOs

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DSO People, Process, and Technology and Data Action Considerations

Based on EY DSO experience and thought leadership, the following people, process, and technology and data action considerations will help Alectra in transitioning towards a DSO. All of those elements are fundamental DSO strategy pieces.

Action Considerations

- **People**
- **Process**
- **Technology and Data**

Internal DSO Vision Alignment

Successful DSO advancement requires a strong vision alignment between the internal stakeholders. Senior leadership must have a common understanding of the required transformation, goals, risks, and benefits of a select DSO pursuit.

Internal Roles and Responsibilities

Internal stakeholders must clearly understand the sequential and gated decision-making processes of advancing a DSO model and relevant developmental pieces. They should also know how their contribution may help the organization in this transformation over time.

Innovative and Transformational Culture

Utilities need to further advance their innovative and transformational cultures to encourage exploration of new technologies and processes. DSO models are still somewhat unclear and uncertain, so accepting a certain degree of risk should be fundamental.

Employee Training

As novel processes and technologies are adopted, employees naturally identify some skillset and knowledge gaps. Thus, they should have appropriate training modules to prepare them for working with the DSO of the future.

Change Management Strategy

Fundamental shifts, caused by a DSO transition, will require an appropriate change management strategy to avoid information siloes and unforeseen risk exposures, while encouraging stakeholder buy-ins and accountability.

Scenario Planning

Aspiring DSOs need to conduct scenario planning exercises on various topics, including DER adoption rates and changing policy environments, to develop more accurate and risk considerate DSO transition plans.

Source: EY Knowledge. EY Report Future of DSOs

DSO People, Process, and Technology and Data Action Considerations

In total, there are 12 primary action considerations. However, due to the continuously evolving DSO space, the organization needs to also recognize that more prerequisites could emerge throughout its DSO journey.

Action Considerations

- **People**
- **Process**
- **Technology and Data**

Stakeholder Engagement Plan

DSO pursuit efforts could benefit from stakeholder engagements, such as customer interviews, regulatory and other LDC conversations, to further inform organizational efforts and design more wholesome strategic plans.

Data Gathering and Management Standards

As more pilots and different technologies get deployed, utilities need consistent data gathering and management standards to ensure relevant data integrity and comparability, as well as analytical accuracy.

DER Monitoring Capabilities

Since an accelerated DER adoption growth is expected in Ontario and other jurisdictions, DSOs must have relevant grid monitoring and operational capabilities to track the uptake, plan accordingly, and maintain system reliability.

Flexible Solution Integration

In order to provide customer centricity and enable their choices, utilities develop and apply technologies to integrate flexible solutions. DERs, such as EVs, will be critical for the future grid and the DSO role in Ontario.

Pilots and Case Studies

Utilities satisfy and enable customer needs by testing pilots and case studies, while avoiding large scale investment risks. The end results and key learnings are used for further data analyses and construction of new business cases.

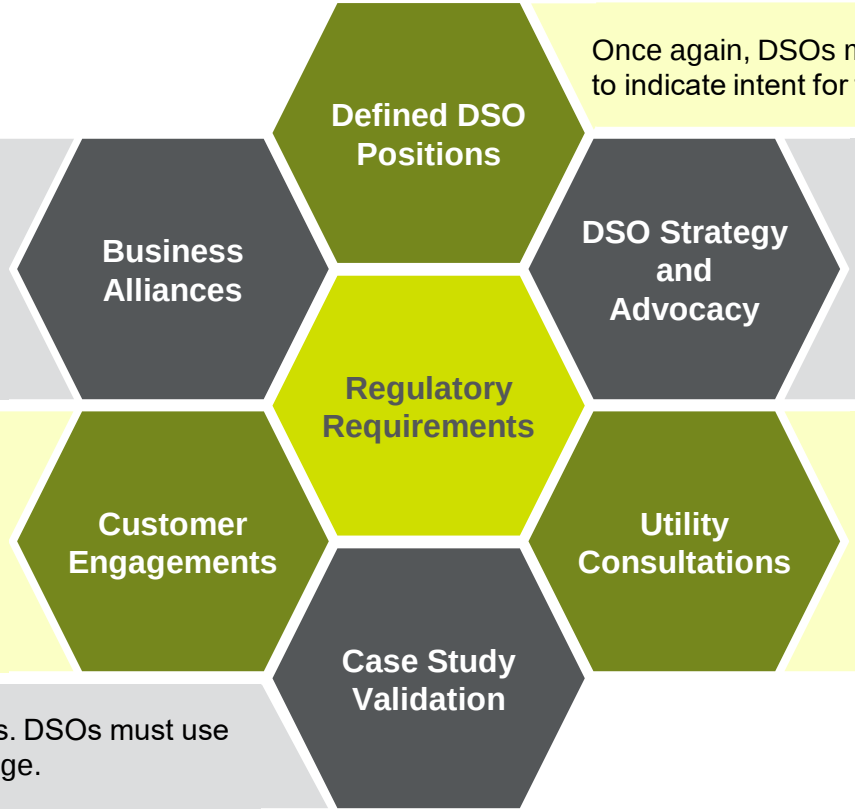
Advanced Security Measures

Cyber defenses are critical to DSO transition efforts by addressing the evolving digital threats and risks of more open systems. Customer and proprietary data must be protected to avoid public scrutiny and potential lawsuits.

 Source: EY Knowledge. EY Report Future of DSOs

DSO Regulatory Action Considerations

Regulatory alignment is going to be important for Alectra's DSO journey. Hence, the organization needs to also take into account these six action considerations for enabling a supportive regulatory environment observed in other jurisdictions.



Once again, DSOs must have a defined and internally aligned DSO positions to indicate intent for the future transition and the description of the "why".

DSO transition will require partnerships and collaboration with industry stakeholders and vendors.

Utilities must identify prospective business alliances to speed up DSO model transitions in their respective markets and showcase viability/proofs of concept to the regulators.

Utilities must build their own DSO strategies, based on the local context and key roadmaps from other jurisdictions, with notable key steps.

The strategy will push the regulators to consider a DSO model in greater detail and allow those utilities to advocate and champion for change.

Utilities must tap into customer engagements and utilize testimonies/data to demonstrate the DSO value, including customer choice enablement, potential investment deferral, etc.

The insights help utilities in crafting and backing their value propositioning messages for the regulators.

DSOs must gather as much knowledge as possible from other provincial, national, and global LDCs and DSOs to learn from their experiences, successes, and mistakes.

Earlier discussions with SPEN and Stedin have showcased the value of collaboration in this highly innovative and evolving space.

The regulators want to see "proven" and quantified results. DSOs must use pilots, gather data, and then build credible cases for change.

"*We have to put a case forward as to why we are doing this and why this is good for our customers.* ***We should answer the hard questions before they even ask them****".*

"*The regulator* ***wants to know****: how to align 60+ LDCs; how to resolve conflicts of interest, how to avoid and integrate stranded assets; and how to protect customer needs in light of new costs?".*

"***Perhaps its our job to answer their questions****… We need to convince them that this is* ***just the beginning*** *of the DSO journey and* ***Alectra is not alone****".*

EY wavespace workshop participant quotes: "DSO Around the World"

 Source: EY Knowledge. EY Report Future of DSOs

High-Level DSO Roadmap

The combined action considerations can be aggregated into a high-level DSO roadmap with four core stages discovered throughout the research study and workshops. Successful DSOs ensure that each stage is conducted in great detail.

Stage 1: Internal Alignment

Socialize the key findings of the research study, develop a DSO position, and align on any outstanding issues:

People – Internal DSO Vision Alignment, Internal Roles and Responsibilities
Process – Internal Stakeholder Engagement, Current State Assessment
Technology and Data – Review Pilots In Flight and Data Strategy
Regulatory – Defined DSO Position, DSO Strategy and Advocacy

Stage 2: DSO Strategizing

Develop a DSO strategy, clarify the necessary steps, and allocate roles and responsibilities:

People – Innovative and Transformational Culture, Employee Training
Process – Change Management Strategy, Scenario Planning, Stakeholder Engagement Plan
Technology and Data – DER Monitoring Capabilities
Regulatory – Utility Consultations

Stage 3: Strategy Launch

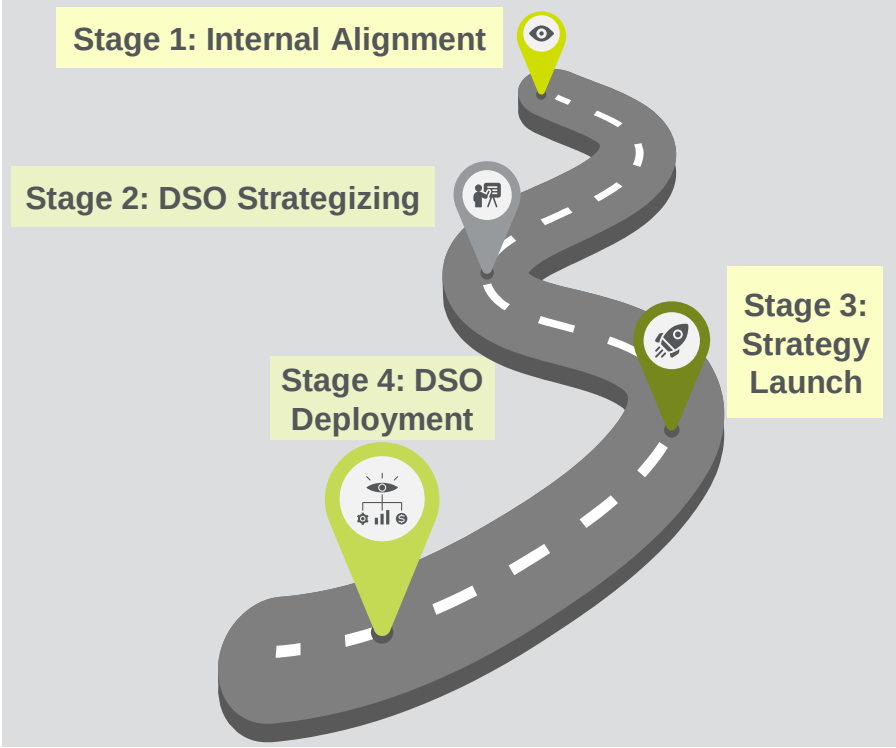
Initiate the early strategy activities, begin collecting supportive data, and engage the relevant stakeholders:

People – Evaluate and adjust
Process – Data Gathering and Management Standards
Technology and Data – Flexible Solution Integration, Pilots and Case Studies
Regulatory – Case Study Validation, Customer Engagements, Business Alliances

Stage 4: DSO Deployment

Prepare for a full-scale DSO model pursuit in Ontario and accomplish the near-term objectives:

People – Evaluate and adjust
Process – Evaluate and adjust
Technology and Data – Advanced Security Measures
Regulatory – Case Study Validation



Key Takeaway

Each roadmap stage must be conducted sequentially, not rushed, and diligently. Based on the Jurisdictional Scan, DSO journeys can take prologued periods of time, so a successful roadmap ensures that all stages are addressed wholistically.

Source: EY Knowledge. EY Report Future of DSOs

Note: the stages are filled by action considerations mentioned on pages 55 to 57 in their respective categories.

Potential Alectra “No Regret” Moves

Irrespective of whether Alectra becomes a DSO in Ontario, the organization can undertake the following no regret moves. Those suggestions were based on the action considerations, Alectra stakeholder perceptions, and the current market state.

3. Employee Training

Alectra needs to educate and upskill its staff for them to be able to handle and work with emerging grid-edge technologies. Advanced training for engineering, customer, and line staff will be highly valuable.

4. Collaboration and Partnerships

Alectra needs to identify and begin discussions with potential technology partners/vendors to better understand their combined path forward. Their inputs will enhance internal timelines and goals.

2. SGAM Deployment

Alectra needs to implement a Smart Grid Architecture Model (SGAM) to model interactions, better understand the smart energy arena, and determine interoperability levels between various business functions.

5. Customer Value Proposition

Alectra needs to determine and document potential benefits to their customers in terms of avoided capital investments, DER programs and revenues, and how stabilization or downward influence could affect rates.

1. Digital Investments

Alectra needs to invest in digital and communication technologies, including SCADA, DERMS or ADMS upgrades, to have greater visibility, control, and planning over the grid of the future and DERs.

6. New Opportunities

Alectra needs to identify which business development opportunities the entity aspires to support or even create for its communities. Note, inaction can lead to becoming a barrier to electrification.

08

Next Steps

Key next steps for Alectra post the research study.

Key Project Takeaways

Underpinned by the energy transition, the DSO construct is rapidly evolving across the globe. Yet, in many instances, the DSO is still conceptual given that definitions, market roles, and functions vary from market to market.

01

Similar drivers for various DSOs, but no playbook.

While there are common drivers for DSOs around the world, each jurisdiction is influenced by its own policies, dynamics, regulations, and technologies that drive respective developments.

There is no one-size fits all model for a DSO and Alectra will need to develop its own vision for Ontario.

02

A DSO is a journey, not a destination

The DSO journey can take decades, where the end state is not well defined.

Tackling the transition challenge begins with no-regret moves.

Successful DSOs start with aligning on vision, building business cases, investing in digital grid technologies, campaigning to stakeholders, and demonstrating new capabilities with partners.

03

Regulators may not have the answers, but utilities can help shape the future

Regulatory barriers undoubtedly exist, but the risk of inaction threatens operational control over utilities' own networks.

Utilities drive DSO development and advocacy through pilots to test key DSO functionalities and build quantitative business cases.

Regulators often reciprocate with public consultations and utility advisory to shape the DSO space and future.

04

Utility mindset must shift to become more proactive

Traditional utilities respond to market changes and regulatory directives. However, conventional planning will be insufficient.

Now, aspiring DSOs must proactively anticipate and manage the system.

In other jurisdictions, a high DER adoption uptake occurred much faster than expected, for example 1/3 of residential properties in Western Australia are already equipped with solar PVs in contrast to a minimal adoption rate just five years ago.

05

Alectra is beginning to recognize DSO as an imperative for its future business

The team witnessed a gradual change in stakeholder perspectives on the DSO subject.

During the workshops, Alectra representatives became more engaged, interactive, and aligned on the potential DSO value for Alectra.

Afterwards, they gained a consensus that a DSO is an important model that will shape the future business.

However, a quantitative business case and clear vision are still required.

06

The customer is at the core of the DSO transition

Despite tendencies to view DSO as a technical pursuit, customers are the driving force for change.

Other DSOs are trying to better understand future customer needs through consultations and engagements.

The data is used to more accurately plan for the future and appropriately address customer concerns in a DSO.

EY x Alectra DSO Research Study Snapshot

The DSO Research Study was the first step in tackling this ambiguous topic for Alectra. It was facilitated by interactive workshop sessions and individual discussions with three other DSOs. Now Alectra needs to focus on the following steps:

1. DSO Research Study Kick-Off

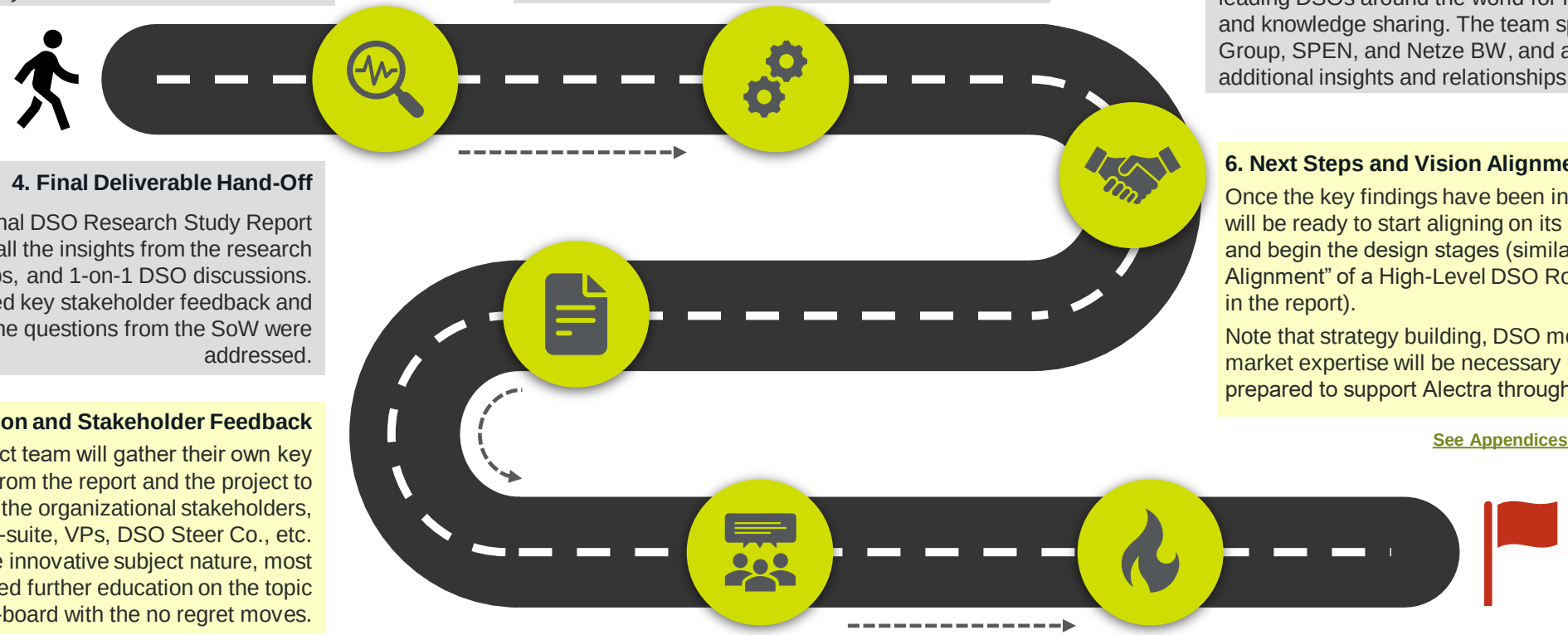
EY and Alectra undertook a 15-week project to research the DSO subject, develop 8 detailed case studies on leading DSOs around the world, and synthesize the value propositioning for Alectra in Ontario. Throughout the study, both parties provided inputs to foster a truly collaborative effort.

2. Wavespace Workshops (SCAN +FOCUS)

EY hosted 25+ Alectra stakeholders at two interactive workshops to educate the attendees on the DSO subject through eight speaker series and group activities. EY witnessed a change in the attendee perspectives by becoming more open to DSO models and aligning in their perceptions.

3. 1-on-1 DSO Discussions

As an extra addition to the scope, EY leveraged its global network to connect Alectra's project team with leading DSOs around the world for further collaboration and knowledge sharing. The team spoke to Stedin Group, SPEN, and Netze BW, and as a result gained additional insights and relationships.



4. Final Deliverable Hand-Off

EY prepared a final DSO Research Study Report that amalgamated all the insights from the research phases, workshops, and 1-on-1 DSO discussions. The team integrated key stakeholder feedback and made sure all the questions from the SoW were addressed.

5. Socialization and Stakeholder Feedback

Alectra's project team will gather their own key takeaways from the report and the project to socialize them with the organizational stakeholders, including the C-suite, VPs, DSO Steer Co., etc. Given the innovative subject nature, most stakeholders will need further education on the topic to be fully on-board with the no regret moves.

6. Next Steps and Vision Alignment

Once the key findings have been internalized, Alectra will be ready to start aligning on its DSO vision/strategy and begin the design stages (similar to "Phase 1: DSO Alignment" of a High-Level DSO Roadmap mentioned in the report).

Note that strategy building, DSO model, and Ontario market expertise will be necessary for this step. EY is prepared to support Alectra through this phase ("ACT")

See Appendices for further ACT details.

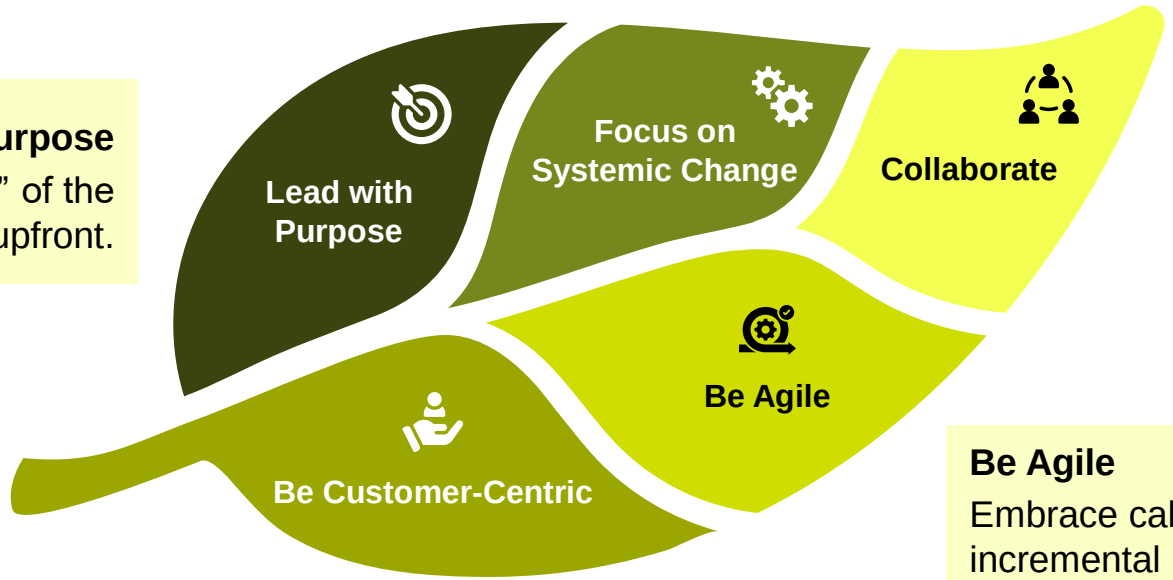
Legend Completed SCAN + Focus Activities | Outstanding ACT Future Activities

Key Success Factors

Alectra's DSO journey and undertaking will require a solid strategy, alignment, and mindset. Fundamentally, each piece of the transformation must be guided by the following five key success factors:

Focus on Systemic Change
Work on initiatives that are in cohesive portfolios to address tangible and impactful themes.

Lead with Purpose
Clearly understand the "why" of the transformation and articulate it upfront.



Collaborate
Balance the autonomy of workstreams with the need for transparency to avoid siloes.

Be Agile
Embrace calculated risks and engage in incremental cycles to validate and optimize workflows.

Be Customer-Centric
Continuously listen, analyze, and prioritize what customers want and value.

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09

Appendices

Supplementary materials for this final report.

Appendix Index

The report is supplemented by the following five documents that were prepared and leveraged throughout the engagement. Although not included directly in this final report, the files were separately delivered to Alectra for further analysis and review:

Appendix A	**DSO Overview Chapter** The first chapter of the deliverable materials that provides foundational DSO information, such as drivers, definitions, model types, etc.
Appendix B	**DSO Jurisdictional Scan Chapter** The second chapter of the deliverable materials that provides regulatory overviews and eight detailed DSO case studies, including UKPN, National Grid, ENWL, Western Power, ESB, Netze BW, ConEd, and PG&E.
Appendix C	**Workshop 1 – DSO Around the World SCAN Retrospective** Workshop 1 overview and key takeaways materials that focused on educating Alectra stakeholders on the general DSO space and four case studies.
Appendix D	**Workshop 2 – DSO Around the World FOCUS Retrospective** Workshop 2 overview and key takeaways materials that allowed Alectra stakeholders to deep dive on three specific case studies in greater detail and engage in group activities.
Appendix E	**Raw Research Notes on Excel Depository** The research tracking document for the project with raw notes and data. The insights stored in the file informed this project deliverable.

Research References

EY referred to a variety of internal proprietary and publicly unavailable data, research, and analysis to deliver this work. “EY Knowledge” and “EY Analysis” refer to analysis conducted by the firm for internal and client purposes that are relevant for the DSO space and Alectra.

Page(s)	Year	Publisher	Title
17, 18, 19	2019	EY	Regional Comparison - Global Countdown Clock
17, 18	2022	EY	Navigating the Energy Transition Research
20, 22, 23, 24, 25, 43, 44, 47, 51, 54, 55, 56, 57, 58	2019	EY	EY Report on the Future of DSOs
17, 18, 20, 22, 23, 25, 26, 28, 32, 33, 34, 35, 37, 38, 43, 51, 52, 53, 54, 55, 56, 57, 58	N/A	EY	EY Knowledge/Analysis
26, 32	2022	Gridworks	Evaluating Alternative Distribution System Operator Models for California
28	2019	ETNO	Structural Options for Ontario’s Electricity System in a High-DER Future
32	2019	IRENA	Future Role of Distribution System Operators
35	2019	EY	EY DSO Survey
28	2021	ETNO	Distribution System Structures for a High DER Future
43	2023	IESO	Ontario Electricity Grid - Supply Mix and Generation

Disclaimer: EY SMEs who provided data and validation include Paul Micallef (EY Global Digital Grid Leader), Andrew Horstead (EY Global Power and Utilities Lead Analyst), and Andre Winarto (EY Global Energy Knowledge Leader). In addition, EY engaged its Global Knowledge team for further research and validation.

Research References

EY referred to a variety of internal proprietary and publicly unavailable data, research, and analysis to deliver this work. “EY Knowledge” and “EY Analysis” refer to analysis conducted by the firm for internal and client purposes that are relevant for the DSO space and Alectra.

Page(s)	Year	Publisher	Title
43, 44	2022	Land Information Ontario	LDC Boundaries Map
43	2022	IESO	Annual Planning Outlook
46	2022	IESO	Pathways to Decarbonization
46	2021	OEB	OEB IESO Grid Innovation Fund
46	2021	OEB	Distributed Resources and Utility Incentives
46	2023	Government of Canada	NRCan RFI Canada’s Electricity Monetization
23, 43	2021	Energy Networks Association	ENA DSO Transition
Appendices	2020	IESO	Innovation and Sector Evolution White Paper Series
Appendices	2022	Ofgem	Future System Operator: Government And Ofgem Response To Consultation
Appendices	2021	Policy Papers	How to Improve Ontario Energy Forecasting
Appendices	2019	EY	EY Knowledge, Client Workshops and DSO Survey (2019) [internal]
Appendices	2021	ScienceDirect	A Decentralized Flexibility Marketplace Fostering TSO-DSO Cooperation
Appendices	2020	IET	Design Of A DSO-TSO Balancing Market Coordination Scheme For Decentralised Energy
Appendices	2019	EY	How network transformation will enable decarbonization | EY Canada

Note: A number of public reports, articles and website material was also referred to for the purposes of this research including market operator and regulator thought leadership from AEMO, ENA, OFGEM, CAISO, NYSO, OEB and IESO.

Research References

EY referred to a variety of internal proprietary and publicly unavailable data, research, and analysis to deliver this work. “EY Knowledge” and “EY Analysis” refer to analysis conducted by the firm for internal and client purposes that are relevant for the DSO space and Alectra.

Page(s)	Year	Publisher	Title
Appendices	2022	IEA	Unlocking the Potential of DERs Power system opportunities and best practices
Appendices	2022	UK Gov	Electricity Act 1989, GEMA, ESO, ENCC, DSO, Future of Local Energy Institutions and Governance, FSO, Ofgem Position paper, Sixth Carbon Budget, GM energy system operation
Appendices	2013 - 20	AU Gov	Australian Energy Market Agreement, AER, AEMC, AEMO, ENA, Energy Works AU, Cost-Benefit Analysis, Transformation Roadmap, National Connection Guidelines, Distributed Energy Resources Roadmap, AU New Regulatory Arrangements
Appendices	2021 - 22	EU Commission, IR Gov, Eirgrid	I-SEM, CRU, SEMO, PR5 Regulatory Framework, Work Plan Covering 2022-2026, ESB commenced a pilot, Renewable Energy Directive, Energy Efficiency Directive, Internal Electricity Market Directive, Better Energy Communities Scheme, Interim Clean Export Guarantee, Clean Energy for all Europeans Package, CRU Paper
Appendices	2019 - 22	German gov, Agora	German Power System Report, Energiewirtschaftsgesetz (EnWG), Bundesnetzagentur, EEX, Renewable Energy Act 2021, Directive (EU) 2019/944, Directive 2019/944
Appendices	2015 - 20	US Gov (NY), NYISO	FERC, NYSERDA, DPS, PSC, NYISO, REV, Joint Utilities of New York, DSP: REV Ecosystem, DSIP, REV Initiative, ISO Roadmap, FERC Order 841, NYISO Strategic plan
Appendices	2016 - 21	US Gov (Cali), Casio	CAISO, FERC, CPUC, DRAM, PDR-DERP-NGR Comparison Matrix, California Distribution Plan , DER Action Plan 2.0, rulemaking proceeding, FERC Tariff revisions, FERC Order 2222, DER Action Plan, DER Adoption new plan
Appendices	2021 - 22	UKPN	RIIIO-ED2 Business Plan, Future Smart Strategy 2017, Net-Zero Roadmap 2019, Digitalization Strategy and Action Plan 2022, Renewable Energy (RE) Strategy, Innovation Strategy, UKPN History, Ofgem, IDSO, Electrical Times, DSO Transition: Energy Policy Research Group, DSO Flexibility
Appendices	2021 - 22	UKPN	The Energy Transition: Lexology, SP Group’s Smart Grid Index,
Appendices	N/A	UKPN	DSO Dashboard
Appendices	N/A	UKPN	Power Potential: TDI 2.0
Appendices	N/A	National Grid	National Grid: Climate Transition Plan 2022

Research References

EY referred to a variety of internal proprietary and publicly unavailable data, research, and analysis to deliver this work. “EY Knowledge” and “EY Analysis” refer to analysis conducted by the firm for internal and client purposes that are relevant for the DSO space and Alectra.

Page(s)	Year	Publisher	Title
Appendices	2022	National Grid	Future System Operator (FSO), NGESO’s “Enabling the DSO Transition” Plan, NGED’s DSO Strategy, National Grid: Climate Transition Plan 2022, SIF, net-zero electricity network, Enabling the DSO Transition, ENCC
Appendices	2022	National Grid	Fair and affordable transition to net zero, Providing fossil-free heating services to customers, Expansion of electric vehicle usage and related services, NG A Fair Transition, NG – Investor Relations, Distributed ReStart
Appendices	N/A	National Grid	Distributed ReStart
Appendices	2021 - 22	National Grid	Distribution System Operations, Enabling the DSO transition, Distribution Grid Lessons Learned in 2022: Utility Dive
Appendices	2021-22	ENWL	ENWL Strategy, DSO Strategy 2021, Open Networks Project, DSO Implementation Plan, ROCBA, DER contracts, Flexible Portal, BiTraDER
Appendices	2020 - 22	WP	Energy Transformation Strategy, Decarbonization Plans, AEMO Operations Technology Roadmap, Achieving goals strategy , Western Power Annual Report 2022, ERA, Project Symphony, Open Energy Networks, DER roadmap, ARENA, EV fast charging network, Project Symphony Lesson Learnt Report
Appendices	2022	ESB	NNLCP, The Joint System Operator’s Program, ESB Net-Zero Strategy 2040
Appendices	2020 - 22	ESB	CRU, Price Review 5, Single Electricity Market Committee recently published a consultation paper (2022), pilots planned by ESB, CRU Energy Networks Revenues & Tariffs, ESB Networks Consultation, ESB National Network Local Connections Program, StoreNet, StoreNet Project Case Study, StoreNet Innovation Project Close-out Report, Multi-year DSO/TSO Work Plan Covering 2022-2026
Appendices	N/A	NBW	EnBW Corporate Strategy 2025, Network Development Plan
Appendices	2022	Utility Dive	Distribution Grid Lessons Learned in 2022: Utility Dive
Appendices	2022	Utility Dive	Distribution Grid Lessons Learned in 2022: Utility Dive
Appendices	2019 - 22	PG&E	PG&E, Climate Positive by 2050, Transition to a GridCo, DSO transition efforts, CPUC, DERMS, STAR Software, Customer and Distribution Automation Devices, EPIC 2.02 – Distributed Energy Resource Management System,
Appendices	2021	CAN Gov	Distributed Energy Resources Integration Research Roadmap (ca.gov)

Original Scope

Phase + Workstream	Phase 1: SCAN		Phase 2: FOCUS		Phase 3: ACT
	Define DSO Model and Key attributes	Conduct a jurisdictional scan and value assessment of DSO Models	Assess the value of DSO Models	DSO Shortlist and Roadmap Considerations	DSO Alignment, Strategy and Operational Roadmap
Activities	➢ EY will leverage its global Power & Utilities expertise to assess and define 3-5 DSO models and key attributes that are most applicable to Ontario's energy market structure	➢ EY will engage its Global SMRs, Knowledge Base, and client experiences to perform a jurisdictional scan of DSOs in other markets (i.e., UK, US and Australia)	➢ EY will further assess, comparing and contrasting the examined DSOs, to clarify the value proposition, renumeration, and long-term feasibility in the Ontario market	➢ EY will work with Alectra and EY SMRs to shortlist the most viable DSO options, leveraging EY's DSO implementation framework to provide hi-level operational considerations	➢ EY will work closely with Alectra and EY SMRs to leverage the completed DSO research and EY's DSO framework to assess Alectra's current state, strategic alignment, and feasibility to pursuing a DSO model ➢ EY will support the development of a DSO strategy for Alectra, including operational capabilities, investment, and timeline required to reach the desired DSO model.
Questions Answered	1. What is a DSO and what types of DSO's exist? 2. Compare and contrast DSO's to other market structures (e.g. LSE, RTO) 3. What are the roles/ responsibilities of different players? 4. What are the drivers for DNO>DSO 5. What are the benefits and shortcomings for becoming a DSO?	1. Where do other DSO models exist? 2. What are their characteristics and value/challenges? 3. What are some best practices and lessons learned from DSO implementation to date?	1. Clarify the business value of a DSO. 2. What are the renumeration options? 3. Lay out business model optionality. 4. Contrast/compare benefits/disadvantages to various options. 5. Assess longer term value given ecosystem changes.	1. Outline viable DSO options for Ontario and create a shortlist. 2. Align on 1-2 to use for the roadmap/future state operationalizing. 3. Are there existing roadmaps/implementation plans from other geographies to become a DSO? 4. What are EY's hi-level capabilities roadmap considerations for DSO (e.g. organizational structure, system planning, technology, regulatory and workforce capabilities.)	1. What is the viability of Alectra's pursuit of a DSO role? 2. What is the most attractive DSO model for Alectra? 3. What is Alectra's current strategic alignment and business model feasibility for assuming a DSO role? 4. How does Alectra compare to successful DSOs in similar markets? 5. What are the capabilities that Alectra needs to leverage and develop further to assume a DSO model? What are the gaps? • organizational structure • System planning • Tech requirements - system software (i.e. DERMs, dispatch capabilities); Telemetry (i.e. AMI etc.) • Regulatory framework (i.e. ARC, etc.) • Workforce skills and people capabilities (i.e. control room) 6. What is the investment level required? 7. What is the timeline to achieve this DSO goal?
Outputs	✓ DSO Overview: including definitions, model structures, roles/ responsibilities of market players, ownership options.	✓ Jurisdiction Scan: Highlighting real-world case studies, best practices and lessons learned, benefits/risks and challenges ✓ OPTIONAL: wavespace-Lite workshop (TBD) ✓ Value Assessment of DSO Models: including unique value proposition, renumeration options, advantages/disadvantages, long-term value assessment	✓ DSO Model Options Shortlist ✓ Hi-Level considerations of operational enablers and capabilities		✓ DSO current state assessment and capabilities alignment report ✓ DSO strategic roadmap ✓ Board presentation/ELT materials support
Timeline	2 Weeks	2 Weeks	2 Weeks	2 Weeks	8 Weeks

Note: the set of questions and Phase 3 were not answered, as they were out of scope for the DSO Research Study.

Alectra Utilities 2020-2024 Capital Plan Assurance Review

Guidehouse

Alectra Utilities 2020 to 2024 Adjusted Capital Plan

Assurance Review

Prepared for:

alectra utilities

May 2022

Submitted by:

Guidehouse Canada Ltd.
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May 6, 2022

Subject: Alectra Utilities 2020 to 2024 Adjusted Capital Plan Assurance Review

Mr. Bassindale:

On behalf of Guidehouse Canada Ltd. (Guidehouse), we are pleased to submit the attached report presenting the findings and conclusions of our review of Alectra Utilities ("Alectra") five-year investment plan that will be used to support a forthcoming rate application before the Ontario Energy Board ("OEB") under the Incremental Capital Module funding mechanism ("ICM").

Guidehouse's assurance review assesses the processes and analytical methods Alectra applied to develop its most recent Distribution System Plan (DSP) and evaluates actual capital investments for 2020 and 2021, forecast investments for 2022, and an adjusted five-year capital investment plan for the years 2023 and 2024.[1] The DSP documents the approach and rationale Alectra used to prepare a five-year investment plan across the four investment categories as outlined in Chapter 5 of the Ontario Energy Board's (OEB) filing requirements for rate applications submitted by electricity distributors in Ontario.[2]

Our review addresses the following questions.

1. Is Alectra's DSP and adjusted five-year investment plan consistent with the guidelines and objectives set forth in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications?
2. Are the planning practices, methods and tools employed by Alectra to develop and prioritize capital expenditures in the DSP consistent with industry best practices?
3. What additional investments are needed and justified for funding approval under the OEB's ICM rate application mechanism?

The assessment includes an evaluation of Alectra's responsiveness and compliance with Sections 5.2, 5.3, and 5.4 of the OEB's Chapter 5 filing requirements for rate regulated electricity distribution utilities in Ontario. The findings and conclusions from our review is based on our independent assessment of Alectra's DSP submitted in its rate application to the OEB in May 2019 covering the rate period 2020 through 2024, and subsequent adjustments to the capital investment plan for years 2023 through 2024.[3]

[1] Alectra's DSP was submitted to the OEB to support an Incentive Rate (IRM) rate application on May 28, 2019 (EB-2019-0018). The current plan includes actual investments for 2020 and 2021, forecast investments for 2022, and adjusted investments for 2023 and 2024.

[2] Filing Requirements or Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications, July 12, 2018.

[3] In its January 30, 2020 Partial Order under EB-2019-0018, the OEB directed Alectra to resubmit its application as an Incremental Capital Module rate application. On April 19, 2020, Alectra notified the OEB that it would not seek funding in 2020 under an ICM rate application and that the 2020 rate order be made final. On April 23, 2020, the OEB submitted its final Order which accepted Alectra's request and approved interim 2020 rates approved in February 2020 as final. Guidehouse understands Alectra will submit an ICM rate application seeking authorization to accelerate spending for cable and accessory equipment in 2022.

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1.1 Summary Assessment

From our review of the documents referenced above and discussions with Alectra distribution staff, Guidehouse concludes that Alectra has met or exceeded the OEB's filing requirements set forth in Chapter 5 for electricity distributors. This finding is based on Guidehouse's assessment of Alectra's investment plan as outlined in Sections 5.1 through 5.4 and certain sections of Appendices A through H of its DSP for the four categories that electricity distributors are required to address for the assignment of capital projects in rate applications: (1) System Access; (2) System Renewal; (3) System Service; and (4) General Plant. Guidehouse believes that Alectra's revised five-year investment plan is appropriate and justified based on the level of rigor applied in its capital planning processes and rationale supporting each of the associated business cases in the DSP.

Our assessment recognizes that there are distinct differences among the five legacy electric utilities that now comprise Alectra's electric distribution system.[4]These differences include highly variable load density and growth, a range of delivery voltages, a mix of station and circuit design and configuration, and reliability performance that varies by region. More common among the four operating areas is the presence of large quantities of deteriorated assets, particularly for underground cable and associated equipment. Alectra provided evidence that risk of failure for deteriorated assets is expected to substantially increase over the next five years absent proactive replacement or upgrade of equipment in poor or very poor condition. Accordingly, over 50 percent of total proposed investments is for renewal replacements. Guidehouse concurs that the analysis Alectra presented in its DSP justified, at the time, the proposed amount and percentage of capital investments assigned to renewal replacements.

Since the time the DSP was prepared and submitted to the OEB, Alectra has encountered conditions and circumstances that supports a $97.3 million downward adjustment to its original five-year investment plan.[5] Foremost among these is a reduction in investments due to Covid-19 related impacts. Further, to maintain spending within current authorized base rates, Alectra has significantly reduced investments by approximately $58 million over five years for System Renewal; mostly underground cable injection and replacement.

Guidehouse's review of the DSP and asset condition indicates the reduced investments for renewal replacements will accelerate and increase the volume of deteriorated underground assets, resulting in degraded reliability and unacceptable levels of service to customers located in areas most susceptible to prolonged and repeat interruptions. Our assessment confirms that Alectra's proposal to accelerate investments for underground cable is consistent with good utility practice, Chapter 5 DSP requirements and in conformance with the OEB's September 2019 Order.

Accordingly, Guidehouse concludes that Alectra's DSP provides the OEB, its customers and other stakeholders with sufficient information to make a determination that the Company's revised five-year investment plan fully complies with Chapter 5 objectives and requirements for ICM rate applications; namely, electricity distributors must demonstrate that its DSP should fully addresses the following topics.

[4] Alectra has created four operating areas comprising the five legacy utilities: East, Central, West and Southwest.

[5] Alectra current investment plan for the years 2020 through 2024 includes a net reduction of approximately $100 million from the prior $1,457 million IRM funding request.

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- Asset related performance and the approach used to determine the level of investment required to meet performance targets as outlined in Chapter 5
- Approach to lifecycle asset management planning and the management of assets related operational and financial risk
- Plan for capital-related expenditures over a five-year forecast period and the justification of these expenditures
- Planned investments related to accommodating the connection of renewable energy generation (REG)
- Planned investments for the development and implementation of technology to support grid modernization and expenditures as required by provincial legislation[6]

Guidehouse's assurance review and assessment of Alectra's DSP fully is structured to determine whether the DSP complies with OEB Chapter 5 filing requirements, including its request to obtain approval to accelerate investments for underground cable and accessories via the OEB's Incremental Capital Module rate mechanism.

1.2 Assurance Review Process

Guidehouse's assurance review addresses the processes documented in the DSP and analytical methods Alectra applied to prepare a five-year capital plan across the four investment categories outlined in Chapter 5. It includes an assessment of the processes and methods applied to determine project need and the level of investment proposed for each of the OEB's four investment categories. Our assessment focuses on the level of rigor and consistency Alectra applied to determine investment needs across four operating areas based on the following criteria.

1. Assessment of Alectra's planning and budgeting processes, and how its approach to identify investments required to address at-risk assets is appropriate and consistent with industry best practices.
2. Comprehensiveness of technical analysis and justification of specific investments, including the quantification of benefits, where applicable.
3. Value and incremental impact of the proposed investment relative to a clearly defined baseline (e.g., do nothing case).
4. Prioritization, optimization and selection of investments within each investment category (i.e., how does Alectra determine which assets need to be replaced or upgraded to achieve performance targets?) .
5. Level of detail and cost breakdown of proposed investments with supporting evidence and analytics during project review and selection process.
6. Evaluation of adjustments made to the original investment plan, options considered, and robustness of analysis supporting the need for incremental investment under an ICM rate application.

Guidehouse reviewed both the DSP and worksheets Alectra prepared to develop an adjusted five-year capital plan to support its findings and conclusions and opinion of the reasonableness

[6] Grid modernization includes investing in innovative solutions that make systems more efficient, reliable and cost effective; and more prepared for technological changes, such as electric vehicles and distributed energy resources, and to provide greater customer choice.

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of proposed investments. We also interviewed Alectra's management and project owners on specific details and findings presented in the DSP and adjusted five-year investment plan. Our findings are also informed by our experience and knowledge of leading electric utility engineering, operations, asset management and capital planning practices in North America, and the level of effort and approach Alectra applied to identify assets at greatest risk of failure and impact to its customers. Our review includes an assessment of the impact of reduced spending levels across the OEB's four investment categories, and why accelerating investments for underground distribution assets is justified.

1.3 Distribution System Plan (Compliance)

Per Chapter 5 requirements, the DSP presents in detail the methods, assumptions and data Alectra applied to support and justify adjustments to the investment plan for the years 2023 and 2024. Guidehouse's review of the DSP indicates Alectra meets this requirement by affirmatively demonstrating that it has provided or outlined in sufficient detail:

- The process followed to proactively incorporate customer preferences and input into the capital planning process. These include customer surveys and outreach via community meetings to ensure that proposed investments address customers' preferences and expectations regarding their impact on area residences, communities and businesses;
- The value and benefits Alectra expects to achieve over the rate application period via effective approaches asset management and capacity planning;
- Specific details on the vintage and condition of major asset classes as a basis to justify proposed renewal investments, by year, during the five-year rate application interval;
- Documented enhancements to asset management processes, tools and methods that Alectra has implemented, post-merger, to support asset condition assessments and need for upgrades or replacement;
- Informed targeting of asset replacements, including the timing and location of underground based on predicted levels of performance (e.g., based on prior outages) and risk exposure (e.g., customers interrupted);
- A rationale and analysis supporting project need for capacity expansion, local infrastructure project such as the light rail transit projects, deteriorating asset support the capital investments needed to meet reliability, performance and capacity targets;
- Efficient utilization of assets to minimize investments needed to meet capacity deficiencies, including effective coordination with Hydro One and regional planning organizations[7] (e.g., enhanced tie transfers, voltage conversions and demand management); which have deferred the need to add new or upgrade existing stations;
- Balancing of capital projects among the four investment categories via an optimization approach using industry leading tools (e.g., Copperleaf C55); and
- Identifying grid modernization investments, distributed energy resources**,** and foundational technologies and systems to reduce costs and improve efficiency.

[7] Alectra actively participates and contributes to the IESO's Regional Planning Process, including development of the Integrated Regional Resource Plan ("IRRP") and Hydro One Transmission Regional Infrastructure Plans ("RIP"). Alectra's role and participation in regional planning processes focuses on seven of the IESO's 21 planning areas located within its service territories.

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Guidehouse Conclusion: *Alectra's DSP and proposed adjustments outlined in the current Plan meet OEB's Chapter 5 filing requirements, as it presents in detail how each project or investment optimally meets performance targets while balancing risk over the five-year investment plan. It documents performance targets over several categories and how each investment contributes to achieving each of these targets. Further, the acceleration of cable and equipment replacements and upgrades is justified based on the rigorous condition and impact analysis Alectra conducted to support the additional investments. Guidehouse did not identify any material deficiencies or omissions in the DSP or current investment plan with respect to Chapter 5 requirements.*

1.4 Customer Engagement

Consistent with OEB requirements, Alectra has proactively sought input from its customers to inform its capital planning strategy and project selection process, achieved via direct outreach and customer survey instruments. The customer engagement process and surveys are prepared by a third-party firm (Innovative Research) with expertise in customer surveys. The survey used to inform the DSP spending plan covers a range of topics related to electric reliability, customer service, rates and costs, among other topics. Alectra's customer outreach offered customers the opportunity to voice their concerns in public meetings. Alectra conducted initial and follow-up surveys to ensure all topics were fully addressed. The results of the survey indicated customers are most concerned with reliability (including major storm impacts) and electricity price.

Importantly, customer feedback from these surveys was incorporated into Alectra's project selection process, and adjustments were made to the proposed investment plan to reflect customer concerns or requests – $17.5 million was reduced in the DSP. For example, Alectra reduced proposed investments in capacity expansion and renewable energy pilots and increased investment in underground infrastructure as reflected in its DSP. Ultimately, the process resulted in agreement among customers surveyed supporting Alectra's proposed spending levels outlined in the 2018 DSP. A follow up survey completed in April 2022 confirmed among all customer groups that ensuring reliable electric service was their highest priority.[8] The survey group also indicated that accelerated spending for cable investments is warranted, as highlighted in the following excerpt from page 8 of the report.

> *"In both the Enersource and PowerStream rate zones, a majority of customers in all rate classes would like to see at least some increase in investment in cable injection. A plurality chose the most accelerated investment option."*

Guidehouse Conclusion: *Guidehouse views Alectra's customer engagement processes and efforts to solicit feedback to inform its capital planning and project selection process to be consistent with or exceeding industry practices, and affirmatively addresses OEB customer engagement requirements outlined in Chapter 5.4 (a).*

1.5 Asset Management

In the Introduction section of the DSP, Alectra states that its "Asset Management Framework sets the foundation for the DSP and all planned capital investments through five guiding principles: Customer, Financial, Operational, Regulatory, and Organizational." Following these and related

[8] Alectra Utilities 2022 ICM Application Customer Engagement Overview, prepared by Innovative Research Group Inc., April 2022.

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corporate objectives, Alectra, beginning in 2017, adopted best practices from its legacy utilities to harmonize its approach to Asset Management, thus, ensuring that asset management practices and policies are uniformly applied to each of the four operating areas.[9] The objective of Alectra's AM approach, applied in the DSP, is to quantify and manage risk for its distribution and station assets in a manner that results in the efficient use of these assets while meeting performance and reliability targets.

Alectra's asset management framework is structured to align with four primary strategic goals and objectives, summarized in below excerpt from Table 5.3.1 – 1, with a proposed five-year spending designed to achieve these goals.

1. Optimize operations and lifecycle management and related processes regarding asset renewal to maintain reliability and customer service levels.
2. Invest in and leverage emerging technologies to enable operations, maintain reliability, integrate conservation and demand management and distributed generation activities.
3. Proactively enhance customer engagement and levels of service through levering various channels/technologies.
4. Maintain and continue to improve upon our strong safety record.

From its assurance review, Guidehouse has determined that Alectra's adjusted five-year investment plan and incremental investments for underground assets is based on asset management principles that achieves these objectives, while complying with OEB requirements set forth in Chapter 5. Additional detail on the results of our evaluation are outlined in sections that follow.

Guidehouse is aware of the distinct differences in Alectra's four operating areas and legacy utilities practices, both in terms of distribution system configuration and asset condition. Further, Alectra's distribution system operates over a range of delivery voltages, from 4kV up to 44kV, with some areas predominantly served by overhead lines and others mostly served by underground cable. Further, electricity demand in greenfield development sections of Brampton and Vaughn is increasing while more established areas such as Mississauga are encountering redevelopment; other areas that have been built out absent redevelopment are seeing minimum load growth. Similar to distribution circuits, Alectra owns and operates Transmission Stations (TS) and Municipal Stations (MS) that vary significantly among the four operating areas with respect to rated capacity, design and delivery voltages.

Alectra has transitioned from pre-merger asset management practices that varied among the five legacy utilities to one that incorporates best practices from each; for example, legacy practices for maintenance, inspection and data management differed among each organization. The process Alectra now follows to manage its assets and support proposed investments is well documented, with responsibilities and sequential steps outlined in its AM process. Importantly, Alectra's AM processes have been adopted by all regions, thereby ensuring the project selection is consistent among all asset classes across the entire service territory. One of these enhancements is the use of a single data repository in Alectra's Assets Analytics Platform for recording asset data, key attributes and inspection results.

[9] The harmonization of asset management practices is succinctly described in the following statement on page 9 of Appendix D of the DSP: "The harmonization process included the alignment of all computational models' inputs, nomenclature and methodology."

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Alectra has introduced common design and planning standards to the extent practicable given the distinct differences in its distribution assets. Because the harmonization and transition to consistent asset management policies and practices is relatively new, Guidehouse expects the accuracy and level of detail in data collected will continue to improve over time, particularly for entries related to asset condition and health.

Alectra's AM policies and practices are described in detail in the DSP and their adoption has produced a five-year capital investment plan that is based on sound AM principles and practices. Coupled with leading industry tools used to identify the optimal level of spending to meet performance targets and address risk, Alectra applied AM practices to produce a capital investment plan that is consistent with OEB Chapter 5 requirements for cost-effective investment choices. For example, Alectra's applied asset management principles and ACA results to defer infrastructure replacements that could be justified based solely on of age (i.e., equipment age exceeds expected end of life criteria); yet remains in service beyond predicted end of life due to favorable condition assessments or performance that justified continued use of older, but reliable equipment. In addition, Alectra is proposing technology enhancements, including real-time monitoring of major equipment such as station transformers and breakers, which provide critical operational data to control room operators to detect abnormal conditions prior to failure.

Guidehouse Conclusion: *Alectra's Asset Management practices and project evaluation methodology is consistent with leading industry practices and conforms to OEB requirements outlined in Chapter 5.3. Alectra quantifies the degree to which proposed investments reduces risk and provides value to customers over the life of the asset. Alectra has made good progress ensuring that AM policies and practices consistently applied across all regions; particularly with respect to asset condition assessment and project selection processes. Alectra recognizes that transitioning to common design and AM practices has produced gaps in data records and legacy design standards and configurations that will need to be addressed over time. For example, there is a significant 4kV in some regions, whereas 27kV is dominant in other areas. Further, Alectra's current planning guidelines include reserving capacity on up to three feeder ties to enable station transformer back-up from adjacent stations during outages or maintenance, which Guidehouse views as an effective capacity practice. Guidehouse is aware that feeder ties do not exist in all locations and may not be cost-effective to create due to limited load growth or presence of mobile transformers*.

1.6 Asset Condition Assessment (ACA)

The determination of asset health via ACA is a key element of Alectra's asset management processes. The DSP documents in detail the methods and level of rigor Alectra currently applies to assess and determine the condition and health of its distribution and station assets.[10] Alectra's uses an analytical approach to quantify asset condition as measured by Health Indices (HI) for 11 distribution categories, with asset condition scaled via designations ranging from very poor to very good.

The methodology Alectra uses to derive asset health indices is based on a formulaic approach: HI's are derived based on the product of weighted inspection scores (or percentage scores when

[10] Terms for Distribution and Stations are intended to refer to equipment located beyond the station fence and within the station, respectively.

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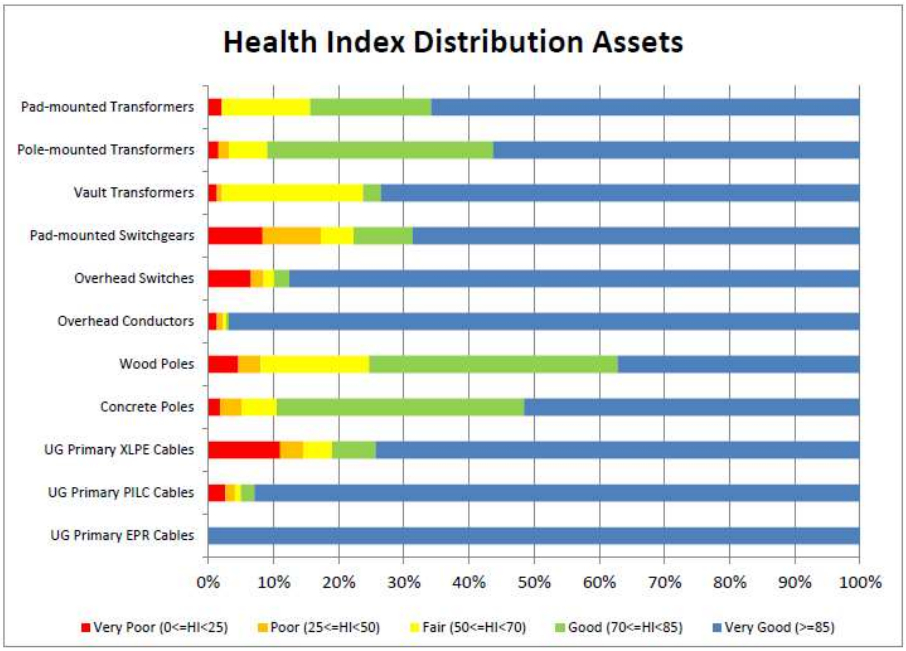
more detailed inspection data is available)[11] and a conduction multiplier; the latter limits the maximum HI score to reflect safety, obsolescence or field/measurement results. The criteria Alectra applies to determine deterioration levels is based on detailed inspection reports, known risk factors (e.g., defective components), historical performance and expert judgement from staff qualified to assess equipment condition or obsolescence. It is from these processes and HI results that Guidehouse has determined that accelerating the replacement or upgrading of underground assets is required.

The results of Alectra's 2018 asset condition assessments as determined by the HI processes described above appears in Figure 5.2.3. - 1 of the DSP, presented below.[12]



Alectra's ACA confirms a correlation between age and condition for several asset categories. For example, direct buried cross-linked polyethylene extruded (XLPE-DB) installed in the 1960's and early 1970's is well-known throughout the electric utility industry to be prone to failure due to treeing caused by contaminants embedded in cable insulation during original fabrication. Alectra has a significant amount of XLPE-DB on its distribution system and has identified and documented areas with high concentrations of deteriorated cable, along with line sections most susceptible to failure. Similarly, older station switchgear and padmount switchgear installed on underground feeders have experienced higher failures rates – older station switchgear also has greater arc flash hazard potential as well. A study conducted by Kinetrics, a firm with expertise in ACA and distribution engineering,[13] confirms that a significant amount of equipment in certain categories is at or beyond expected lives.

[11] The level of deterioration and overall condition is scored on a range of 0 [imminent failure] to 5 [excellent condition] .

[12] Similar asset health designations were prepared for station power transformers, switchgear and circuit breakers.

[13] Twenty-year "Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc. Report No: K-418033-RA-001-R000 July 8, 2010" (Appendix J of DSP). Kinetrics also provided a detailed summary of Alectra's ACA methodology and results, along with its opinion that Alectra methodology is consistent with good utility practice, in Appendices D and E of the DSP.

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ACA data is now collected and analyzed via Alectra's Assets Analytics Platform for each region. The transition from Microsoft Excel to Alteryx is preferred as it provides consistent checks for data entries (e.g., asset inspections) and ease of access for analytical studies. Alectra recognizes the quantity and quality of data such as those obtained from inspection reports varied among the five legacy utilities and expects the accuracy of ACA processes will improve over time as improved and consistent data is collected. There are recommended improvements in the Kinetrics report such as DAI and development of failure curves based on failure rates (versus depreciation schedules) that will improve the ACA process.

Guidehouse Conclusion: *Alectra's ACA methodology and formulaic determination of asset Health Indices is consistent with or exceeds current utility practices. The data and analyses used to determine asset condition is sufficiently rigorous to justify the quantity of replacement or upgrade of at-risk assets over the five-year investment period. The acceleration of investing in underground equipment is necessary to sustain replacement of deteriorated cable and accessories in sufficient quantities to reduce the percentage in very poor or poor condition and to avoid degradation of reliability performance. These incremental investments, if approved, will produce an adjusted five-year investment plan that is still below amounts included in the DSP. The addition of charts or tables highlighting the net change in percentage of assets in poor or very poor condition resulting from the proposed spend plan for Renewal replacements would further clarify how these investments would reduce the amount of deteriorated assets.*

1.7 Risk Management

Alectra's DSP and adjusted five-year capital plan centers on managing risk so as to produce the most favorable outcomes based on a range of risk factors: i.e., reliability, safety, security, cost, environmental, and rates. The DSP outlines how Alectra aligned proposed investments to balance spending among the OEB's four investment categories to avoid increasing risk to unacceptable levels for each of the assigned risk factors. The investment selection process incorporates results from a risk matrix that includes the assignment of numerical values ranging from low to high for each risk factor. The process that Alectra applied to assign scores for each level within the risk matrix is clearly delineated in Table 5.4.1. – 1 (Attachment A), which was developed using input from a mix of stakeholders across Alectra's distribution organization; thus, ensuring assigned values is prepared with input from a cross-section of the utility covering planning, operations, economics/rates, regulatory, customer service, and human resources (e.g., minimum work crew requirements and availability[14]), among others.

Alectra's risk management approach is structured to ensure that proposed spending in each of OEB's four investment categories is balanced and distributed so as to manage risk across all categories to within acceptable levels. For example, in Table 5.4.1. - 1, Alectra determined that acceptable risk scores should not exceed 1000 to 1500 for certain risk categories. These assignments ensures that the adjusted five-year capital investment plan incorporates constraints imposed by risk factor limits. The process establishes minimum or maximum risk thresholds or drivers for six planning categories that are incorporated into the C55 model; i.e., spend levels are optimized in C55 for each of the four investment categories subject to risk-based constraints or limits. Alectra's project selection and optimization process also recognizes mandatory investments for customer connections, highway relocations and other non-discretionary projects.

[14] Alectra's risk assessment process seeks to achieve work force efficiency by identifying projects needed to best utilize work crews based on the minimum and maximum number of available hours.

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The results of Alectra's risk management process results in an annual capital spend plan that meets Alectra's risk profile and performance targets at least cost. Notably, deteriorated assets and their impact on reliability is a key driver for managing risk, with over 50 percent of proposed investment targeted to System Renewal, which underscores the degree to which asset condition and increased likelihood of failure contribute to the overall risk profile and extent to which mitigation is achieved via asset replacement or upgrade.

Guidehouse Conclusion: *Alectra's risk management process thoroughly captures key risk factors and incorporates these factors into its capital planning process. The integration of risk management into the capital budgeting process minimizes the likelihood of unacceptable risk exposure across several components to Alectra's distribution system, its employees and customers. The level of capital spend Alectra proposes for each of OEB's four investment categories is set to manage risk and produce desired performance outcomes at lowest cost. Additional details on Guidehouse's assessment of Alectra's project selection and budgeting process is discussed in the Five-Year Capital Plan.*

1.8 Performance Measurement and Continuous Improvement

Alectra's DSP presents in detail past performance as measured by industry-accepted reliability indices, unit costs and delivery efficiency, including how certain metrics vary by region. Specific targets over the five-year investment plan are documented, including how performance targets will be achieved to address the challenges associated with an electric delivery system whose condition continues to deteriorate for critical asset classes such as underground cable, while subjected to increasingly severe weather events. Alectra expects to meet performance targets at lowest cost via proactive asset management and cost control, achieved through harmonization of critical AM processes and efficiencies gained from consolidation of the legacy utilities. Reliability metrics will be met by targeting investments to assets at greatest risk of failure combined with the consequence of failure.

The DSP lists performance targets for reliability, customer satisfaction, unit costs, projects completed, work efficiency and percent of cable in poor or very poor condition, among others. The targets set are based on historical patterns where data exists and new measures on a forward-looking bases, with values established based on proposed expenditures in the five-year investment plan. The performance target for SAIDI (excluding Major Event Days), is presented in Table 5.2.3 – 6 of the DSP and presented below. The .98 value was set to improve performance and address a decline in reliability performance as measured by IEEE P1366 metrics, which increased 8 percent annually over the prior five years.

Measure Category	2020-2024 Performance Measure	5-Year Historical Performance	Target (2020-2024)
Operational	SAIDI – Excluding MEDs	0.98 hours	Maintain

Figure 5.2.3 – 4 from the DSP, presented below, illustrates that defective equipment is the leading cause of customer outage hours (similar charts show similar patterns for number of interruptions), followed by adverse weather and loss of supply.[15] The majority of these interruptions, over 75 percent, is due to cable or padmount switchgear failure, with most of the remainder caused by

[15] For example, interruption caused by failure of HONI transmission lines or station equipment.

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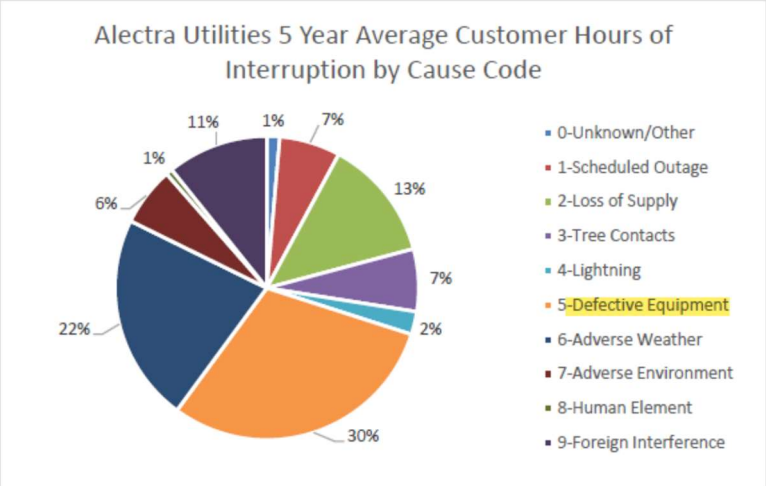
overhead line failures. Alectra's effort to target System Renewal investments on vulnerable underground equipment and overhead lines will help achieve performance targets at lowest possible cost.



Guidehouse Conclusion: *Alectra's DSP documents in detail historical performance measurements and proposed targets for each of the metrics outlined in section 5.2.3 of Chapter 5, and how these metrics are derived and tracked. The DSP also provides evidence that Alectra's use of rigorous asset condition and risk evaluation methods, when combined with analytics to determine optimum investment, produces a five-year investment plan will help Alectra achieve performance targets at lowest life-cycle cost. However, although the additional investment under the OEB's ICM funding mechanism is needed to avoid degradation in reliability, performance and customer satisfaction, it is unlikely that Alectra will achieve the same performance levels if the original DSP five-year investment plan was approved*

1.9 Renewable Energy Generation

Section 5.3.4 of Alectra's DSP addresses renewable energy generation or REGs, with the quantity, capacity rating, location and type summarized in tables and charts for both small medium and larger REGs. The DSP lists remaining REG interconnection capacity, by station, for both spinning and inverter based REGs. Alectra lists stations that currently are constrained (12), and actions the company undertake to mitigate these constraints; mostly reverse power or thermal violations.

The amount of new REG capacity projected for installation on Alectra's distribution system over the next five years is projected to be low compared to historical levels due to changes in Feed-in Tariff ("FIT") and Alectra's predominantly urban system that limits rooftop solar. Table 5.3.4. – 2 projects about 75 MW of cumulative new REG capacity by 2024, a fraction of Alectra's peak demand of over 5,000 MW – total connected REG as of 2018 was about 150 MW. Hence, REG impacts and the need to mitigate potential hosting capacity constraints and station limits (i.e., DESN transformer limits and fault duty constraints) to accommodate new REGs is modest. Hence, the number of projects and proposed investments targeted to REG is thus low over the five-year DSP.

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Notwithstanding the nominal REG capacity forecast, Alectra proposes to assess the role and value of REG (and demand response and energy efficiency as part of a DER strategy) in its planning processes. Several pilot initiatives are proposed, including the potential for DER to defer or eliminate the need for station capacity upgrades.

Guidehouse Conclusion: *Alectra has identified areas where hosting capacity limits or other operating constraints limit the amount of new REG absent system upgrades and has proposed appropriate mitigation and projects to enable increasing amounts of REGs. Alectra recognizes the potential for REG to defer capacity investments and has proposed pilot projects to determine the conditions under which REG may be a cost-effective alternative.*

1.10 Capital Planning Processes and Optimization

Alectra follows a structured approach using rigorous analytics to determine the level of investments required to achieve strategic objectives, meet performance targets and mitigate risk. The DSP describes in detail Alectra's capital planning process and documents the activities Alectra uses justify the magnitude and timing of proposed investments for programs and projects for which it seeks funding approval. Project "owners" are assigned to specific investment categories and are responsible for preparing business plans and documentation need to ensure proposed projects address risk or produce high value for money. Information for all ongoing and proposed capital projects resides in a common repository within the Copperleaf C55 capital management system. The use of a single system to enter and track information relating to project costs and benefits is a critical feature of Alectra's capital planning process, as the assumptions and methods used to determine project value and need are consistently applied, thereby avoiding potential biases associated with processes based on judgement or inconsistent project evaluation methods.

Copperleaf's C55 suite of investment planning modules is used by Alectra to manage capital projects and to produce an optimized investment portfolio over five years, subject to the constraints outlined in the risk management section.[16] The C55 multi-variate optimization software is an industry leading tool used by electric utilities throughout the United States and Canada, including other electricity distributors in Ontario that have submitted rate applications before the OEB. The need for such a tool and structured approach to investment planning is underscored by the large number of projects in Alectra's capital portfolio – over 1000 in the DSP. One of the key features of C55 is its ability to evaluate and rank dissimilar projects, including those in each of Alectra's four investment categories, on a common economic scale.

The C55 suite includes a Value Framework module, which is used to quantify project benefits across a wide range of economic, performance and risk avoidance categories. The DSP presents in detail the assumptions and rationale Alectra used to support proposed investments, with descriptive details and data highlighted for many of these projects. The capital planning process prioritizes investments subject to funding constraints, including mandatory investments for customer connection requests, municipal relocation or highway projects, equipment failures and projects required per provincial or regulatory requirements. Alectra's optimization process produced an investment plan that is distributed equally over time, with modest annual increases over the five-year plan.

[16] Also referred to as Alectra's Capital Investment Portfolio application.

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Guidehouse Conclusion: *Guidehouse's review of Alectra's capital planning process and its application of C55, confirms that Alectra applied an appropriate level of rigor to support the assumptions and values used to support the prioritization and selection of capital projects and programs. Alectra's capital budgeting process and its use of C55 justifies the adjusted five-year capital plan. Our assessment of Alectra's capital plan for each of the OEB's investment categories is addressed in further detail below.*

1.11 Five-Year Investment Plan

Alectra's DSP and ten-year investment horizon – five historical and five forward-looking – spanned the years 2015 through 2020 of approved spend (2018 through 2020 was budgeted) and the years 2020 through 2024 in its original IR rate request. Table 5.2.1 – 4, presented below, shows Alectra's proposed investment plan at the time the DSP was submitted for each of the OEB's Chapter 5 investment categories. The original 2020 through 2024 DSP investment plan was $1,457 MM, with modest increases in investment over the five-year plan for System Access and System Renewal.

DSP Five-Year Investment Plan

Investment Category ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
System Access	66.5	66.9	63.2	67.1	70.2	333.9
System Renewal	139.0	142.0	154.0	156.1	177.2	768.3
System Service	38.0	36.9	36.0	42.4	37.2	190.5
General Plant	39.4	34.4	35.1	30.2	24.7	163.8
Total	**282.9**	**280.2**	**288.3**	**295.8**	**309.3**	**1,456.5**

Since Alectra notified the OEB in April 2020 that it would withdraw its pending IR rate application, it has adjusted its five-year base investment plan. The current plan includes actual investments for 2020 and 2021, forecasted investments for 2022, and adjusted investments for 2023 and 2024. The five-year total has been adjusted downward to reflect lower growth due to Covid 19 impacts, and further downward adjustments for renewal replacements and rebuilds; mostly cable replacement and injection, and rear lot conversions. These reductions are partially offset by increased costs of mandatory overhead replacements, and higher costs for material and labor (approximately 4 percent) in years 2022 through 2024 due to inflation. The revised five-year total is now $1,359 MM[17], presented below, which excludes a $52.3 million funding request that Alectra proposes to file with the OEB under its incremental rate application mechanism.[18]

Adjusted Five-Year Investment Plan

Investment Category ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
System Access	63.0	67.4	64.8	69.2	68.3	332.7
System Renewal	135.5	136.5	125.4	150.1	162.9	710.4
System Service	26.8	28.4	27.2	24.4	22.0	128.8
General Plant	30.8	29.6	41.9	44.1	40.3	186.7
Total	**256.1**	**261.9**	**259.3**	**287.8**	**293.5**	**1,358.6**

[17] Values entered for years 2020 and 2021 are actual spending amounts, while those entered for 2022 are forecast, and 2023 and 2024 are adjusted investment plans.

[18] Proposed incremental investments for cable includes $25.4 in 2023 and $26.9 million in 2024.

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Guidehouse's assurance review assesses the adequacy of Alectra's current investment plan based on the processes and rationale outlined in the DSP and applied to justify adjustments to the investment plan for years 2023 and 2024, and the need to accelerate by $52.3 million for underground equipment. Our review is summarized below for each of the four DSP investment categories. For each category, tables listing proposed adjustments to the investment plan by major subcategories are presented for the years 2020 through 2024. An assessment of the impact of changes in proposed investment on performance metrics is provided based on Guidehouse's assessment of Alectra's DSP as applied to major investment categories.

1. System Access

The majority of Alectra's investments for System Access – over 80 percent - is for mandatory projects such as new customer connections, metering, highway relocations and customer-initiated distribution projects; up to 50 percent of proposed investment is for new connections in some years. The remaining 20 percent is mostly for meter replacements. Although Guidehouse did not independently review Alectra's load forecast, the DSP provides details on how the forecast were developed and the factors driving load growth in certain areas versus flat projections in other regions. Outlying areas with growth opportunities such as Brampton and Vaughn are expected to increase at modest levels while built-out areas such as Mississauga will see growth related to downtown redevelopment.

Adjusted System Access Investment Plan ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Network Metering	17.0	14.3	12.9	12.4	12.7	69.3
Customer Connections	33.8	39.4	36.8	39.1	39.8	188.9
Road Authority & Transit Projects	12.4	13.5	13.8	16.5	15.7	71.9
Transmitter Related Upgrades	(0.2)	0.2	1.3	1.2	0.1	2.6
Total	**63.0**	**67.4**	**64.8**	**69.2**	**68.3**	**332.7**

Just over twenty percent of annual spend is for road authority projects and a slightly lower percentage for network metering, each of which represent mandatory investment (e.g., network meter investment is based on projections for new connections; whereas road authority projects are based on information provided by municipal and provincial entities). The amounts assigned for transmitter related upgrades is low, less than one percent, due to the relatively small number projects that require Alectra capital contributions.

The following table presents the net change in proposed investment documented in the DSP for System Access versus Alectra's current plan by major subcategory. The total five-year adjusted five-year investment plan is mostly unchanged, with increased investments for customer connections offset by decreased investments for roadway projects from 2022 through 2024. The increase in investments for network metering and new customer connections is primarily due to continued residential and commercial growth in sections of Alectra's service territories while the decrease in Road Authority projects reflects a decrease in roadway construction due to Covid impacts. A portion of the increase in network metering costs is related to system upgrade requirements discovered during harmonization. Guidehouse agrees with the need for these adjustments and concludes that the minor reduction in net investments will not materially impact reliability, performance or customer satisfaction.

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Investment Plan Adjustments ($MM) System Access	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Network Metering	2.2	0.0	2.7	0.8	0.5	6.2
Customer Connections	2.4	6.3	2.0	2.8	2.1	15.6
Road Authority & Transit Projects	(7.3)	(3.8)	(4.4)	(2.7)	(4.6)	(22.8)
Transmitter Related Upgrades	(0.8)	(2.0)	1.3	1.2	0.1	(0.2)
Total	**(3.5)**	**0.5**	**1.6**	**2.1**	**(1.9)**	**(1.2)**

Note: Increased investment appears as a positive adjustment; decreases in brackets

Conclusion: *The level of investment Alectra proposes for System Access is appropriate given recent changes to its load forecast and downward adjustments for pending or ongoing road and highway projects obtained from transportation authorities, and scheduling commitments for installation or new or replacement network meters. The of amounts listed for the years 2022 through 2024 align with these adjustments and revised forecasts. Guidehouse also recognizes that Alectra has elected to shift investment among System Access categories to accommodate delays of new roadway projects or changes in the load forecast, and to account for unanticipated economic impacts or other factors that impact investment levels. The amounts budgeted are expected to cover total investments across all categories, collectively, absent additional major adjustments.*

2. System Renewal

Over 50 percent of Alectra's proposed five-year capital investment plan is for renewal replacements, with annual investment amounts increasing over the five-year investment plan as documented in the table below. Guidehouse's review and assessment confirms that Alectra has assigned an appropriate and justifiable amount of capital funds to System Renewal, as distribution assets will unacceptably deteriorate beyond current levels and therefore, must be proactively addressed to avoid degraded reliability to its customers.

Guidehouse's finding is supported both by customer survey results and the detailed analysis Alectra conducted to identify those assets at highest risk of failure (some asset categories are in good condition and require minimal spend). Alectra's analysis recognizes and confirms that asset replacements are targeted to areas of greatest need on its distribution system rather than system wide. The use of C55 project optimization models incorporates risk exposure across several categories to prioritize projects and to balance investment versus risk over each set of assets. Guidehouse concludes that Alectra's approach to determine required investment levels for System Renewal is consistent with leading asset management practices.

Adjusted System Renewal Investment Plan ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Overhead Asset Renewal	32.8	39.8	36.7	39.7	46.8	195.8
Underground Asset Renewal	61.5	55.6	55.3	75.9	80.6	328.9
Reactive Capital	22.5	26.8	21.1	21.8	22.3	114.5
Rear Lot Conversion	2.4	0.1	1.1	0.5	1.0	5.1
Substation Renewal	10.5	7.3	4.8	5.0	4.7	32.3
Transformer Renewal	5.8	6.9	6.4	7.2	7.5	33.8
Other System Renewal	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**135.5**	**136.5**	**125.4**	**150.1**	**162.9**	**710.4**

Approximately 60 percent of Alectra's distribution system is located underground (or ground-mounted in the case of transformers and switchgear), with a substantial percentage, up to 17% or higher, determined to be in poor or very poor condition.

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Accordingly, just under 50 percent of total spend for System Renewals is for underground assets. Approximately 40 percent of annual spend on cable is for silicone injection on cable sections identified as eligible for replacement[19] - cable injection is a proven, low-cost option to extend cable life (by up to 20 years or longer per warranty provision). Alectra's proposed five-year investment plan is structured to replace or upgrade at risk cable and accessories on a sustainable basis to meet performance targets and to avoid degraded reliability and interruptions to customers served in areas where cable condition is poor. Notably, customers confirm in a recent survey their support of Alectra's proposed investment plan for the replacement of deteriorated underground cable and equipment..

For overhead lines, at risk poles and obsolete conductor (e.g., number 6 wire size) is targeted for replacement based on safety and reliability criteria. For example, Alectra proposes to install new poles on the opposite side of roadways where existing poles incapable of supporting four sets of primary conductor, often with communication lines built underneath, during majors storms – pole failures on these circuits can and have caused significant interruption to a large number of customers (Figure A05 - 1 from the DSP is highlighted below). Approximately $22 million is assigned annually to reactive replacements, which essentially is a mandatory spend category used to replace or repair (via corrective maintenance) of failed equipment.

Approximately $11 million, on average, is assigned annually for converting lower voltage distribution assets (4kV) to operate at higher voltage to improve asset utilization and performance, such as reduced losses and capacity. Alectra has been converting low voltage assets, including the elimination of older stations, on an ongoing basis, consistent with common utility practices. The selection of stations and lines for conversion is based on a combination of factors, including reliability, load growth, asset condition and equipment obsolescence. The amount of spending targeted to voltage conversions has decreased due to shifting of funds to higher priority renewal projects, including station equipment where voltage conversions eventually will need to be completed. The delay in undertaking voltage conversion projects due to reduced spending likely will increase total costs over the long term.

The following chart derived from the 2020 lists assets in several categories that are well beyond expected end-of-life, but not targeted for replacement due to favorable

[19] Cables suitable for silicone injection include those with relatively few in-line splices and are less than 35 years in age.

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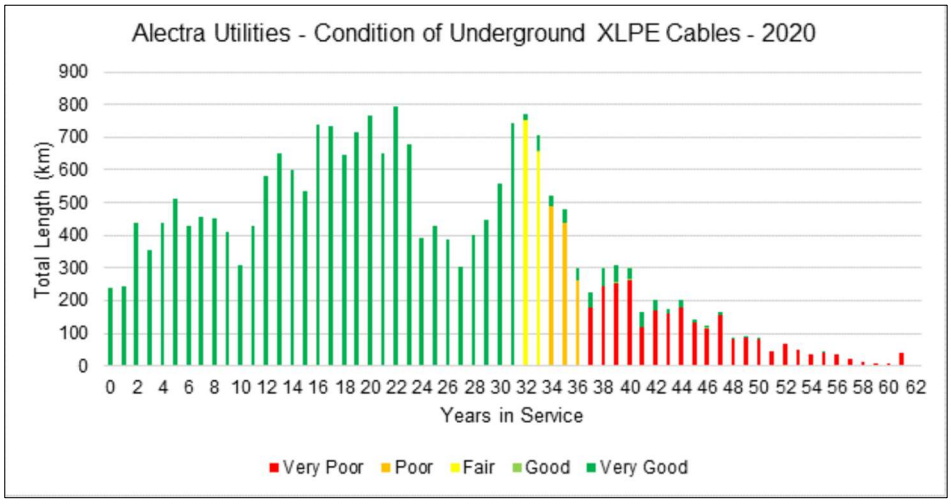
performance or condition assessments. This practice confirms that Alectra has properly targeted investments to equipment based on actual deterioration and a value analysis quantified via C55 modeling. Alectra has identified areas where cable has failed repeatedly – often these are locations where soil or environmental factors lead to insulation breakdown – and proposes to accelerate investments to proactively address at-risk cable in areas most vulnerable to repeat or prolonged outages.



The following table presents the net change in proposed investment in the DSP versus the current plan for System Renewal by major subcategory. Total five-year investments is reduced by approximately $58 million, with significant reductions in underground (cable) replacement and injection between 2021 and 2024. The lower investment is partially offset by increases for overhead assets in 2023 and 2024 to comply with Municipal and Regional Government requirements to remove redundant overhead lines in conjunction with ongoing high-speed communication system upgrades. The cost of reactive capital has and is expected to be higher than DSP levels due to an increase in equipment failures caused by reduced investments for renewal replacements resulting from the denial of Alectra's prior M-Factor application. The increase in other System Renewal investments of $9 million over five years is for lower cost projects that fall below the OEB's materiality threshold.

Investment Plan Adjustments ($MM) System Renewal	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Overhead Asset Renewal	(1.5)	5.0	(2.6)	8.8	9.2	18.9
Reactive Capital	3.7	7.6	1.5	1.8	1.9	16.5
Rear Lot conversion	(2.4)	(1.1)	(0.1)	(3.7)	(7.5)	(14.8)
Substation Renewal	(2.3)	2.9	2.0	1.8	(0.8)	3.6
Transformer Renewal	0.3	0.6	(0.6)	(0.2)	(0.3)	(0.2)
Underground Asset Renewal	0.4	(18.9)	(26.9)	(12.6)	(14.9)	(72.9)
Other System Renewal	(1.7)	(1.7)	(1.8)	(1.9)	(1.9)	(9.0)
Total	**(3.5)**	**(5.5)**	**(28.6)**	**(6.0)**	**(14.3)**	**(57.9)**

The reduction in investment for rear lot conversions is not expected to materially degrade reliability over the next two to three years. In contrast to rear lot deferrals, Guidehouse finds that downward adjustments cable will materially impact reliability and customer satisfaction, as cable is expected to continue to deteriorate to unacceptable levels as

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discussed in prior sections on asset management and condition assessment. The amount of cable that will be assigned as in poor or very poor condition is likely to increase. As such, Guidehouse anticipates that reliability will likely decline absent accelerated investment, as proposed, under the OEB's ICM rate mechanism.

Guidehouse Conclusion: *The methods Alectra applies to identify required investment for System Renewal is based on a thorough and consistently applied condition assessment methodology and analytics that balances cost versus risk. Alectra's methodology, which identifies those assets with greatest risk and consequence of failure, justifies the projects it selects for replacement or upgrade. The level of proposed investments aligns with Alectra performance targets, particularly for reliability, which is expected to degrade absent proposed investments for asset renewal as outlined in both the DSP and Alectra's most recent capital plan.*[20] *Based on its Assurance Review, Guidehouse concludes Alectra's current investment plan for System Renewal is inadequate. The deferral of renewal investments is not sustainable as lines and equipment will deteriorate at increasing higher rates. Hence, the acceleration of investment of $52.3 million for cable and accessories is essential to enable Alectra to achieve a sustainable level of replacements without jeopardizing reliability in sections of its system where cable failures are highest, and customers are at risk of repeat and lengthy interruptions.*

3. System Service

Alectra's annual investment plan for System Service is approximately $25 million, which includes up to ten million annually, on average, for supervisory control (SCADA), automation, and communications and control systems. Notably, on average, about two to three million is for station capacity upgrades, a relatively low amount of investment that Alectra is able to achieve via efficient use of existing assets in lieu of new capacity. Alectra demonstrated that it is able to cost-effectively defer several station capacity additions or upgrades by expanding or adding new distribution circuits along with new feeder ties points to increase available transformer back-up capacity to and from adjacent stations. This approach is consistent with good industry and asset management practices. About $10 million, on average, is assigned to distribution line upgrades to increase transfer capability between stations and enable capacity deferral; and to increase utilization of existing lines via load balancing and line segment transfers.

Adjusted System Service Investment Plan ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
SCADA & Automation	3.4	9.0	4.7	2.4	2.8	22.3
Capacity (Lines)	11.2	7.0	11.2	12.2	11.7	53.3
Capacity (Stations)	0.7	5.3	2.6	0.7	0.8	10.1
System Control, Communications & Performance	5.5	4.2	5.9	6.1	4.0	25.7
Safety & Security	5.6	2.6	1.6	1.6	1.4	12.8
Distributed Energy Resources (DER) Integration	0.4	0.3	1.2	1.4	1.3	4.6
Total	**26.8**	**28.4**	**27.2**	**24.4**	**22.0**	**128.8**

As noted, effective coordination with the IESO, Hydro One and other regional planning entities, along with recent reductions in major industrial load, has led to the deferral of major station investments – a $10 million downward adjustment in station capacity is

[20] The DSP projected that reliability would worsen by up to 50% over the next five years under a partial funding scenario for renewal replacements and upgrades.

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included in the above table.[21] Further, Alectra is using technology to enhance performance via real-time monitoring of major equipment (such as station transformers), which provides critical operational data to distribution system operators that enable them to help detect abnormal conditions before failure, and to improve visualization and monitoring, and prospectively, control of distribution energy resources; processes that will enable greater amounts of renewable and other non-conventional resources, and ensure compliance with the regional Long-Term Energy Plan.

Guidehouse is aware of the low forecast for new distributed generation capacity over the next five years, which results in less than $1 million allocated annually for DER integration. All proposed funding is for pilot projects designed to assess the capability of DER to defer capacity investments (e.g., via non-wires alternatives) – some investments deferred in 2020 and 2021 due to Covid have been moved to 2023 and 2024. However, no investments are proposed to expand the distribution system to accommodate REG. Proposed investments include the development of a DER Control Platform (i.e., Distributed Energy Resource Management System of DERMS), a foundational investment designed to enhance visualization, management and control functionality that will be needed if Alectra is to rely on DER and storage as a source of firm capacity to defer both TS/MS stations and distribution capacity additions.

Alectra's investment plan for System Service investments includes upgrading SCADA and automation technologies, such as the installation of automated tie transfers of feeder ties to improve reliability and asset utilization. Investment in SCADA and automation via tie transfers has been demonstrated by electric utilities throughout North America as a cost-effective approach to improve reliability and efficient use of distribution assets.[22] However, the improvement in reliability achieved by automation does not diminish the need for renewal upgrades, as outages will continue to occur and increase more frequently as equipment further deteriorates.

The following table presents the net change to the DSP Investment Plan for System Service from the current plan by major subcategory. Total five-year investment has been reduced by approximately $62 million. Virtually all reductions are for distribution and station capacity investments during the years 2020 through 2024. Some reductions in capacity related investment has been redirected to support critical System Renewal replacements, and Alectra has accepted a modest increase in capacity-related risk. However, because demand forecasts and major load additions have declined since the issuance of DSP, Guidehouse does not expect these adjustments will materially affect Alectra's ability to serve customer electricity demand, nor negatively impact reliability, performance or customer satisfaction.

[21] For example, deferring the need for additional capacity at Barrie TS from 2022 to 2026.

[22] Amounts assigned to automation and that appear in the table assume a funding request from Natural Resource Canada for Alectra's Smart Grid program is approved. If funding is not approved, the investment will increase and investments in other projects will need to decrease.

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Investment Plan Adjustments ($MM) System Service	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
SCADA & Automation	0.0	5.4	1.0	(1.4)	(1.9)	3.2
Capacity (Lines)	(9.9)	(17.0)	(12.7)	(14.2)	(3.1)	(57.0)
Capacity (Stations)	(0.1)	4.6	1.8	(4.5)	(11.2)	(9.4)
System Control, Communications & Performance	(1.1)	(1.6)	1.2	2.0	1.2	1.7
Safety & Security	0.2	0.6	(0.4)	(0.4)	(0.6)	(0.6)
Distributed Energy Resources (DER) Integration	(0.3)	(0.4)	0.3	0.5	0.4	0.5
Total	**(11.2)**	**(8.5)**	**(8.8)**	**(18.0)**	**(15.2)**	**(61.7)**

Guidehouse Conclusion: *Alectra approach and planning criteria for capacity investments is consistent with good utility practices as it provide for the most efficient use of assets. Further, Alectra's current investment plan for System Service is appropriate and justified as the reductions align with lower forecasts for peak demand over the five-year investment period. Absent unexpected growth or other significant changes, Guidehouse does not expect the downward adjustments in investment will materially impact performance or reliability, or other performance targets.*

4. General Plant

Alectra's General Plant programs describes in details the company's non-electric delivery assets, physical facilities, tools and fleet investments, technology initiatives and specific programs that are underway or proposed for the five-year capital plan. It also outlines plans to significantly enhance information technology systems to support its modernization programs, data management, and business processes, with over 50 percent of the total budget assigned to IT and operational technology (OT) software.

Adjusted General Plant Investment Plan ($MM)	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Facilities Management	7.4	2.6	3.4	4.3	5.9	23.6
Information Technology	13.8	13.8	29.3	29.4	21.8	108.1
Fleet Renewal	8.1	6.6	7.3	7.7	10.6	40.3
Connection and Cost Recovery Agreements	0.0	5.5	0.4	0.6	0.0	6.5
Other General Plant	1.5	1.1	1.5	2.1	2.0	8.2
Total	**30.8**	**29.6**	**41.9**	**44.1**	**40.3**	**186.7**

The proposed five-year investment plan for General Plant reflects a shift in investment, with increased between 2022 and 2024, mostly Covid-related to adjustments in Information Technology. Several ongoing or proposed IT upgrades or enhancements have been delayed or deferred due to remote work locations for Alectra employees, and logistics challenges associated with vendor software provision and support.

While Guidehouse did not conduct an independent assessment of individual IT programs and projects, we reviewed major investment categories and the rationale supporting these investment. We observed that Alectra has prepared a comprehensive IT plan that outlines in detail the numerous software systems and hardware that are needed to efficiently support its work force and financial and operational obligations of a modernized electric power enterprise. For example, the transition to an Enterprise Resource Management ("ERP") and associated work planning and scheduling systems, cyber security enhancements, operational support systems are consistent with good utility practice. It also introduces new IT initiatives, in addition to replacing or upgrading obsolete systems such as those where vendor support of older versions is no longer available.

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Several of these initiatives increase productivity and efficiency that improve work quality and reduce internal and contractor labor costs. They also align with Alectra's asset management harmonization initiatives, as enhanced IT/OT systems, consistently applied, are foundational technologies that are needed to realize the performance, organizational, financial, regulatory and customer-related objectives outlined in the Chapter 5; and enable the OEB to affirm that Alectra's DSP fully addresses requirements outlined in its *Handbook to Utility Rate Applications*.

The following table presents the net change in investments outlined in the DSP for General Plant versus the adjusted plan by major subcategories. The total five-year adjusted investment plan has increased by approximately $20 million, with most increases for IT hardware and software between 2022 and 2024. As noted, the net increase in IT-related investments is due to a range of factors including Covid-related delays, increased costs associated with equipping employees with hardware and software to enable them to work remotely, increased cyber security-related requirements, enhanced operational support systems, and new foundational IT systems designed to improve operational technology functionality and work force efficiency. The increase in years 2022 through 2024 also reflects the higher cost of hardware and software due to inflation.

Investment Plan Adjustments ($MM) General Plant	Actual 2020	Actual 2021	Forecast 2022	Budget 2023	Budget 2024	Total
Facilities Management	3.2	0.0	0.5	(0.3)	2.4	5.8
Information Technology	(1.3)	(4.4)	9.5	17.1	13.4	34.3
Fleet Renewal	(0.8)	(2.9)	(2.6)	(2.6)	0.4	(8.5)
Connection and Cost Recovery Agreements	(8.7)	3.9	0.4	0.1	0.0	(4.3)
Other General Plant	(1.0)	(1.4)	(1.0)	(0.4)	(0.6)	(4.4)
Total	**(8.6)**	**(4.8)**	**6.8**	**13.9**	**15.6**	**22.9**

Guidehouse Conclusion: *Alectra's General Plant program as presented in the DSP describes in detail the company's non-electric delivery assets, physical facilities, tools and fleet investments grid modernization, technology initiatives and specific programs that are underway or proposed during the rate period. The DSP specifically describes how foundational IT and OT systems will improve reliability, efficiency and customer-oriented measures to enhance system performance, organizational efficiency, regulatory costs and customer service. These systems including post-DSP additions and adjustments, will produce savings both for capital investments and operational expense and are needed to achieve benefits via harmonization of the merger of the legacy electric utility systems across Alectra's service territories. Reduced investments for Fleet Renewal is warranted as it reflects Alectra's decision to lease vehicles due to supply chain issues related to Covid 19.*

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Attachment A

Copperleaf C55 Risk Matrix

Consequence Aide	None	Impact 150	Impact 500	Impact 1,500	Impact 4,500	Impact 7,500	Impact 12,500	Impact 30,000
COMPLIANCE	None: no corporate or legal requirements	**Threat:** Non-compliance resulting in receipt of an administrative order OR Non-compliance with a law or regulation resulting in a financial penalty of $150K or more	**Threat**: Corporate/Other: Corporate or other requirements (including contractual issues) where obligations would be approximately $500K. OR Non-compliance with a law or regulation resulting in a financial penalty of $500K or more	**Threat:** Municipal: Regulated (local level through Municipal by-laws) OR Non-compliance with a law or regulation resulting in a financial penalty of $1M or more	**Threat:** Non-compliance with a law or regulation resulting in a financial penalty of $3M or more	**Threat:** Federal/Provincial: Regulated (including OEB, CSA) OR Non-compliance resulting in work shut-down	**Threat:** Non-compliance resulting in a criminal conviction	**Threat:** Non-compliance resulting in suspension of license
DISTRIBUTION SYSTEM CAPACITY	**Threat:** Able to supply load without exceeding planning limits.	n/a	**Threat:** Can supply all load but temporarily exceeding planning limits	**Threat:** Can supply all load but there is sustained operation exceeding planning limits	**Threat:** Can supply all load but exceeding thermal limits	N/A	**Threat:** Unable to service a new load	N/A
SAFETY	No risk of incidents	**Threat:** Impact of event can be absorbed through routine activity Reportable incidents. Opportunity: Small operational improvements can be managed through routine activity	**Threat:** Risk of injury requiring medical attention	**Threat:** Non-life threatening Injuries requiring hospitalization	**Threat:** Impact of event required actions greater than routine activity. Reportable incident with serious but non-life threatening injuries **Opportunity:** Operational improvement provides minor or incremental improvement to day to day operations	**Threat:** A significant event which cannot be managed under routine activity Life threatening injuries **Opportunity:** Operational improvement provides sustained improvements to day-to-day operations	**Threat:** A critical event with a long recovery period which stretches plans to the limit and requires significant management effort to endure Life threatening injuries with long-term health implications **Opportunity:** Operational improvements provides significant improvements to day-to-day operations	**Threat:** A disaster with the potential to lead to the collapse of the organization Any loss of life and/or multiple serious long term health implications as a result of our actions **Opportunity:** Operational improvement provides a major innovative approach or significant rethink in terms of service delivery or operational improvement
ENIVRONMENTAL	No noticeable impacts with minor clean-up implications	Known impacts contained to the worksite such as fugitive emissions, minor spills with short term (< 1 year) clean-up implications	Known impacts contained to the worksite such as fugitive emissions, minor spills with medium term (up to 2 years) clean-up implications	Impacts with medium term (2 to 5 years) cleanup implications that are contained to the worksite.	Impacts are long term (>5 years) and are not contained on the worksite resulting in potential loss of flora, fauna and/or fish habitat. Impact significant enough to gain attention in provincial news media.	N/A	Impacts cause long term (> 20 years) damage to a water body, an environmentally/culturally sensitive receptor resulting in actual loss of flora, fauna or fish habitat. Impact significant enough to gain attention in national news media.	N/A
FINANCIAL	**Threat/Opportunity:** Immaterial financial impact	**Threat/Opportunity:** Financial impact of an event up to $300,000	**Threat/Opportunity:** Financial impact of an event $300,000 to $1,000,000	**Threat/Opportunity:** Financial impact of an event $1,000,000 to $3,000,000	**Threat/Opportunity:** Financial impact of an event $3,000,000 to $5,000,000	**Threat/Opportunity:** Financial impact of an event $5,000,000 to $10,000,000	**Threat/Opportunity:** Financial impact of an event $10,000,000 to $15,000,000	**Threat/Opportunity:** Financial impact an event over $15,000,000
REPUTATIONAL	Immaterial consequence	**Threat:** Some public embarrassment OR Minor effect on overall staff morale/public attitudes.	**Threat:** Short term local adverse media coverage	**Threat:** Negative press in more than one media **Opportunity:** Positive press in more than one media	**Threat:** Short-term negative media focus and /or significant concerns raised by one stakeholder **Opportunity:** Short-term positive media focus and/or significant recognition from one stakeholder	**Threat:** Long-term negative media focus and/or sustained concerns raised by more than one stakeholder **Opportunity:** Long –term positive media focus and/or sustained recognition raised by more than one stakeholder	**Threat:** Long-term negative and/or sustained concerns raised by more than one stakeholder. Indications of Stakeholders loss of confidence **Opportunity:** Long-term positive media focus and/or sustained recognition from more than one stakeholder, indicating stronger long term support	**Threat:** Stakeholders lose confidence in the organization in the long-term, permanent withdrawal of support by several key stakeholders **Opportunity:** Sustained recognition from the majority of stakeholders, long-term commitment for additional support
IT CAPACITY	Lack of capacity (or currency) of a system has no expected impact on Alectra's workforce.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 10	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 50	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 150	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 450	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 750	Lack of capacity (or currency) of an Enterprise wide system that impacts significantly (e.g. >10% average decrease in productivity)	N/A

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Continuous Improvement Framework Review

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Continuous Improvement Framework Review

July 3rd Findings Presentation

DRAFT

PVA

Recommendations

DRAFT

1) Systematically Create a Center of Excellence (COE)

- Integrate a single BU at a time
- Start with a BU already fairly aligned or “friendly” in terms of process
- The COE should encompass BT, OCM and the PMO teams using a tiered system based on project size
- Create and train a network of BU specific Change Champions
- COEs and their systems, processes, and behaviours are designed to change over time, which require them to be scalable and agile

We suggest the following recommendations be optimized in each integrating BU, starting with the BT team itself, where applicable.

Recommendations

DRAFT

2) Optimize Roles, Responsibilities, and Accountabilities.

- Clarifying each BUs core area of expertise and value proposition
- Optimizing individual roles, responsibilities, and accountabilities and aligning with existing processes
- Identifies opportunities to delegate
- E.g., Hedgehog, RACI, DARE exercises

Recommendations

DRAFT

3) Enhance Integrated Management Operating Systems (MOS)

- Optimizes communications, reporting requirements, to enhance a BUs ability to plan, manage and execute on work.
- Enhances the ability to identify key handoffs
- Optimize communication flow throughout the organization as required and using the least number of meetings possible
- Each element is supported by an agenda or coaching document
- Opportunity to embed concepts of psychological safety, physical safety, opportunity identification, and solutioning into key conversations and meetings

Recommendations

DRAFT

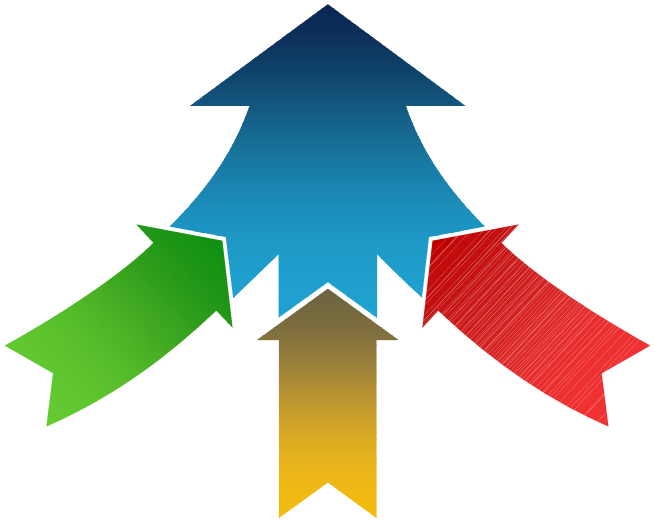
4) Enhance Opportunity Collection with an Opportunity Resolution Program (ORP)

Process:

- Collect opportunities from the employee/field level in M365
- Solution ‘quick fixes’ at the manager level (1-2 weeks to solution)
- Region/BU level ORP to tackle bigger issues (1-3 months to solution)
  - Steering Committee would prioritize opportunities and assign corrective teams (CTS)
- Root cause analysis (RCA) “toolkit” required for CTs
- Solutions selected for implementation by the Region/BU steering committee will be implemented by the team and designated Change Champion*
- Enterprise Level ORP for tackling wider-ranging opportunities (4-12 months)
- Creates a scaling data base of opportunities to data mine and support the cases going through the C55 process

Continuous Improvement

DRAFT



Management Operating System (L.O.S.)

Provides a structured methodology and a set of tools for effective forecasting, planning, work execution and reporting

Process Standardization and Optimization (O.R.P)

Standardized structure and rigour to continuously identify and resolve opportunities

Aligned Roles, Responsibilities and Accountabilities

Manager, Supervisors and Employees behaviours have been adapted for more effective work planning and management, while being aligned with the BU's core value proposition and overall strategic goals of the organization

Recommendations

DRAFT

5) Centralize all CI initiatives on a M365 SharePoint Site

- Enhances visibility, data collection and automation
- Enhances reporting in PowerBI
- Enhances data collection (Microsoft forms, PowerApps)
- Completely customizable
- No expensive software upgrades required
- ~6 months to train and develop SMEs*

Recommendations

DRAFT

6) Enhance Management by including CI qualifiers to optimize communication, performance monitoring, and sustainment of CI initiatives

Examples include:

- X Number of Quick Fixes Solutioned
- X Number of Successful Corrective Team Initiatives Completed
- Metrics for enhancing the success of C55 implementations
- Productivity Savings Achieved

Recommendations

DRAFT

7) Create a network of Change Champions to support COE and ORP

- BU specific change champions to support sustainment of COE initiatives and the ORP
- Support leadership with training, workshops, materials, and toolkits

- Workshops and Training could be on the following:
  - Effective Communication and Facilitation
  - Leadership Coaching and Development
  - Creating High-performing Teams
  - Psychological Safety and Emotional Intelligence
  - Change Management

- Each enhanced process will require training/workshops that the change champions will eventually lead and refresh as required, for example:
  - Defining and Aligning Roles and Responsibilities
  - Introduction to M365
  - Introduction to the ORP
  - Introduction to the MOS
  - RCA Toolkits for CTs etc.

Recommendations

DRAFT

8) Enhance Data and Metrics with a Base Data Taskforce

- Explore data needs of each BU
- Explore enhancement opportunities for measuring productivity savings in each BU on year-over-year basis

Examples include:

- Baselining/benchmarking units of work
- Estimate to actual
- Schedule loading
- Earned hour ratios
- OT hours
- Contractor Spend
- Outage Frequency and Duration
- Labour Productivity/Revenue per employee
- Employee utilization rate etc.

Frameworks

DRAFT

- Many valuable CI Frameworks exist, which are applicable in certain cases, but generally, most utilities use **Initiate-Plan-Execute-Monitor and Control –Close** because it is simple, adaptable and likely already used throughout the organization (i.e., PMO office)

- It is important to be consistent with a universal language and use a framework that is adaptable, scalable and allows for customization based on the needs of any initiative or team

- No two projects or initiatives are the same

- ADKAR is a crucial change management model that contributes immensely by focusing on the people side of change, but it doesn't inherently provide a framework for ongoing systems and process improvement

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Recommendations Roadmap

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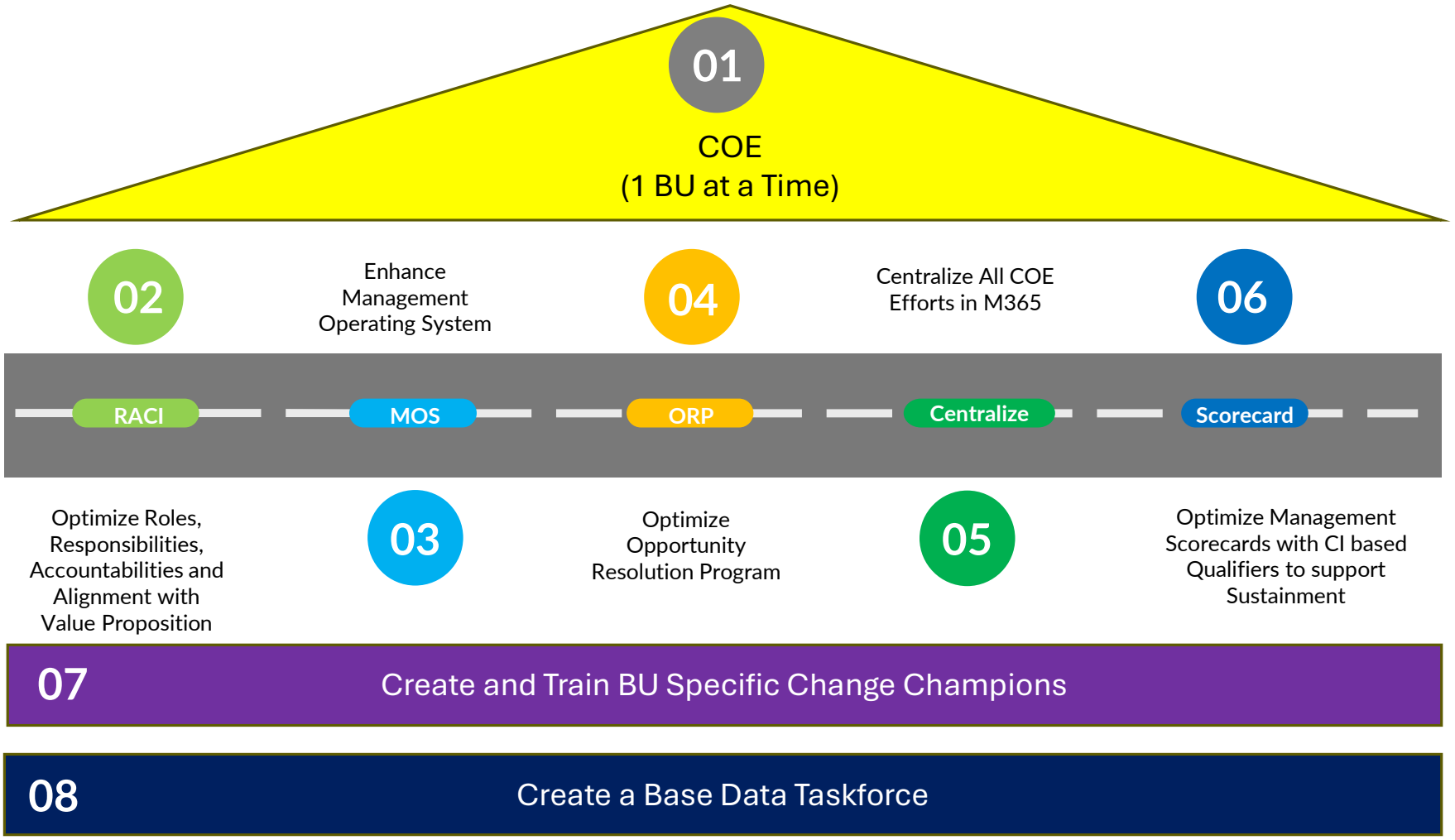

Thank you!!

DRAFT

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Determination of Asset Utilization Report

QUANTA TECHNOLOGY

February 11, 2020

Tom Wasik, P.Eng., MMSc
Vice President, Asset Management. Alectra Utilities
55 John Street North
Hamilton, ON L8R 3M8

RE: Methodology for Asset Utilization Targets

Dear Mr. Wasik:

Alectra Utilities is proposing adjustments to be incorporated to the Asset Utilization Targets procedure, so that more precise estimations of equipment needs are produced. This letter states Quanta Technology's observations and opinion on the proposed methodology.

The adjustments involve three main steps:

- Apply weather correction factors to the recorded transformer peak loads
- Use non-coincident peak load for station transformers
- Apply power factor to active peak load

Weather Correction Factors

Weather correction factors or weather normalization is a methodology widely used in the power systems industry, to bring historic recorded load to the same comparison base, independent of weather fluctuations. The method removes weather influence from recorded electric peak loads, and levels everything to the desired reference weather conditions.

Natural behavior of electric load vs. temperature is seen as a positive slope curve, where identical loads appear to be higher at higher temperatures, and lower at lower temperatures. For instance, what is recorded as 1 MW at 25 C, could be recorded as 1.2 MW at 30 C or as 0.8 MW at 20 C. This dependence of load on temperature, and on weather in general, when not considered, can result in misleading interpretation of actual electrical conditions, leading to deceiving assessment of current conditions and to poor estimations of future asset needs.

Another advantage of weather normalization is that historic load can be reflected to any desired reference weather conditions. For example, the recorded historic peak load series can be referenced to hot weather conditions of 35 C, to evaluate transformer capabilities at this specific temperature.

The weather correction methodology recommended by Alectra Utilities to be considered for asset utilization target definition, follows the process below.

1. Update of historic weather series
   The historic weather series is updated with the current year information. Each day's temperature is filtered using a 3-day weighted moving average function.
2. Define conditions representing a 10% probability of occurrence

Statistical processing of the weather data series is done to define one in ten (1-in-10) years conditions, to be used as reference.

3. Determine peak load as if the current year had 1-in-10 years hot weather conditions.
   Use regression analysis to determine correlation between the 3-day moving average, and peak temperature. Use regression techniques to determine the current peak load as if in 1-in-10 years hot weather conditions.

Non-Coincidence Factors

The coincident peak load at system level represents the maximum combined load of all transformer stations at the same time. However, at the time of occurrence of the coincident peak load, not all the transformer stations will necessarily be at their peak load condition; some might peak minutes or hours apart from the system peak on the same day.

Alectra Utilities make use of the coincidence factor to compensate for eventual slight changes in energy consumption patterns, that could lead to an increased coincident load seen by the transformer station. Application of the coincidence factor results in a slightly higher transformer load than what is observed at the coincident system peak time. This factor is computed as:

$$Coincidence\ Factor = \frac{Coincident\ System\ Peak\ Load}{Sum\ of\ Individual\ Station\ Peak\ Loads\ on\ the\ Same\ Day}$$

Power Factor Adjustment

The transformation capability of a station transformer is designed in terms of the apparent power it can deliver. The apparent power includes the active and the reactive power components, and can be calculated from the active component and power factor.

$$Apparent\ Power = \frac{Active\ Power}{Power\ Factor}$$

Power factor for station transformers is typically between 0.9 and 1.0, where the actual value depends on the amounts of active and reactive power being delivered.

Alectra Utilities has analyzed the historic records of active and reactive power for all stations in the Alectra Utilities service territory, and in the Hydro One service territory. A difference has been made between the average power factor registered during all year, and the average power factor registered in July, during times of peak load occurrence.

Alectra Utilities proposes using a power factor of 0.93 to account for reactive power consumption of a station transformer. This value corresponds to the weighted average power factor occurring in July for all stations in the Alectra and Hydro One (HONI) systems, as shown below.

	Avg. PF, July (peak loading)	Yearly Avg. PF
Alectra	0.96	0.97
HONI	0.92	0.93
All Stations	0.93	0.93
Weighted Average	**0.93**	0.94

Quanta Technology's Opinion

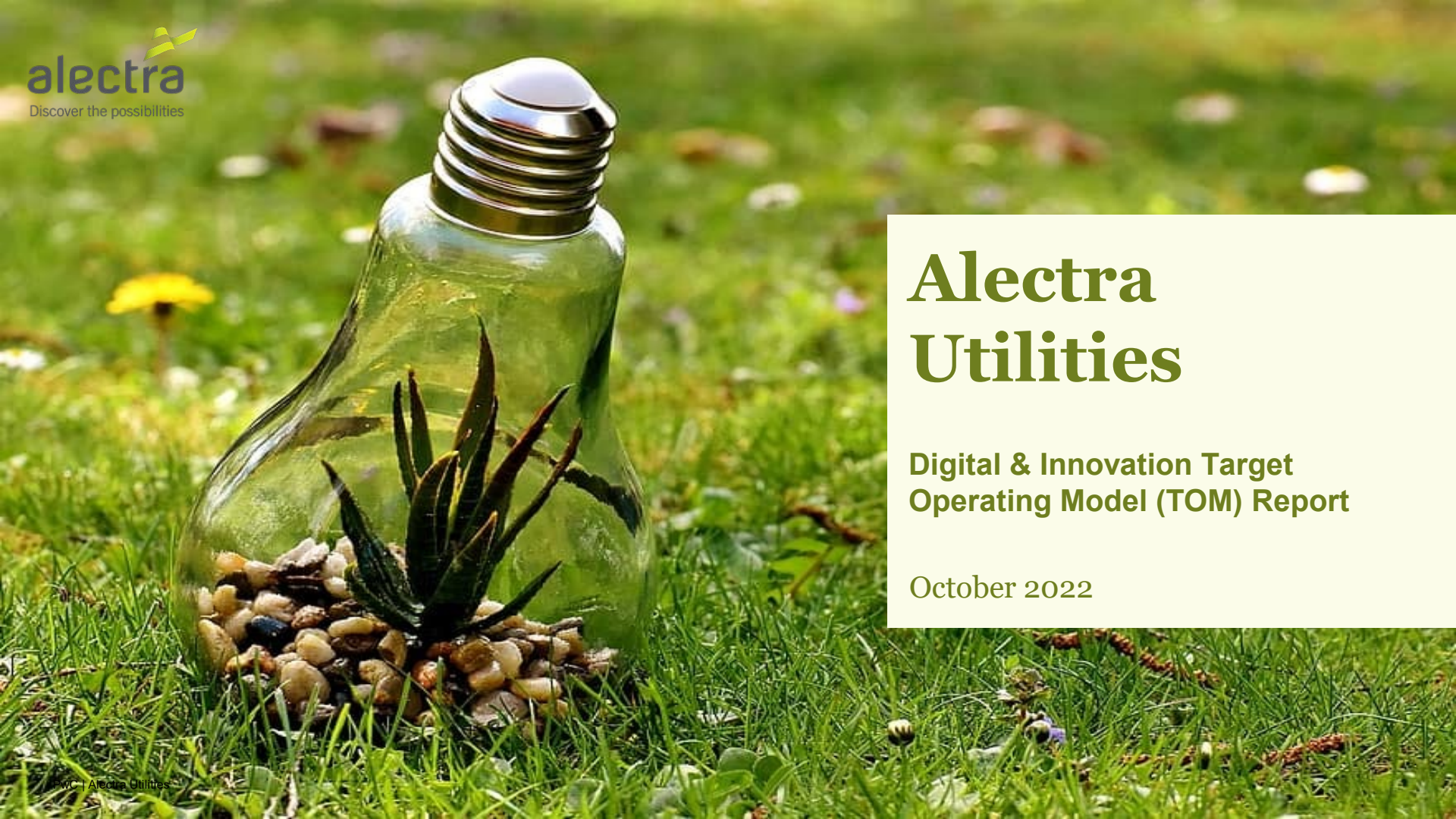
After reviewing the methodology Alectra Utilities proposes to incorporate to the Asset Utilization Targets procedure, it is Quanta Technology's opinion that the proposed adjustments are adequate and necessary to provide better estimations of asset utilization needs and targets.

The methodologies proposed for weather adjustment, coincidence factor correction, and power factor adjustment, are correct and aligned with the best planning practices followed by electric utilities throughout North America.

Sincerely,

Gerardo Sanchez, PhD
Advisor
Quanta Technology, LLC

Digital and Innovation Target Operating Model Report



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Alectra Utilities

Digital & Innovation Target Operating Model (TOM) Report

October 2022

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About this Report

This document presents the recommended target state operating model for Alectra's Digital & Innovation Team, and:

- provides overview of the various operating models that were considered to inform the future state
- defines a set of design principles to guide the development of Alectra's conceptual target operating model for the Digital & Innovation team
- describes the target operating model (TOM), capturing the high level governance and functional structure

Acknowledgements

The project team would like to express its gratitude to all of the dedicated and committed individuals at Alectra for their engagement, and the subject matter specialists for their candid and creative input to the process of defining the target state conceptual operating model for the Digital & Innovation team.

Background & Context Setting

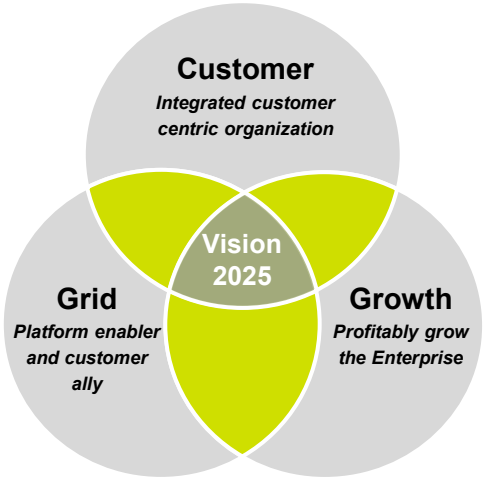
Background & context for refreshing Alectra's D&I operating model

Disruptive forces have set the stage for Alectra's ambitious transformational business strategy, resulting in the need for a refreshed digital strategy and operating model to better enable Digital & Innovation to both support and shape Alectra's strategic direction

Focuses on why Alectra exists and how the organization will transform the business at the enterprise level

Vision 2025

To be a leading provider of distribution and integrated energy solutions



Focuses on how digital and innovation can enable Alectra to run, grow & transform the business through Strategy 2.0

A business capabilities driven approach was taken to better align on how the Digital & Innovation team will be better positioned to accelerate Strategy 2.0

Digital Strategy

Determines **which business capabilities need technology investment** and "why", "what" and "when" those investments should be made

Digital & Innovation Target Operating Model

Defines **how the Digital & Innovation function delivers value** and achieves business-technology ambitions through various business capabilities

Approach for refreshing Alecta's D&I conceptual operating model

Evolving the role of technology at Alectra requires early and ongoing engagement with key stakeholders across business and technology...

Digital Strategy Workshop: align on what moving to digital means for Alectra, define and validate the target state business capability model, and prioritize key capabilities

Operating Model Workshop: review operating model options, align on best fit for Alectra

Roadmap Workshop: review implementation roadmap for the right path forward

PURPOSE OF THIS REPORT

Key business stakeholder input required

1 Review the current state

✓ Alignment & shared understanding of what would need to materially change to support the future state vision and strategy for Alectra

✓ Increased visibility & understanding of leading practice in terms of how digital & innovation is leveraged and delivered

2 Define & assess options for the future

✓ Shared understanding of how technology can be leveraged to deliver business in an optimal manner

✓ Alignment of digital & innovation delivery with business outcomes and capabilities outcomes

✓ Alignment on an appropriate go-forward option for how to connect the dots and create partnerships between business and digital & innovation

3 Define the path forward

✓ Clear direction set on the roles and responsibilities of business and digital & innovation at the functional level

✓ Alignment on the prioritized set of initiatives required to transition and evolve the digital & innovation function

Key benefits to be realized throughout the journey...

- Improved collaboration between business and digital & innovation stakeholders
- Shared understanding and articulation of how digital & innovation drives and enables business outcomes
- Enhanced ability to deliver digital & innovation and business capabilities more efficiently and effectively

Focus of this report

This report defines Digital & Innovation's conceptual target operating model to meet Alectra's strategic priorities and address the opportunities set out in the current state assessment

FOCUS OF THIS REPORT

Key Questions Asked

What are the current strengths and opportunities influencing the future direction of Digital & Innovation?

How well does Digital & Innovation collaborate with other portfolios and business units?

What is the optimal design of Digital & Innovation to meet future state objectives?

What are major gaps to address in the organization?

How do we ready the organization for change?

What is the plan to bridge those gaps, and what is the case for change?

Key Deliverables

Current State Assessment of D&I's Capabilities

Target State Operating Model Recommendations for D&I

Digital Strategy & Operating Model Roadmap to Implement & Realize the Desired Target State

Approach for developing the target conceptual operating model

A collaborative approach was taken to build the contents of this document. Draft materials were reviewed with Alectra's Digital & Innovation leadership team before being reviewed, discussed and refined through a broader cross-functional Digital & Innovation stakeholder workshop. Finally, a post-workshop validation session was conducted with Alectra's Digital & Innovation leadership team to align on the outstanding items.

The recommended conceptual target operating model and supporting recommendations have been developed from the viewpoint of what Alectra's desired Digital & Innovation operating model would look like (rather than a transition state model).

Key inputs and stakeholder engagement activities in developing this document

15

Stakeholder interviews

30+

Document reviews

2

Workshop preparation sessions

1

D&I stakeholder workshop

1

Post-workshop validation session

A proposed draft contribution statement and set of guiding principles have been prepared for further refinement, finalization and approval by Alectra's Digital & Innovation core leadership and broader cross-functional stakeholder team.

Current State Assessment Recap

We conducted a broad stakeholder consultation for the assessment…

We engaged stakeholders across multiple IT teams and business streams… and discovered some prominent topics across the interviews.

…which identified areas that are working well…

Successful Integration

The MergeCo system integration was successful and Alectra's focus has shifted from "integrating the five distinct organizations" to "being positioned as a leading energy solutions provider". While there is still work to be done to harmonize and standardize processes, there is positive enthusiasm to transform and change across the organization.

COVID Transition and Support

The Digital & Innovation team was able to quickly adapt and support a virtual workforce at the start of the COVID-19 pandemic.
Digital & Innovation have demonstrated the ability to adapt and meet emerging business needs with success, highlighting capabilities to enable the business to transform and grow further.

Running the Business

Digital & Innovation have consistently shown their ability to execute projects within project parameters. Support services provided to Alectra are prompt and timely and business units expressed positive sentiments in issue resolution.

Innovating Ideas and Energy Solutions

The Digital and Innovation team have increased their capacity to develop and test innovative energy solutions. It used to be that ideation time would take over 10 years, this has reduced significantly to a 2-3 year timeframe, enabling the team to fail fast, adapt quickly and select the right ideas to move forward to market integration.

People-Centric Organization

In addition to Alectra's focus on being internal and external customer centric, efforts have been in place to foster a people-centric culture where the employee experience and their overall wellness is also viewed as a top priority in the organization.

…as well as key areas for improvement

Clarity on Strategy 2.0

Grid, Growth and Customer needs to be explained for all employees and what it means for their day to day activities. Alectra's vision should be focused and universal. The strategy should include clear timelines, expectations, direction, and measurable goals that cascade to all the business units.

Enhance Data Governance and Analytics

Data collected by the organization should be leveraged. Externally, data mining is an opportunity to promote business growth, become more efficient, and it has the potential to be monetized. Internally, improved data and analytics capabilities will enable greater visibility into organizational performance and enhance decision-making through greater use and availability of dashboards and reporting.

Create Capacity to Focus on Growing and Transforming the Business

There are concerns about resource constraints in Digital & Innovation. There are lots of great initiatives and projects that were planned for, and were delayed consistently due time, resource constraints and business priorities. Alectra is currently experiencing a backlog of major projects across core applications such as CX, work management and HCM.

Enabling Digital & Innovation to be a Strategic Partner to the Business

MergeCo worked to achieve integration across systems, however, while there are common systems in place, there are still many systems where there are different processes still in place e.g. the billing process is unique for each business unit. Additionally some business units invest and select systems without early and frequent communication with Digital & Innovation; this can result in a shadow IT, operations that Digital and Innovation are unaware of and have not planned to support.

Improve knowledge retention and effective service delivery

There are a number of legacy systems that have not been decommissioned, and knowledge has not been retained making it difficult to support operations or upgrade. When Project Manager's are outsourced, there is a lack of integration between their knowledge and knowledge retained by Alectra. Process standardization and harmonization would bridge some of these gaps.

The Existing Alectra IT Operating Model

General Observations

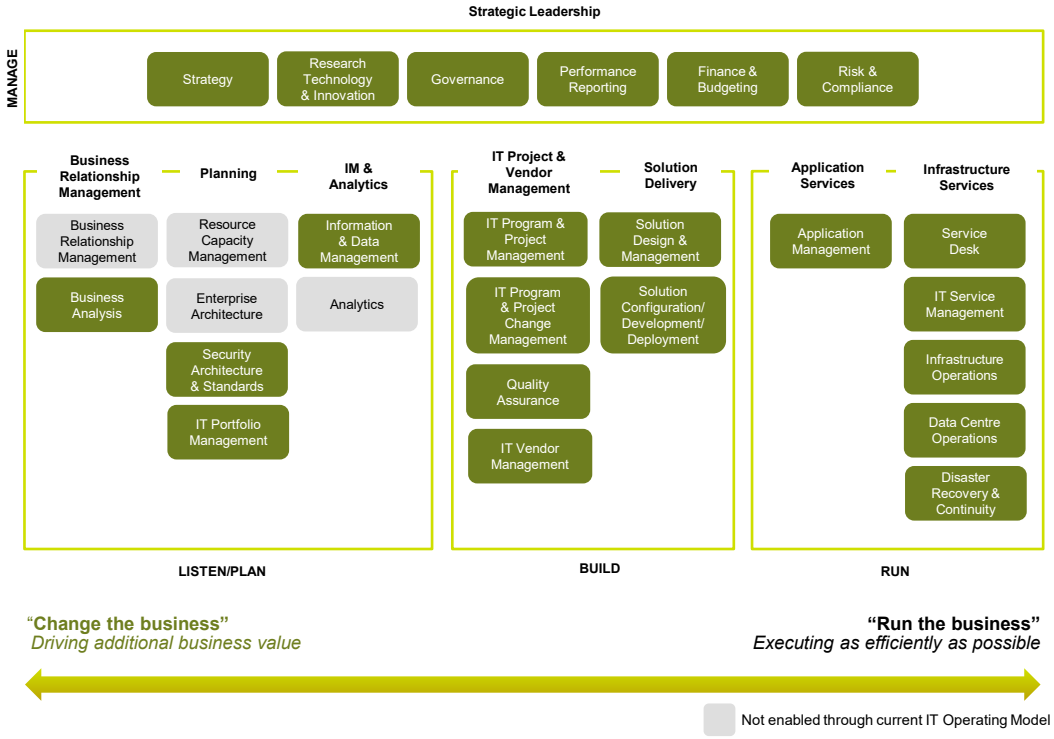
- The evolution of the function's focus from "IT" to "Digital & Innovation" requires a renewed approach to how the group operates to enable the strategic direction of the enterprise
- Modeled through the "Listen, Plan, Build, Operate" structure, the existing model is operating in more of an informal and ad-hoc rather than formal and process-driven manner
- A shift in how business and digital & innovation interact is required to enhance existing efforts to harmonize, optimize and modernize business processes as well as accelerate Strategy 2.0 ambitions
- Data and analytics capabilities are not enabled within the current operating model, and are instead performed by departments individually

What's Going Well

- Ongoing and successful completion of integration activities
- Planning and capacity to support and execute "run the business" activities and projects is adequate
- Projects from a "Build" and "Run" point-of-view were recognized as being well managed and delivered by the business

What Could Be Improved

- Gaps exist across Enterprise Architecture and Business Relationship Management, resulting in greater siloes between D&I and business units and limiting D&I's ability to serve as a strategic partner to the enterprise
- D&I resources are largely focused on "run the business"-related projects, which does not allow for a greater allocation of resources to support strategic, enterprise-wide "transform" and "grow" initiatives (including opportunities to better leverage 3rd parties capability and capacity wise)



Target State Contribution Statement & Design Principles

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Design considerations for Alectra's D&I operating model

FOCUS OF THE ENTERPRISE

Vision
What does Alectra want to be in the future?
What is our ideal state?

Cultural & Behavioural Commitments
How do we work at Alectra?
How do we lead at Alectra?

FOCUS OF DIGITAL & INNOVATION

Contribution Statement
What positive impact does D&I deliver?
For whom and why does D&I's contribution matter?

Guiding Principles
What will guide our decision-making within D&I?
How do we determine priorities when serving the enterprise?

Informs the development of

D&I Operating Model

How do we organize?
What is the functional and governance structure?

Key Considerations for Alectra's D&I TOM:

- Take into account Alectra's vision and CBCs, D&I's contribution statement and guiding principles, and current capabilities and constraints when evaluating the feasibility of TOM options
- Assess whether there are common requirements across the BUs that can be consolidated and delivered via shared services
- Assess what unique aspects need to stay close to the business

Contribution statement and guiding principles overview

The contribution statement and guiding principles describe a set of attributes that are important for Alectra's Digital & Innovation team to aspire to in the target state and apply to the development and implementation of the Digital Strategy and conceptual target operating model

What is a Digital & Innovation contribution statement?

A Digital & Innovation contribution statement **focuses on the team's contribution to Alectra as well as the customers, employees, external stakeholders and communities it serves**. It communicates and expresses the committed and positive contribution that each Digital & Innovation team member makes - beyond simply making a profit.

Align with the GRE&T Center's contribution statement:
Where great minds collaborate to power a better tomorrow.

What are Guiding Principles and is their purpose?

Guiding Principles are **tactical statements** that will guide **decision making** and **prioritization** related to the Digital and Innovation Strategy & Roadmap. They are simple, direct statements of Alectra's basic beliefs (4 to 6 guiding principles). Guiding principles serve as a structure to capture and gain stakeholder consensus on preferences and priorities to inform the initiatives for the Digital and Innovation Strategy & Roadmap.

Align with Alectra's Cultural & Behavioural Commitments (CBCs)

Proposed draft Digital & Innovation contribution statement

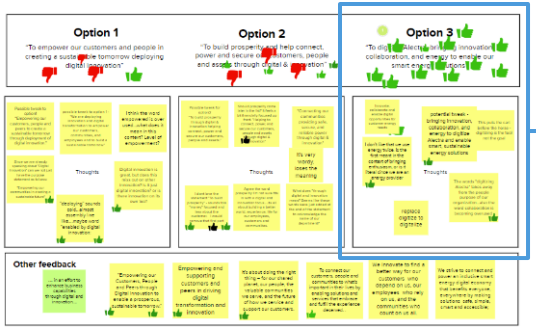
Approach for refining the proposed draft contribution statement

1. Prepared statement options for the broader D&I stakeholder group to provide feedback on through the D&I TOM workshop, and encouraged the development of new statements

2. Selected option with most positive feedback (Option 3) to prepare the refined draft contribution statement for the D&I team to review/finalize

   (considering other feedback provided)

3. **[What's Next]** Refine, finalize and approve the proposed draft contribution statement as a Digital & Innovation core and broader stakeholder team to support buy-in and acceptance of the statement



PROPOSED DRAFT FOR FINALIZATION

Transforming business processes with digital, not just converting data to a digital format

Across Alectra's business

Close collaboration with Alectra business units and the broader partner ecosystem

Digitalizing Alectra through **partnerships, innovation,** and creating a **great place to work** for **everyone**, to enable Alectra's **smart energy solutions**.

Bringing diversity and inclusion

Support for the corporate mission

Creating opportunities that attract and retain the right people

Proposed draft Digital & Innovation guiding principles (1 of 2)

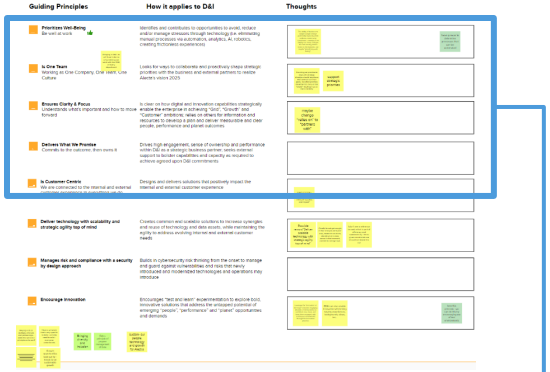
Approach for refining the proposed draft set of guiding principles

1. Prepared draft guiding principles for the broader D&I stakeholder group to provide feedback on through the D&I TOM workshop, and encouraged the development of new guiding principles

2. Discussed and aligned on what changes needed to be made to existing principles and whether gaps existed in the proposed of principles (to be incorporated in the next iteration)

   (note: a decision was made to separate the D&I application of the CBCs with the D&I specific guiding principles)

3. **[What's Next]** Refine, finalize and approve the proposed set of guiding principles as the Digital & Innovation core and broader stakeholder team to support buy-in and acceptance of the principles



Digital & Innovation Guiding Principles

What the Cultural & Behavioural Commitments (CBCs) Mean for Digital & Innovation

Separated from the D&I Guiding Principles

Please refer to the following slides for the updated set of guiding principles for D&I and the application of the CBCs for D&I

PROPOSED DRAFT FOR FINALIZATION

Proposed draft Digital & Innovation guiding principles (2 of 2)

The guiding principles help define the focus for Alectra's Digital & Innovation strategy and operating model as well as inform decision-making when new ideas emerge in order to ensure continued alignment between business and D&I strategies and plans

Digital & Innovation Guiding Principles

Guiding Principle	Description
1. Make decisions driven by strategic business priorities	Understands enterprise strategic priorities and prioritizes investment decisions (i.e. of time and human/financial capital) in order to fulfill customer requirements and enable innovation in alignment with Strategy 2.0
2. Deliver scalable technology with strategic agility	Increases synergies and reuse of technology while maintaining strategic agility to address evolving internal and external customer needs by promoting new technologies (e.g. cloud, RPA) to create common and scalable solutions
3. Draw greater insights from our data assets	Enables information assets are available across the organization in real time to support fact-based reporting and insights-driven decision making by establishing a strong data and information governance foundation
4. Consider alternative delivery options to scale	Promotes effective and efficient D&I service delivery by leveraging strategic partnerships, managed services, and third parties as required to close capacity and capability gaps
5. Encourage innovation	Encourages "test and learn" experimentation to explore bold, innovative solutions that address the untapped potential of emerging "people", "performance" and "planet" opportunities and demands
6. Manage risk and compliance	Builds in cybersecurity risk thinking from the onset to manage and guard against vulnerabilities and risks that newly introduced and modernized technologies and operations may introduce

Proposed draft CBCs application and what it means for D&I

The CBCs were used to communicate how Alectra Digital & Innovation team members work and lead within the context of the D&I specific commitments and priorities

Embracing the CBCs and How It Applies in the Digital & Innovation Context

Alectra's Cultural & Behavioural Commitments (CBCs)	How It Applies to Digital & Innovation
1. Prioritizes Well-Being *Be well at work*	• Identifies and contributes to opportunities to avoid, reduce and/or manage stressors through technology (i.e. eliminating manual processes via automation, analytics, AI, robotics, creating frictionless experiences) • Delivers an effective change experience that is employee-centric and time sensitive in order to reduce the risk of change fatigue
2. Is One Team *Working as One Company, One Team, One Culture*	• Looks for ways to collaborate and proactively shape strategic priorities with the business and external partners to realize Alecta's vision 2025 • Embraces various viewpoints and understands the additional value that can be delivered when equity, diversity and inclusion are kept top of mind
3. Ensures Clarity & Focus *Understands what's important and how to move forward*	• Is clear on how digital and innovation related investments in business capabilities strategically enable the enterprise in achieving "Grid", "Growth" and "Customer" ambitions • Partners with others for information and resources in order to develop a plan and deliver measurable and clear people, performance and planet outcomes
4. Delivers What We Promise *Commits to the outcome, then owns it*	• Drives high engagement, sense of ownership and performance within D&I as a strategic business partner • Seeks external support to bolster capabilities and capacity as required to achieve agreed upon D&I commitments
5. Is Customer Centric *We are connected to the internal and external customer experience in everything we do*	• Designs and delivers solutions that positively impact the internal and external customer experience • Develops means to measure success and impact

IT / Digital & Innovation (D&I) Target Operating Model Overview

Where Alectra's D&I operating model fits into the bigger picture

The D&I target operating model will focus on how D&I could be organized in the future to deliver and execute on Alectra's Strategy 2.0 in an efficient and effective manner.

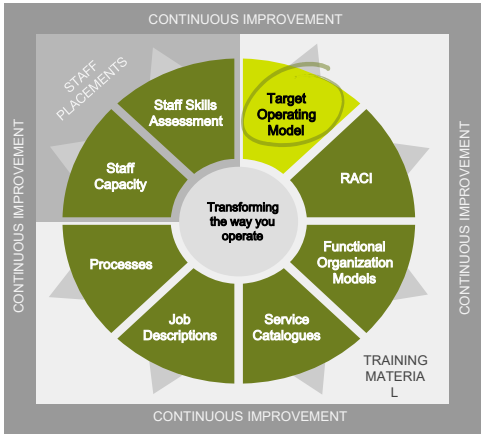
Focus of Strategy 2.0 | **Focus of the Digital Strategy** | **Focus of this Report** | **Focus of the Roadmap**

Focuses on the **"why"** of the business	Focuses on the **"what"** of the business	Focuses on the **"how"** of the business
the plans, actions and goals that outlines how Alectra will compete in the market **delivers "value" to customers & beneficiaries**	the tangible and intangible building blocks of Alectra's business to deliver its value **delivers an "outcome"**	represents how Alectra's Digital & Innovation team (including the GRE&T Centre) can be optimally organized to more efficiently and effectively deliver and execute on its corporate strategy **delivers "capabilities"**

Target operating model overview

A Digital & Innovation target operating model (TOM) represents the **set of functions required to achieve the organization's vision and strategic objectives, and deliver digital and innovation services**. The functions are grouped by related capabilities and organized in a way that creates focus, seamless integration and optimal experiences with clients, partners and suppliers.

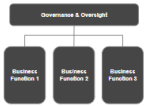
However, a TOM is **not** an organization chart.



Successful transformations address all **elements in the transformation** wheel illustrated to the left. While all elements are important, **the starting point begins with determining a target operating model** that aligns best with an organization's future state vision and business objectives.

Common operating models seen in practice

There are a number of different ways to organize IT and D&I functions and enable them to deliver services/products to the business. Outlined below are a number of operating models options that are commonly used in industry that were reviewed to inform the TOM design for Alectra's D&I.



IT Function Based

Most traditional IT organizations are structured by IT functions across applications and infrastructure with more of an operational focus where IT is seen as a service provider.

IT Demand & Supply

Emphasizes a delineation of capabilities related to demand and supply of IT services. The organizational structure is often grouped by demand and supply as well.

Listen, Plan, Build, Operate (LPBO)

The majority of organizations looking to increase their IT maturity organize around the solution lifecycle. Dedicated groups focus on each stage, each of which have distinct processes and skills.

Analytics & Information Enabler

Brings analytics capabilities closer to the business by making a priority to invest in functions to manage their data assets, enabling the business to use analytics to drive actionable insights.

Digital Innovation & Enablement

(Product Management Based Model)

Organizes and orients IT and D&I around technology products and services to manage their end-to-end lifecycle.

Agile DevOps

Breaks down the silos in how solutions are developed, tested and operated.

Traditional Operating Models → **Progressive Operating Models**

These IT operating models have been implemented to varying levels of success within industry, often when technology environments were largely managed and deployed in-house and on premise.

The consumerization of technology, digitization, and advancements in industry leading practices, architectures, and capabilities, are driving digital transformation, including the need for IT and D&I functions to improve their value proposition, relevance to the business, and agility to respond to changing needs.

Shortlisting TOM options based on guiding principles alignment

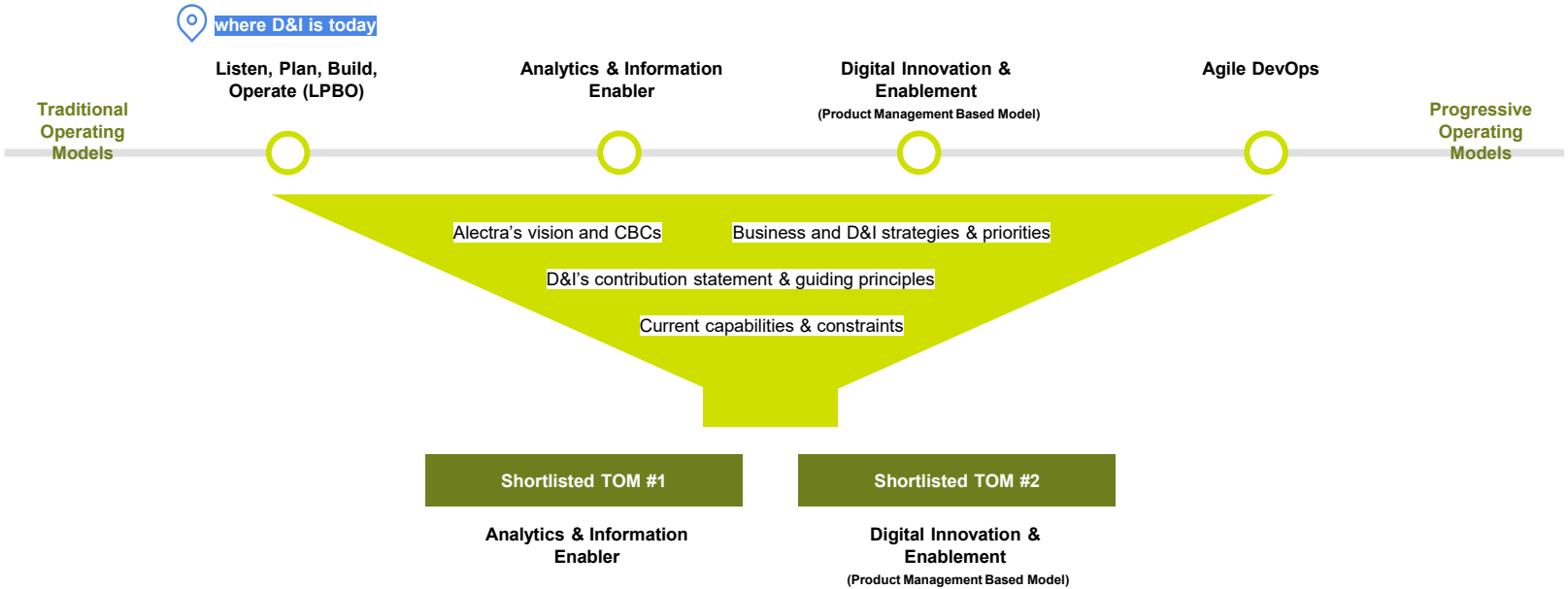
Based on an assessment of the various operating model options against the proposed D&I guiding principles, four options demonstrated a higher degree of alignment and were shortlisted for initial consideration.

Four proposed shortlisted options for Alectra

D&I guiding principles	IT Function Based	IT Demand & Supply	***2016 Model*** Listen, Plan, Build, Operate	Analytics Information Enabler	Digital Enablement & Innovation	Agile DevOps
Make decisions based on strategic business priorities Understands enterprise strategic priorities and prioritizes investment decisions (i.e. of time and human/financial capital) in order to fulfill customer requirements and enable innovation in alignment with Strategy 2.0	✓	✓	✓	✓	✓	✓
Deliver scalable technology with strategic agility Increases synergies and reuse of technology while maintaining strategic agility to address evolving internal and external customer needs by promoting new technologies (e.g. cloud, RPA) to create common and scalable solutions			✓	✓	✓	✓
Draw greater insights from our data assets Enables information assets are available across the organization in real time to support fact-based reporting and insights-driven decision making by establishing a strong data and information governance foundation			✓	✓		
Consider alternative delivery options to scale Promotes effective and efficient D&I service delivery by leveraging strategic partnerships, managed services, and third parties as required to close capacity and capability gaps	✓	✓	✓	✓	✓	✓
Encourage innovation Encourages “test and learn” experimentation to explore bold, innovative solutions that address the untapped potential of emerging “people”, “performance” and “planet” opportunities and demands					✓	✓
Manage risk and compliance Builds in cybersecurity risk thinking from the onset to manage and guard against vulnerabilities and risks that newly introduced and modernized technologies and operations may introduce			✓	✓	✓	✓

Downselecting 2 options that aligned with Alectra's strategic direction

Among the four shortlisted options, key considerations were taken into account related to Alectra's D&I current state capabilities and constraints as well as target state aspirations and strategic business priorities. Considering that the LPBO model being similar to what is in place in Alectra today and the Agile DevOps model not aligning with the strategic direction of the enterprise, the Analytics & Information Enabler and Digital Innovation & Enablement model were identified as two potential TOM options that are well positioned to enable D&I to optimally deliver digital and innovation services.



Proposed Target State Model for Alectra's D&I Team

Defining the conceptual D&I TOM that meets Alectra's needs

Approach for defining the conceptual Digital & Innovation target operating model

1. Prepared TOM overview and deep dive on the two proposed TOM options (Analytics & Information Enabler and Digital Enablement & Innovation) to gather feedback on the strategic alignment, benefits and challenges of each option

2. Collated and synthesized feedback from the workshop in order to develop a tailored D&I conceptual target operating model that addresses the strategic context and ambitions of as well as the unique environment at Alectra

3. **[What's Next]** Build on the D&I TOM structure and functions to develop in greater detail elements of the "transformation wheel" that will enable the implementation and operationalization of the TOM (e.g. team structure, roles and responsibilities, processes, staff capacity and skills)

Target Operating Model Workshop:
Analytics & Information Enabler and
Digital Enablement & Innovation TOM Deep Dive

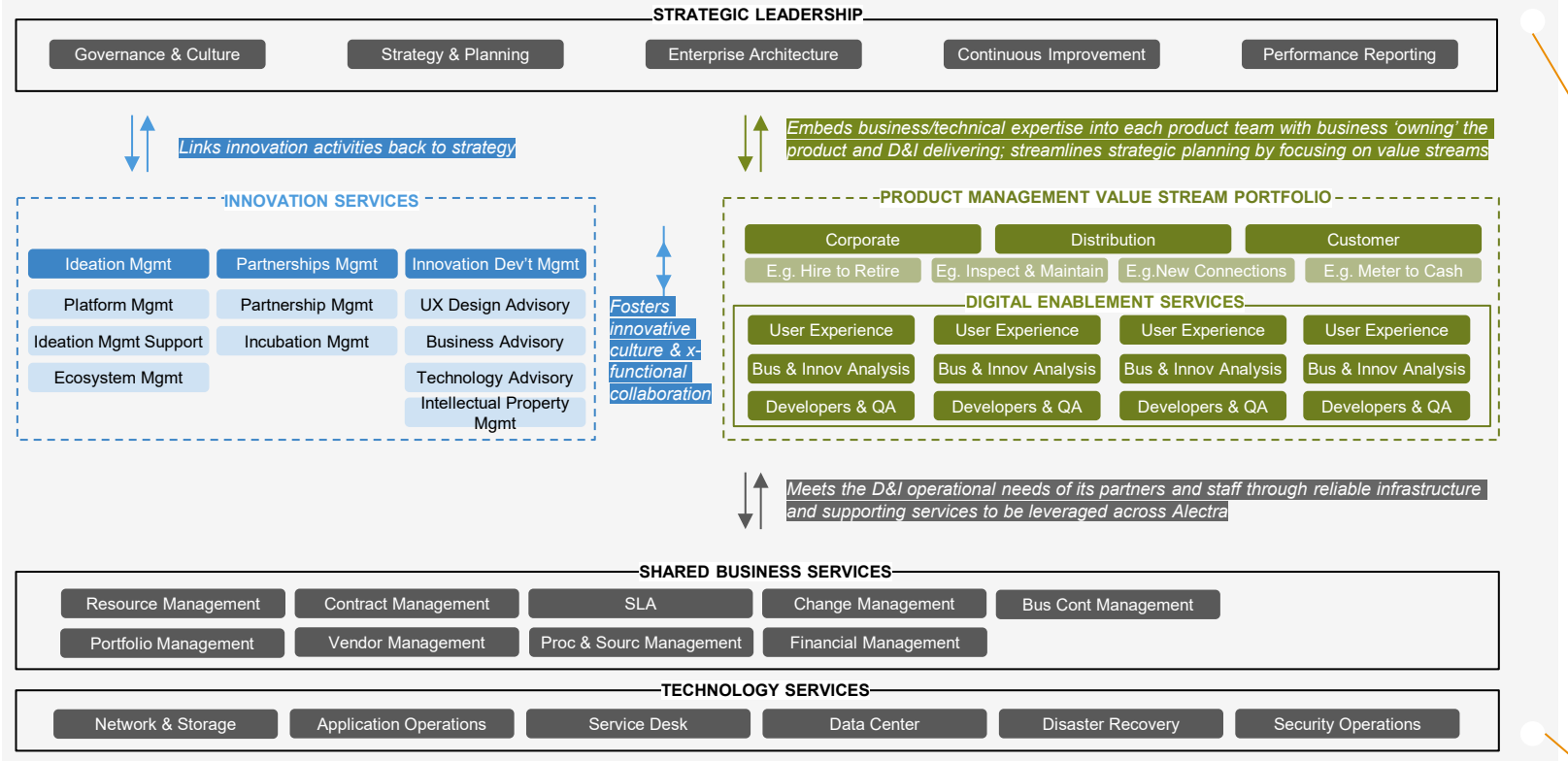
PROPOSED "HYRBRID" MODEL

Alectra has a unique set of goals, requirements and constraints that impact the design of Digital & Innovation. This requires the **design of a target operating model that accounts for industry leading practices and unique needs of Alectra** (e.g. focus on being data-driven and innovation-minded).

Based on the inputs from D&I stakeholders (i.e. through the stakeholder interviews, business capability model prioritization workshop and target operating model workshop), a **purpose-built target operating model was designed that took elements of the Analytics & Information Enabler and Digital Enablement & Innovation model** that addressed Alectra's unique strategic needs and aligned with the D&I guiding principles.

The **D&I TOM builds on the benefits of both models explored** and designs the key functions of the D&I organization accordingly. The TOM functions and governance structure will be outlined in this section, starting with a conceptual overview of the key building blocks of the organization.

Alectra's D&I conceptual target operating model overview



Validation of the TOM through D&I guiding principles

1. Make decisions based on strategic business priorities

Formalizes functions to drive strategic planning and innovation to support alignment between D&I's portfolio and enterprise strategic priorities. Instills a culture to continuously monitor and improve to address evolving business needs. Nurtures internal and external relationships, and builds a positive brand for D&I as a strategic partner.

2. Deliver scalable technology with strategic agility top of mind

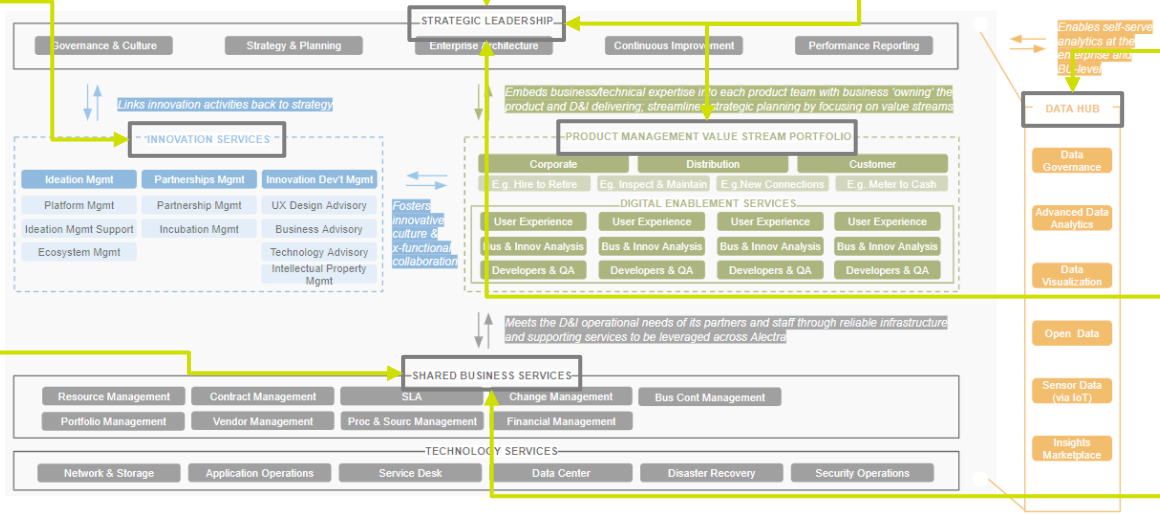
Increases proximity and interfaces between strategy, delivery and operations to enable D&I begin to adopt some agile practices when bringing together the needs of the business, user and technology in a strategic manner. Promotes the re-use of technology assets and products for both customers and the enterprise.

3. Draw greater insights from our data assets

Enables improved use of data assets across the enterprise through formalized functions to serve both "commodity" and "business specific" analytics activities and improve decision-making and address unsolved business problems and unmet business needs.

5. Encourage innovation

Establishes an innovation engine and defines how D&I can add value to the enterprise through each step of the innovation value chain to encourage a "test and learn" approach (from ideation to concept evaluation, development and approval, to launch and commercialization).



4. Consider alternative delivery options to scale

Enables improved resource and portfolio management to better assess when build versus buy options would make most strategic and operational sense. Improves vendor management and performance tracking to allow Alectra to outsource solution delivery and support in an objective and coordinated manner.

6. Manage risk and compliance

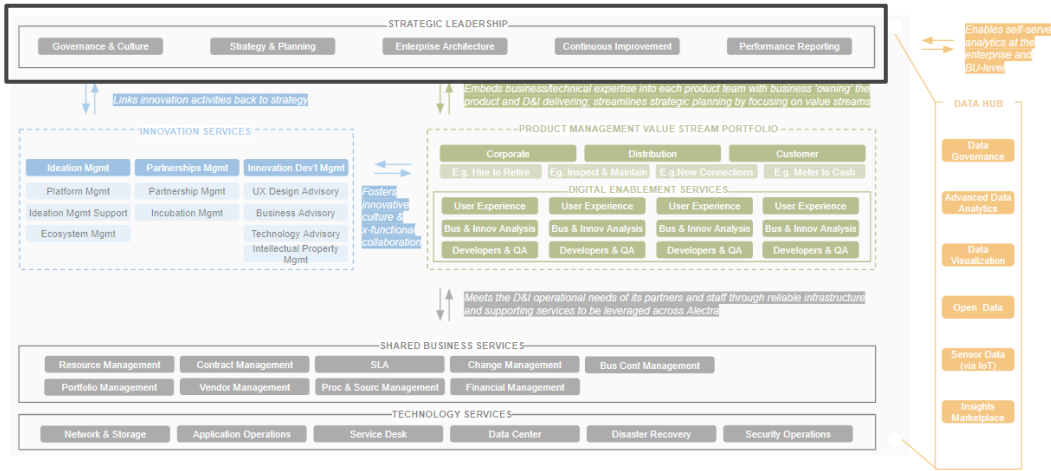
Establishes a "security by design" approach to strategic planning and execution by ensuring that risk and compliance are incorporated in the D&I strategy as initiatives, enterprise architecture as capabilities, and executed as part of steady state operations through security operations.

Overview: D&I TOM strategic leadership layer

Strategic Leadership:
D&I will provide strategic leadership in digital and innovation to enable Alectra's strategic enterprise objectives as a strategic partner to the enterprise

Key areas of focus include:

- **Establishing business management & partnership practices for D&I**, including: setting a clear D&I purpose and strategy; directing and overseeing execution; establishing relationships with and communicating D&I's value proposition to internal and external partners; managing and prioritizing investments; and monitoring performance to continually improve
- **Establishing integrated enterprise planning across the D&I portfolio with partners**, including: maintaining Alectra's target state enterprise architecture and technology blueprint (including the business capability model); and identifying portfolio of investments and reusable assets that can be leveraged across the enterprise and programs to deliver those blueprints



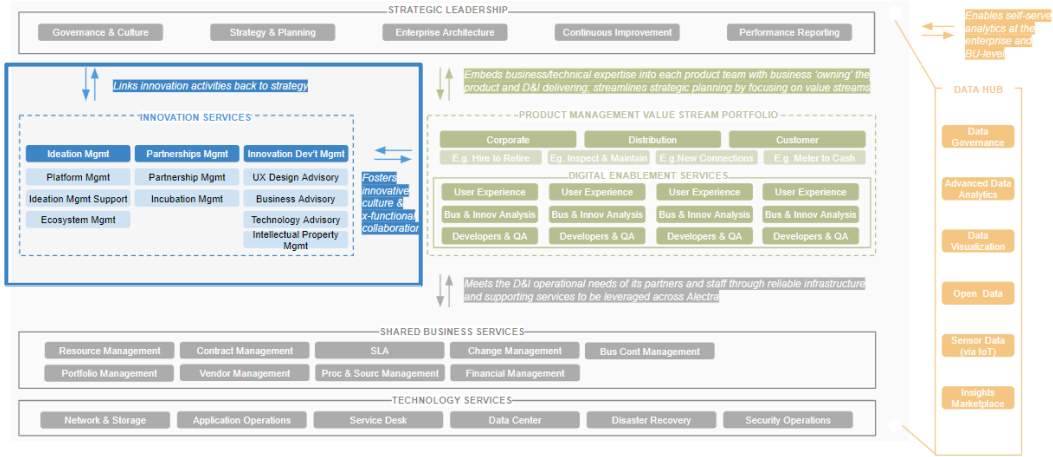
Overview: D&I TOM innovation services layer

Innovation Services:

D&I will develop internal innovation capabilities, establish strategic alignment, and leverage partnerships and external sourcing across the innovation development value chain (i.e. from ideation to launch and commercialization) to develop value-added business model, functional and process-based innovation concepts

Key areas of focus include:

- **Overseeing innovation activities and establish strategic alignment**, including: developing updating an integrated innovation strategy and roadmap; aligning and advising senior leadership; streamlining activities by defining how innovation stages and stakeholders add value
- **Managing ideation activities (sourcing, evaluation and integration)**, including: developing an ideation strategy and platform establishing efficient and effective ideation and reporting mechanisms
- **Verifying all innovation sourcing requirements are met**, including: evaluating and sourcing potential investment/partnership opportunities (startups, developers, entrepreneurs); and pursuing partnerships that enable the development and execution of the innovation roadmap
- **Managing innovation development and acceleration activities**, including: identifying integrated innovation opportunities and developed detailed concepts for evaluation; develop opportunities concepts (if approved) into proof of concepts and prototypes; and managing innovation teams and intellectual property



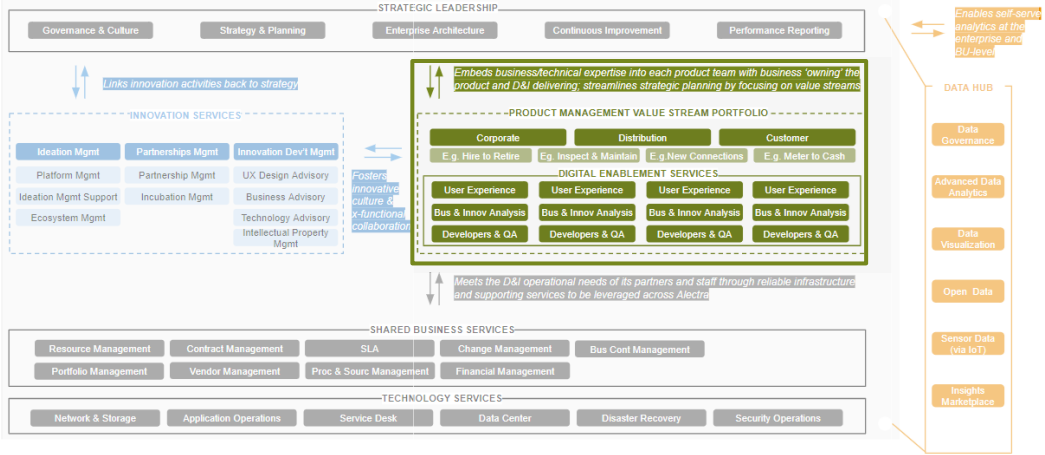
Overview: D&I TOM value stream led product management layer

Value Stream Lead Product Management:

D&I will meet the needs of each of its partners through end-to-end management of the technology products they rely on. Adopting a value stream approach to product management enables Alectra to continuously deliver value through each step of the customer and/or employee journey using value stream portfolios (e.g. corporate) and value streams (e.g. hire to retire)

Key areas of focus include:

- **Establishing a clear and consistent approach for managing products**, including: defining and aligning on how D&I and the business are organized together across value streams; defining products by their business capabilities and outcomes; and maintaining portfolio-level visibility and funding/approvals
- **Planning and coordinating the end-to-end product lifecycle**, including: setting a clear vision for product success and ensuring consistent business-led and agile product delivery; and developing a 12-18 month roadmap for products to address program, user and technology needs
- **Managing end-to-end product delivery**, including: enabling the continuous flow of value from concept to value realization using persistent product and platform teams (i.e. solution features or platform capabilities)*



***Note:** End-to-end product delivery is focused on: 1) **solution features** are specifically aligned to the business product needs associated to a value stream; 2) or enterprise wide consumable **platform services/capabilities** that could be leveraged across Alectra for current and future product needs

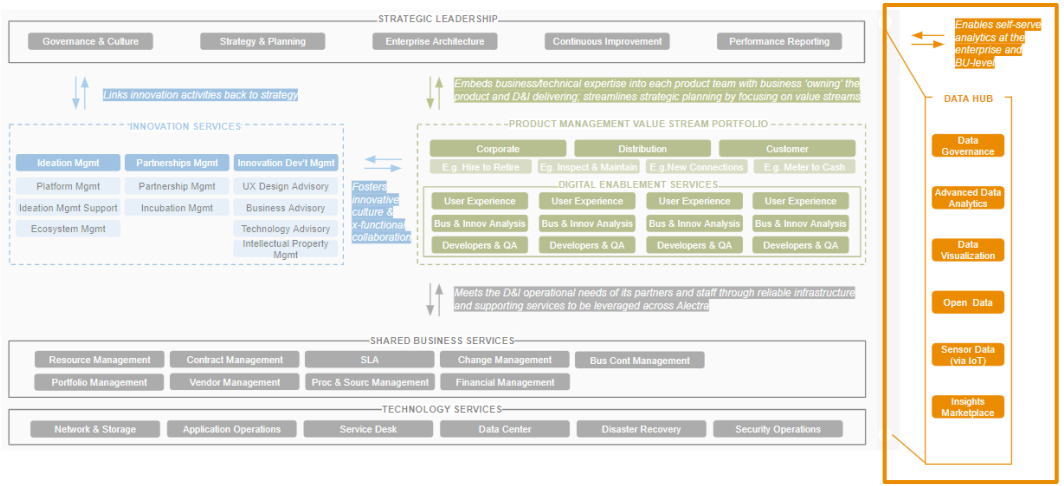
Overview: D&I TOM data hub layer

Data Hub:

D&I will develop and maintain internal data and analytics capabilities and establish the formal roles to interact with data across the entire data and analytics lifecycle: from data sourcing, management and analytics

Key areas of focus include:

- **Managing the enterprise data strategy & governance approach**, including: enabling data use prioritized for business decisions and analytics that address a clear business problem/need; and ensuring that the right organization and governance structure as well as roles, policies, and metrics are in place for efficient and effective use of information
- **Enabling data use across the enterprise**, including: provisioning user access to the right data; and having the right systems, tools and infrastructure in place to created an integrated, real-time view of data to provide actionable insights and inform business decisions
- **Building and encouraging a data-driven culture**, including: demonstrating the value on a use cases basis that data and analytics can drive cost savings and business values with varying degrees of data ownership and management; and establishing communities of practice, user groups and regular demos that encourage employees to listen, discuss, share and contribute to the data culture



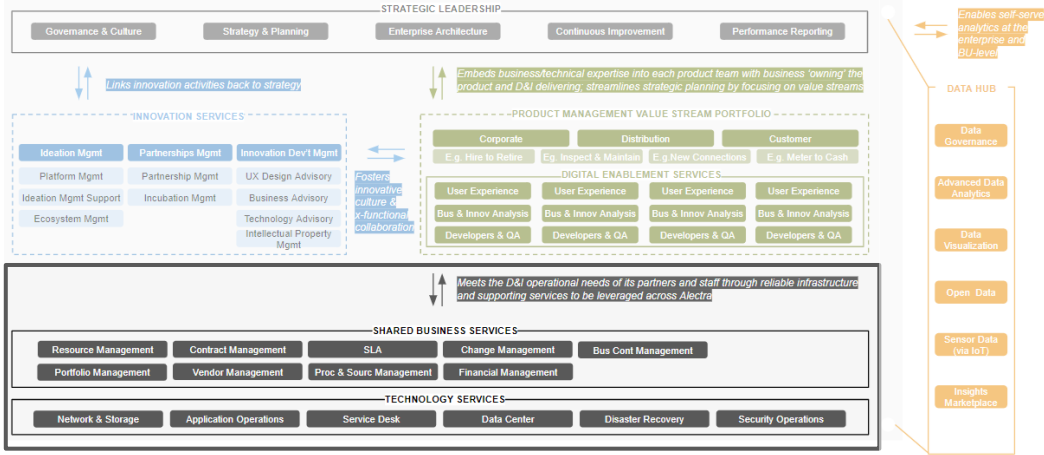
Overview: D&I TOM operational and support layer

Operational and Support:

D&I will meet the technology infrastructure and operational needs of its partners and staff. Shared business services can be viewed as an “enabling layer” that help in increasing the speed and quality of outputs of delivery teams by removing any bottlenecks and roadblocks faced by them. Technology Services can be viewed as the layer that provides reliable, secure and scalable technology infrastructure across Alectra.

Key areas of focus include:

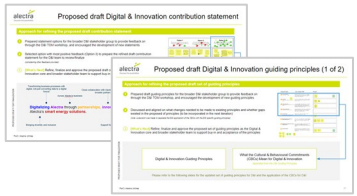
- **Enabling delivery teams through shared business services**, including: participating in the activities of other teams primarily “on demand”; enabling the products teams as a priority also assisting the technology services and data hub layers.
- **Providing shared technology infrastructure and supporting services leveraged across the enterprise**, including: establishing common service deck and mature IT service management processes (i.e. service requests, incidents, changes, etc.); improving the management of resources for day-to-day operational needs across the enterprise (i.e. infrastructure governance, architecture and deployment, application release management and production support); and engaging with product teams in the planning and delivery stages.



Proposed Governance Model for Alectra's D&I

Alectra's D&I governance and where it fits into the big picture

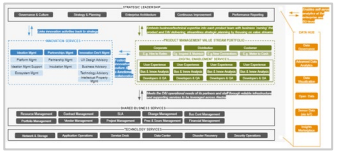
Contribution Statement & Guiding Principles



Focuses on how D&I: 1) is **committed and makes a positive contribution** to Alectra and the customers, communities and partners it serves; and 2) **prioritizes and makes decisions** to enable Strategy 2.0

+

Target Operating Model



Focuses on how D&I can be **optimally organized into functions** to more e**fficiently and effectively deliver and execute on its corporate strategy**

Alectra's D&I target operating model will be activated and implemented through:

People	D&I Organizational Structure	D&I Capability Model
	D&I Roles & Responsibilities	D&I Resourcing/Strategy
Processes	D&I Process Model	D&I Process Accountabilities
	D&I Process Maps	D&I Process Metrics
Technology & Information	D&I Architecture Standards	Info Management Strategy
	Applications/Product Portfolio	IT Infrastructure
Performance Management	Performance Mgmt Framework	Key Performance Indicators
	Reporting Mechanism	
Governance	**D&I Governance/Decision Model**	**D&I Governance Comms**
	D&I Policies	

Focus of this Section

Governance model overview for Alectra's D&I

D&I governance focuses on providing clarity on decision rights, accountability and:

- Enables **operational, financial and risk management** to ensure that D&I activities are aligned with Strategy 2.0 and complies with regulations
- Establishes appropriate committees/forums to enable business and D&I conversations across Alectra to discuss D&I's priorities and opportunities in **response to changes in business, operational, competitive and regulatory needs**
- Focuses on establishing widely supported strategies to **reduce the risk of shadow IT emerging within business units**
- **Translates the governance model into operational realities** by describing roles, responsibilities, reporting lines, communications and reporting processes

Effective D&I governance relies on decision making structures, policies and good communication

D&I Governance/Decision Model

- What committee(s) are needed for aligned decision making?
- What decision rights will stakeholders have?
- How do committees interact?

D&I Policies

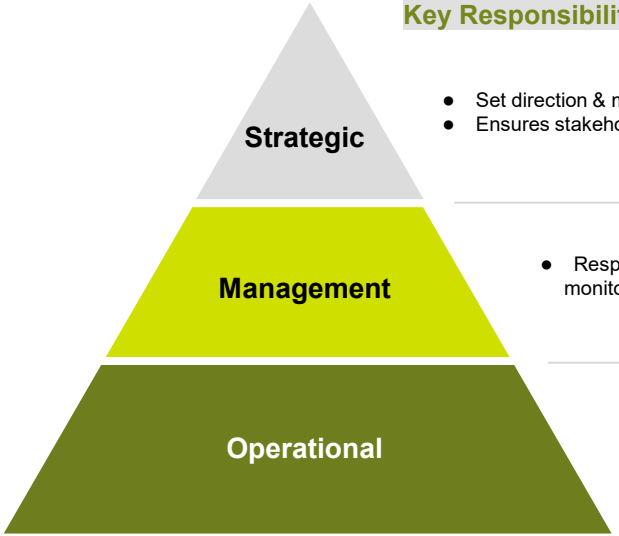
- What key policies will be needed to govern the management and use of D&I?

D&I Governance Communications

- How should D&I organizations communicate effectively to increase the awareness of and compliance to D&I governance standards?

Three-tiered governance model overview for Alectra's D&I

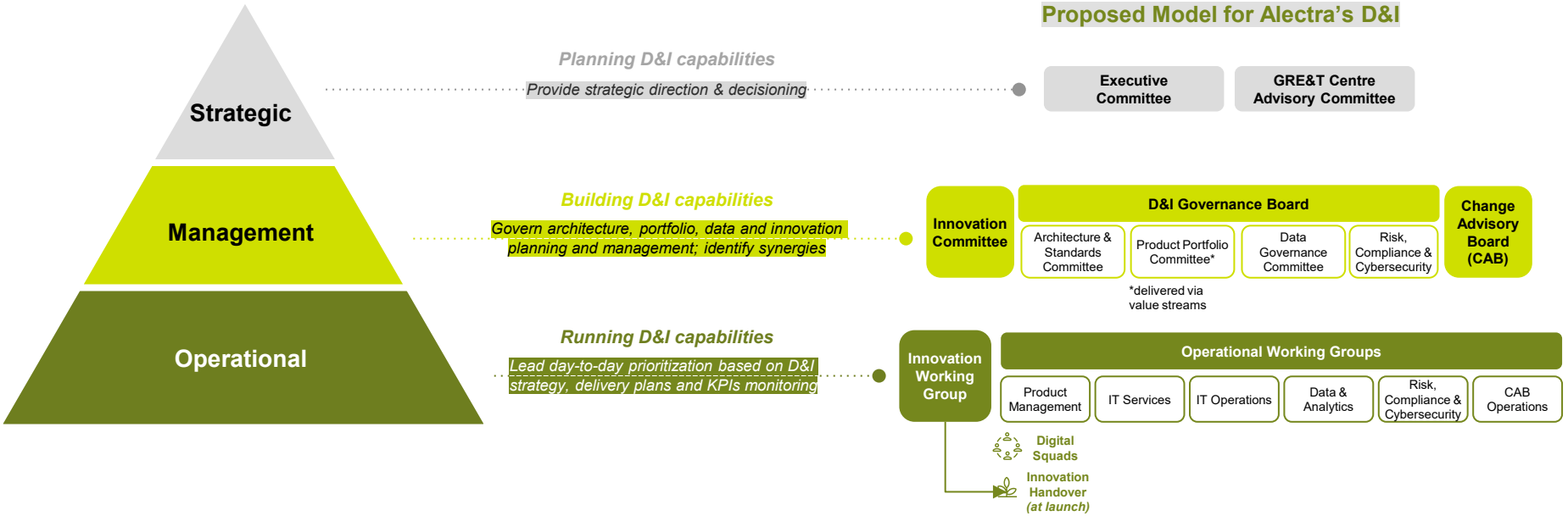
The proposed three-tiered governance model for Alectra's D&I provides clear points of engagement at the strategic, management and operational layer. The model is defined factoring in considerations related to strategic alignment, investment management, benefits realization, resource alignment, operational processes, and risk management.



	Key Responsibilities	Examples
Strategic	• Set direction & monitors achievement of objectives • Ensures stakeholder needs and options are evaluated to make balanced decisions	*Joint business and D&I direction setting and overseeing execution through Executive Committee updates*
Management	• Responsible for decisions related to planning, building, running and monitoring within the direction provided by strategy	*Joint planning and managing execution of value stream portfolio product roadmaps with Product Owners, Product Managers, and Partner/Vendor Representatives*
Operational	• Day-to-day operational activities • Executes plans and decisions	*Joint business and D&I execution of end-to-end product delivery, addressing day-to-day requests / events / incidents / changes through Service Desk/Change Advisory Board, etc.*

Proposed three-tiered governance model for Alectra's D&I

The D&I governance model will support Alectra's strategic and transformational objectives as well as avoid common pitfalls related to duplication of efforts, limited visibility into benefits and overspending. The model provides a centralized view of programs and enables a strategic approach to executing initiatives, timelines and responsibilities.



Proposed Alectra's D&I governance membership and cadence (1 of 3)

Strategic

	DESCRIPTION	MEMBERSHIP
Executive Committee monthly 8 members	• Provide executive level oversight and strategic direction across the enterprise • Make decisions regarding Alectra's Digital & Innovation policies, programs and initiatives (including major investments and expenditures) identified and/or escalated to the strategic/portfolio level • Validate opportunities as business as usual or innovation, and approve/prioritize ideas to advance as innovation concepts to transition to development and commercialization/launch at the innovation portfolio level • Set, review and monitor Digital & Innovation related corporate-level metrics that track Alectra's trajectory against Strategy 2.0 (e.g. quarterly) to track progress and identify performance improvement areas	President & Chief CEO EVP & CFO EVP - Legal, Gov't Relations, Corporate Secretary EVP - People & Transformation EVP - Energy Solutions & Growth EVP - Asset Strategy & Operations EVP - Customer Experience EVP & Chief Digital and Innovation Officer
GRE&T Centre Advisory Committee 4 to 6 times / year 6 to 12 members	• Provide advice on the strategic direction of the GRE&T Centre in alignment with Alectra's vision, mission and growth strategy • Provide strategic advice related to GRE&T Centre pilots, demonstrations, partnerships, community engagement activities, accelerator cohorts and other pertinent activities • Monitor the progress of the Centre	Chair (Elected from Alectra's Board of Directors) Independent Committee Members (5) Ex Officio Members from Alectra Leadership (3) ○ CEO ○ VP GRE&T Centre ○ EVP & Chief Digital and Innovation Officer Alectra Board Chair and 1-2 Board Members Guelph Representative Other Alectra Members (as needed)

Proposed Alectra's D&I governance membership and cadence (2 of 3)

Management	DESCRIPTION	MEMBERSHIP

D&I Governance Board
monthly
7 members (min)
	• Align and integrate D&I strategy with business needs, and oversee progress in achieving desired outcomes
	• Review and provide guidance to Alectra's Board of Directors and Executive Committee on all relevant D&I organizational and technical aspects required drive and enable Strategy 2.0 at the strategic level
	• Establish policies, roles and responsibilities; prioritize projects and ensure balanced investments are made in initiatives to support critical day-to-day operations as well as business innovation, transformation and growth
	• Review technology commercialization/deployment decisions to support handover on new product/technology opportunities from the Innovation Committee
	• Review and approve recommendations made by the following D&I Governance committees:
	  ○ **Architecture & Standards Committee:** Review and provide guidance on enterprise architecture, technology architecture, and infrastructure design and development plans; ensure compliance to common technology and architecture standards, processes and practices
	  ○ **Value Stream Portfolio Committee:** Review and provide guidance on where to prioritize D&I value stream (product) portfolio efforts and investments to create value in alignment with Strategy 2.0 priorities
	  ○ **Data Governance Committee:** Review and provide guidance on policies, standards, roles and responsibilities and metrics that define how data is gathered, stored, processed and disposed of at Alectra
	  ○ **Risk, Compliance & Cybersecurity Committee:** Review and provide guidance on Alectra's cybersecurity framework and potential risks related to technology, regulatory compliance, and data privacy
		Chair: VP, Information Technology
		Members: Select D&I Leads (6) representing core D&I operations and governance committees:
		• Primary focus on 'run' the business
		  ○ IT Services
		  ○ IT Operations
		• Primary focus on 'grow' and 'transform' the business
		  ○ Architecture & Standards
		  ○ Value Stream (Product) Portfolio
		  ○ Data Governance
		  ○ Risk, Compliance & Cybersecurity

Innovation Committee monthly 5 members (min)	• Align Alectra's innovation strategy with business needs, and oversee progress in achieving desired outcomes • Establish policies, processes, roles and responsibilities (including handover to D&I and business units for commercialization/launch); manage budget to support investment in value added areas • Facilitate cross-functional decisions related to innovation development and design innovation teams coordinating with D&I, business units and external partners • Review and provide guidance to the Board of Directors and Executive Committee on opportunities to be categorized as business as usual or innovation, and present prioritized ideas to transition to innovation concepts to develop and commercialize/launch at the individual opportunity level • Review, approve and provide oversight over innovation proof of concepts, prototypes and final business cases to inform a go/no-go launch and commercialization decision at the individual opportunity level	**Chair:** VP, GRE&T Centre **Members:** Select D&I Leads (min 5) representing innovational functional areas and the business: • Ideation Management • Partnership Management • Innovation Development Management • Business/Functional Expertise (based on priorities)

Proposed Alectra's D&I governance membership and cadence (3 of 3)

Management

Change Advisory Board

monthly (or as needed)
6 members (min)

DESCRIPTION

- Facilitate digital and innovation related change balancing responsiveness to customer and business needs with risk - ensuring alignment to Alectra's Strategy 2.0
- Review and provide guidance on whether digital and innovation related changes should be approved, factoring technical details of the change as well as business and service related scheduling, resourcing and risk factors
- Review upcoming changes (considering strategic priority, architecture, risk, impact and timeline factors), past changes (considering successes, lessons learned, incidents/resolved problems, unauthorized changes), and the change process (considering dependencies, business needs, compliance and regulatory requirements)

MEMBERSHIP

Chair: Director, IT Innovation & Governance
Members: Select D&I representatives (min 5) to review, assess and prioritize changes from the lens of:

- Technical: IT Operations, Application/Product Manager, Service Desk Manager, Business Relationship Manager, Risk & Security Lead
- Business/Service: Owners (as needed)

Operational

Innovation Working Group

weekly or bi-weekly
Pending priorities

DESCRIPTION

- Provides oversight of in-house incubation and innovation activities, as well as plays a key role in managing the internal and external (e.g. startups, incubators, developers, etc.) relationships
- Provides oversight related to the prioritization, management and reporting of day-to-day activities
- Serve as the first point of escalation and resolution for operational issues and/or escalate to the Innovation Committee when issues cannot be resolved at the operational level

MEMBERSHIP

Chair (Rotating): Head of Smart Cities, Head of Advanced Planning, Head of Grid Innovation
Members: Select D&I and business representatives leading/delivering key incubation and innovation initiatives

Operational Working Group

weekly or bi-weekly
Pending priorities

DESCRIPTION

- Provides oversight of in-house operations and the delivery of approved initiatives, as well as plays a key role in managing the internal and external (vendor) relationships (aligned to a specific area outlined on slide 39)
- Provides oversight related to the prioritization, management and reporting of day-to-day activities
- Serve as the first point of escalation and resolution for operational issues and/or escalate to the D&I Governance Board when issues cannot be resolved at the operational level

Change Advisory Board (CAB) Operations

- Prepare for CAB monthly meetings to triage changes that can be addressed at the operational level (i.e. via CAB Operations) or at the management level (i.e. via the Change Advisory Board for larger magnitude changes that have a direct impact on Alectra's strategy)
- Review, assess and recommend changes to certify quality release (i.e. from a release timeline, architectural and standards, quality and service level, security and compliance, and resource and financial perspective)

MEMBERSHIP

Chair (Rotating): Identified initiative leads for 'Value Stream Led Products', 'IT Services', 'IT Operations', 'Data & Analytics', 'Risk, Compliance & Cybersecurity', 'CAB Operations'

Operational Working Group Members: Select D&I and business representatives leading/delivering key initiatives and operational activities

Operational CAB Members: Similar composition to the membership of the Change Advisory Board

Next Steps

Defining a plan for Alectra's D&I transformation journey ahead

Alectra's D&I can follow a three-phased approach to implement the recommendations over the next 8-10 months. This recommended approach enables Alectra's D&I to activate, test and refine the target operating model design in meaningful increments while delivering value in a timely and agile manner.

What's Been Done

Phase 0 - Design a Conceptual TOM (2 months)

Aligned on conceptual TOM based on where Alectra's D&I is today and the target state aspirations and strategic priorities

- Reviewed current IT strategy and capabilities
- Drafted D&I contribution statement and guiding principles
- Developed a refreshed Digital & Innovation strategy
- Conceptualized the target state operating model design

What's to Come

Phase 1 - Design a Lean Organization (2 months)
Phase 2 - Execute a Pilot (3-4 months)

Start with the lean design of the organization to activate the TOM; pilot and transition to new model

- i) Define approach for being a product-driven organization
- ii) Design minimum viable organization to activate TOM
- iii) Define and execute the training and transition plan
- iv) Pilot the org and transition in 1 value stream (product)

Phase 3 - Facilitate a Broader Transition (3-4 months)

Refine the transition plan based on the pilot results, and prepare for a broader transition to the new operating model

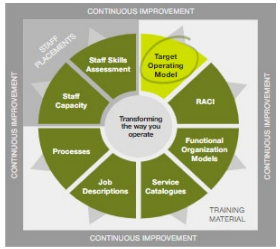
- v) Monitor performance of piloted value stream (product)
- vi) Refine transition plan based on lessons learned
- vii) Plan for a broader transition to the new model

(with the option to refine, test, learn & activate the TOM in increments)

Key activities and milestones for enhancing the design of the D&I TOM

Activating the D&I TOM through an initial pilot followed by a broader enterprise rollout considers the following key activities and milestones:

Alectra's D&I TOM will be activated & implemented through:



Implementing D&I's TOM will address all remaining elements of the transformation wheel

Key activities & milestones (within the recommended time horizon):

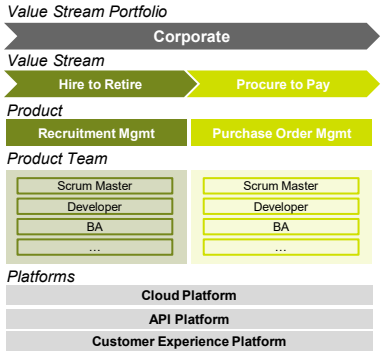
Current state → Pilot completed → Broader TOM rollout

	FOR THE LEAN ORGANIZATION PILOT (5 TO 6 MONTHS)	FOR THE BROADER ENTERPRISE ROLLOUT (7 TO 10 MONTHS)
D&I Transformation	• Identify value stream(s) to pilot	• Assign a Digital & Innovation Lead to manage the overall transition • Define value stream taxonomy (e.g. portfolio, value streams) and key product terms • Plan and sequence value streams for the broader TOM rollout
People	• Identify and train pilot team(s) • Establish clear business and D&I value stream / product roles	• Conduct D&I employee skills and capacity assessment • Define D&I organizational structure, job descriptions, roles & responsibilities • Define D&I resourcing strategy and delivery model (i.e. internal or external)
Processes	• Define high level processes & interaction model for the pilot	• Define change management, training and transition strategy & plan • Define processes around portfolio management, planning and coordination, end-to-end delivery and technology operations • Define interaction model between D&I functions in the TOM
Technology & Information	• Outline key technologies for use in the pilot	• Define D&I architecture standards, information management strategy, and infrastructure governance • Define value stream product portfolio
Performance Management	• Define measurable success criteria for the pilot	• Define performance management framework, KPIs and reporting mechanism • Incorporate pilot metrics into lessons learned for further TOM activation and refinement
Governance	• Define high level governance and funding model	• Define governance model, policies, communications, and reporting mechanism

Recommended action plan for Phase 0: Set the Foundation

The foundational elements of activating Alectra's Digital & Innovation target operating model focuses on building on the refresh of the organization's enterprise architecture (i.e. business capability model) in order to define the value stream taxonomy that will be used to enable product-based delivery.

Key Activities



Define Value Stream Taxonomy

- Identify Alectra's value stream portfolios that can be further broken down into value streams. For example, *'Corporate'* could be a value stream portfolio and *'Hire to Retire'* could be a value stream.
- Define products by their business capabilities and outcomes. For example, *'Hire to Retire'* could be a value stream and *'Resourcing/Recruitment Management'* could be a product.
- Map applications to products for a few value streams as a starting point.
- Identify and define platforms at D&I that enable the product teams to consume functionality in a self-service fashion (e.g. providing APIs).
- Develop a glossary of key product-related terms with definitions.

Rationale & Benefits

- Value stream, product and platform taxonomy allows for a clear and consistent understanding of the product model across the organization.
- Enables agile product delivery in priority areas of investment for the enterprise - enabling greater speed to market and a continuous release of valuable products and services to Alectra's regulated and competitive businesses.

Assumptions & Dependencies

Assumptions

- Alectra's D&I would transition to adopting an agile delivery methodology to support the transition to being a product-based organization.
- Alectra's business capability model refreshed in 2022 would serve as the base for the initial development of the value stream, product and platform taxonomy.
- Alectra's application/solution architecture (overlayed on top of the business capability model) refreshed in 2022 would serve as the base for mapping applications to value streams, but may require further validation/refinement.

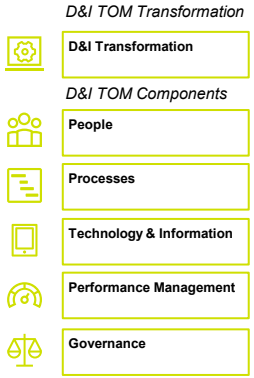
Dependencies

- Confirmed Digital & Innovation lead has been assigned the role of leading the target operating model transition
- Completion and sign-off on Alectra's Digital & Innovation Strategy
- Confirmed completion/refresh of the business architecture (as required based on the 2022 version of Alectra's business capability model)

Recommended plan for Phase 1: Design a Lean Organization

The lean design of Alectra's Digital & Innovation organization focuses on designing the minimum viable organization to activate the TOM in a pilot to support of the transition to digital and analytics enabled product delivery. This will include design of high-level processes, interaction model, roles, etc.

Key Activities



Design lean organizational components to activate the TOM

- Based on the recommendations provided, determine essential D&I operating model updates required to execute the pilot:
  - **D&I TOM Transformation:** Identify value stream(s) to pilot, starting with high priority investment areas; establish prioritization framework for the value stream(s) backlog.
  - **People:** Establish value stream / product roles and responsibilities for both business and D&I stakeholders.
  - **Process:** Define the high level processes and interaction model for the pilot related to portfolio management, planning and coordination, end-to-end delivery and technology operations.
  - **Technology & Information:** Outline the use of key technologies for the pilot, including the need for any training.
  - **Performance Management:** Define the pilot's measurable success criteria.
  - **Governance:** Formalize governance bodies/policies required to enable the pilot.

Rationale & Benefits

- Enables D&I to demonstrate value, enhance the design of the organization and adapt based on lessons learned in an agile and timely manner.
- Minimizes the impact and limitations related to resource constraints through the incremental activation of the TOM.
- Prioritizes the delivery of business value in high priority investment areas - with a focus on the customer (internal and external) and business outcomes.

Assumptions & Dependencies

Assumptions

- The minimum viable operating model components will be designed for the pilot; other operating model components can be defined (and/or refined) on an ongoing basis or part of the broader enterprise TOM rollout.

Dependencies

- Completion of the value stream, product and platform taxonomy work identified in Phase 0
- Confirmed alignment/sign-off on Strategy 2.0 objectives and priorities to support value stream pilot identification

Recommended plan for Phase 2: Define Strategy & Execute a Pilot

The pilot will include selecting one or more high priority opportunities (i.e. value stream(s)) to test out the recommendations of Alectra's D&I target operating model. Key learnings from the pilot will provide the basis for a broader transition to the new model.

Key Activities

Define pilot strategy and validate initiatives

- Define high level objectives and timeline for the pilot.
- Identify and select candidate initiatives based on the high priority value stream opportunities identified in Phase 1 - Design a Lean Organization.
- Validate scope areas of the operating model to be tested in the pilot based on Phase 1 - Design a Lean Organization.
- Validate measurable success criteria for the scope areas based on Phase 1 - Design a Lean Organization.
- Define the communication strategy and plan.
- Form teams for the pilot initiatives, provide onboarding training for the pilot and commence execution.

Execute pilot and measure results

- Execute the initiatives based on the updated operating model through the delivery of product and platform teams (as well as the enabling teams/functions from a shared business and technology services support perspective).
- Measure progress against defined scope elements (reporting data to be provided by pilot teams).
- Perform a pilot review at the end of the pilot execution timeline.
- Make prioritized updates to the operating model based on lessons learned.

Rationale & Benefits

- Enables Alectra's D&I leadership to determine any changes required to the organizational structure before enterprise wide rollout of the target operating model.
- Measures progress against a baseline success criteria to identify opportunities to improve and refine the target operating model design.

Assumptions & Dependencies

Assumptions

- Suitable initiatives can be identified for the pilot in the outlined timeframe.
- Business stakeholders will be supportive of the pilot initiatives; 100% resource dedication will be committed.
- Appropriate onboarding of pilot team members to the new delivery and operating model.
- ~12-week (i.e. 3-4 month) length was selected to test a full quarterly product/platform planning and execution cycle.

Dependencies

- Completion of Phase 1 - Design a Lean Organization

Recommended action plan for Phase 3: Facilitate a Broader Transition

The broader transition to the target operating model can be planned based on lessons learned through the pilot. Additional considerations can be made to activate Alectra's D&I TOM through a phased and incremental approach if desired.

Key Activities

Define and/or Refine TOM design and transition plan based on pilot lessons learned

- Define and/or refine TOM components to facilitate the broader enterprise rollout (across *People*, *Processes, Technology & Information*, *Performance Management* and *Governance* key activities and milestones identified on slide 60)

Plan a broader rollout

- Determine value streams aligned to: 1) product based teams and ; 2) project based teams in the product model.
- Plan and sequence value streams for broader rollout of the product model (incl. key activities and timelines).
- Assess training needs for teams to transition to the new model and facilitate training.
- Define a temporary support organization to help teams transition to the new model and to manage communications.

Execute broader rollout

- Execute transition based on the rollout plan and timelines.
- Provide transition support to the teams on an as needed basis.
- Manage transition communications to D&I and business stakeholders.

Rationale & Benefits

- Builds on momentum and earlier successes from the pilot to expand and deliver value across the enterprise
- Supports a phased approach to adopting the target operating model more broadly while managing competing priorities

Assumptions & Dependencies

Assumptions

- Appropriate onboarding of transition team members to the new delivery and operating model.
- Details related to enabling and implementing the "Data Hub" functions of the D&I target operating model have been identified and defined through the *"Managing our Data & Information"* theme as part of Alectra's Digital Strategy

Dependencies

- Completion of Phase 2 - Define Strategy & Execute a Pilot where updates to the organizational structure based on the lessons learned have been identified and implemented

Factors to consider when activating the D&I TOM

Activating the TOM will require a prioritization of efforts to implement changes that are directly attributed to delivering the greatest value to the enterprise.

Setting the Strategy & Direction

Prioritize the activation of the operating model by aligning and mapping operating model changes to strategic value. The following questions can be served as a guide:

1. What does Alectra need to do to create value?

- *What aspects of Alectra's value chain are the most critical to creating value?*
- *How can Alectra differentiate itself across the value chain?*

2. What business capabilities does Alectra need to create this value?

- *What capabilities does Alectra need in order to deliver critical areas of value?*
- *How can Alectra excel compared to its peers based on the capabilities it invests in?*

3. Do these capabilities exist today or do they need to be built?

- *Do these capabilities exist at the enterprise and D&I level?*
- *What improvements need to be made to existing D&I capabilities and/or what D&I capabilities gaps need to be closed to achieve the desired target state?*

4. How would reconfiguring, building or acquiring new capabilities support the activation of the operating model and deliver on strategic priorities?

- *What are the implications of enhancing or building new D&I capabilities?*
- *Are these changes reflected in the design of the D&I TOM?*

Securing the Funding & Support

Two approaches are commonly adopted to activate a TOM - through a "traditional" standalone effort, or a more agile and integrated approach.

Standalone & Extended

Embedded & Incremental

'Standalone & Extended' Characteristics:

- Led and delivered by technology
- Formalized as a project with a standalone business case and budget
- Delivered through multiple phases through an "end to end" transformation in a "big bang" format - limiting the ability to demonstrate value early and through quantifiable measures
- Accelerated with operating model activation support from external parties from a capability and capacity perspective (e.g. organizational design, service delivery model and staffing capability assessments)

★ **Recommended approach**

'Embedded & Incremental' Characteristics:

- Led and delivered by technology and the business
- Embedded as an "investment" in enhancing and/or building business capabilities required to deliver strategic value
- Delivered through business-led programs/initiatives (i.e. with a % of programs/initiative spend allocated to TOM activation)
- Demonstrated value delivery through the incremental activation of the TOM using pilots and phased rollouts to support a "test and learn" approach
- Accelerated with operating model activation support from a capability perspective (e.g. product-based organizational design, agile and product based delivery coaching, capability assessment)

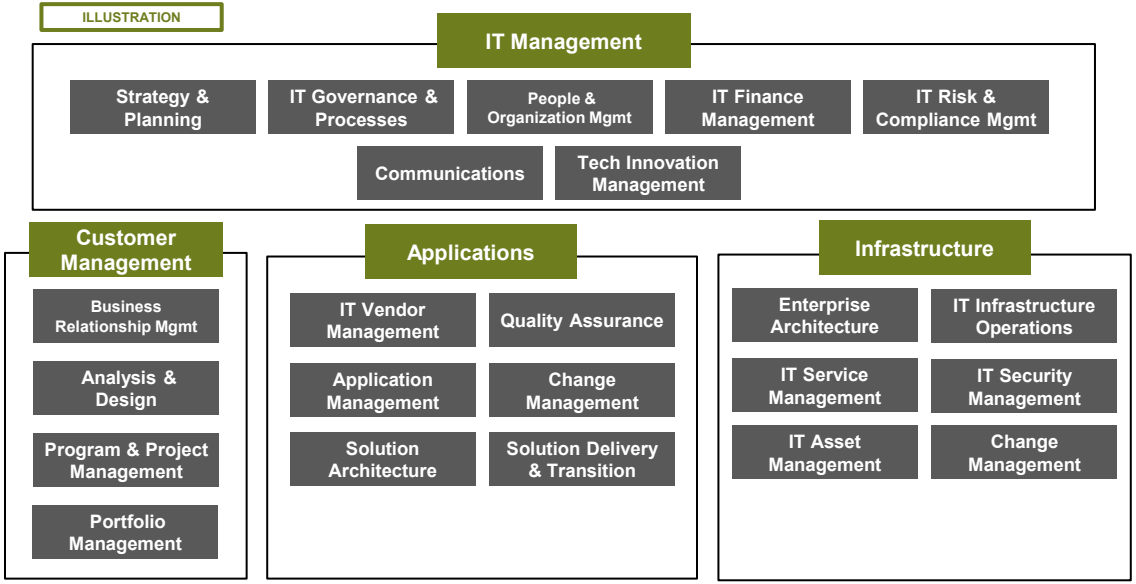
Appendix

IT / D&I Target Operating Model Overview

Overview: IT Function Based Model

This model is operationally-focused and structures the IT organization by applications and infrastructure.

ILLUSTRATION



Key Characteristics

- IT is seen as a service provider with the rest of the business seen as customers.
- Emphasizes shared services for functions across the organization.
- Focuses on end-to-end accountabilities for processes (e.g. applications own plan, build, operate).
- Removes duplicated effort found in business-function based models by aligning IT teams to the IT capabilities and functions that they support.
- Allows IT teams to build speciality in specific areas.
- Model is leveraged by traditional IT organizations as they are structured by IT functions across applications and infrastructure.
- Organizations with more of an operational focus see IT as a service provider in this model which enables the business with less focus on IT.
- The split between infrastructure and applications allows for defined accountability across IT activities.

Pros

- Clear accountability, ownership and responsibility for roles and activities
- Effective in reducing overlap and shadow IT
- Enables overarching enterprise architecture and service catalogue
- Likely to be the lowest-cost option
- Centralized IT function provides the highest degree of coordination

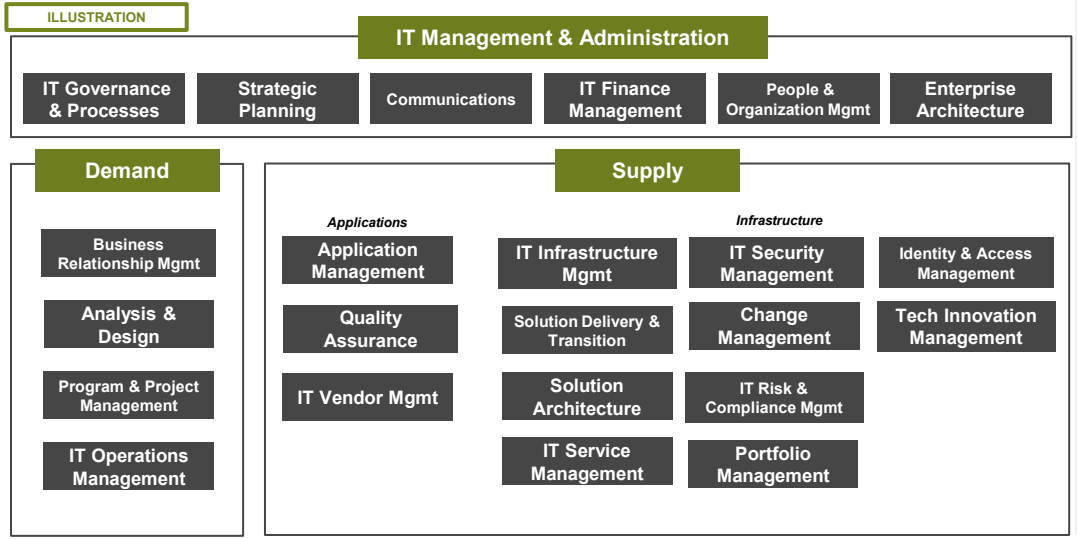
Cons

- IT is prioritized over the business in design, with business needs being secondary to IT capabilities
- User requirement gathering will remain difficult to coordinate
- Large revisions to existing organizational teams will be required (mainly on the business side)

Overview: IT Demand & Supply Model

The IT Demand & Supply model has been around in many organizations for a long time, with an emphasis on delineating capabilities related to IT demand and supply.

ILLUSTRATION



Key Characteristics

- Many IT organizations are structured by applications and infrastructure, but more commonly seen in organizations with a large footprint of on premise solutions.
- Customer management centralizes capabilities that have touch points with clients related to IT demand, requirements and business needs.
- Supply capabilities are often grouped by layer of the technology stack (e.g., application, platform, and infrastructure).
- Model is operationally focused - IT is typically seen as a service provider; with an objective to minimize costs.
- Typically implemented in organizations that structure their functions around the ITIL v3 framework (e.g., application management, technical management).
- This model can result in siloed knowledge associated with the development and maintenance of a full stack solution.

Pros

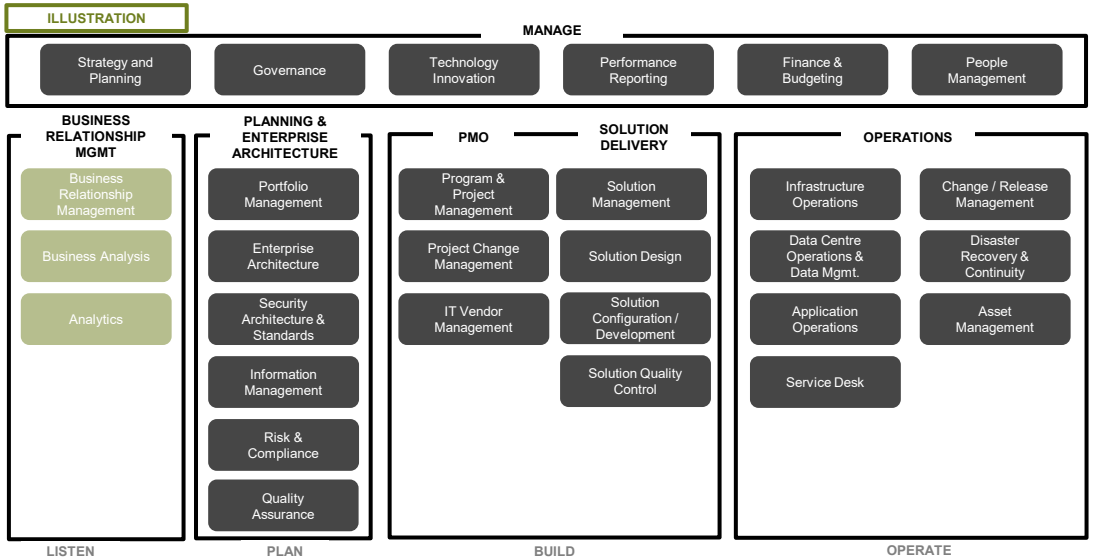
- Clear ownership and accountability of demand and supply functions within IT
- Clearly separates customer-facing tasks such as requirements management and strategic planning from supply-focused work streams such as application development and maintenance
- Can help improve organizations where IT's ability to communicate needs improvement
- Provides a clear line of sight between business requirements (demand) and resource allocation (supply)

Cons

- Process ownership is sometimes difficult to establish as responsibilities may span multiple groups
- Generally there is reduced accountability around process outcomes due to handcuffs between demand and supply
- May increase the difficulty of iterative development
- May result in career inflexibility and perception of being "left behind" on the supply side

Overview: Listen-Plan-Build-Operate (LPBO) Model

The Listen-Plan-Build-Operate Model places a strong emphasis on relationships between the technology organization and their partners.



Key Characteristics

- Builds on the Plan-Build-Operate model by formalizing a pillar around client relationship management and business needs identification.
- By grouping "Listen" capabilities together, there is an opportunity to explore the synergies of insights driven decision making and planning, design thinking, and business relationship management as input to enterprise technology planning and delivery.
- Clearly differentiating the "listen" and "plan" capabilities provides the business a clearer delineation between the organizational functions that deliver these capabilities.
- Works well in organizations who are currently operating in a Traditional IT or a Plan-Build-Operate model, looking to establish stronger foundations for tighter integration between business and IT.

Pros

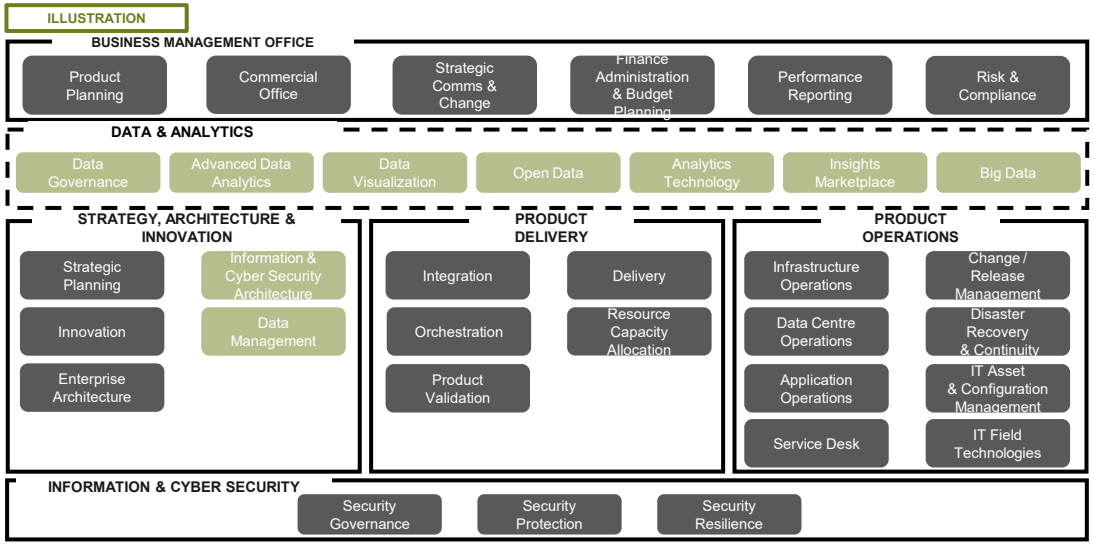
- Allows the "listen" function to take an unbiased approach to business needs identification (works well when IT is a service provider or strategic partner), limiting the perception of IT as being a challenge function or "gate".
- Each stage of the life cycle encompasses a distinct set of functions with segregation of duties.
- Supports a more complex and deeper relationship between the technology group and their partners by allowing for more focus on managing client relationships and listening to their needs.

Cons

- The interactions between IT clients and the listen and plan functions may be iterative in nature, and the linear capability groupings by high level IT process increases the need for integration, coordination, and cooperation between pillar leads.
- May create tension between "listen" and "plan" functions as the accountability of the business relationship may not be clear or ideal.
- IT subject matter expertise may not be an input early enough in the ideation process (e.g. architecture as an afterthought).

Overview: Analytics & Information Enabler Model

This model enables the delivery of analytics by any group within the organization while preserving the benefits of other models.



Key Characteristics

- Typically implemented as a response to the need for business agility and insights driven strategy and decisions.
- Information and analytics capabilities are delineated from core IT delivery and operations to improve strategic focus and integration with the business.
- Model is flexible for information and analytics capabilities to be centralized within IT, decentralized into business units, established as a separate organizational function, or implemented through a hub-and-spoke model.
- Hub-and-spoke model enables a central “hub” to focus on enterprise wide information (e.g. transaction data) while allowing “spokes” (e.g., business teams) to “slice and dice data” to address unique business and operational needs.
- Other parts of the model provide the technology infrastructure and services that underpin and deliver information and analytics capabilities.

Pros

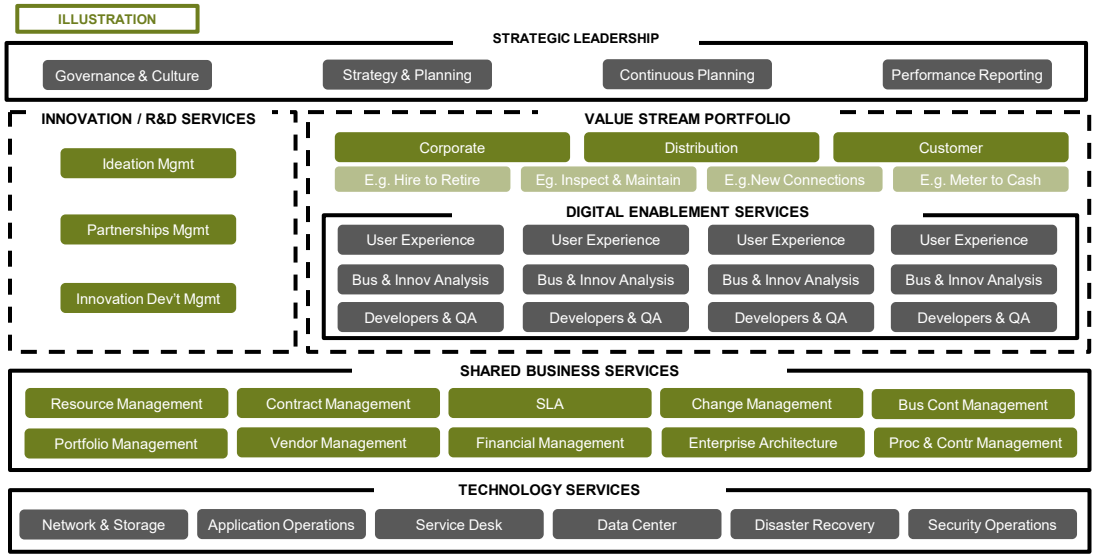
- Allows a greater level of focus, innovation, and agility related to analytics capabilities.
- Often seen as a lighter-weight approach to enabling enterprise analytics while trimming lengthy engagement processes and reducing request backlogs.
- Enables increasingly self-sufficient business users to carry out “commodity” or “business specific” analytics activities.

Cons

- Coordinating management and governance of hub-and-spoke model or decentralized analytics capabilities with IT can be challenge without clearly defined processes, accountabilities, and leadership buy-in.
- Some of the synergies of having a centralized information management and analytics function may not be realized if the respective functions are not closely aligned.

Overview: Digital Innovation & Enablement Model (1 of 2)

This model attempts to incorporate the digital mindset into each line of business and institutionalize an innovation engine.



Key Characteristics

- This model provides insight to how digital capabilities can be implemented across functional areas to enable an organization's digital strategy, with a focus on adoption of digital principles and methods across an organization to improve end user experience.
- This model also provides insights to how innovation capabilities can be institutionalized through the establishment of an innovation engine that will enable the innovation strategy and value chain (across near (innovation) and long-term (experimentation) initiatives).
- Some implementations of this model include "innovation labs", "digital factories", and "digital service delivery" teams.
- Rarely implemented across all business lines at once; generally piloted within lower risk areas to demonstrate viability of the concept.
- Client engagement is built around enabling the digital mindset, with a focus on customer/user experience early in the ideation phases.
- Segregates digital and innovation capabilities and roles from core traditional technology roles; digital roles are generally embedded within the business while innovation roles are generally distinctly maintained.
- Leverages a suite of common business and technology services across the various lines of business to deliver technology in a more efficient and cost effective manner.

Pros

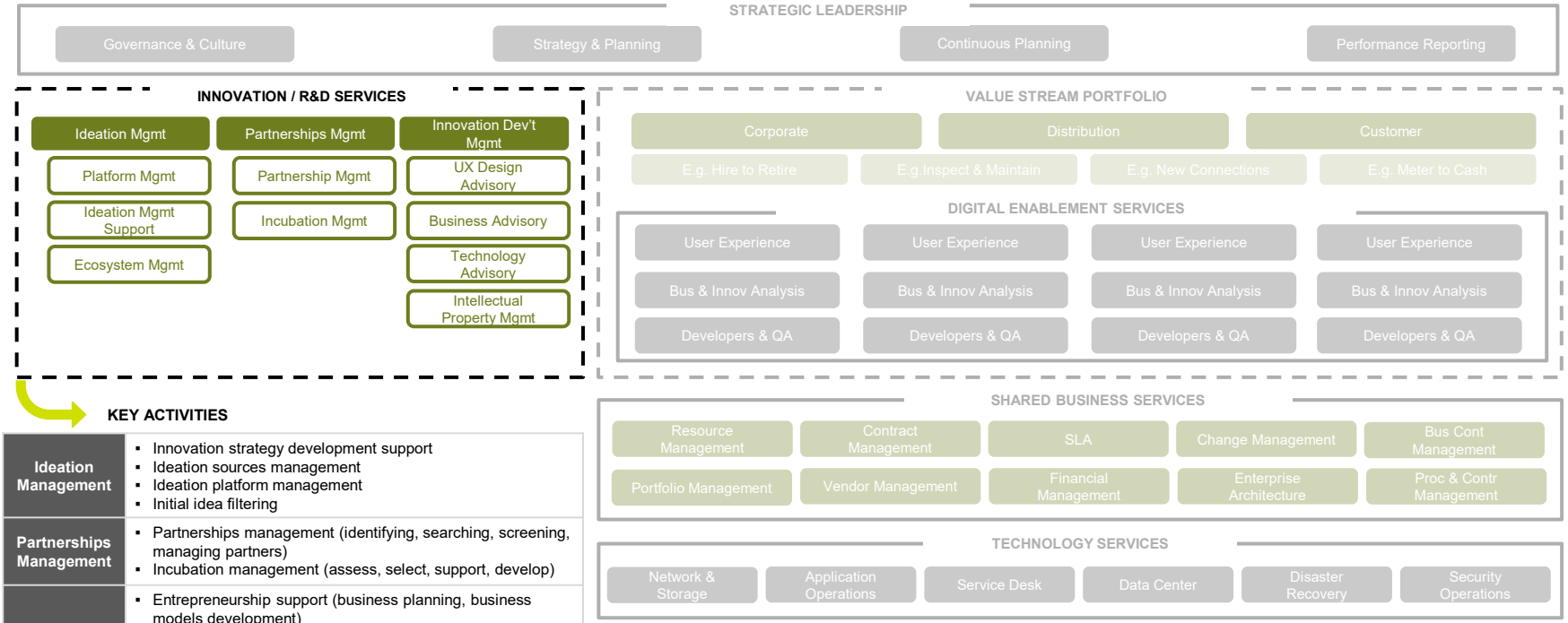
- Ease of skills transfer and knowledge reuse between digital & innovation teams and the business, with prompt access to expertise when required.
- Highly collaborative approach, as product management and development occur within the business, with a focus on customer experience early in the ideation process.
- Supports innovation development activities and clear transfer ownership at concept approval.
- Leverages a suite of business and technology shared services across the various lines of business to deliver technology in a more efficient and cost effective manner.

Cons

- Effectiveness and quality of solution design are highly dependent on the maturity of an organization's business architecture capability, as business solution development is embedded within various lines of business.
- Segregates digital and innovation capabilities and roles from core IT, which may result in inconsistent experiences.
- IT teams are not aligned to products or business units, missing an opportunity to build product-specific or business-related expertise in IT teams.

Overview: Digital Innovation & Enablement Model (2 of 2)

This model requires Alectra's D&I to assume an innovation facilitator role.

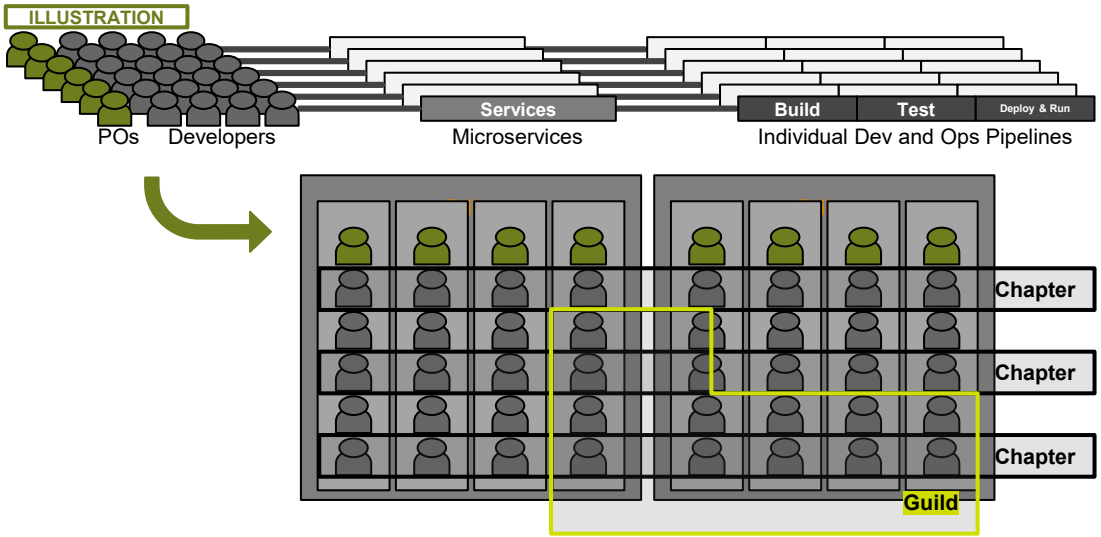


KEY ACTIVITIES

Ideation Management	▪ Innovation strategy development support ▪ Ideation sources management ▪ Ideation platform management ▪ Initial idea filtering
Partnerships Management	▪ Partnerships management (identifying, searching, screening, managing partners) ▪ Incubation management (assess, select, support, develop)
Innovation Development Management	▪ Entrepreneurship support (business planning, business models development) ▪ User Experience Design Advisory (manage UX design support to innovation teams) ▪ Technology Advisory (manage technology support to innovation teams) ▪ Intellectual property management (IP, patent, licensing)

Overview: DevOps Model

Although not a new concept, DevOps Models have seen increased interest and adoption recently due to the potential benefits.



Key Characteristics

- Products are decomposed into distinct, separately deployable 'microservices', each with product owners (PO) and teams (squads) that perform specific business functions.
- Product owners set the product vision and prioritize product backlogs, while squads are small cross-functional product teams that are responsible for the full lifecycle of activities including building, testing, and deploying services in rapid and frequent releases.
- Chapters represent a group of developers of similar discipline and guilds are interest groups with a focus area.
- Having chapters and guilds help to promote best practices and standards organically between teams. Although not the same as mandated standards, this ensures teams have similar development practices where it makes sense.
- Typically requires a highly automated environment for testing and deployment to realize full potential.

Pros

- Organizations can swiftly react to customer needs through agile teams that practice rapid, iterative development and deployment of applications into production
- Continuous software delivery decreases resolution time, results in less complex releases, and enables faster delivery of features
- May increase customer satisfaction, decrease incidents/bugs and accelerate overall delivery

Cons

- Shifting culture to accept a DevOps approach will take time, as well as a significant amount of change management and upskilling
- Significant investment may be required to successfully implement a mature DevOps model (e.g. continuous deployment), including investment into automated tool sets
- Requires a high degree of coordination across teams (likely more than what currently exists)

Appendix

Proposed Target State Model for Alectra's D&I Team

Overview: D&I TOM strategic leadership functions

Strategic Leadership Function Descriptions	
Function	**Description**
Governance & Culture	Provides the framework and capacity for making and implementing decisions required to manage, control and monitor D&I's direction and accountability within the organization. The framework defines the decisions, stakeholder involvement, the structures, processes, responsibilities and other mechanisms required. It involves 3 tiers of governance (strategic, management, and operational) to define, plan, manage, execute and measure D&I's progress against the D&I strategy and ability to enable enterprise-level strategic objectives.
Strategy & Planning	Creates and maintains D&I's strategy and vision.The right D&I strategy will help to increase alignment between D&I's portfolio and enterprise strategic priorities. The strategy will follow a 3-year forward looking outlook plan and will leverage the Business Capability Model to identify and prioritize technology investments.
Enterprise Architecture	Manages the view of enterprise-wide business capabilities required to achieve the organization's desired target state (i.e. based on business vision and strategic ambitions). It supports in responding to change in the D&I landscape by defining, maintaining and prioritizing business capabilities that require digital and innovation-related investments across various dimensions, including: business architecture (business processes, locations, and business services), data/information architecture, applications architecture and technical/infrastructure architecture. The enterprise architecture sets architecture standards and guidelines that align and map D&I initiatives to business capabilities that will enable Alectra's desired target state.
Continuous Improvement	Enables the ongoing effort to monitor and evaluate current processes. Finding efficiencies for cost, quality and product/service delivery. It provides frequent improvements to streamline workflows while reducing cost and optimizing outputs.
Performance Reporting	Captures and distributes management information and key performance indicators within D&I, including D&I's contribution to corporate objectives. Covers how performance in all D&I areas is assessed, how D&I business plans are adapted to the outcome, the usage of KPIs, and benchmarking practices. Establishes reporting processes and identifies and supports the adoption of the appropriate tools for reporting.

Overview: D&I TOM innovation services functions (1 of 2)

Innovation Services Function Descriptions	
Function	**Description**
Ideation Management	Provides the enterprise and D&I with relevant innovation ideas from multiple sources, with a minimum required assessment for D&I to further develop ideas into concept evaluation and integrate the innovation process at Alectra if the concept is reviewed and approved.
Ideation Platform Management (Internal Ideation)	Manages and supports the adoption of Alectra's ideation platform by defining, reviewing and updating Alectra's ideation platform objectives and system requirements, establishing efficient and effective internal ideation mechanisms. Manages partnership with the solution developer (internal or external) to implement and maintain the ideation platform supporting D&I's ideation platform adoption strategy and ensuring strong internal ideation.
Ideation Management Support	Supports D&I ideation management by defining, reviewing, and/or updating Alectra's ideation strategy. Manages the consolidation of ideation sources including but not limited to Alectra's ideation platform, research, trend scouting and ecosystem activities. Coordinating with Business Advisory to develop the initial assessment of an innovation opportunity and final ideation report.
Ecosystem Management (External Ideation)	Support D&I ideation management in defining, reviewing, and/or updating Alectra's innovation ecosystem strategy. Develop and implements ecosystem management activities (e.g. sector based events, hackathons, conferences, etc.) in close coordination with partnerships management. Provides Ideation Management and Partnerships management with potential partners and other innovation sources.
Partnerships Management	Ensuring all innovation sourcing requirements are met by pursuing partnerships that enable the development and execution of Alectra's innovation strategy and roadmap.
Partnership Management	Enables D&I innovation sourcing through partnerships and incubation. Develops Alectra's innovation partnerships strategy including partner categories definition, partnership base definition based on the D&I strategy, and partnership development approach to support ideation and concept development. Manages partnerships and maintains oversight when operational day-to-day interactions are transferred to the business owner.
Incubation Management	Manages D&I incubation activities to enable startup sourcing. Identifies and evaluates potential incubation partners and all activities leading to incubation partnership (including memorandum of understanding (MOU) development, negotiations management and partnership deal finalization).

Overview: D&I TOM innovation services functions (2 of 2)

Innovation Services Function Descriptions	
Function	**Description**
Innovation Development Management	Manages all innovation development and acceleration activities to enable efficient and effective operations. Coordinates with Ideation Management for the preliminary evaluation of innovation ideas and integrates validated opportunities into the innovation process. Oversees the development of detailed concepts for evaluation, and (if approved) proof of concepts and prototypes. Manages innovation teams and intellectual property.
UX Design Advisory	Enables the successful design of user experiences for innovation opportunities. Manages all UX design support activities to innovation teams, including defining and consolidating functional requirements for assigned innovation opportunities, managing all UX design activities within the proof of concept phase, including but not limited to use cases development, design of key interfaces, and design of key interactions and workflows. Supports Technology Advisory in prototype development as required.
Business Advisory	Enables innovation opportunities to be evaluated from a commercial viability perspective. providing business advisory to innovation teams. Manages all concept evaluation development activities and provides business advisory to innovation teams. Develops opportunities concept evaluation once integrated in the innovation process, including business model definition and high-level business case development.
Technology Advisory	Enables the technology capabilities for innovation opportunities. Manages all technology support activities to innovation teams, including defining and consolidating technical requirements for assigned innovation opportunities. Supports UX Design advisory (when required) in design activities. Manages prototype testing and refinement activities through internal development or external sourcing.
Intellectual Property (IP) Management	Identifies intellectual property and licensing opportunities in order to establish additional revenue streams from both the regulated and competitive side of Alectra's business. Applies for patents and manages the IP portfolio.

Overview: D&I TOM value stream led product management functions

Value Stream Lead Product Management Function Descriptions	
Function	**Description**
Value Stream Portfolio (e.g. "Corporate")	Manages the products (delivered through a value stream) for a value stream portfolio, which is the highest order building block of value that can be delivered to an internal or external customer (e.g. corporate, distribution and customer related activities or services). Focuses on allocating resources for an optimal return on investment, keeping products aligned with the enterprise strategy, and identifies key opportunities for improvement.
Value Stream (e.g. "Hire to Retire")	Manages products through the delivery of dedicated squads/pods. Each Value Stream is dedicated build, support and maintain a product or service following a sequence of steps used to continuously deliver value to the customer, mapping back to its broader Value Stream Portfolio.
User Experience	Facilitates a strategic, customer-centric vision across D&I, including conducting employee/customer research and usability testing to guide design and identifies employee/customer needs, define digital employee/customer personas, create user flows, and develop journey maps.
Business Innovation & Analysis	*Before a product is approved,* conducts discovery (i.e. user research to understand user needs) to assess the desirability and viability of a product. *Once a product is approved,* identifies solutions and analysis of requirements prior to integration or creation, aligns with organizational/ business requirements, including reviewing feasible options (i.e. factoring costs and benefits, risk analysis), and approving requirements and proposed solution designs.
Development & Quality Assurance	Develops, designs and implements the test plan, following testing practices throughout the development lifecycle. Steward the desired quality is achieved for the organization, executing consisting standards, and methodologies that are most effective and aligned to D&I Strategy.

Overview: D&I TOM data hub functions

Data Hub Function Descriptions	
Function	**Description**
Data Governance	Manages the standards, processes, policies and controls that must be followed within the organization to make data secure, private, available, accurate and usable. Identifies the appropriate technology is in place to guarantee data integrity, quality and security is maintained throughout the data lifecycle.
Advanced Data Analytics	Analyzes and transforms raw data into deeper customer, product and operational insights making predictions and generating recommendations to help the organization optimize performance and enhance decision-making leveraging analytics and insights. Provides all the technology, infrastructure and tools to support D&I in delivering analytics capabilities across the enterprise.
Data Visualization	Enables decision makers to view and/or interact with data and analytics in a quick and easy manner through visualization. Facilitates experimentation by processing large amounts of complex data into different scenarios through a pictorial or graphical format and by changing what data is selected and processed to inform decision-making. Enables all of the technology, infrastructure and tools required to support D&I in delivering data visualization capabilities across the enterprise.
Open Data	Enables availability and access to data that is machine-readable as well as universally available and shared without restrictions (subject only to the requirement to attribute data to the source). Allows Alectra to share data with external partners, customers and industry associations while consistently meeting requirements and conditions from a data, technology, processes, and regulatory perspective.
Sensor Data (via IoT)	Enables data to be collected, stored and processed from sensors and IoT Devices in a consistent and secure manner. Enables the organization to capture and analyze increasing volumes and varieties of data flowing from various systems and connected devices as well as integrate streaming data with analytics and visualization (where appropriate). Supports the business through various use cases and opportunities, including improving the ROI of smart grid investments, optimizing distributed energy resource (DER) integration, and identifies innovations for customer and grid applications.
Insights Marketplace	Enables data to be quickly accessible to users through the availability of a dashboard or BI tool (i.e. thereby removing the need for complex data engineering work). Makes data models and analytics available to the organization to enable accurate and real-time decision-making.

Overview: D&I TOM shared business services functions

Shared Business Services Descriptions	
Function	**Description**
Resource Management	Manages staff capacity and planning resources for projects across D&I with input from the overarching D&I strategy and the prioritized portfolio of D&I projects.This includes having the visibility into resources capacity and the ability to optimize the productivity and profitability of resources. It also deals with centralization/decentralization of IT service provisioning, and the use of part-time/contract vs. permanent staff, so resource administration meets the demand.
Contract Management	Establishes contract management strategy and managing supplier management operations. This includes tracking of contract information, supplier performance monitoring and reporting activities, review of contracts near expiration in order to meet the renewal or cancellation requirements established in the contracts.
Service Level Agreement Management	Provides the required support structure to meet service objectives, incorporating continual service improvement and enabling consistent delivery (i.e. performance and quality are delivered at the expectation of the organization). This includes ensuring all provided services and processes within the organization (whether delivered by internal or external partners) are in alignment with agreed-upon service level targets defined by D&I and/or stipulated by a contract (e.g. for help desk, infrastructure/data center, applications, IT services).
Change Management	Manages technology-driven change and establish clear, timely, and effective communication channels across D&I. This includes managing the people and organizational side of change, by assessing impact and needs of all stakeholders and helping them transition into the new state.
Business Continuity Management	Enables business operations to plan, exercise, and recover from disasters. This includes ensuring that appropriate risk management procedures and processes are in place to prevent interruptions to mission critical services, and re-establish full function to the organization in an efficient and effective manner.

Overview: D&I TOM shared business services functions

Shared Business Services Descriptions	
Function	**Description**
Portfolio Management	Manages Business demand for D&I services and investments by selecting, prioritizing, and sequencing programs and projects that are aligned with Alectra's vision, missions, business and D&I strategy, as well as manage workforce allocations against the pipeline of projects.
Vendor Management	Selects appropriate vendors and manage vendor relationships to deliver business objectives, while continually assessing contracts and service levels to improve value-add from vendor relationships. This includes, maintaining strategic partnerships and vendor performance management.
Procurement & Sourcing Management	Establishes the sourcing strategy (including alignment with procurement processes) and carries it out. Based on the guidelines set out in the sourcing strategy, this function will determine the appropriate service delivery approach and its components (from in-house to full outsourcing) and the general procurement of software development activities (where applicable). This function is closely interlinked with the Vendor Management and Contract Management functions..
Financial Management	Manages the planning, defining, and monitoring of D&I budgets and manage technology investment on an ongoing basis such that D&I initiatives with highest priority are successfully executed. This includes technology/IT cost recovery and chargebacks, activity-based costing, and technology/IT cost management practices, such as capturing of shadow spend.

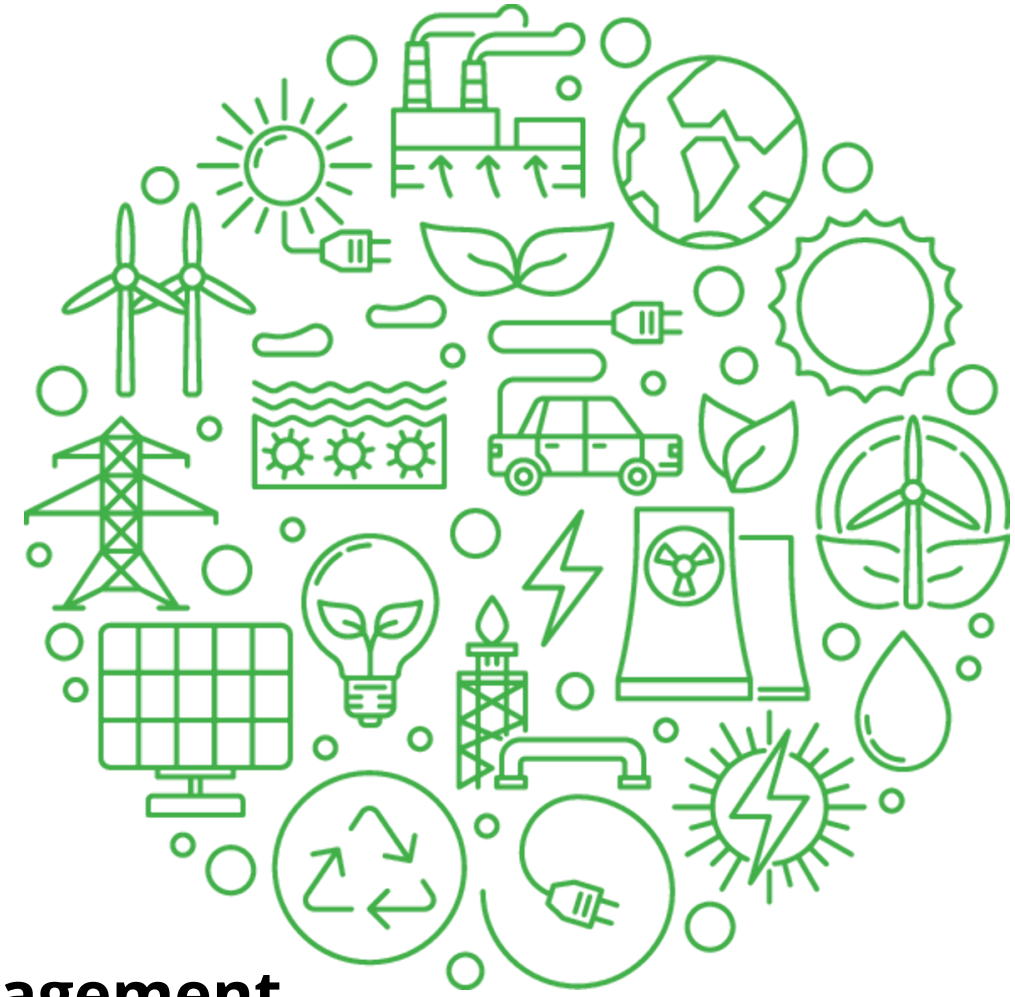
Overview: D&I TOM technology services functions

Technology Services Descriptions	
Function	**Description**
Network & Storage	Supports and maintains data and voice networks. It includes working with 3rd party telecommunication providers, network resource monitoring and tuning, service level management and reporting for external providers, and network capacity management.
Application Operations	Maintains and supports production applications, and defines a comprehensive maintenance and enhancement strategy for the portfolio of applications. The function also includes defining and managing an effective test environment for portfolio solutions.
Service Desk	Covers all aspects of service / help desk, including service desk operations (through the full life cycle of problem management), service desk performance management, incident management, communication during major incidents, queue management, 3rd party task assignment and liaison, and the acceptance, approval and fulfilment of provisioning requests.
Data Center	Covers the operational management of data centres, data backup and configuration, data centre security and capacity management.
Disaster Recovery	Covers the establishment, testing, and maintenance of plans, processes and policies to enable the enterprise and D&I to recover from incidents, disasters and disruptions, such that critical business processes and Alectra service delivery can continue and that information availability can be maintained.
Security Operations	Maintains security infrastructure and access control, performing threat and vulnerability testing, and managing security incidents in alignment with the established security standards and policies of Alectra.

Hardware Asset Management Review

Deloitte.

alectra utilities



Hardware Asset Management Program: Internal Audit Assessment

January 29, 2024

Executive Summary

Executive Summary: Project Background and Deliverable Overview

Below is a summary of the activities completed during the scope of this engagement, as well as an overview of this deliverable's contents

Alectra's Ask of Deloitte

Alectra requested support related to the **assessment of their Hardware Asset Management (HAM) Program** from an Internal Audit lens, and required tangible recommendations to further mature their HAM Program across the organization

As part of this project, Deloitte worked alongside Alectra to **assess the HAM Program's design and implementation** (D&I) of process controls, **identify improvement opportunities**, and **build a strategic roadmap** to implement and realize the relevant HAM capabilities.

The scope of the engagement included the following asset classes:

- Data Center Assets (i.e., server infrastructure)
- End User Computing Devices (laptops, consumables*, etc.)
- Network Equipment (firewalls, routers etc.)

Hardware Asset Management (HAM) Internal Audit Assessment & Roadmap Overview

This report summarizes Deloitte's **analysis & evaluation of the HAM Program** at Alectra. It includes **detailed observations** on the current state of affairs, as well as **actionable recommendations and roadmap initiatives** to further mature the HAM business function within the enterprise. Observations and recommendations are based on the **Deloitte IT Asset Management (ITAM) Framework**, which includes the pillars required to deliver an efficient and effective ITAM program across an organization.

Alectra's key **HAM stakeholders were interviewed**, and **existing documentation & data** was leveraged to understand the current **pain points, gaps**, and **areas for improvement** within the HAM Program.

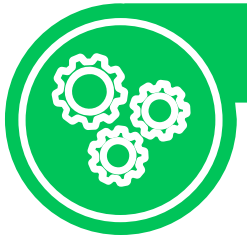
Overall Risk Assessment Rating: Low**

*Consumables: IT hardware used for a specific period that is expected to be replenished regularly due to wear & tear/depletion of useful value (e.g., keyboards, mice, toner, etc.)

**Refer to the Risk Assessment Rating Definitions for the ratings used throughout this report

Executive Summary: Positive Observations

During interviews with Alectra's key Hardware Asset Management (HAM) stakeholders, Deloitte's current state assessment revealed some areas where Alectra is making positive progress with its HAM program and leveraging industry best practices



HAM processes are defined, and tools have automation built in

Robust hardware asset lifecycle processes for end user, network, and infrastructure devices have been defined and documented, from planning to disposal. Alectra has implemented ServiceNow with AssetTrack as a tool to support and automate their operational HAM activities (e.g., receiving hardware, assigning an asset to a user).

Continuous improvement of HAM is a focus for stakeholders

The HAM stakeholders are committed to improving the maturity of Alectra's HAM program and positioning it to assist in the achievement of broader business goals. Plans to enforce organizational change management to facilitate process adoption have been discussed.

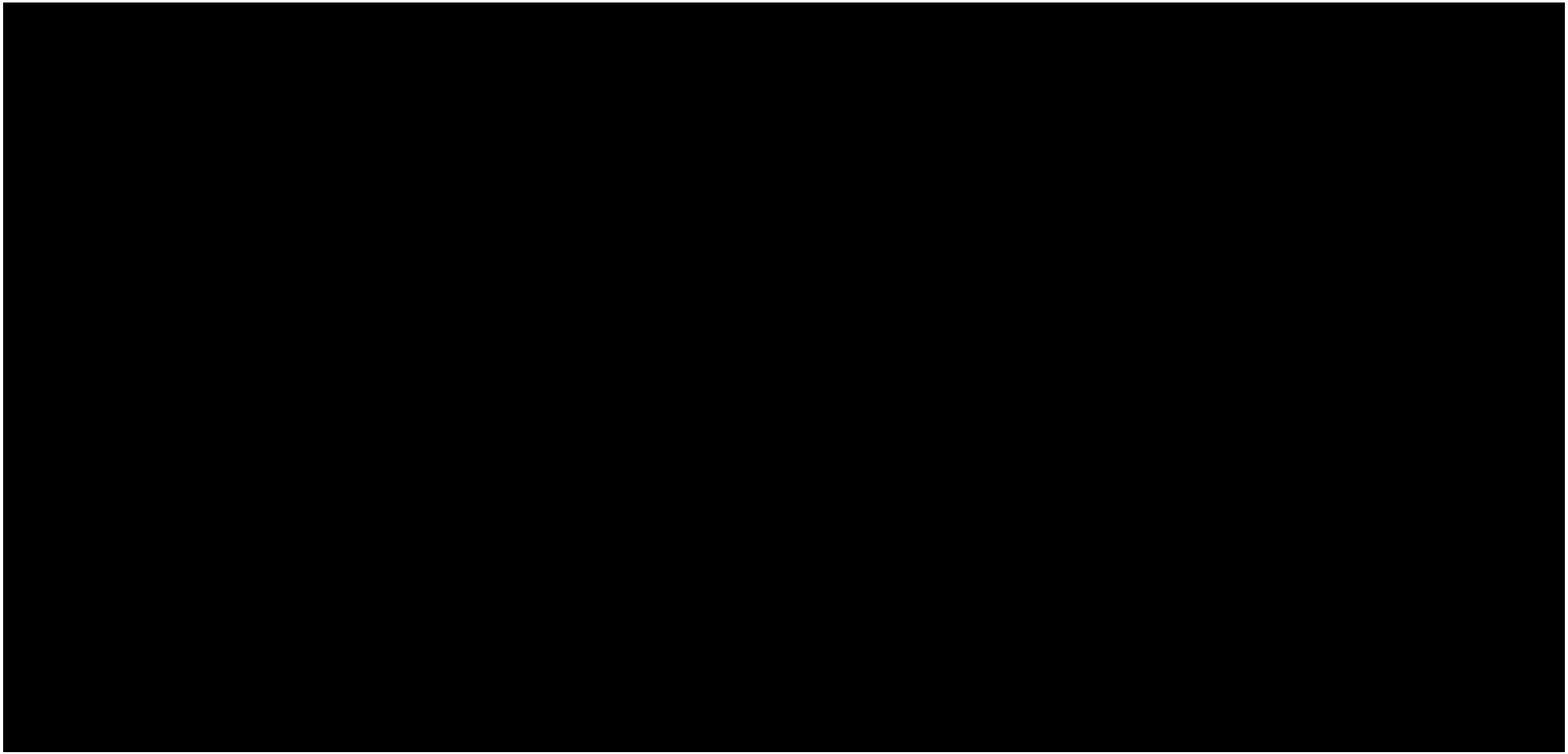
Self-Awareness

Alectra's team demonstrates a strong awareness of HAM goals & objectives, as well as some of the next steps required to reach the target state for HAM. Active and robust stakeholder engagement is crucial to foster organization-wide buy-in.

Detailed process documentation

Hardware asset lifecycle processes have detailed documentation describing how to complete the steps of each process within AssetTrack (e.g., marking assets for disposal, auditing a stockroom). This is a very useful resource for supporting HAM personnel in the completion of day-to-day tasks and can assist in the onboarding of new employees to the HAM team.

The Deloitte ITAM Framework



Detailed Observations: Strategy & Policies

Pillar Assessment Rating: Moderate

Deloitte's current state assessment and observations of Alectra's existing Hardware Asset Management (HAM) function for the Strategy and Policies pillar of the IT Asset Management (ITAM) framework

Findings & Observations	Recommendations
Limited policy to support adherence to lifecycle processes Hardware lifecycle processes are formally documented within Alectra, but there is a lack of policies to enforce compliance to the standard processes & procedures across the organization.	• Develop and implement policies governing HAM to support process adoption • Communicate new policies to key stakeholders to promote awareness and run training sessions to further facilitate process adoption
Lifecycle definition for End User Devices Formal lifecycles are defined for infrastructure and network hardware in Alectra's ITAM Framework, but they are not defined for end user computing devices (although International Financial Reporting Standards (IFRS) are informally adhered to)	• Define and document formal lifecycle timeframes for end user computing devices within Alectra's ITAM/HAM policy documents (aligned with any current finance policies)
Consumable classification methodology There currently isn't a clear definition of how to classify a consumable, and which consumables will be tracked within ServiceNow (e.g., a cost threshold of $500, non-data bearing assets etc.)	• Define and document methods for "consumable" and "asset" classification to remove any ambiguity in processes where assets and consumables are handled differently (e.g., recording the asset's serial number in the asset repository upon receipt)

Limited KPIs to track HAM program success
Some ITAM Key Performance Indicators (KPIs) to are used to measure performance and track progress in AssetTrack, however there are additional HAM-specific metrics that can be captured to further enhance hardware visibility and the program's performance
	• Define formal KPIs* to measure program progress, by looking at metric categories such as:
	  • IT Estate Visibility & Optimization
	  • Data Completeness
	  • Cost Optimization
	  • Compliance Risk Management

Risks

- **Moderate:** Inadequate enforcement of Alectra's standard hardware asset management policies resulting in siloed/disparate processes being followed across the enterprise
- **Moderate:** Absence of adequate KPIs to track the HAM Program's effectiveness may limit the ability to demonstrate the value and impact of the HAM program to the executive stakeholders, potentially hindering program credibility and support from management

Impacts

- **Moderate:** Potential inefficiencies, compliance issues, and difficulties in tracking assets through their lifecycle
- **Moderate:** Increased risk of outdated devices, potential security vulnerabilities for Alectra, and challenges in budgeting for replacements
- **Low:** Potential for redundant hardware spending from limited consumable asset visibility
- **Low:** Missed opportunities for HAM program improvement, reduced visibility into performance, and potential failure to meet Alectra's broader goals & objectives

*Refer to Suggested HAM Key Performance Indicators

Detailed Observations: Technology & Data (1/2)

Pillar Assessment Rating: Low

Deloitte's current state assessment and observations of Alectra's existing Hardware Asset Management (HAM) function for the Technology & Data pillar of the IT Asset Management (ITAM) framework

Findings & Observations

Cost information not being captured

The monetary cost of hardware assets is not currently a data attribute captured on the asset record, limiting Alectra's visibility into the financial component of the hardware estate

Missing/duplicate hardware asset attributes

Some "In use" asset records within ServiceNow have duplicate/empty serial numbers & asset tags or are missing assignment information, resulting in data gaps and inaccurate asset counts. Additionally, there are very few assets with a State of "In stock", which may be due to a process adherence issue or data update gap when assets are received

Linking contract management to assets in ServiceNow

Contract management is currently performed in ServiceNow, however it is not currently linked to asset record information

Recommendations

- Integrate cost information into ServiceNow to improve visibility and reporting (e.g., procurement tool integration with ServiceNow or uploading cost data)
- Set up depreciation schedules & rules within ServiceNow to automate depreciation tracking and report on expenditure by vendor, asset class etc.
- Perform a data remediation exercise to reconcile any duplicate asset records and update any missing data attributes
- Configure ServiceNow to define "Serial number" as a mandatory attribute when asset records are created
- When entering contract information into ServiceNow (e.g., warranty contracts), include information about the asset records that are covered by the contract

Risks

- **Moderate:** Duplicate asset attributes can potentially cause issues in asset identification (i.e, correct vs duplicate) leading to challenges in planning, budgeting and lifecycle management
- **Low:** Incomplete financial visibility into the hardware estate can result in challenges to assess the depreciation & total cost of ownership of hardware assets
- **Low:** Limited contract management in ServiceNow can result in difficulties in tracking asset management contract details and performing renewals (e.g., warranties) leading to noncompliance to contract terms and agreements

Impacts

- **Moderate:** Can impact the accuracy and completeness of financial statements, audits or meeting compliance requirements
- **Low:** Inaccuracies in asset counts within ServiceNow, challenges in asset tracking and identification, and potential errors in financial reporting for asset value & depreciation
- **Low:** Challenges in budgeting, financial planning, and assessing the overall cost-effectiveness of the hardware asset landscape at Alectra
- **Low:** Potential missed contract renewals, challenges in compliance, and difficulties in managing and maintaining vendor relationships

Detailed Observations: Technology & Data (2/2)

Pillar Assessment Rating: Low

Deloitte's current state assessment and observations of Alectra's existing Hardware Asset Management (HAM) function for the Technology & Data pillar of the IT Asset Management (ITAM) framework

Findings & Observations

Recommendations

Incomplete hardware lifecycle data
Manufacturer lifecycle data is not tracked within ServiceNow (such as End of Life and End of Support dates), which limits visibility into when devices are no longer going to be supported by the vendor

- When creating new hardware models within ServiceNow, enter the End of Life (EOL) and End of Support (EOS) dates on the hardware model record to further enable EOL/EOS visibility and reporting

Incomplete Inventory
Inventory data for consumables is not currently populated in ServiceNow, leading to limited asset class visibility within the organization

- Populate existing inventory captured in external data sources (if applicable) to track consumables
- Establish lifecycle management policies to ensure assets are tracked in ServiceNow
- Regularly track KPIs for hardware asset classes (including consumables) to ensure consistency in inventory & reporting

Limited HAM KPI tracking in ServiceNow
The current Key Performance Indicators (KPIs) that are measured on AssetTrack's dashboards can be enhanced to capture additional key HAM insights for hardware asset in a clearer view.

- Create additional reports & dashboards within ServiceNow that capture and track HAM KPIs* over time

Risks

- **Moderate:** Limited visibility into manufacturer end-of-life and end-of-support dates for devices resulting in security and compliance risks
- **Low:** Incomplete insights into the hardware asset management program's performance due to limited reporting and metrics
- **Very Low:** Incomplete inventory can lead to difficulties in management of hardware assets/consumables resulting in delays in replenishing the inventory stock

Impacts

- **Moderate:** Increased risk of using unsupported devices, potential security vulnerabilities, and delayed replacements of devices requiring refresh
- **Low:** Reduced visibility into key HAM performance metrics, potential missed opportunities for HAM program improvement, and challenges in demonstrating program success to Alectra Executives
- **Very Low:** Consumable inventory management challenges, potential stockouts, and difficulties in resource planning

*Refer to Suggested HAM Key Performance Indicators

Detailed Observations: Process

Pillar Assessment Rating: Low

Deloitte's current state assessment and observations of Alectra's existing Hardware Asset Management (HAM) function for the Process pillar of the IT Asset Management (ITAM) framework

Findings & Observations

Recommendations

Process adoption for new asset management tools

Adoption of new hardware asset lifecycle processes and technology requires further effort from personnel managing the day-to-day HAM activities

- Establish robust policies for hardware asset management that promote adherence to process across all teams.
- Enforce organizational change management activities (e.g., additional trainings and workshops) with personnel completing HAM lifecycle activities to facilitate improved process adoption and adherence

Enable consumables management within ServiceNow

Lifecycle management processes are not currently performed within ServiceNow for consumable IT hardware assets, which limits inventory visibility and tracking for this asset class

- Develop standardized lifecycle management processes for the consumable hardware asset class
- Formally document the steps of each lifecycle process and communicate procedures to the HAM operations team
- Enable the standardized consumable lifecycle processes within ServiceNow so that consumable asset data can be captured & updated in the platform

Risks

- **Moderate:** Without effective change management activities, there is a risk of incomplete adoption of asset management processes in the new technology resulting in inconsistent practices being followed across the enterprise
- **Low:** When enforcing organizational change management activities, there is a risk of encountering resistance from HAM personnel
- **Low:** Limited visibility and tracking for consumable assets leading to difficulties in managing and planning for replacement

Impacts

- **Low:** Lower than expected efficiency gains from newly defined asset management tools & technologies
- **Low:** Slower IT service delivery times and reduced data accuracy within ServiceNow
- **Low:** Challenges for asset managers to have a comprehensive view of the consumables in stock and their lifecycle status

Detailed Observations: People

Pillar Assessment Rating: Very Low

Deloitte's current state assessment and observations of Alectra's existing Hardware Asset Management (HAM) function for the People pillar of the IT Asset Management (ITAM) framework

Findings & Observations

Recommendations

Lack of formal governance forum

While there is constant communication between the IT Operations and Support teams at Alectra, there is no formal meeting cadence with key stakeholders to create goals and monitor HAM program progress.

- Establish quarterly/bi-annual HAM governance council meetings* with key ITAM & HAM stakeholders** to develop and communicate HAM program goals, and monitor progress towards those goals
- Review KPIs*** in HAM Governance Council meetings to monitor HAM health and performance

Data stewardship of asset management data

Some data stewardship activities are performed by Alectra's asset manager and ServiceNow Administrator. However, as the HAM program matures further and the organization scales, this responsibility may become difficult to manage.

- Assign formal responsibility for data stewardship of asset management data to the appropriate party
- As the count of hardware assets grows and Alectra's HAM program scales, add support staff for maintaining data quality & integrity within the hardware asset repository

Risks

- **Low:** Over-reliance on manual efforts from ServiceNow administrators can lead to further data integrity/quality issues as the HAM program at Alectra expands
- **Very Low:** Without a formalized forum for discussion, there is a risk of misalignment between key HAM stakeholders resulting in conflicting goals, duplication of efforts or missed opportunities for collaboration and synergy

Impacts

- **Very Low:** Efforts and goals across various HAM/ITAM teams may not be coordinated limiting progress leading to suboptimal outcomes
- **Very Low:** Lack of formalized forum for discussing improvement opportunities can hinder the ability to drive continuous improvement. This could impede growth and efficiency gains

*Refer to Suggested HAM Meeting Cadence

**Refer to HAM Roles & Responsibilities at Alectra

***Refer to Suggested HAM Key Performance Indicators

Hardware Asset Landscape at Alectra

Below is a high-level snapshot of the data captured in Alectra's hardware asset repository inside ServiceNow

Asset Type	Asset Classes	Total # of Assets, ServiceNow	Assets In Stock	Assets In Use	Retired Assets	Discovery Source
Hardware Assets	Network	472	6	344	122	ServiceNow Discovery
	Server	626	-	524	102	ServiceNow Discovery
	End User	5067	-	4187	880	Microsoft System Center Configuration Manager (SCCM)
	Consumables*	0	-	-	-	N/A

*Consumables are not currently tracked within ServiceNow

Next Steps for Hardware Asset Management (HAM)

Below are some immediate next steps for Alectra's HAM Program to action that will further progress its maturity and effectiveness

For Now

Enhance Existing ITAM Policies

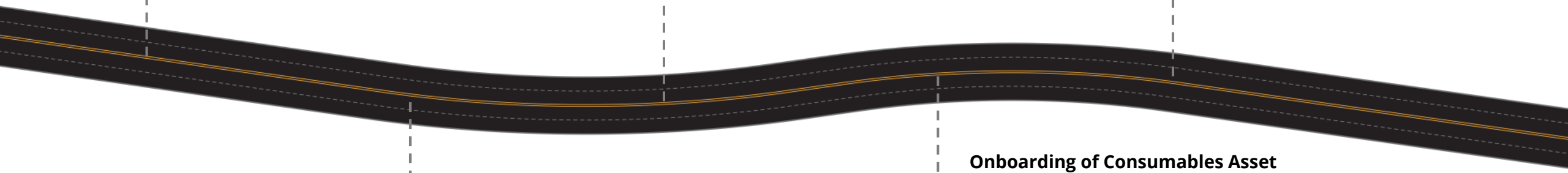
- Add details around HAM procedure adherence & hardware lifecycle timeframes to ITAM Policy Documents

Process & Technology Adoption

- Enforce organizational change management to improve the adoption of new HAM processes & technology (AssetTrack) amongst all day-to-day HAM personnel

Capture Additional Asset Management Attributes

- Capture data points like Manufacturer End of Life and End of Support dates & cost information within ServiceNow



Establish meeting cadence with HAM Stakeholders

- Formalize communication channels with key HAM stakeholders to enhance HAM program goals and monitor progress & KPIs

Onboarding of Consumables Asset Class

- Design, enablement and rollout of HAM lifecycle processes for Consumables across Alectra for inventory management and tracking

For Later

Direct Integration of Financial Data into the Asset Management Database

- Unidirectional/bidirectional integration with procurement systems to provide cost and real-time depreciation information on hardware assets for financial budgeting & forecasting

Integration of Contract Management & Asset Data

- Leverage the native integration of the IT Asset Management (ITAM) and Contract Management modules within ServiceNow to directly link contract data (e.g., warranty contracts) and asset data

Discovery Source Remediation for Microsoft SCCM

- Adjust the configuration of SCCM with the ServiceNow Configuration Management Database (CMDB) to reduce the amount of manual effort required to maintain data quality within the CMDB

Refer to the Detailed Roadmap section for a timeline view and descriptions of each recommended activity and initiative

Management Comments – Strategy and Policies

Response:	Information Technology supports and agrees with the recommendations in the Strategy and Policies Pillar. Information Technology will review and revise the current ITAM policy document to include HAM end user process tracking, end user lifecycle timeframes, tool adoption and additional KPIs. Information Technology will seek approval and communicate updated ITAM policy to all IT leadership and key stakeholders.	
Accountable Parties:	Marco Scafati Product Manager, Digital Workplace	
Estimated Implementation Date(s):	Q3, 2024	

Management Comments – Technology and Data

Response:	Information Technology supports and accepts findings for Technology and Data pillar. Information Technology will review CMDB data within defined and agreed upon cadence for data accuracy, and completeness. Remediation steps will be planned, documented and verified for completeness as part of CAB review process. Information Technology will put in place procedure to update warranty expiration as part of end of life for each asset record on a weekly basis to be tracked by ITAM team. Information Technology will implement cost uploading at defined intervals and verify on a weekly basis by ITAM personnel. Information Technology will review AssetTrack dashboard and reporting, as part of KPI reporting management and develop procedures and framework to track, manage and report.	
Accountable Parties:	Marco Scafati Product Manager, Digital Workplace	
Estimated Implementation Date(s):	Q4, 2024 Cost uploading will be addressed by Q2, 2025.	

Management Comments – Process and People

Response:	Information Technology supports findings for Process and People pillars. Information Technology will establish lifecycle process and make available as knowledgebase article(s) and implement KPI reporting to make available as knowledgebase article(s) Information Technology will establish quarterly cadence to review Asset Track with Operations and Security verticals and provide education for IT Support and IT Operations for AssetTrack tool, to promote and sustain adoption of asset tracking. KPI's will be established to measure.	
Accountable Parties:	Marco Scafati Product Manager, Digital Workplace, to work with teams from IT Security/ IT Operations and IT Support	
Estimated Implementation Date(s):	Q4, 2025	

Acknowledgement of Review

Name	Signature	Date
Peter Chong Administrator, IT	Provided via email	January 24, 2024
Marco Scafati Product Manager, Digital Workplace	Provided via email	January 24, 2024
William Schmidt VP, Information Technology	Provided via email	January 24, 2024

Risk Assessment Rating Definitions

The risk assessment ratings used throughout this deliverable are defined below.

Rating	Definition
Very High	The risk to Alectra is extremely high and the potential impact to the business is severe, posing a critical threat to the organization. Urgent action is required to address the risk and prevent catastrophic consequences.
High	The risk to Alectra is high and the potential negative impact to the business is significant. Immediate attention is required mitigate the risk and prevent or minimize adverse consequences.
Moderate	The risk to Alectra is moderate, and the impact could have noticeable consequences if left unchecked. Some controls are in place, but additional measures should be developed to effectively mitigate the risk.
Low	The risk to Alectra is low, and any potential impact is manageable. There are controls in place that can undergo some enhancements, and the risk is unlikely to cause substantial harm or disruption to the organization.
Very Low	The impact to Alectra is minimal, and any impacts are negligible. There are robust controls in place that require minimal enhancements, and the risk is considered unlikely to pose any significant threat.

Definitions

Below is a dictionary that defines the terms, acronyms, and abbreviations used within this report

Abbreviation	Term	Definition
CMDB	*Configuration Management Database*	The Configuration Management Database is a centralized database that contains information about the configuration items (CIs) in an organization's IT infrastructure.
CI	*Configuration Item*	A configuration item is a distinct and manageable entity within an organization's IT infrastructure, such as hardware or software, that is uniquely identified and subject to configuration management. Configuration management is the process for planning, identifying, controlling, and verifying changes to configuration items within an organization's IT infrastructure
EOL	*End of Life*	EOL refers to the stage in a product's lifecycle when it is no longer produced or supported by the manufacturer.
EOS	*End of Support*	EOS signifies the point at which a product's vendor discontinues providing support or updates, leaving it vulnerable to potential risks.
HAM	*Hardware Asset Management*	Hardware Asset Management is a component of IT Asset Management. It focuses specifically on the systematic tracking, maintenance, and optimization of IT hardware assets throughout their lifecycle.
ITAM	*Information Technology (IT) Asset Management*	IT Asset Management is the practice of managing the lifecycle of IT assets, from procurement to disposal, to optimize the asset's value and minimize any risks associated with the asset.
SCCM	*System Center Configuration Manager*	Microsoft System Center Configuration Manager (SCCM) is a tool that deploys, manages, and updates software and configurations for computers. The tool automates tasks related to system deployment, software distribution, patch management, and inventory tracking.

National Electric Customer Survey – 2025

2025 CSAT Summary

Electricity Canada

INNOVATIVE RESEARCH GROUP

alectra utilities | Discover the possibilities

Alectra is gaining ground on some important performance attributes despite marginal decline in overall satisfaction.

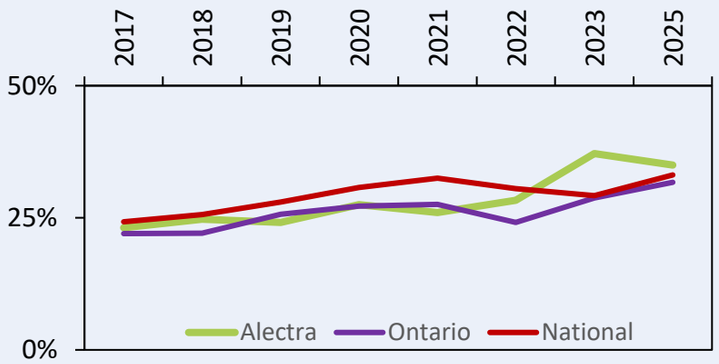
Electricity Canada's 2025 Customer Satisfaction Survey is an online survey conducted by INNOVATIVE between October 14th and October 28th, 2025 among 4,301 Canadians (18 yrs or older).

A targeted oversample provided a total of 646 surveys with respondents who identified Alectra as the company from which they receive their electricity bill. In the final data, we weighted the sample to a representative sample size of n=630.

Changes of at least 5 percentage points could be considered at least directionally significant

OUTCOME: Overall Satisfaction

[% Very Satisfied]



Alectra	35%
	-2%
Ontario	32%
	+3%
National	33%
	+4%

NOT IN YOUR CONTROL

As seen throughout Ontario and across the country, Alectra is operating in a more favourable environment in 2025, fewer customers report their bills having a major impact. ***Satisfaction with government management of the electricity system is also up for Alectra customers.***

	2025			Change from 2023		
	Alectra	Ontario	National	Alectra	Ontario	National
Satisfaction with gov't management [% Very Satisfied]	12%	10%	10%	+4%	-1%	-1%
Agree that bill has a major impact [% Strongly Agree]	13%	10%	12%	-10%	-5%	-3%

KEY DRIVERS YOU CAN CONTROL

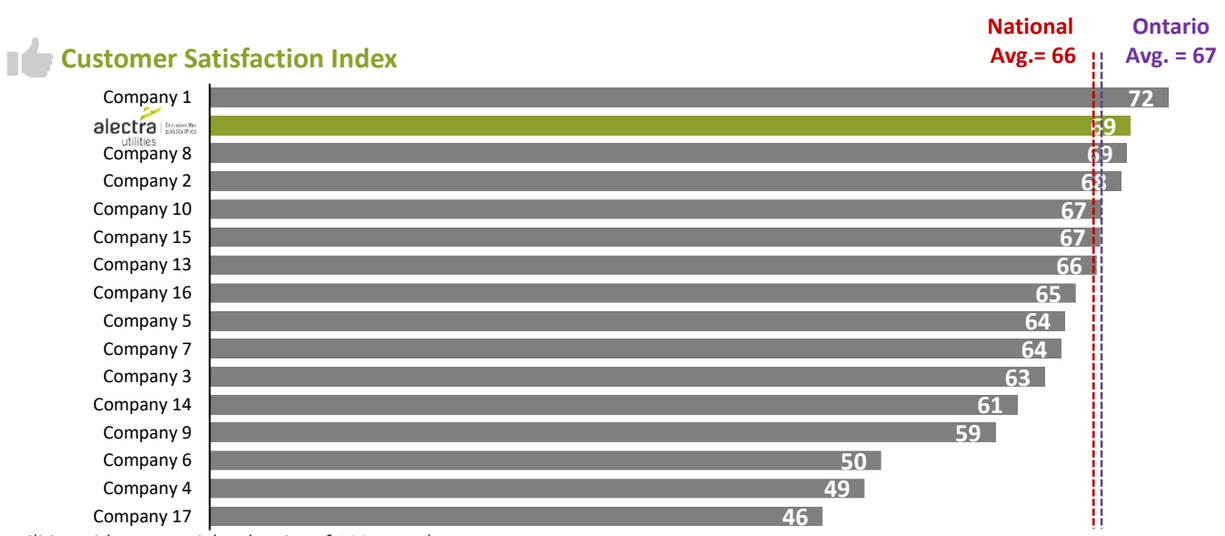
Since 2023, Alectra has gained on overall communications and taking care of problems the first time – gains which are only marginal at the provincial and national levels. Across the following measures, Alectra's results are either on par or above the national results.

CSAT Drivers

	2025			Change from 2023		
	Alectra	Ontario	National	Alectra	Ontario	National
Overall communications [% Very Satisfied]	38%	33%	33%	+6%	+2%	+2%
Consulting with customers [% Very Satisfied]	20%	18%	16%	+4%	+1%	+1%
Reliable electricity service [% Very Satisfied]	41%	33%	35%	+2%	+2%	+6%
Taking care of problems the 1st time [% Very Satisfied]	29%	27%	28%	+6%	+2%	+2%
Good value for money [% Very Satisfied]	16%	13%	15%	+4%	0%	+1%

CUSTOMER SATISFACTION INDEX

Alectra's Customer Satisfaction Index is 2 points above the regional average and 3 points above the national average.



NOTE: Only utilities with an unweighted n-size of 100+ are shown.

2025 ELECTRIC BUSINESS DEEP DIVE RESULTS

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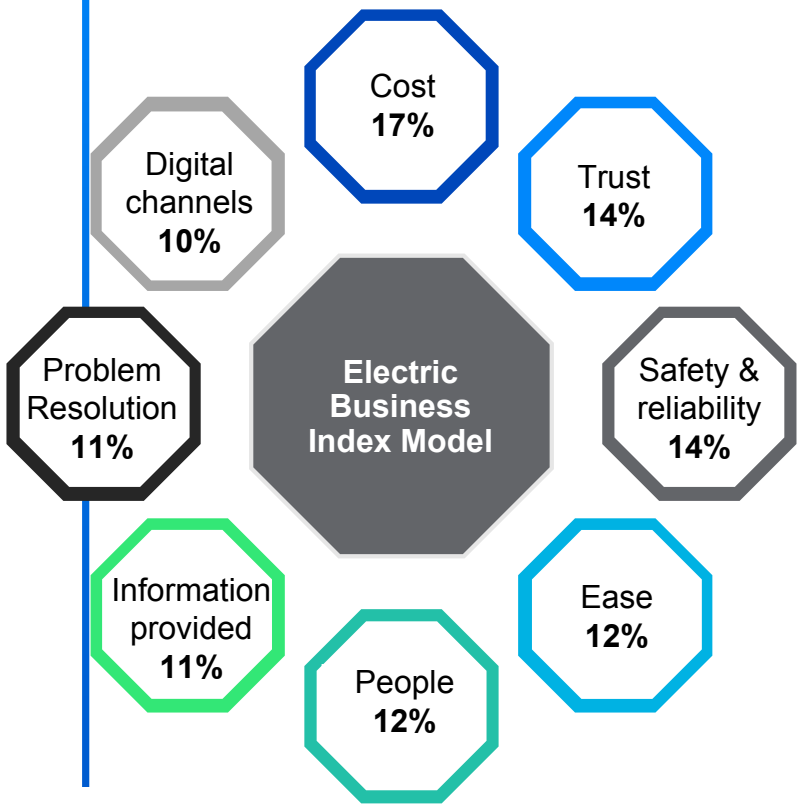

Study Methodology

U.S. Electric Utility Business Customer Satisfaction Study

Who

- Online interviews
- U.S. Business Electric Customers

When

- Wave 1: February – May 2025
- Wave 2: June – October 2025

Criteria

- Award Segments:
  - East Large
  - East Midsize
  - Midwest Large
  - Midwest Midsize
  - South Large
  - South Midsize
  - West Large
  - West Midsize
- Size Segment Split:
  - Large (100k+ customers)
  - Midsize (<100k customers)
- Electric utilities serving 50,000+ business customers

Results

- 18,000+ TOTAL RESPONSES NATIONALLY
- 80 BRANDS
- 27 YEARS OF HISTORY

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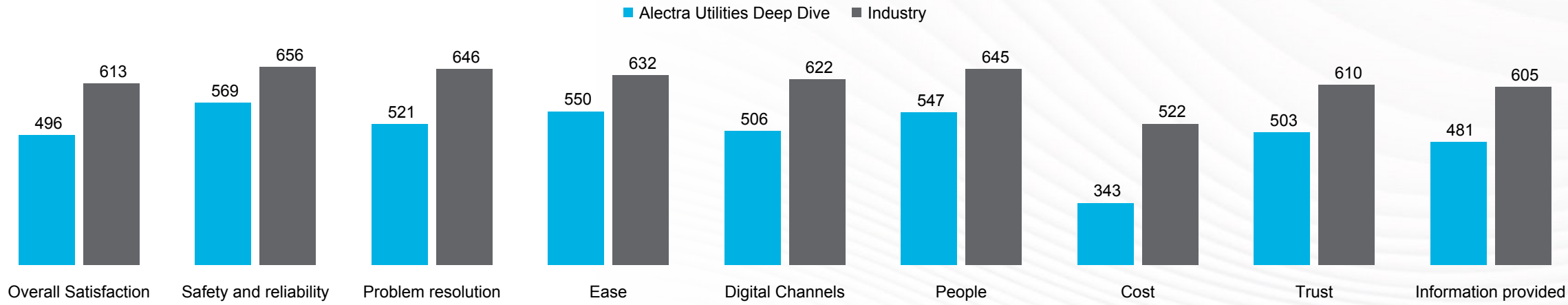
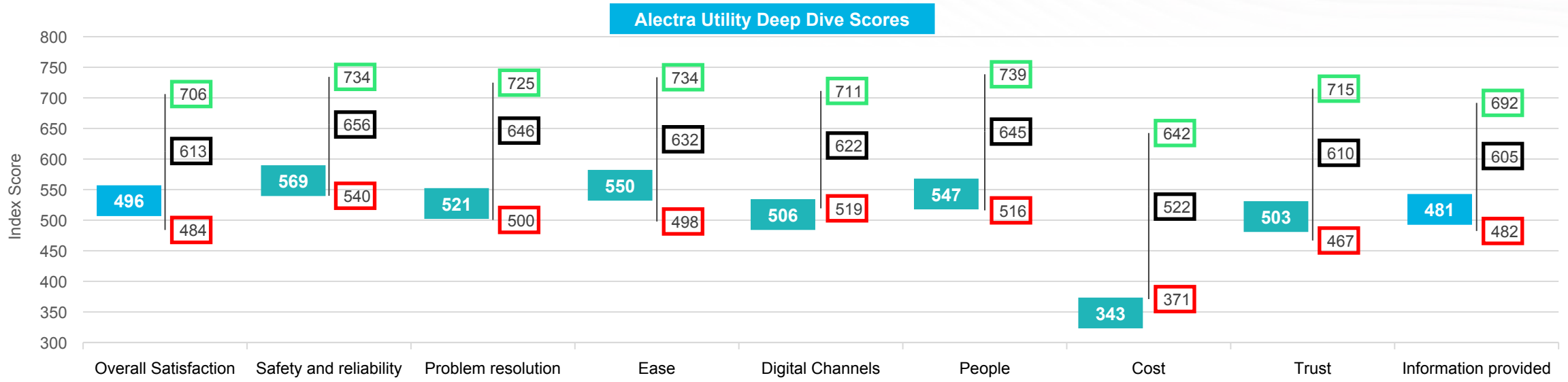
Dimension Scores

Alectra Utility Deep Dive vs. U.S. Industry



Utility Scoring Range by Dimension



Note: Alectra Utility sample size = 318

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BUSINESS DEEP DIVE KEY FINDINGS & BEST PRACTICES

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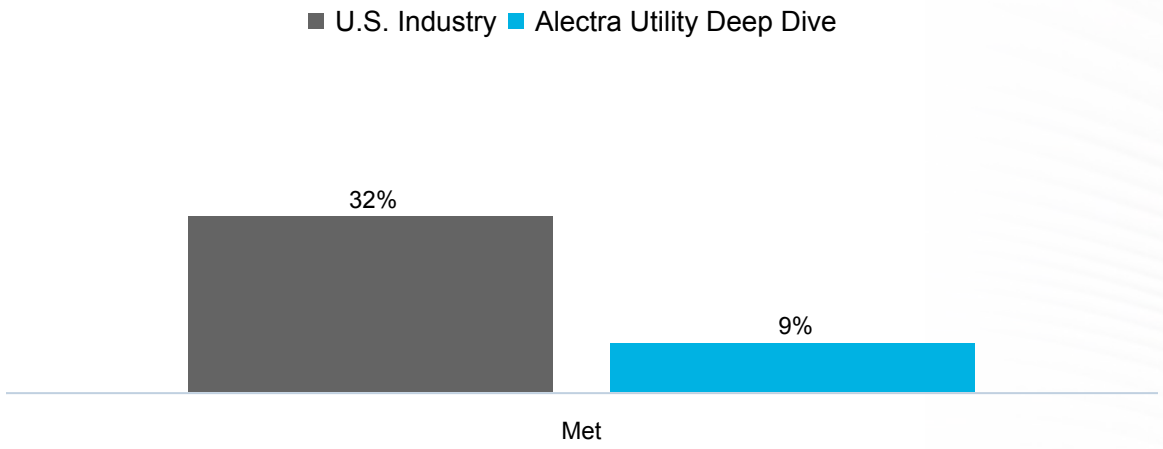
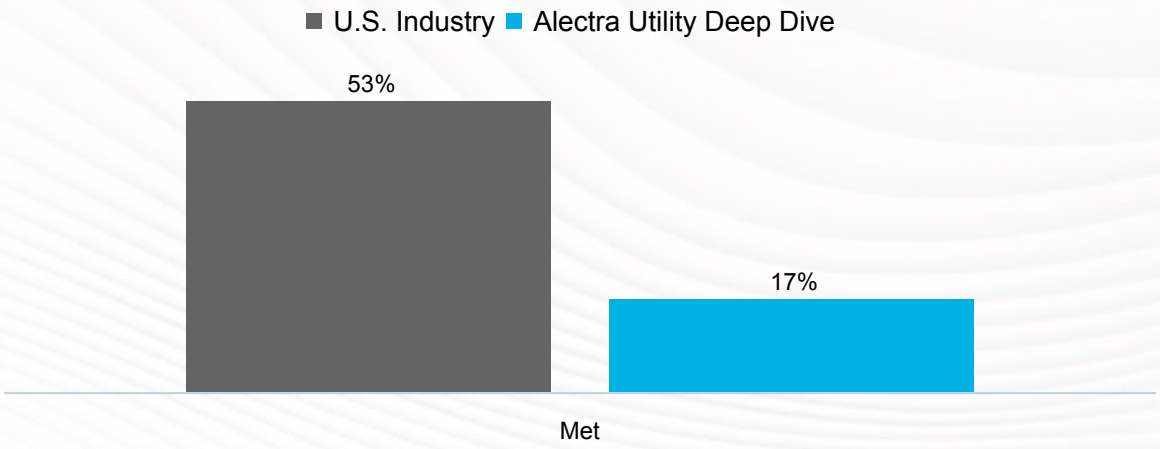
Rate Plans - Electric Business

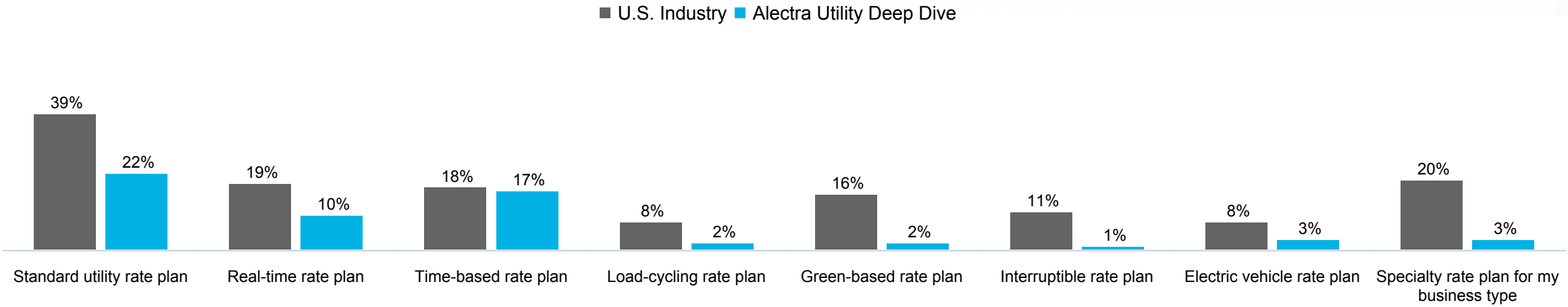
Researched/Inquired about rate plan



Actively selected rate plan



Type of rate plan chosen



Note: Alectra Deep Dive - Don't know type of rate plan chosen = 48%

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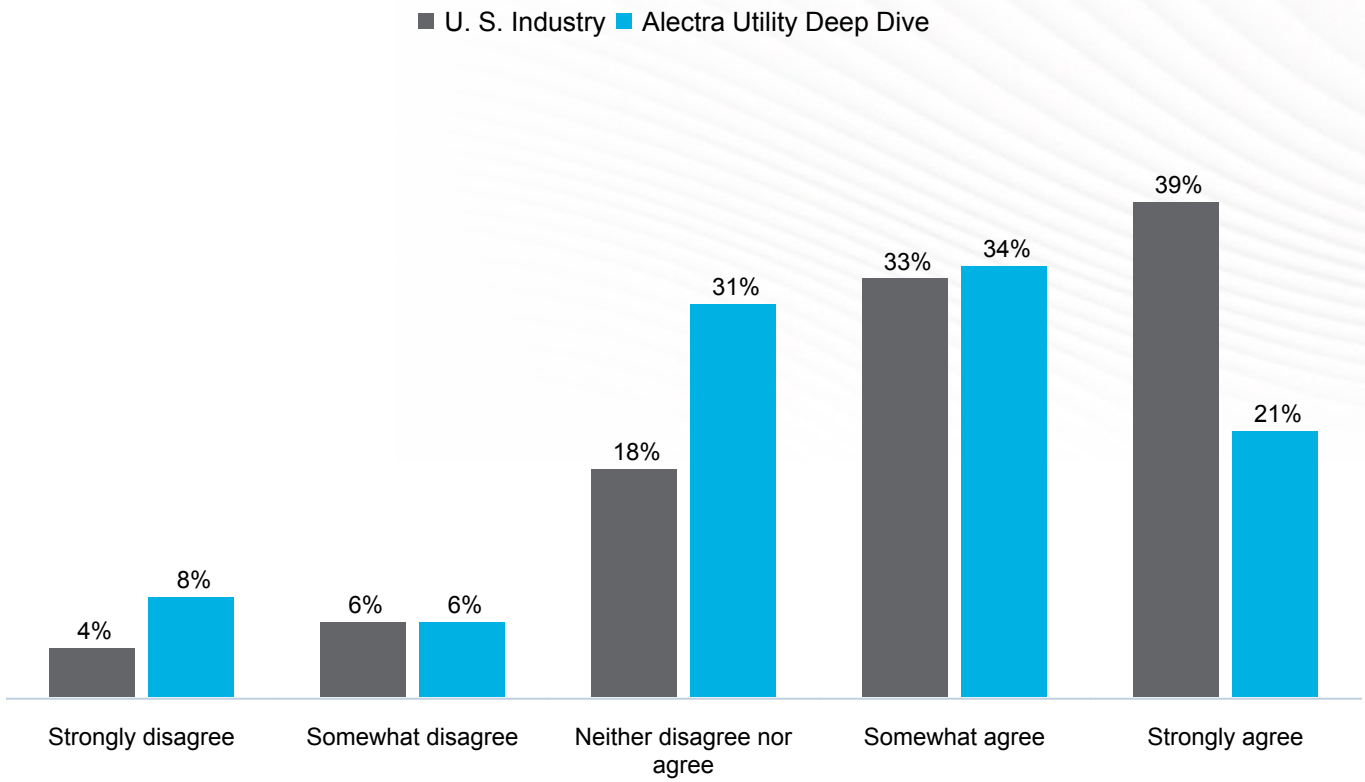
Electric Business

Considered a valued business partner



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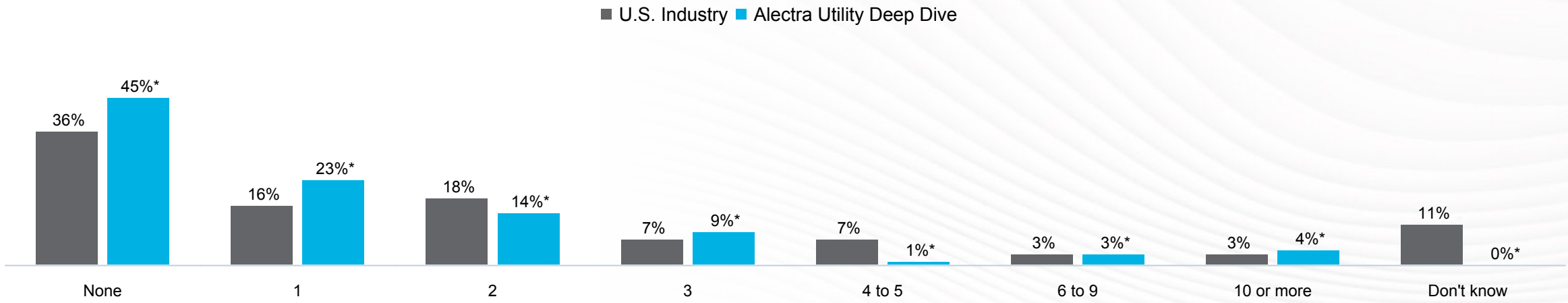
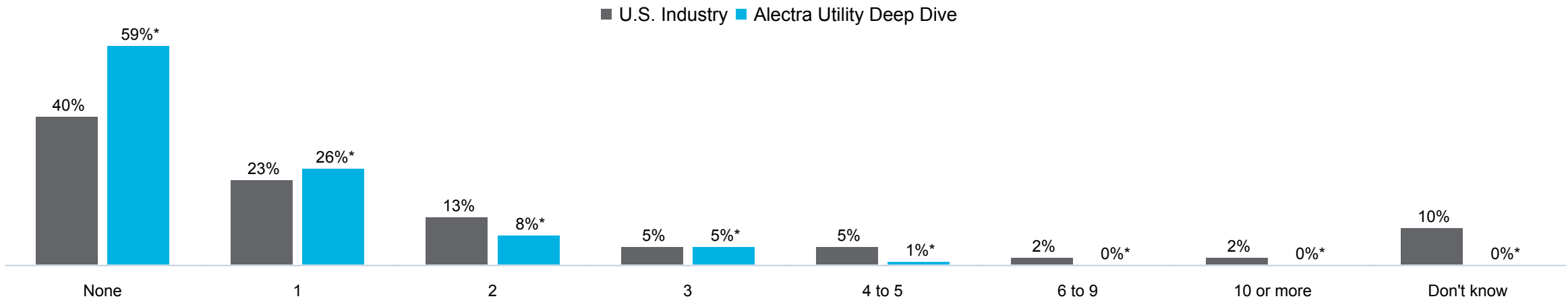
Power Outages - Electric Business

Number of brief interruptions



Number of lengthy interruptions



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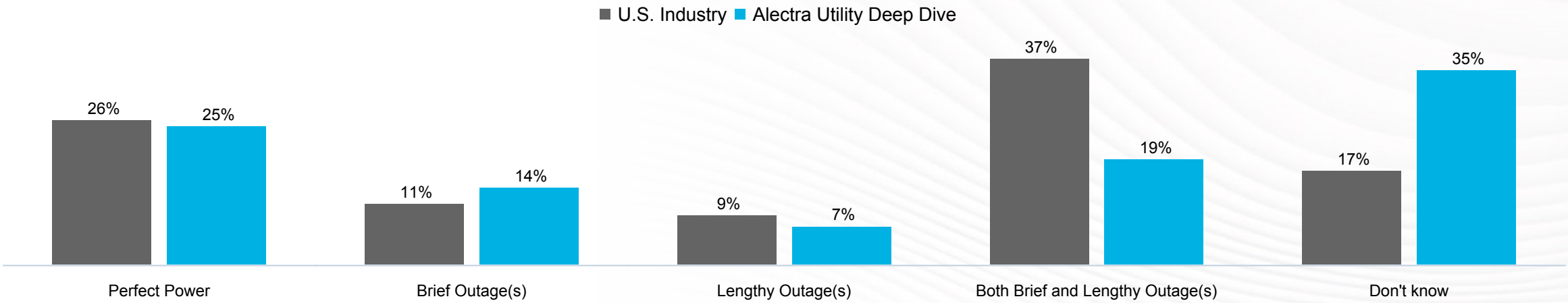
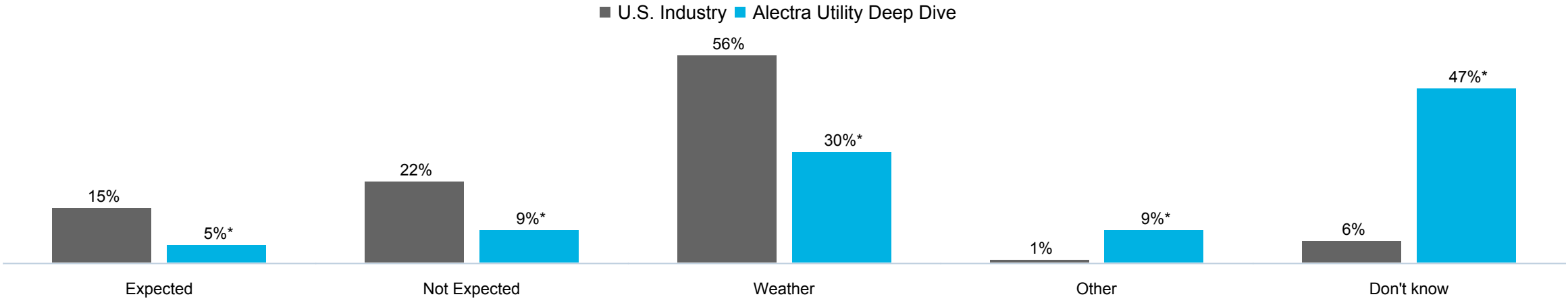
Power Outage Type and Cause - Electric Business

Length of power outage



Type of outage



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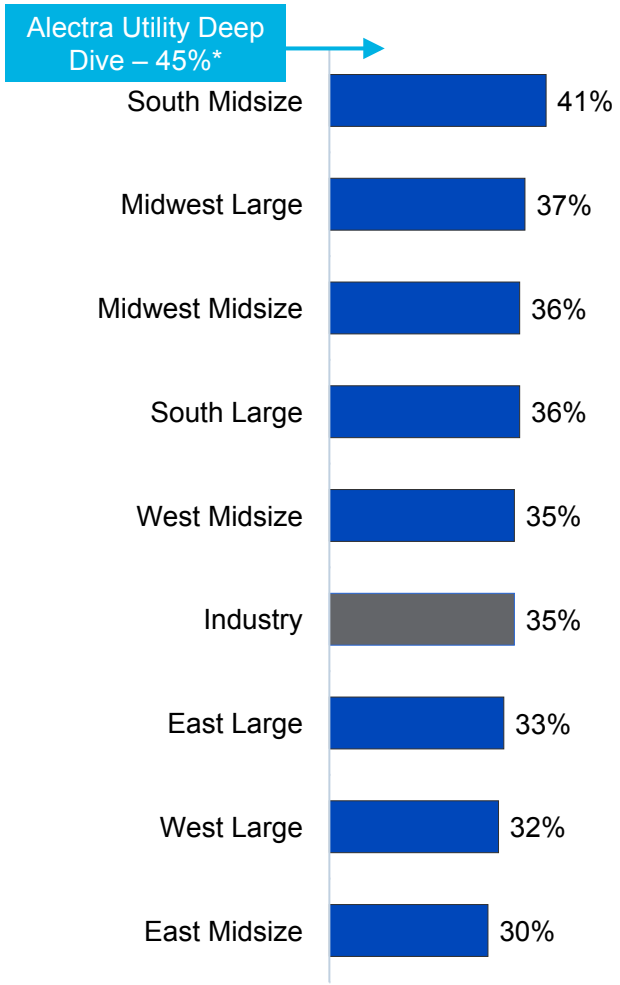
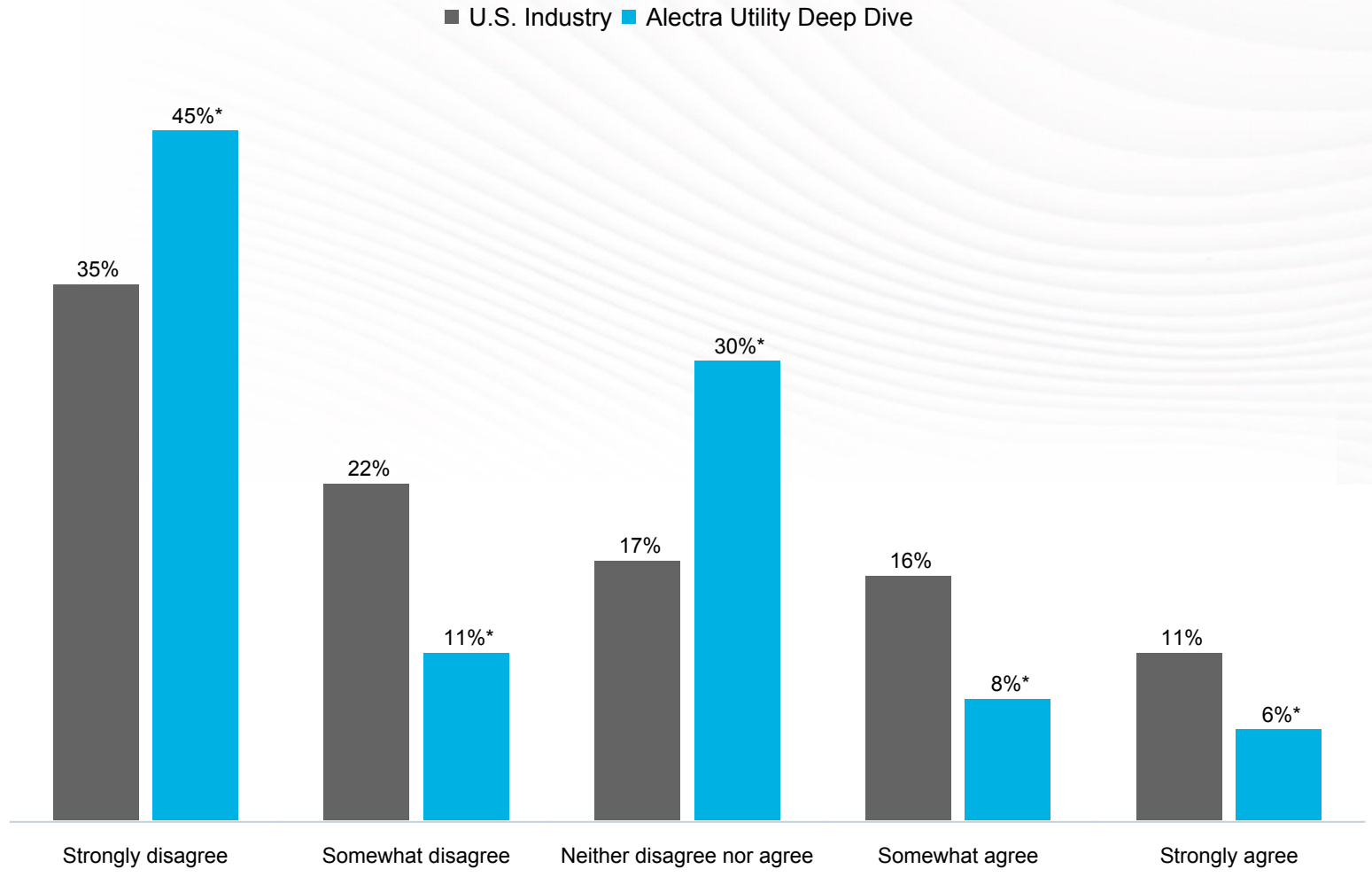
Effort to Resolve Most Recent Issue - Electric Business

It required little effort to resolve most recent issue



It required a lot of effort to try to resolve my most recent issue



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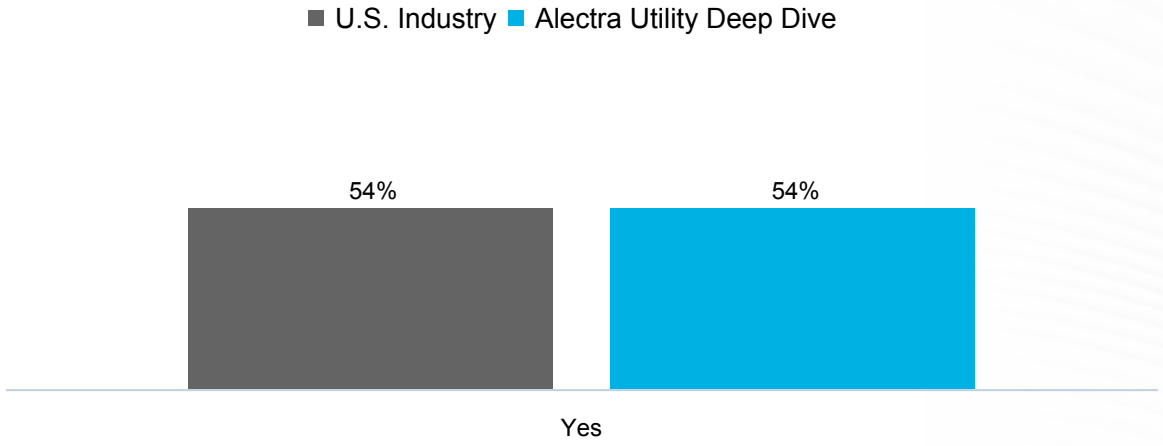
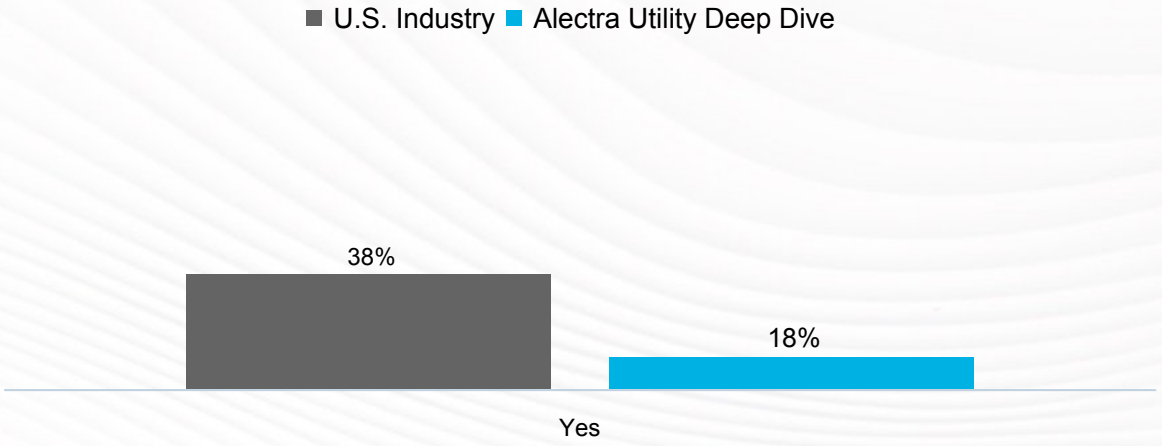
Recall Communications - Electric Business

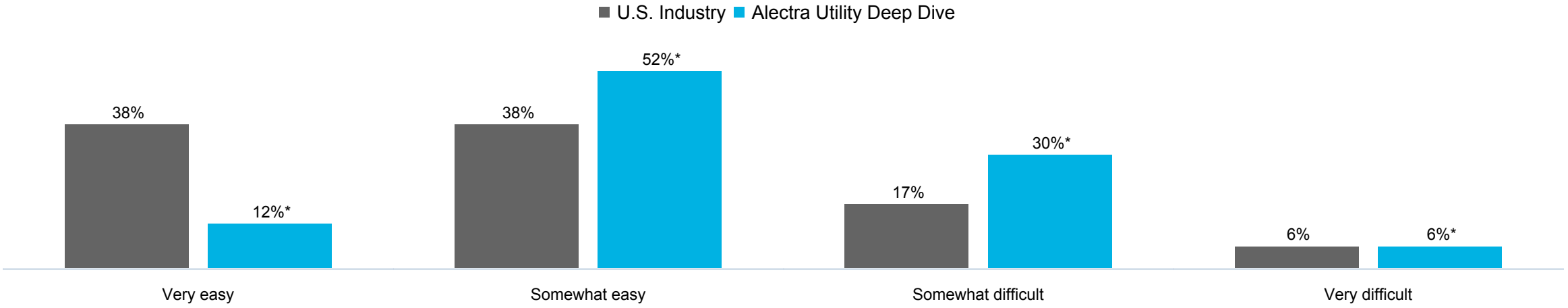
Recall utility communication in the last 6 months



Recall media communication in the last 6 months



Ease of finding outage information



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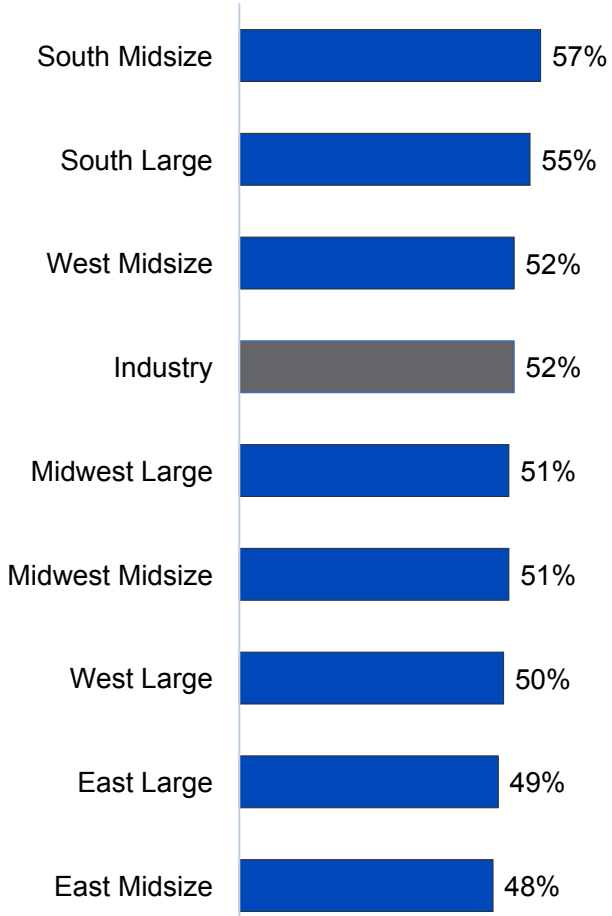
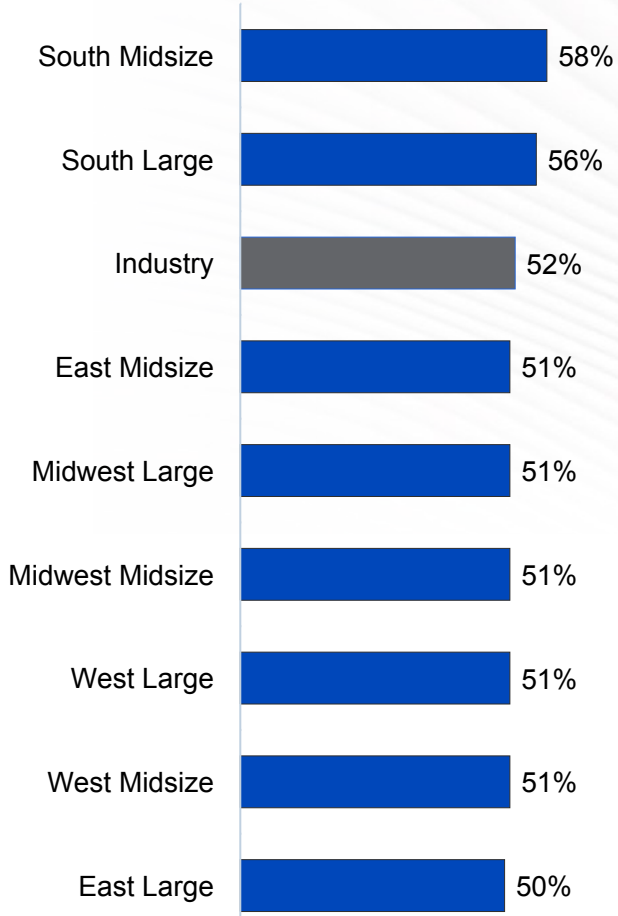
Corporate Citizenship Improves Reputation - Electric Business

Seen utility volunteering in community



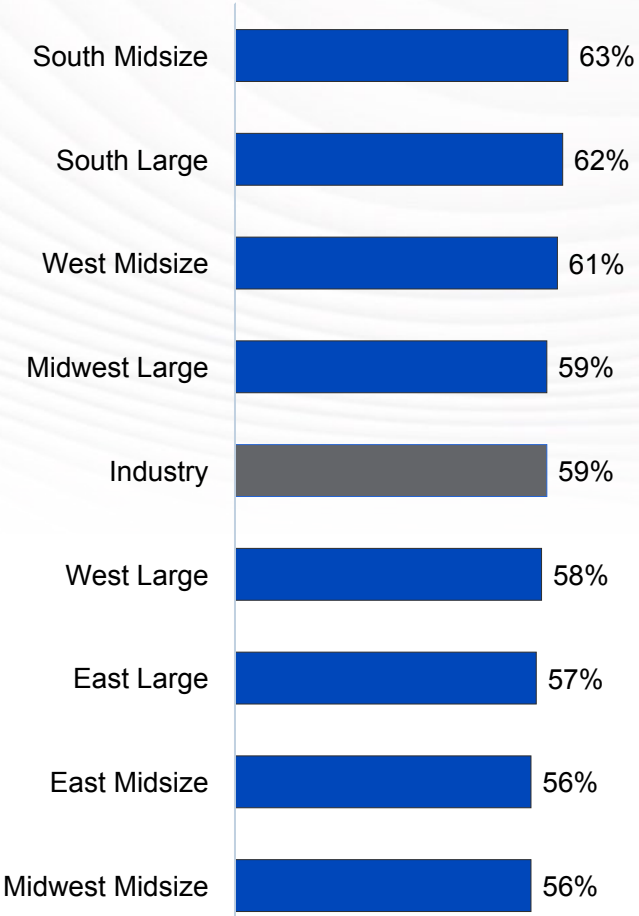
Alectra Utility Deep Dive – 10%

Work to attract new business in community



Alectra Utility Deep Dive – 7%

Create jobs directly or indirectly



Alectra Utility Deep Dive – 21%

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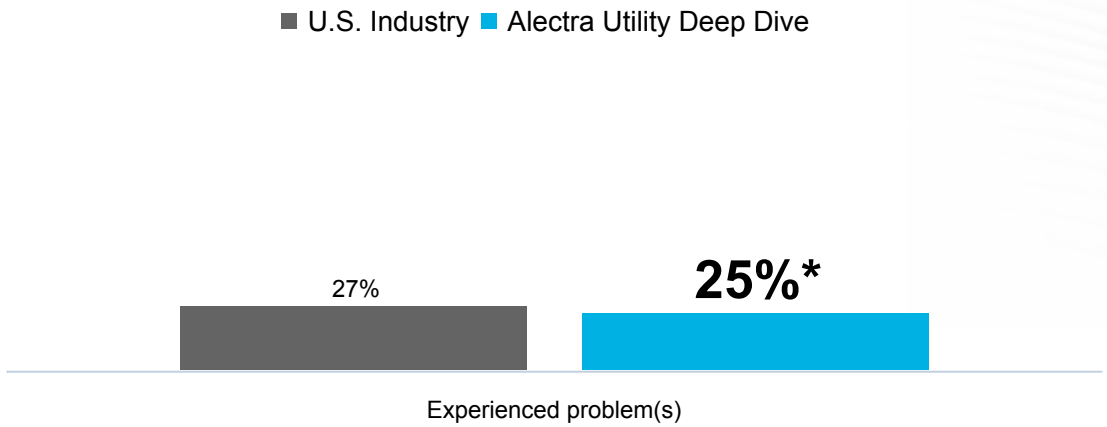
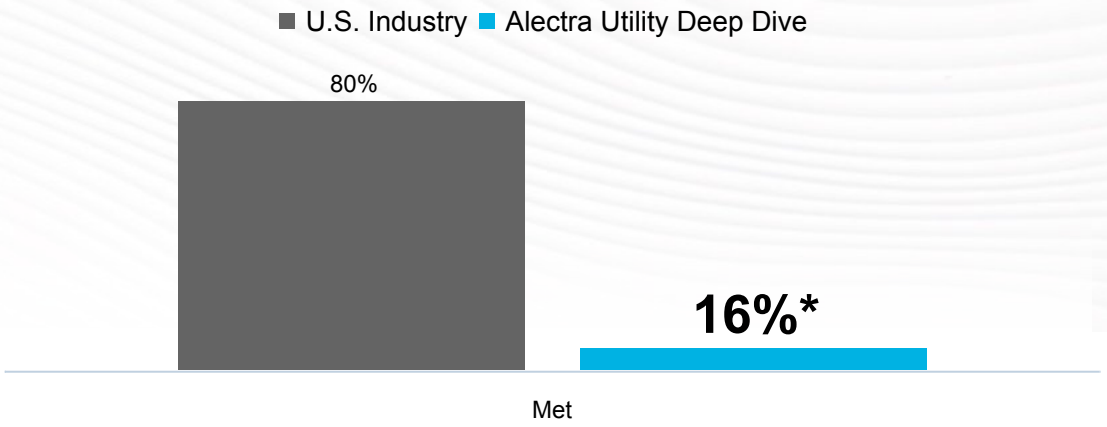
Experienced Problem and KPIs

Experienced a problem



Utility contacted after power restored



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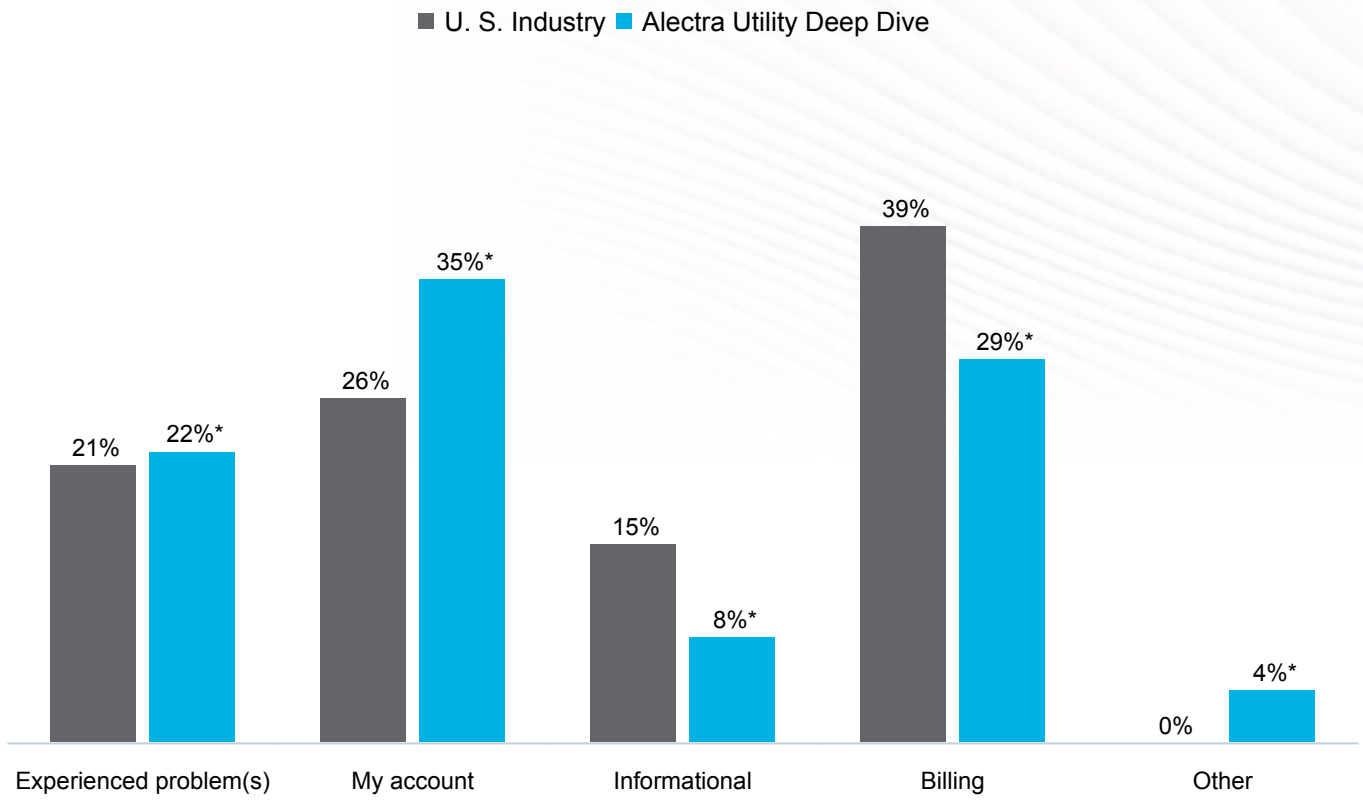
Reason for Digital Contact

Primary reason for website/mobile app contact



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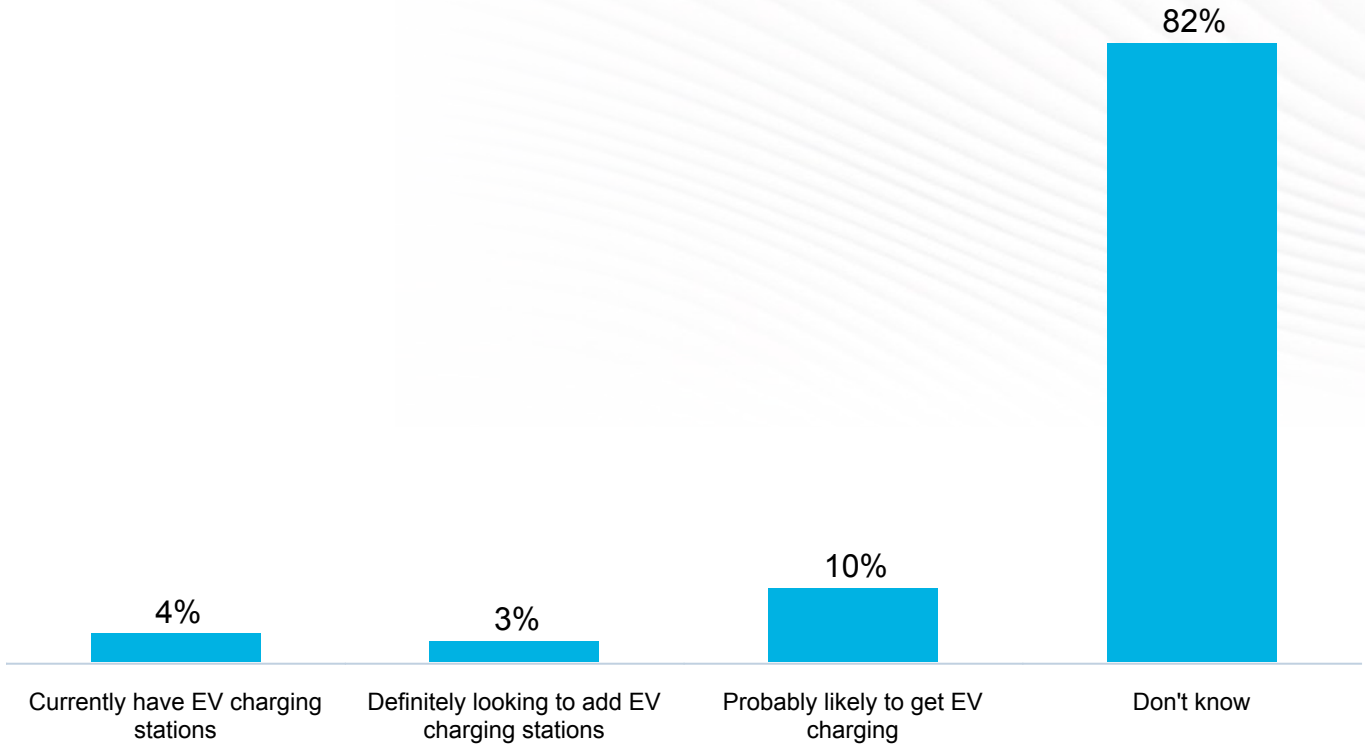
Alectra Utility Deep Dive

Plan for EV Charging Stations



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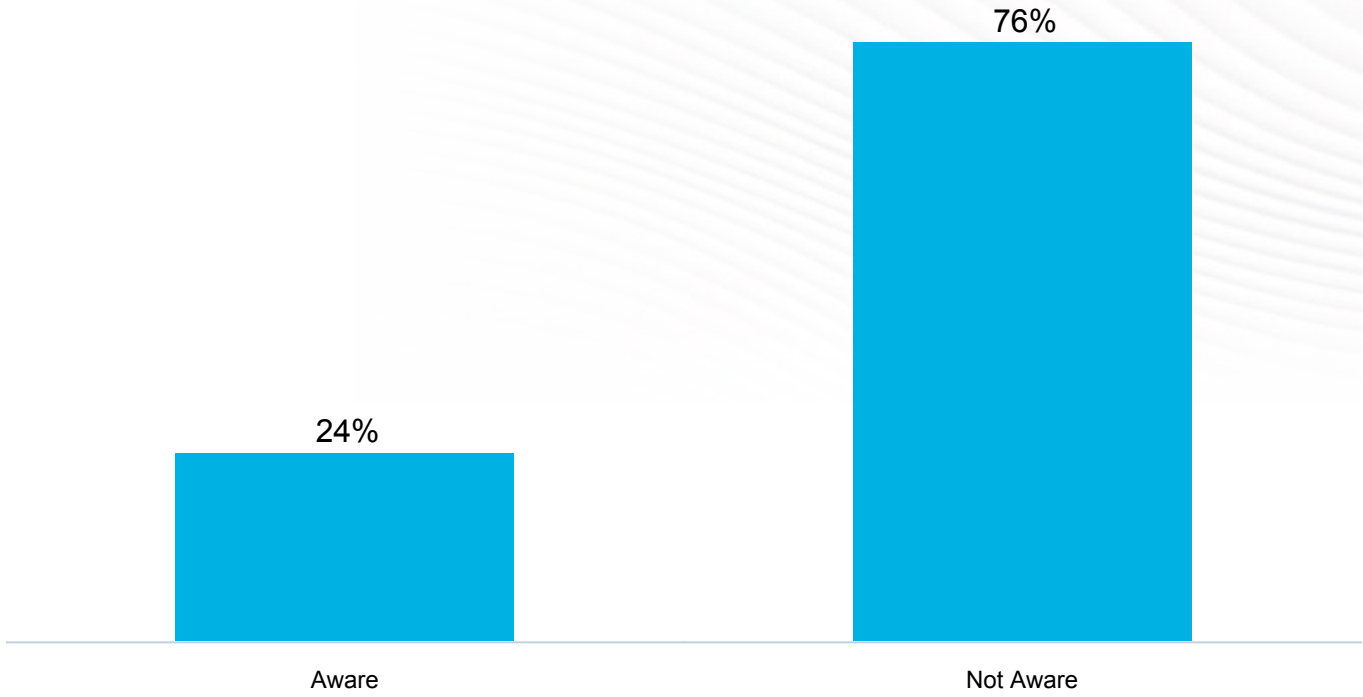
Alectra Utility Deep Dive

Aware of efforts to support businesses in reaching their environmental or social goals



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Alectra Utility Deep Dive

Challenges facing your business

%

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STRATEGIC FOCUS

Alectra Recommendations

Win Through Proactive Value Communications

Make outages, safety, and savings the centerpiece of communications

Drive program awareness to reinforce affordability and support

Use community and preparedness messaging to strengthen trust and reputation

Eliminate Customer Effort

Fix digital friction that undermines ease and satisfaction

Ensure outage information is fast, clear, and easy to find

Expand alerts and real-time updates to reduce inbound demand

Strengthen Service Experiences

Reinforce empathy and proactive support in frontline interactions

Reduce holds, transfers, and repeat contacts to lower effort

Improve business customer confidence by clarifying value and partnership support

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Mercer

welcome to brighter

Alectra Utilities

Executive Pension Benchmarking

May 2022

A business of Marsh McLennan

Table of Contents

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2. Relative Value Analysis 5
3. Prevalence Benchmarking 12
4. Appendix: Assumptions and Methodology 17

Executive Summary

1

Executive Summary

- Mercer Canada Limited (“Mercer”) has been engaged by Alectra Utilities (“Alectra”) to conduct a market assessment of their pension benefits provided to executives, including registered plans and supplemental plans above Income Tax Act limits.
- This study reviews the pension benefits for Alectra executives against the plans provided to executives by 16 selected organizations in the Utilities industry from the Mercer plan design database and other data sources. Only plans that are open to new entrants are valued in the analysis (i.e. any closed or grandfathered plans that may apply to some executives are excluded from the analysis). The list of comparator organizations is included in the Appendix.
- The approach used in this review is consistent with Mercer’s typical practice and considers the value provided by, rather than the cost of, Alectra’s arrangements relative to those provided by others in the market.
- Alectra provides a significantly above median pension value on both an employer-provided and total value basis to executives, primarily since the plan is a Defined Benefit (“DB”) pension while 11 of the 16 comparators provide a Defined Contribution (“DC”) pension or savings benefit. In the current economic environment, DB pensions are generally significantly more valuable than DC pensions.

Relative Value Analysis

Relative Value Analysis

Cost versus Relative Value

Key factors when reviewing benefits programs depend on the type of review you undergo.

Cost Review

Considers:
Plan Design
Funding Policy
Participation
Demographics
Expenses

Relative Value

Considers:
Plan Design Only

- Relative value analysis focuses only on the plan design as it sets all other cost drivers at a common level.
- When comparing the value of the benefit programs of several organizations, cost is NOT an accurate measure of the perceived value.
- For example – Under a cost review, a less generous plan design offering may cost more than a rich plan if employees did not fully utilize a defined contribution matching program.

Relative Value Analysis

Executive Profiles

- The following executive profiles have been considered in the relative value analysis:

Executive	1	2	3	4	5	6
[redacted]						
Median of Comparators	35,257	30,942	68,529	56,705	37,094	35,742

Relative Value Analysis

Approach

- The relative value analysis projects future pension accruals for the executives assuming that those under age 60 would have a 50% chance of retiring at age 60 and 50% chance of retiring at age 65. For executives above age 60, the pension accruals are projected to age 65. The future pension accrual is then divided by future earnings to generate the one-year value of the pension.
- Pension benefits already accrued for past service are not included in the calculations, but accrued service does impact early retirement reduction calculations if retiring at age 60.
- For DB pensions, the employer-provided value of the pension is the total value of the pension less the value of the employee contributions if the plan does not have a formal cost share (e.g. for a single employer sponsored plan). For a multi-employer pension plan (like OMERS) where the employee and the employer make prescribed contributions, then the employer-provided value is calculated as the total value of the pension multiplied by the employer cost share.
- All pension values are calculated on a pre-tax basis. Registered benefits and supplemental benefits have different tax treatments and can have different values to executives on an after-tax basis depending on individual circumstances.

Relative Value Analysis

About the Chart

- The relative value benchmarking results are presented as a percentage of base salary for each individual profile.
- Plans for all comparators have been valued using the same earnings information and employee profile. Using different assumptions may change the value of the benefit, but changes in relative positioning of the plan amongst the participants would not be material.
- The grey diamond represents Alectra's value.
- The stacked bars illustrate the distribution of observed values among the comparator group (including Alectra's plans). On the stacked bar:
  - The green segment represents the 75th percentile to maximum value
  - The orange segment represents the 50th percentile to 75th percentile value
  - The red segment represents the 25th percentile to 50th percentile value
  - The blue segment represents the minimum to 25th percentile value
  - The median is where the orange and red segments meet
- Index Rating is the plan value divided by the median value which provides a measure of variance from the median.
- Results are shown on both a Total Value (TV) and an Employer Provided Value (EPV) basis.

Relative Value Analysis

Pension and Savings

Maximum
75th Percentile
Median
25th Percentile
Minimum
Alectra

Relative Value Analysis

Commentary on Results

- Alectra's pension benefits for executives, including the OMERS pension for earnings up to 7x YMPE plus a 14.6% taxable DC SERP contribution on earnings above the OMERS limit for 2 executives, is either the top or 2nd ranked plan for all executives.
- The most valuable plans provided by comparators are DB pensions, in most cases public sector plans like OMERS. Private sector organizations provide DC pensions to new executives, while organizations that are public sector or were in the past, being more likely to continue providing DB pensions.
- For select Ontario-based comparators from public disclosures:
  - Toronto Hydro and Hydro Ottawa also participate in the OMERS pension plan with the same benefits as Alectra, but do not have additional SERPs valued in the analysis
  - Ontario Power Generation continues to sponsor a DB pension plan that does not have cost sharing like OMERS, and thus the employer is responsible for funding risk
  - Hydro One provides a 6% DC employer contribution to new executives which is significantly less generous than the DB pensions provided by other organizations
- Alectra covers bonuses in pensionable earnings which provides significant value. Most of the DB comparators include bonus, but under half of the DC pensions include bonus in pensionable earnings.
- The OMERS pension has valuable early retirement subsidies so executives who would qualify for an unreduced pension at age 60 (i.e. executives with higher service) would receive more value than those that don't.

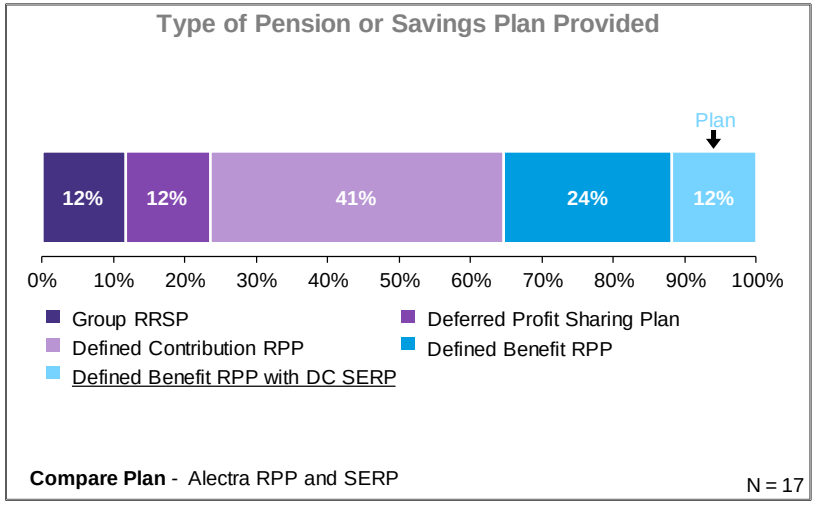
Prevalence Benchmarking

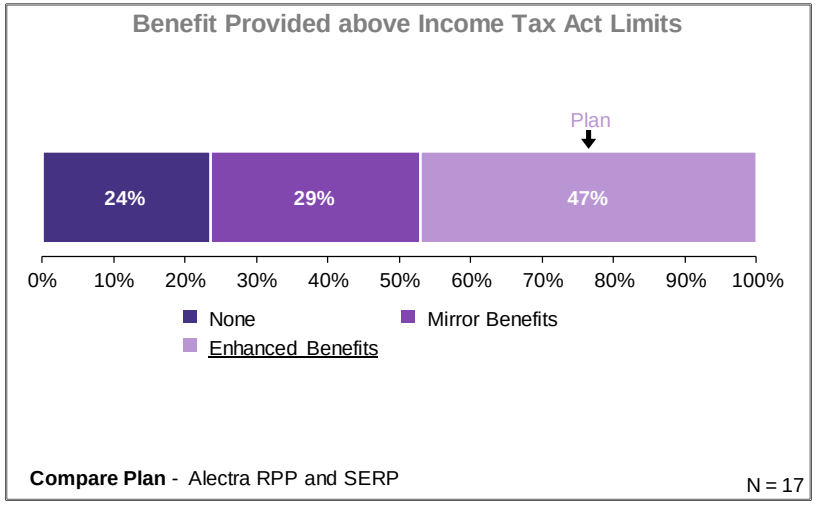
Prevalence Benchmarking

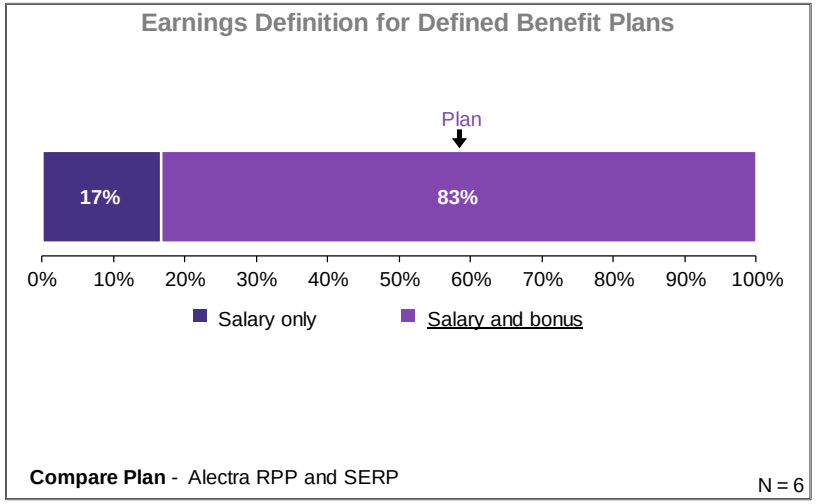
Detailed Charts by Provisions

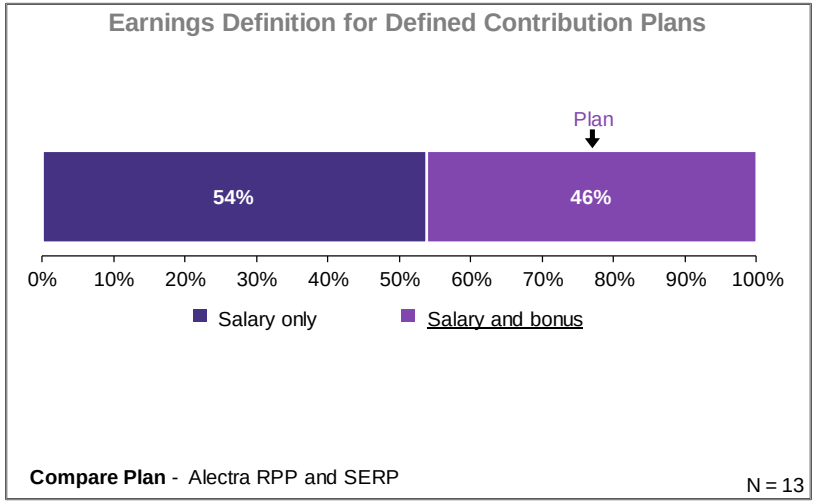
In general, plan provisions that appear to the right of the charts are more generous. When reviewing the attached, we suggest you do not give equal weighting to all measured provisions. For example, the maximum employer contribution to a Capital Accumulation Plan is more significant than the contribution structure.

Pension and Savings Plan Type and Earnings







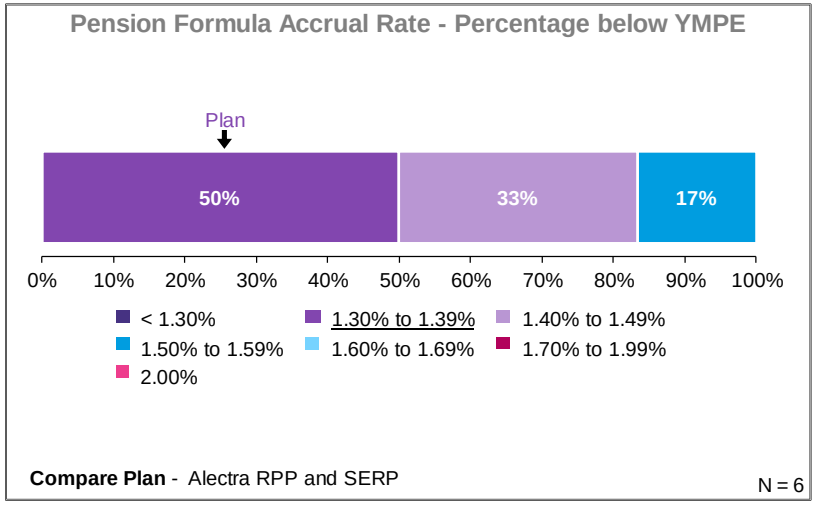


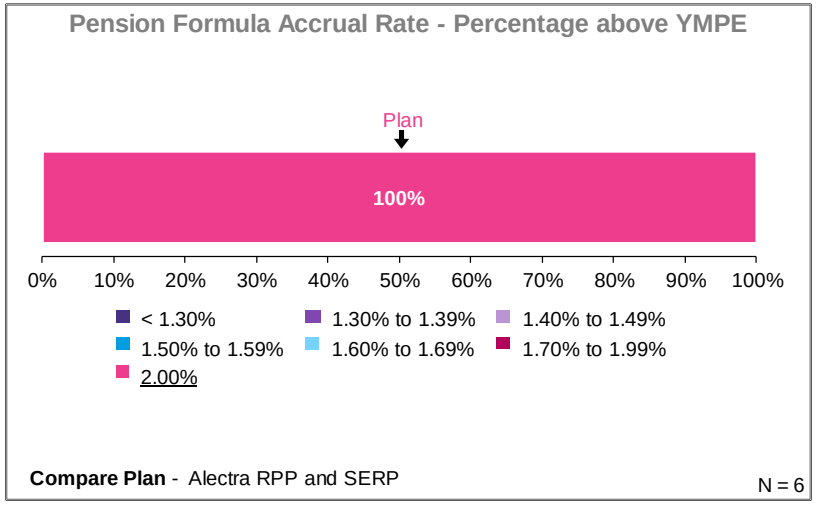
Alectra is among the 36% of comparators that provides a DB pension to executives. Most plans provide the same type of benefit for excess benefits as well, but Alectra also includes a DC SERP for some executives.

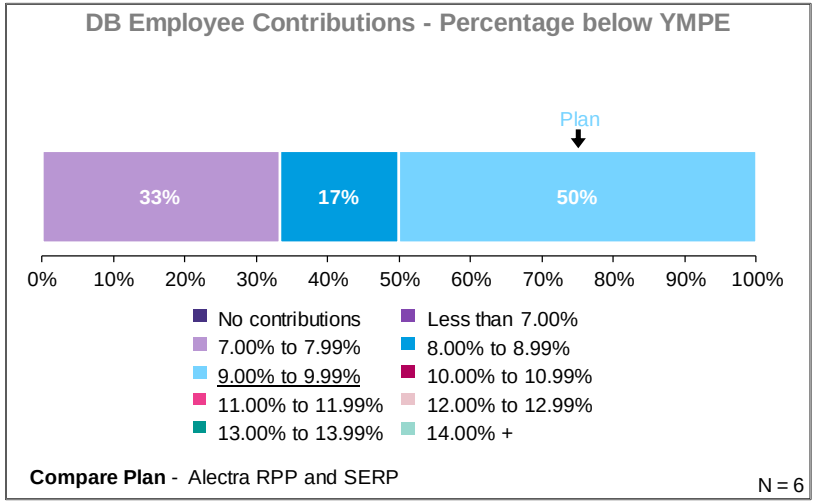
47% of the comparators provide enhanced benefits that are more generous than the registered plans provided up to the Income Tax Act limits.

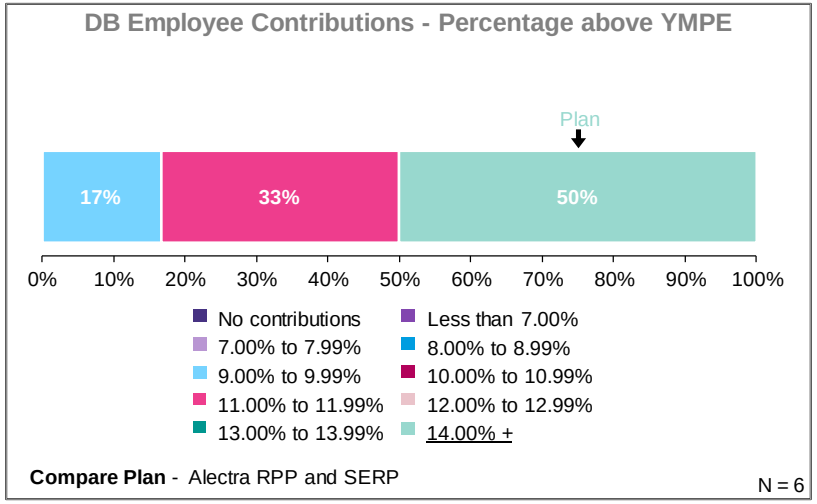
Bonus coverage is common in the plans for executives and provides significant value.

Defined Benefit Plan Formula and Employee Contributions



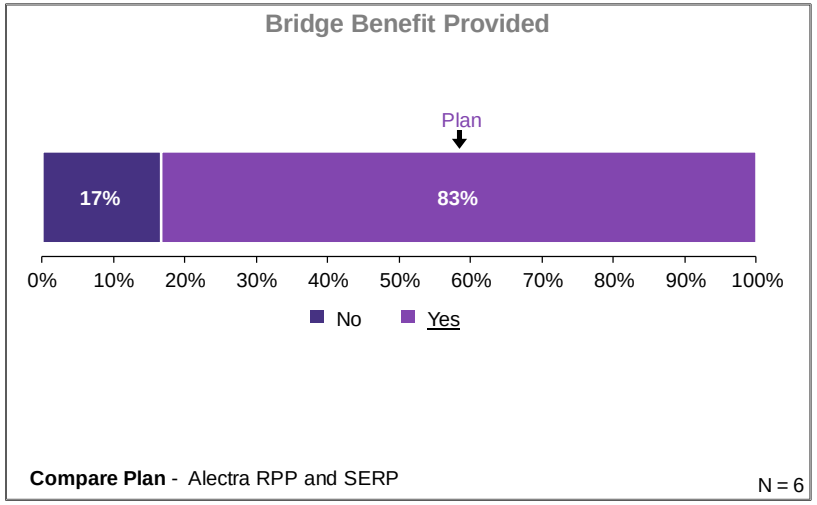


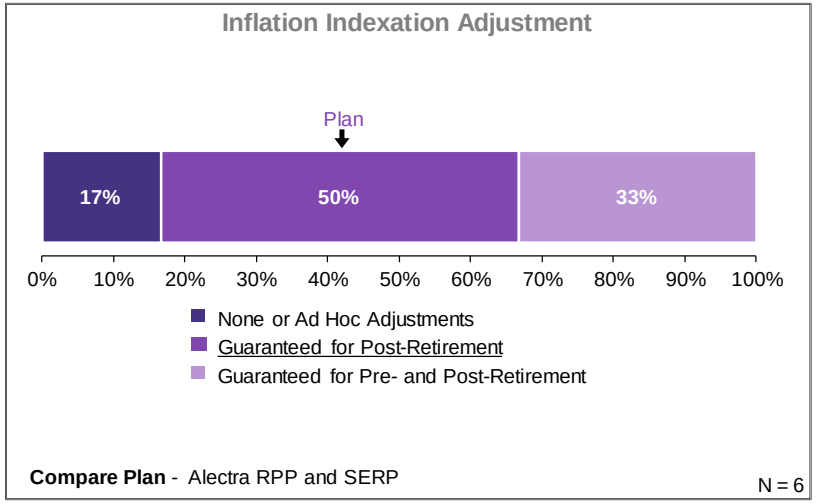


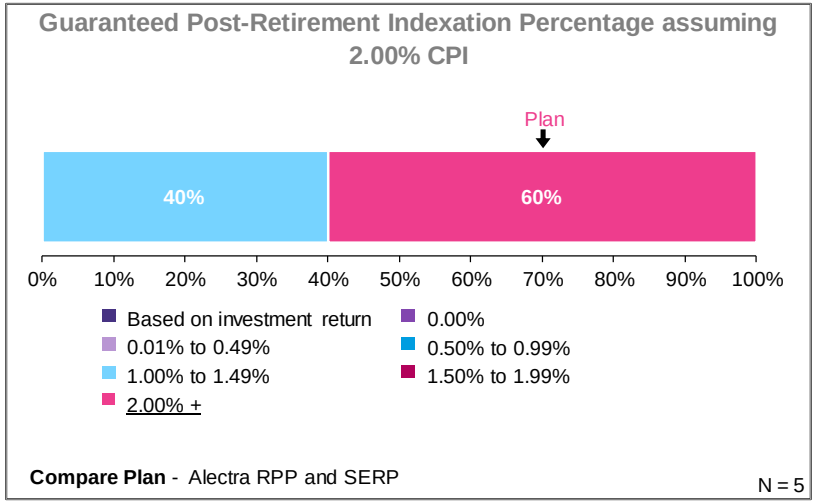


For the Defined Benefit pensions provided to executives, Alectra (and other OMERS covered organizations) has a slightly lower benefit formula for earnings below YMPE, but also higher required employee contributions.

Defined Benefit Ancillary Benefits





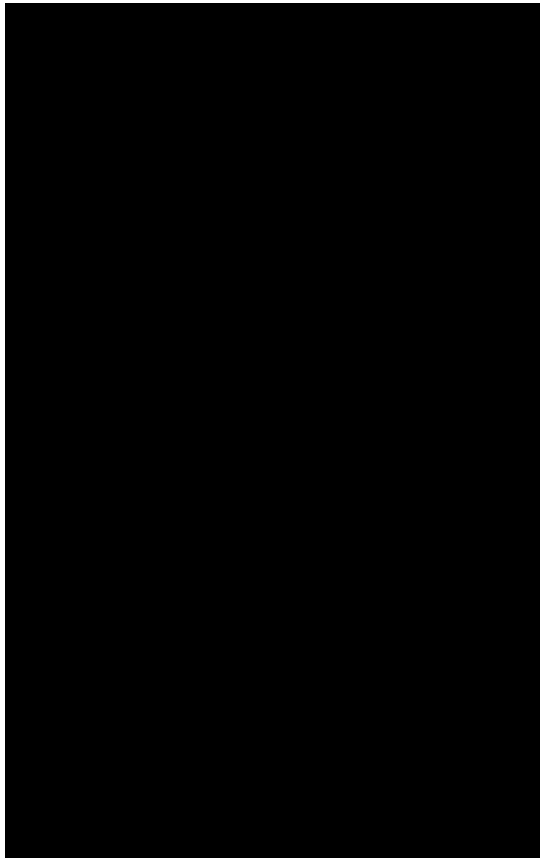


The Defined Benefit pensions have generous ancillary benefits with bridges and post-retirement indexation since they are public sector plans.

Appendix: Assumptions and Methodology

4

List of Comparator Organizations



Assumptions

Financial Assumptions

• Discount rate	5.0%
• Salary increase rate	3.0% per year
• Increase in YMPE	2.5% per year
• Inflation	2.0% per year

Demographic Assumptions

• Pre-retirement decrements	None
• Retirement decrements	50% at age 60, 100% at age 65
• Mortality	100% of CPM 2014 Combined mortality projected with CPM-B Scale
• Percentage married at retirement	75%

Methodology

Defined Benefit Pension

Where employees have a choice of different pension plans, all plans are valued and the one which results in the maximum benefit is assumed to have been selected.

Valuation Methodology for Defined Benefit Pension Plans

1. Project earnings and service for each individual profile to the assumed termination or retirement ages.

2. Determine the actuarial present value of the pension benefit at each assumed termination or retirement age in accordance with the rules of each pension plan.

3. Multiply the actuarial present value of the pension benefit (from 2.) by the ratio of future service to total service. *(This represents the additional benefit value attributable to staying with the organization until retirement.)*

4. Divide the actuarial present value of future service benefits (from 3.) by future earnings to determine the benefit value as a level percentage of salary. *(This gives a value which reflects the percentage of salary one would need to place in a retirement account in each future year to substitute for the benefits expected to be payable from the pension plan, owing to future years of employment.)*

5. Calculate a single level percent of salary by multiplying the level percentages of salary (from 4.) by the associated exit likelihood at each assumed termination or retirement age.

Methodology

Capital Accumulation Pension and Savings

Employees are assumed to contribute the amount required to earn the maximum employer contribution.

Valuation Methodology for Capital Accumulation Pension and Savings Plans

1. Project earnings and service for each individual profile to the assumed termination or retirement ages.
2. Determine the accumulated value of the benefit earned, projected to assumed termination or retirement, as a percentage of future salary, in accordance with the rules of each plan.
3. Calculate a single level percent of salary by multiplying the level percentages of salary (from 2.) by the associated exit likelihood at each assumed termination or retirement age.

Mercer

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.25

Reference: Exhibit 1, Tab 11, Schedule 2, Table 1-11-4

Provide an updated version of Table 1-11-4 at Exhibit 1, Tab 11, Schedule 2, page 14.

RESPONSE:

Table 1 below presents an updated version of Table 1-11-4.

Table 1 – Updated Table 1-11-4: RGF

Line		2027	2028	2029	2030	2031
1	Average Net Fixed Assets	4,184.5	4,441.2	4,752.1	5,123.8	5,505.1
2	Working Capital Allowance	346.1	361.4	373.8	389.7	405.2
3	Rate Base	4,530.6	4,802.6	5,125.8	5,513.4	5,910.3
4	Return on Debt	113.4	124.4	133.2	143.6	158.7
5	Return on Equity	163.1	172.9	184.5	198.5	212.8
6	Depreciation	194.4	199.9	215.6	233.6	244.6
7	PILs Taxes	22.3	38.0	29.8	33.1	38.2
8	Total Capital Related Revenue Requirement	493.2	535.1	563.2	608.8	654.3
9	Less Incremental Working Capital Related Revenue Requirement		(0.5)	(1.3)	(2.3)	(3.3)
10	Total Capital Related Revenue Requirement (including working capital adjustment)	493.2	534.6	561.9	606.6	651.0
11	OM&A	352.4	352.4	352.4	352.4	352.4
12	Add: Inflation Factor		7.0	14.4	22.0	30.0
13	Add: G Factor		6.4	13.0	19.9	27.0
14	Add: IPD Factor		1.3	2.6	4.0	5.5
15	Total OM&A	352.4	367.1	382.4	398.4	415.0
16	Revenue offset	(31.9)	(32.4)	(29.0)	(29.8)	(30.6)
17	Non-capital Related Revenue Requirement (OM&A and Revenue Offset)	320.5	334.7	353.4	368.6	384.4
18	Total Revenue Requirement	813.6	869.3	915.3	975.1	1,035.5
19	Increase in Revenue Requirement		55.6	46.0	59.9	60.3
20	Increase in Revenue Requirement as a percentage of Previous Year Revenue Requirement		6.84%	5.29%	6.54%	6.18%
21	Inflation back-off		-2.00%	-2.00%	-2.00%	-2.00%
22	Billing Determinant Growth back-off		-0.53%	-0.65%	-0.77%	-0.69%
23	Revenue Growth Factor		4.31%	2.64%	3.78%	3.49%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.26

Reference: 1-SEC-11, Table 1-11-4 and Table 1-11-5

Advise whether the CPCI calculation results in a slight over-recovery related to Table 1-11-5 and, if so, provide a proposed solution including consideration of the formula provided by Mr. Rubenstein on Transcript page 87.

RESPONSE:

In the Technical Conference, Mr. Rubenstein identified a concern with Alectra Utilities' approach to the 'billing determinant growth back-off' incorporated into its derivation of the proposed Revenue Growth Factor (RGF), which is subsequently included in Alectra's Custom Price Cap Index (CPCI). Specifically, Mr. Rubenstein noted that in 2028 through 2031 Alectra's as-filed approach relied on revenue growth from billing determinant growth expressed as a percentage from one year to the next as a reduction to the RGF, without taking account of the reality that these incremental growth-driven revenues would also receive rate increases resulting from the CPCI.[1] Alectra confirms that the dynamic highlighted by Mr. Rubenstein creates variances between revenues resulting from the CPCI and the underlying forecast used to derive the RGF.

Were Alectra to propose an alternative approach which better aligned revenues resulting from the CPCI with the underlying forecast used to derive the RGF, Alectra would not recommend the formula proposed by Mr. Rubenstein. In Alectra's assessment, the source of the dynamic noted is the use of percentages and pro-rations against actual dollar amounts, in circumstances where more specific dollar amounts can instead be used for greater

[1] EB-2025-0252, Technical Conference, Volume 3, March 9, 2026, pages 85-88

accuracy. To this end, were Alectra to adopt an alternative approach it would recommend replacement of the percentage-based Inflation and Billing Determinant Growth Back-Off adjustments, with a dollar-based approach to improve accuracy and transparency. Alectra expects such an approach would be calculated as follows:

1) Determine the Total Revenue Requirement to be relied upon for the purpose of establishing the RGF, in a manner consistent with Alectra's current proposal without alteration;
2) Determine the difference in dollars between the amount calculated in 1) above and Revenue at Existing Rates based on the application of prior year's rates to current year's billing determinants;
3) Determine the incremental revenue in dollars which will be received from the Inflation component of the CPCI, by multiplying Revenue at Existing Rates by the forecast Inflation Factor, and remove this amount from the amount calculated in 2) above to yield the incremental revenue required from the RGF;
4) Divide the amount calculated in 3) above, by Revenue at Existing Rates to determine the percentage increase required relative to Revenue at Existing Rates. This calculation establishes RGF.

The approach described above addresses the dynamic raised by Mr. Rubenstein, by using Revenue Existing Rates to establish the adjustments necessary for billing determinant growth and inflation, which incorporates the escalated revenues resulting from billing determinant growth into the 'back-off' process.

Below is a re-produced version of Table 1-11-4 from Alectra's Exhibit 1 implementing this alternative approach for illustrative purposes, relying on the most current values included with interrogatory responses:

Table 1 - RGF

Line		2027	2028	2029	2030	2031
1	Average Net Fixed Assets	4,184.5	4,441.2	4,752.1	5,123.8	5,505.1
2	Working Capital Allowance	346.1	361.4	373.8	389.7	405.2
3	Rate Base	4,530.6	4,802.6	5,125.8	5,513.4	5,910.3
4	Return on Debt	113.4	124.4	133.2	143.6	158.7
5	Return on Equity	163.1	172.9	184.5	198.5	212.8
6	Depreciation	194.4	199.9	215.6	233.6	244.6

Line		2027	2028	2029	2030	2031
7	PILs Taxes	22.3	38.0	29.8	33.1	38.2
8	Total Capital Related Revenue Requirement	493.2	535.1	563.2	608.8	654.3
9	Less Incremental Working Capital Related Revenue Requirement	-	- 0.5	- 1.3	- 2.3	- 3.3
10	Total Capital Related Revenue Requirement (including working capital adjustment)	493.2	534.6	561.9	606.6	651.0
11	OM&A	352.4	352.4	352.4	352.4	352.4
12	Add: OM&A Inflation Factor		7.0	14.4	22.0	30.0
13	Add: Incremental OMAg Factor		7.6	15.6	23.9	32.6
14	Total OM&A	352.4	367.1	382.4	398.4	415.0
15	Revenue offset	- 31.9	- 32.4	- 29.0	- 29.8	- 30.6
16	Non-capital Related Revenue Requirement (OM&A and Revenue Offset)	320.5	334.7	353.4	368.6	384.4
17	Total Revenue Requirement	813.6	869.3	915.3	975.1	1,035.5
18	Revenue @ Existing Rates		817.9	874.3	921.4	981.0
19	Revenue Deficiency (Row 17 - Row 18)		51.4	41.0	53.8	54.4
20	Inflation Back-Off (Row 18 x Inflation)		- 16.4	- 17.5	- 18.4	- 19.6
21	RGF Revenue Required (Row 19 + Row 20)		35.0	23.5	35.4	34.8
22	**Revenue Growth Factor (Row 21 / Row 18)**		**4.28%**	**2.69%**	**3.84%**	**3.55%**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.27

Reference: 1-SEC-21

Advise whether the only rationale for why Alectra proposed the OM&A specific IPD as opposed to different weightings of the OEB's annual inflation factor is because it would essentially yield similar results and is easier.

RESPONSE:

Response provided by Clearspring:

The rationale stated in Clearspring's response to 1-SEC-21 is that the IPD enables the continued use of the OEB's annual inflation factor by allowing the OEB annual inflation factor to better track Alectra's expected inflationary pressure in its OM&A expenses. The alternative approach is to modify the labour/non-labour weights in an annual custom calculation. Both approaches, in Clearspring's view, are relatively straightforward and would improve the alignment of the inflation adjustment to Alectra's expected inflationary OM&A cost pressure.

Additional Response provided by Alectra:

From Alectra's perspective, incorporating the Alectra-specific OM&A IPD factor into the rate formula offers a simpler and more efficient solution than reconfiguring the OEB's standard inflation factor methodology to account for the effects of IPD on OM&A.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.28

Reference: Clearspring report – Table 6 page 27

Advise where the numbers that are shown in Table 6, page 27 of Clearspring's report come from.

RESPONSE:

Response provided by Clearspring

These numbers and calculations can be found in Clearspring's working papers in the file "Dataset Alectra.xls". The worksheet in that file titled "IPD OM&A" shows the calculations and data used for the calculations.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.29

Reference: Conference Board of Canada

Provide the definitions of the Conference Board of Canada series used to derive the forecast AWE and GDP-IPI.

RESPONSE:

Response provided by Clearspring

The AWE definition given by the Conference Board of Canada is “Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite)” under the data series mnemonic of “RLAWWIO”. The GDP-IPI definition is “Implicit Price Deflator - GDP at Market Prices (2017=1.0)” and has the mnemonic of “PGDP”.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.30

Reference: 5-SEC-94

Advise what the amount would be for setting the OEB's deemed long-term debt rate if set today.

RESPONSE:

The DLTDR would be 4.85% if set on March 9, 2026. See Table 1 below for the details of this calculation.

Table 1 - March 2026 DLTDR Calculation

2026 Cost of Capital Parameter Calculations
Deemed Long-term Debt Rate
Data as at March 9, 2026

Date of Update: 9-Mar-26

Long Canada Bond Forecast

Long Canada Bond Forecast (LCBF)	
Long Canada (30-year Government of Canada) Bond yield March 2026 (Bank of Canada)	3.810%

30-Year A-Rated Utility Corporate Bond Spread

A-Rated Utility Corporate Bond Spread September	
30-Year A-rated Utility Corporate Bond Yield BVCAUA30 BVLI Index March 2026 (Bloomberg)	4.847%
Long Canada (30-year Government of Canada) Bond yield March 2026 (Bank of Canada)	3.810%
Spread	1.037%

2026 Deemed Long-term Debt Rate (DLTDR)

Long Canada Bond Forecast March 2026	3.810%
30-Year A-rated Utility Corporate Bond Yield Spread March 2026	1.037%
Deemed Long-term Debt Rate Based on Data: March 2026	4.85%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.31

Reference: 8-SEC-100

Provide a table that shows the distribution monthly service charge, the distribution volumetric charge, the fixed Group 2 DVA Riders, and the Volumetric Group 2 Riders for each year between 2013 and 2024 and for each rate class and rate zone.

RESPONSE:

Alectra Utilities has compiled an Excel table of 2013 to 2031 distribution and Group 2 rates for each rate class and rate zone as Attachment 1 to this response. The proposed 2027 to 2031 rates reflect updates to Group 2 rate riders through undertaking responses.

JT-3.31

Attachment 1
2013-2031 Rates

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.32

Reference: 8-SEC-105

Provide the number of standby customers both over and under 500 kilowatts for the GS over 50 rate classes in each of the rate zones for the years 2020 to 2025.

RESPONSE:

Table 1 presents the number of standby customers both over and under the 500 kW threshold for the GS > 50 kW rate classes in each of the rate zones.

Table 1 – GS>50 kW Standby Customer Counts - All (2020-2025)

GS>50 kW Standby & GLB Customer Counts							
Rate Zone	**Threshold**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
BRZ	GS 50-499 kW	-	-	-	-	-	-
	GS 500-4999 kW	2	2	4	5	5	6
ERZ	GS 50-499 kW	2	2	2	2	4	5
	GS 500-4999 kW	5	7	9	9	10	11
GRZ	GS 50-499 kW	2	2	2	2	2	3
	GS 500-4999 kW	-	6	6	6	17	17
HRZ	GS 50-499 kW	1	1	1	1	1	1
	GS 500-4999 kW	8	8	10	10	9	9
PRZ	GS 50-499 kW	-	-	-	1	2	2
	GS 500-4999 kW	1	5	5	5	5	5
Total		**21**	**33**	**39**	**41**	**55**	**59**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.33

Reference:

Provide an illustrative example of what the existing rate would look like for a customer with respect to standby and gross load billing for each of the rate zone compared to what would it look like under the proposed approach.

RESPONSE:

Tables 1 to 5 below illustrate the impacts of Alectra Utilities' standby rate design proposal, using a common set of rates and a common customer example.

Tables 1 and 2 provide the assumptions used to illustrate the impacts. Only volumetric demand charges were considered, as only those are affected by the standby proposal.

Table 1 – Assumptions: Common Set of Rates for GS>50 kW Example

	Rate ($/kW)
2027 Proposed Distribution Volumetric Rate	**5.2004**
2027 Proposed Standby Power Rate	**5.2004**
Hypothetical Volumetric Rate Riders (to illustrate the impact)	**1.0000**
2027 Proposed Low Voltage	**0.1706**
2027 Proposed RTSR - Network	**4.8104**
2027 Proposed RTSR - Line and Transformation Connection	**2.8600**

Table 2 - Assumptions: Volumes (kW) for GS>50 kW Example

	Volume (kW)
Average Billed Demand	**300**
Generator Capacity	**100**
Contract Demand	**400**

Table 3 illustrates the resulting gross demand and standby volumes for each of the three scenarios evaluated by Alectra Utilities under the current billing[1] vs. the proposed.

- Scenario 1 - the contract demand is equal to, or greater than, the customer's metered demand and generation.
- Scenario 2 - the contract demand is equal to the customer's metered demand, with no generation.
- Scenario 3 - the contract demand is less than the customer's load, with generation included for illustrative purposes.

[1] The "Current" columns relate to situations in which a customer's standby demand can be calculated based on the metered demand and generation. For customers who are currently billed a fixed standby volume, the standby demand in the "Current" column would instead remain constant, regardless of the metered demand and generation.

Table 3 - Customer Volumes (kW) for GLB and Standby[2] under Each Scenario

		Scenario 1		Scenario 2		Scenario 3	
		Current	Proposed	Current	Proposed	Current	Proposed
Contract Demand			400		400		400
Metered Demand		300	300	400	400	450	450
Generation		100	100	-	-	50	50
Gross Demand	*Metered + Generation*	**400**	**400**	**400**	**400**	**500**	**500**
Standby Demand	*Current (Gross less Metered)* *Proposed (Contract less Metered), where min=0, max=Generation Capacity)*	**100**	**100**	**-**	**-**	**50**	**-**

Table 4 illustrates the calculation of the applicable bill components under the current vs. proposed method and the resulting differences for customers who are billed standby charges.

Table 4 - Standby Power Rates

		Scenario 1					Scenario 2					Scenario 3				
		CURRENT		PROPOSED			CURRENT		PROPOSED			CURRENT		PROPOSED		
	Rate ($/kW)	kW	$	kW	$	*DIFF. ($)*	kW	$	kW	$	*DIFF. ($)*	kW	$	kW	$	*DIFF. ($)*
Dx Volumetric Rate	5.2004	300	**1,560.12**	300	**1,560.12**	-	400	**2,080.16**	400	**2,080.16**	-	450	**2,340.18**	450	**2,340.18**	-
Standby Charge	5.2004	100	**520.04**	100	**520.04**	-	-	**-**	-	**-**	-	50	**260.02**	-	**-**	*(260.02)*
Volumetric Rate Riders	1.0000	300	**300.00**	300	**300.00**	-	400	**400.00**	400	**400.00**	-	450	**450.00**	450	**450.00**	-
Low Voltage	0.1706	300	**51.18**	300	**51.18**	-	400	**68.24**	400	**68.24**	-	450	**76.77**	450	**76.77**	-
RTSR - Network	4.8104	300	**1,443.12**	300	**1,443.12**	-	400	**1,924.16**	400	**1,924.16**	-	450	**2,164.68**	450	**2,164.68**	-
RTSR - L/TC	2.8600	300	**858.00**	300	**858.00**	-	400	**1,144.00**	400	**1,144.00**	-	450	**1,287.00**	450	**1,287.00**	-

[2] Gross Demand line illustrates the derivation of kW volumes for billing under Gross Load Billing; Standby Demand line – under Standby Charges Billing.

Table 5 illustrates the calculation of the applicable bill components under the current vs. proposed method and the resulting differences for customers who are gross load billed ("GLB").

Table 5 – Gross Load Billing

		Scenario 1					Scenario 2					Scenario 3				
		CURRENT		PROPOSED			CURRENT		PROPOSED			CURRENT		PROPOSED		
	Rate ($/kW)	kW	$	kW	$	*DIFF. ($)*	kW	$	kW	$	*DIFF. ($)*	kW	$	kW	$	*DIFF. ($)*
Dx Volumetric Rate	5.2004	400	**2,080.16**	400	**2,080.16**	-	400	**2,080.16**	400	**2,080.16**	-	500	**2,600.20**	500	**2,600.20**	-
Standby Charge	5.2004	-	**-**	-	**-**	-	-	**-**	-	**-**	-	-	**-**	-	**-**	-
Volumetric Rate Riders	1.0000	400	**400.00**	300	**300.00**	*(100.00)*	400	**400.00**	400	**400.00**	-	500	**500.00**	450	**450.00**	*(50.00)*
Low Voltage	0.1706	300	**51.18**	300	**51.18**	-	400	**68.24**	400	**68.24**	-	450	**76.77**	450	**76.77**	-
RTSR - Network	4.8104	300	**1,443.12**	300	**1,443.12**	-	400	**1,924.16**	400	**1,924.16**	-	450	**2,164.68**	450	**2,164.68**	-
RTSR - L/TC	2.8600	300	**858.00**	300	**858.00**	-	400	**1,144.00**	400	**1,144.00**	-	450	**1,287.00**	450	**1,287.00**	-

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.34

Reference: 1-Staff-20

Provide an excel spreadsheet with the Handy-Whitman index values and the Canadian implicit capital stock deflator values used for each year in the Clearspring study.

RESPONSE:

Response provided by Clearspring

Please see the Excel spreadsheet titled, “JT-3.34_Attach 1_Response”.

JT-3.34

Attachment 1
Response

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.35

Reference: 3-SEC-75

Provide an excel spreadsheet that shows the output from the ITRON load forecast updated for 3-SEC-69 as well as the data centre adjustments, electrification adjustments, and EV adjustments.

RESPONSE:

Please see JT-3.35_Attach_1_Load Forecast Output for output from the ITRON load forecast, electrification and EV charging load adjustments and data centre adjustments. The file also includes Other adjustments, as described in Exhibit 3, Tab 1, Schedule 4, section 4.3 of the application, presented on a separate tab to illustrate that the totals reconcile to the updated Appendix 2-IB.

JT-3.35

Attachment 1
Load Forecast Output

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-3.36

Reference: 4-Staff-197

Explain the difference between positions and FTEs and how there can be more FTEs than positions in Table 4-Staff-197.

RESPONSE:

The columns in Interrogatory Response 4-Staff-197 Table 1 have been corrected in the table below to clarify that positions reflect a budgeted number for all years (2023-2027) where as FTEs reflect actuals for 2023-2025 and budget for 2026-2027. In 2023 and 2024 the actual FTEs were higher than the budgeted number of positions due to unbudgeted positions in Regulatory, Government and Corporate Relations and People & Transformation as well as a temporary overlap due to a retirement transition.

Table 1- The number of budget and actual FTEs, and position titles within Alectra Inc. business units.

		2023		2024		2025		2026		2027	
Business Unit	**Position Title**	**Budget FTE**	**Actual FTEs**	**Budget FTE**	**Actual FTEs**	**Budget FTE**	**Actual FTEs**	**Budget FTE**	**Budget FTEs**	**Budget FTE**	**Budget FTEs**
Digital & Innovation (in part)	EVP, Chief Digital & Innovation Officer	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.3	1.3	1.0	1.0
Corporate and Financial Stewardship (in part)	President & CEO, Alectra Inc.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Senior Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Administrative Assistant	1.0	1.0	1.0	1.0	1.0		1.0	1.0	1.0	1.0
	EVP, Chief Financial Officer	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Internal Audit (part)	VP, Internal Audit	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Legal, Strategy & Corporate Secretary (in part)	EVP, Legal, Strategy, & Corporate Secretary	1.0	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Strategy, ERM & Sustainability (in full)	VP, Strategy, Enterprise Risk Management & Sustainability	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Analyst/Coordinator, SES	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
People & Transformation (in part)	EVP, People & Transformation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Consultant, HCM Implementation		0.5		0.6	0.3					
	Strategic Advisor		0.5	0.6	0.5						
	Executive Assistant, People & Transformation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory, Government and Corporate Relations (in part)	SVP, Regulatory, Government & Corporate Relations	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant		1.0		1.0		1.0				
Total		**15.0**	**17.4**	**15.6**	**17.2**	**15.3**	**15.0**	**15.3**	**15.3**	**15.0**	**15.0**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-3.37

Reference:

Provide the most up-to-date version of 2-SEC-66, Attachment 3, to reflect the changes in 1-Staff-1.

RESPONSE:

Please see JT-3.37_Attach 1_ Alternative Monthly Calculations.xlsx.

JT-3.37

Attachment 1
Alternative Monthly Calculation

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-3.38

Reference: 2-CCC-12, page 12

Explain the phase-in period reflected in the 2027 property tax estimate for ratemaking purposes.

RESPONSE:

For all properties, except for the Kennedy Road Operations Centre, property taxes for the 2026 – 2029 period are based on an estimated 50% increase in the Current Value Assessment (CVA). The incremental amount is phased in equally (i.e. 25% of the total increase is added to the CVA each year from 2026 - 2029). Therefore, the 2027 property tax estimate includes half of the CVA increase.

For the Kennedy Road Operations Centre, Alectra has estimated a 2026 CVA of $110MM in comparison to its current CVA of $28MM, resulting in an annual increase of $20.5MM to the CVA each year for the 2026 – 2029 period. As a result, the 2027 property tax estimate for this property includes a $41MM increase to its CVA.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.39

Reference: Appendix 2H

Advise why Alectra forecasted zero dollars for the subaccount "other interest revenue" for the forecast period 2026 to 2031 whereas the historic period has always had an amount.

RESPONSE:

Alectra has forecasted nil for subaccount “other interest revenue” for the rebasing period as the Horizon Rate Zone water billing for the City of Hamilton will end in Q2 2026. This water billing activity generated interest income in the past where this interest income earned was adjusted in subaccount 4405 and reclassified to account 4380 – Expenses of Non-Utility Operations. This adjustment was necessary to ensure the legacy Horizon Utilities water billing activities remained outside the utility operations. Please note that the amount included in 2025 actuals in the interrogatory response to 1-SEC-24 Appendix 2-H was entered incorrectly where $500,709 should have been entered as -$500,709. An adjustment has been made to reflect this change.

JT-3.39

Attachment 1
Appendix 2-H

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.40

Reference:

Advise whether Alectra can provide the forecast amount for tax credit in relation to 6-Staff-206.

RESPONSE:

Alectra will provide an update to the tax credit amounts when the 2025 corporate income tax return is finalized in June 2026.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.41

Reference: 6-Staff-207

Advise why the two attachments in 6-Staff-206 and 6-Staff-207 have variance.

RESPONSE:

Interrogatory 6-Staff-206 requested a copy of the 2025 draft Federal and Provincial corporate tax returns. Alectra's response included a draft tax return and 6-Staff-206-Attach 2_PILs Return Regulated Detail which presents an updated ending 2025 Undepreciated Capital Cost amount of $3,003,952,746 for the regulated utility.

Interrogatory 6-Staff-207 focuses on the calculation of tax credits and the inclusion of tax credits in the PILs model rather than including them into other revenues. 6-Staff-207_Attach 1_PILs Model includes the requested changes related to the tax credit interrogatories. The version of the PILs model that was used to demonstrate the impact of the tax credit changes was the original filed Alectra_Attach 6-7_PILs Workform_20251014 filed on October 14, 2025, containing an ending 2025 Undepreciated Capital Cost of $2,970,715,354. This version of the PILs model was used as the basis in responding to 6-Staff-207 in order to not conflate the impact of other interrogatory responses with the response to 6-Staff-207.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.42

Reference: EB-2025-0055. Section 10; Alliance study

Quantify the impact of revenue requirement, CCA, if the depreciation rates used in the ICM true-up are based on the rates prior to the depreciation study.

RESPONSE:

Table 1 provides the revenue requirement impact for each ICM project if the depreciation rates used in the ICM true up are based on rates prior to the depreciation study.

Table 1 - Impact of Revenue Requirement for each ICM project

RZ	Year	ICM Project Name	Recovery/(Refund) True-ups submitted on February, 23, 2026	Recovery/(Refund) True-ups based on rates prior to the depreciation study	Difference
BRZ	2018	Pleasant TS CCRA True Up	($1,641,650)	($1,641,650)	$0
BRZ	2021	Goreway TS CCRA True Up	($394,349)	($394,349)	$0
BRZ	2021	Goreway Road Widening	$37,954	$38,224	($270)
PRZ	2018	Road Authority YRRT	$1,999,769	$2,001,567	($1,798)
PRZ	2019	Road Authority YRRT	$707,806	$709,997	($2,192)
PRZ	2019	Bathurst Road Widening	$129,305	$129,498	($193)
PRZ	2021	Rutherford Road Widening	$40,255	$40,609	($354)
PRZ	2023	Cable Renewal	$23,019	$20,000	$3,019

RZ	Year	ICM Project Name	Recovery/(Refund) True-ups submitted on February, 23, 2026	Recovery/(Refund) True-ups based on rates prior to the depreciation study	Difference
PRZ	2024	Cable Renewal	($791,289)	($792,723)	$1,434
ERZ	2018	Leaking Transformer - Overhead	($1,966,283)	($1,966,127)	($156)
ERZ	2018	Leaking Transformer - Padmount/Vault	$776,028	$775,387	$641
ERZ	2018	York MS - Civil Construction	$208,975	$205,224	$3,751
ERZ	2019	Leaking Transformer - 2019	($2,566,948)	($2,567,135)	$187
ERZ	2023	Cable Renewal	$152,121	$152,330	($209)
Total			**($3,285,288)**	**($3,289,147)**	**$3,859**

1

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.43

Reference: 9 Staff-243, page 3

Advise whether Alectra is aware of any cases where the OEB approved Group 2 DVA True-ups in a Cost of Service proceeding.

RESPONSE:

The OEB has approved Group 2 DVA true-ups in EB-2018-0165. In EB-2018-0165 (Toronto Hydro-Electric System Limited, Application for Electricity Distribution Rates beginning January 1, 2020 until December 31, 2024, Decision and Order dated December 19, 2019, page 178), the OEB stated that “any variance between the approved forecast 2019 Group 2 DVA balances and Other Amounts and the actual 2019 Group 2 DVA balances and Other Amounts is to be recorded in Account 1595. The balance in Account 1595 will be reviewed as part of Toronto Hydro’s 2021 Custom IR update application.”

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.44

Reference: 9-Staff-248, Attachment 1

Provide a table listing all the Group 2 accounts and specify for each account whether it will continue or discontinue, the final disposition or interim disposition, and the reason for the true-up.

RESPONSE:

Table 1 below provides the listing all the Group 2 accounts and specifies for each account whether it will continue or discontinue, the final disposition or interim disposition, and the reason for the true-up. Please also see Alectra Utilities' response to JT-3.43.

Table 1 – Group 2 Accounts

Group 2 Accounts	Continue / Discontinue	Final/Interim Disposition	Reason for true-up
1508 - sub-account Deferred IFRS Transition Costs	Discontinue	Not seeking disposition as there is no balance in this account	
1508 - CGAAP-CWIP Differential Deferral Account	Discontinue	Final	
1508 - Earnings Sharing Mechanism	Discontinue	Not seeking disposition as there no balance in this account	
1508 - Energy East Consultation Costs	Discontinue	Final	
1508 - OEB Cost Assessment Variance	Continue	Interim	The 2026 actual OEB assessment costs can be materially different than the forecast.
1508 - Other Post-Employment Benefit Deferral Account	Continue	Interim	The 2026 actual actuarial gains or losses from the updated actuarial assumptions related to OPEB can be materially different than the forecast.
1508 - OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account	Discontinue	Interim	The 2026 actual OPEB cash versus accrual can be different than the forecast.
1508 - Advanced Pricing Project	Discontinue	Not seeking disposition as there is no balance in this account	
1508 - Hydro-One Charges	Discontinue	Not seeking disposition as there is no balance in this account	
1508 - Pole Attachment Revenue Variance	Discontinue	Interim	The 2026 actual number of pole attachments can be different than the forecast.
1508 - Capitalization Policy	Discontinue	Interim	The 2026 actual capitalization policy impact can be materially different than the forecast resulting

Group 2 Accounts	Continue / Discontinue	Final/Interim Disposition	Reason for true-up
			from the actual capital expenditure.
1508 - Incremental Capital Module	Discontinue	Interim	The 2026 actual ICM rate riders' collection can be different than the forecast.
1508 - Long-term Load Mitigation	Discontinue	Interim	The 2026 actual balance can be different than forecast
1508 - Collection of Account Charge-Related Lost Revenue	Discontinue	Interim	The 2026 actual number of nonpayment notices issued can be different than the forecast.
1508 - sub-account Green Button Initiative Costs	Discontinue	Not seeking disposition as there is no balance in this account	
1508 - sub-account Customer Choice initiative Costs	Continue	Not seeking disposition as there is no balance in this account	
1508 - sub-account ULO Implementation Cost	Discontinue	Not seeking disposition as there is no balance in this account	
1508 – sub-account EVC Rate Implementation Cost	Continue	Not seeking disposition as there is no balance in this account	
1508 - sub-account Local Initiatives Program Costs	Continue	Not seeking disposition as there is no balance in this account	
1508 - sub-account Designated Broadband Project Impacts	Continue	Not seeking disposition as there is no balance in this account	
1508 - GOCA Variance Account	Discontinue	Interim	The 2026 actual incremental external cost of locates can be different than forecast
1508 - LEAP Emergency Financial Assistance Funding Deferral Account	Discontinue	Interim	The 2026 actual LEAP fund disbursed can be different than forecast
1508 -Extended Horizons Variance Account	Continue	Interim	The 2026 actual balance can be different than forecast

Group 2 Accounts	Continue / Discontinue	Final/Interim Disposition	Reason for true-up
1508 -Capacity Allocation Model	Continue	Interim	The 2026 actual balance can be different than forecast
1509 - Impacts Arising from the COVID-19 Emergency	Discontinue	Not seeking disposition as there is no balance in this account	
1511 - Incremental Cloud Computing Implementation Costs	Continue	Interim	The 2026 actual balance can be different than forecast
1518 - Retail Cost Variance Account (RCVA) Retail	Discontinue	Interim	The 2026 actual balance can be different than forecast
1548 - RCVA STR	Discontinue	Interim	The 2026 actual balance can be different than forecast
1521 - Special Purpose Charge Assessment Variance Account	Discontinue	Not seeking disposition as there is no balance in this account	
1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account	Continue	Interim	The 2026 actual balance can be different than forecast
1525 - Miscellaneous Deferred Debits	Continue	Not seeking disposition through rate riders. Proposes to recover these costs over a five-year period through its revenue requirement.	
1531 - Renewable Connection Capital Deferral Account	Discontinue	Not seeking disposition through rate riders. Proposes to transfer the direct benefit component to rate base.	
1532 - Renewable Connection OM&A Deferral Account	Discontinue	Final - seeking disposition through rate riders for direct benefit component.	
1533 - Renewable Generation Connection Funding Adder Deferral Account	Continue	Final	
1534 - Smart Grid Capital Deferral Account	Discontinue	Not seeking disposition as there is no balance in this account	
1535 - Smart Grid OM&A Deferral Account	Discontinue	Final	

Group 2 Accounts	Continue / Discontinue	Final/Interim Disposition	Reason for true-up
1536 - Smart Grid Funding Adder Deferral Account	Discontinue	Final	
1555 - Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs	Discontinue	Final	
1556 - Smart Meter OM&A Variance	Discontinue	Not seeking disposition as there is no balance in this account	
1557 - Meter Cost Deferral Account	Discontinue	Final	
1568 - Lost Revenue Adjustment Mechanism Variance Account	Continue	Not seeking disposition as there is no balance in this account	
1567 - Board-Approved CDM Variance Account	Discontinue	Not seeking disposition as there is no balance in this account	
1572 - Extra-Ordinary Event Costs	Continue	Not seeking disposition as there is no balance in this account	
1575 - IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	Discontinue	Not seeking disposition as there is no balance in this account	
1576 - Accounting Changes Under CGAAP Balance + Return Component	Discontinue	Not seeking disposition as there is no balance in this account	
1592 - sub-account PILs and Tax Variance for 2006 and Subsequent Years	Continue	Interim	The 2026 actual balance can be different than forecast
1592- Sub-Account HST/OVAT Input Tax Credits (ITCs)	Discontinue	Not seeking disposition as there is no balance in this account	
2425 - Other Deferred Credits	Discontinue	Not seeking disposition as there is no balance in this account	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.45

Reference: 9-Staff-248, Attachment 1

Provide an update to the BRZ Continuity Schedule.

RESPONSE:

Alectra Utilities has provided an updated BRZ Continuity Schedule as JT-1.1.13_Attach 7_DVA Continuity Schedule_BRZ.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.46

Reference: 9-Staff-250 Attachment 2 and Attachment 3

Reconcile 9-Staff-250 Attachment 2 and Attachment 3 with the ERZ continuity schedule.

RESPONSE:

The 2018 transactions and interest for ICM-2018 Leaking Transformer Overhead have been updated to match the associated amounts in 9-Staff-250 Attachment 2. The 2018 transactions and interest for ICM-2018 Leaking Transformer Padmount have also been updated to match the associated amounts in 9-Staff-250 Attachment 3. Alectra Utilities has provided an updated ERZ Continuity Schedule as JT-1.1.13_Attach 5_DVA Continuity Schedule_ERZ.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.47

Reference: 9-Staff-266, page 2, Attachment 1

Provide the HRZ breakdown for 9-Staff-266, page 2, Attachment 1, Row 44, Account 1533, RGCRP variance reconciliation.

RESPONSE:

Alectra Utilities has provided the reconciliation for HRZ Account 1533 Renewable Generation Connection Funding Adder Deferral Account in Table 1 below.

The account balance of $106,100 represents the actual revenue requirement associated with investments made between 2012 and 2014 for renewable generation connections for legacy Horizon Utilities. Of this amount, $56,438 has been recovered through OEB-approved GEA rate riders for legacy Horizon Utilities, and $49,633 has been recovered through RGCRP funding received from the IESO. Accordingly, as the balance has been recovered, Alectra Utilities has excluded this balance from the total disposition amount for the purpose of calculating the Group 2 rate riders. Alectra Utilities will make a correcting entry as there should be no balance in this account.

Table 1 - 1533 Renewable Generation Connection Funding Adder Deferral Account – HRZ

	Actual											
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**	**Explanation**
2012-2014 GEA Rate Adder collected from customers (A)	-$140,314	-$140,836	-$141,573		$0	$0	$0	$0			-$422,724	
OEB approved disposition (B)				$298,119					$116,267	-$48,100	$366,285	The net of $422,724 and $366,285 (i.e. $56,438) represents the 2012-2014 direct benefit based on the actual revenue requirement. Refer to EB-2019-0018 response to HRZ-Staff -4, Attachment Alectra_HRZ-Staff-4_Attach 1_RGCRP HRZ_20190816, Tab RGCRP Reconciliation Cell U33.
RGCRP Funding from IESO (C)		-$16,968	-$8,484	-$8,484	-$8,484	-$8,484	-$8,484	$0		$9,726	-$49,662	The $49,662 represents the Provincial Rate Protection based on actual revenue requirement. Refer to EB-2019-0018 response to HRZ-Staff -4, Attachment Alectra_HRZ-Staff-4_Attach 1_RGCRP HRZ_20190816, Tab RGCRP Reconciliation Cell U39.
Total D=(A+B+C)	-$140,314	-$157,804	-$150,057	$289,635	-$8,484	-$8,484	-$8,484	$0	$116,267	-$38,374	-$106,100	
1533 Renewable Generation Connection Funding Adder Deferral Account (DVA Continuity Schedule) - Transactions (E)	-$140,314	-$157,804	-$150,057	$289,635	-$8,484	-$8,484	-$8,484	$0	$116,267	-$38,374	-$106,100	This balance has been excluded from the total disposition amount for the purpose of calculating the Group 2 rate riders. The balance will be moved to Distribution Revenue Account 4080.
Difference F=(E-D)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.48

Reference: Exhibit 9, Tab 3, Schedule 3, page 3, Table 9-3-3 and 4-VECC-50, Table 1

Reconcile Table 9-3-3 in Exhibit 9 with the Table in 4-VECC-50 for the OEB annual assessment.

RESPONSE:

Alectra Utilities has provided the reconciliation between Table 9-3-3 in Exhibit 9 with the Table in 4-VECC-50 for the OEB annual assessment in Table 1 below.

Table 1 - OEB Annual Assessment Reconciliation

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
4-VECC-50, Table 1 OEB annual assessment	**2,877,844**	**2,990,763**	**2,943,568**	**2,927,431**	**2,833,164**	**3,107,431**	**3,111,140**	**2,815,872**	**3,076,061**	**3,297,918**
Reconciliation items										
GRZ OEB assessment costs included in rates were excluded from VECC-50 Table 1 prior to the ERP integration for GRZ	180,000	180,000	180,000	180,000	180,000	-	-	-	-	
Adjustments made to reflect the correct approved amount in rates	(61,178)	(9,317)	(20,809)	(31,370)	(31,370)	(31,370)	(31,370)	260,189	0	
Other invoices	79,395	(85,385)	(26,698)	-	94,267	-	(3,709)	-	-	
OEB Annual Registration Fee	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	
Budget variance										(222,657)
Total Reconciliation	**197,417**	**84,498**	**131,693**	**147,830**	**242,097**	**(32,170)**	**(35,879)**	**259,389**	**(800)**	**(222,657)**
Table 9-3-3 Amount in Rates	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261	3,075,261

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.49

Reference: 8-Staff-238

Confirm where it is coded that customers must pay a gross load billing for their RTSRs.

RESPONSE:

The 2006 Electricity Distribution Rate Handbook, Chapter 11, section 11.3.2.5, pp. 13-14 describes the billing determinants applied to RTSRs. RTSR Connection is generally billed on a net load basis, but is billed on a gross load basis for customers with embedded generation exceeding 1 MW. Table 11.4 from the 2006 Handbook summarizes the application of billing determinants for RTSR charges.

Table 11.4

	Large Users Interval Meter	General Service Interval Meter	General Service Demand Meter	General Service Energy-only Meter	Residential Energy-only Meter
Network Charge Rate	Peak kW demand in month from 7 AM to 7 PM Weekdays	Peak kW demand in month from 7 AM to 7 PM Weekdays	Peak kW demand in month	Energy kWh consumption in month	Energy kWh consumption in month
Connection Charge Rate	Peak kW demand in month including new embedded generation over 1 MW	Peak kW demand in month including new embedded generation over 1 MW	Peak kW demand in month including new embedded generation over 1 MW	Energy kWh consumption in month	Energy kWh consumption in month

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.50

Reference: 9-Staff-267 and OEB's Decision for EB-2025-0055 as part of the Staff compendium, page 24, Table 8.1

Advise why Alectra has not continued with a request for provincial funding for renewable generation connection rate protection for 2027 and beyond and how Alectra proposes to handle the change in depreciation rate with respect to the revenue requirement collected in 2025 and 2026.

RESPONSE:

Upon further review, Alectra Utilities is seeking OEB's approval for provincial funding for the renewable generation connection rate project for 2027 to 2031.

Alectra Utilities' 2027-2031 RGCRP funding request is provided by RZ, below.

The 2025 and 2026 revenue requirements in the RGCRP workforms are calculated based on the new depreciation rates from the Alliance depreciation study.

Brampton RZ

In the 2015 Cost of Service Rate Application (EB-2014-0083), the OEB-approved Hydro One Brampton's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2015 to 2019. Hydro One Brampton's DSP was reviewed by the OEB and its funding requests for eligible investments for 2015 to 2019 were approved by the OEB.

The requested renewable generation funding for BRZ is provided below, as identified in JT-3.50_Attach 1_BRZ RGCRP Workform. The OEB approved Alectra Utilities' request for the 2026 RGCRP amount of $121, 121 for BRZ in its 2026 IRM application (EB-2025-0055).

Table 1 - RGCRP Funding Request – BRZ

Year	RGCRP Funding Request ($)
2027	**$ 111,282**
2028	**$ 107,036**
2029	**$ 103,426**
2030	**$ 99,718**
2031	**$ 96,118**
Total	**$517,580**

PowerStream RZ

In the 2017 Custom IR Rate Application (EB-2015-0003), the OEB-approved PowerStream's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed DSP, to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2016 to 2020.

The requested renewable generation funding for PRZ is provided below, as identified in JT-3.50_Attach 2_PRZ RGCRP Workform. The OEB approved Alectra Utilities' request for the 2026 RGCRP amount of $229, 052 for PRZ in its 2026 IRM application (EB-2025-0055).

Table 2 - RGCRP Funding Request – PRZ

Year	RGCRP Funding Request ($)
2027	**$210,068 funding request, less true-up of ($237,331), net refund ($27,264)**
2028	**$179,834**
2029	**$150,247**
2030	**$145,915**
2031	**$142,402**
Total	**$591,133**

The true up for PRZ is primarily related to the actual capital additions over the 2014 to 2016 period.

Enersource RZ

Enersource filed a basic Green Energy Plan (the "GEA Plan") which was approved by the OEB in Enersource's 2013 cost of service application proceeding (EB-2012-0033). The GEA Plan identified the projects and expenditures associated with the connection of renewable generation to its system and discussed constraints on the ability to connect renewable generation. The GEA Plan was filed in accordance with the Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397), which requires distributors to identify the costs related to the connection of FIT and microFIT projects and/or to the implementation of a smart grid. The GEA Plan did not include any smart grid initiatives. The requested renewable generation funding for ERZ is provided below, as identified in JT-3.50_Attach 3_ERZ RGCRP Workform. The OEB approved Alectra Utilities' request for the 2026 RGCRP amount of $125,528 for ERZ in its 2026 IRM application (EB-2025-0055).

Table 3 RGCRP Funding Request - ERZ

Year	RGCRP Funding Request ($)
2027	**$95,280**
2028	**$84,563**
2029	**$68,332**
2030	**$52,007**
2031	**$35,120**
Total	**$335,302**

JT-3.50

Attachment 1
BRZ RGCRP Workform

Please see live Excel

JT-3.50

Attachment 2
PRZ RGCRP Workform

Please see live Excel

JT-3.50

Attachment 3
ERZ RGCRP Workform

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.51

Reference: 1-Staff-26A and OEB's RRR

Provide updated data regarding APB cost for all years where there is a difference between the values filed as evidence and the values currently in RRR.

RESPONSE:

To be clear, Alectra Utilities has provided the updated data regarding APB cost for the years 2019-2024. The updated data can be found in response to 1-Staff-26 and also 1-Staff-28.

In the discussion leading up to the Undertaking, OEB staff posed the following question:

The second question is where there is a difference between the values filed as evidence versus the values we currently have in RRR, would you consider updating your RRR data for all the years?

At this time, Alectra is not able to confirm that it will be able to undertake revisions the RRR data. This effort will require a detailed examination of a number of accounts as well as evaluation of their impacts. In any event, this activity cannot be accomplished within the time period allowed for the purpose of Undertaking responses.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.52

Reference: 1-Staff-28

Explain how design activities doubled the unit cost from 286 in 2023 to 595 in 2024 and whether the doubled cost is expected to continue going forward, and provide a breakdown of all the various drivers that doubled the unit cost.

RESPONSE:

To clarify, the costs in this category are not driven solely by design activities, as suggested by OEB staff's request. As expressed in the response to 1-Staff-28,

> *"Additionally in 2024, to ensure continued operational efficiency, transformer reconditioning and remediation projects occurred at various stations, as well as station protection upgrade projects and communications infrastructure deployment projects."*

As such, this unit cost metric should be viewed in that context. In particular, viewing the historical unit costs shows that the annual unit costs vary significantly from year to year, mainly arising from annual changes to total costs. As can be seen from Table 7 in the response to 1-Staff-28 (reproduced below for ease of reference), the average year-over-year change in unit costs over the 2020-2024 period was 20.0%. The standard deviation of total costs over this same period was 68.67%.

Table 7 - Distribution Station Equipment CAPEX - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	5,037	7,968	1,873	2,012	4,159	4,210
Total MVA	7,044	7,044	7,044	7,038	6,986	7,031
$/MVA	715	1,131	266	286	595	599
YoY Change (%)	3%	58%	-76%	7%	108%	

The work effort and capital expenditures pertaining to the stations program area vary from year to year, commensurate with the planning and development of projects relating to new stations and capacity upgrades at existing substations, as well as corrective and reactive equipment replacements and refurbishment activities.

Two issues drove the increase in unit costs for the Distribution Station Capex metric. First, total costs decreased in 2022 and 2023, and in 2024 various drivers increased costs to a level more consistent with (but still below) the 5-year average. Second, the scale metric, Total MVA, saw a modest decline in 2024. Combined, these two drivers caused the capex per unit of Total MVA to increase more than 100% in 2024.

Going forward, Alectra expects the unit cost associated with the Distribution Station Equipment CAPEX program will continue to fluctuate in a manner that aligns with Stations-related capital plans. By 2031 Alectra plans to increase station capacity by 685 MVA, as referenced at Chapter 5.2.3.2 E of Exhibit 2A, Tab 1 Schedule 1, which will impact the scale variable for benchmarking purposes. As noted under Exhibit 2A, Tab 1, Schedule 1, section 5.4.1 C and described in detail in Appendix B13 – Station Capacity, Alectra Utilities proposes to build two transformer stations and one municipal station by 2031, including Webb MS, Vaughan TS#6, and Richmond Hill TS#3. Building a new transformer station is a multi-year process with a timeline of approximately 3 to 5 years for a new MS and 5 to 7 years for a new transmission-connected TS. The forecast cost associated with Stations CAPEX through the rebasing period is provided in Exhibit 2B, Attachment 2B-1, Appendix 2-BA.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.53

Reference: 1-Staff-28

Advise what percentage of any pole work carried out in 2024 was non-standard and advise why the non-standard works had to be undertaken.

RESPONSE:

Of the $60.0M in Poles, Towers and Fixtures CAPEX costs recorded in USoA 1830 in 2024, approximately 40% of pole work involved non-standard installations or related to a project with a higher-than-average unit cost per installed pole due to one or more of the factors described below.

With its use of the term 'non-standard requirements', Alectra indicates that a portion of the work undertaken in 2024 does not reflect a typical or simple poleline installation. A standard pole addition or relocation project would include the installation of a standard height wood or concrete utility pole at a standard depth and the removal of an existing poleline where applicable, in a location without complex features that require additional coordination. Some of the projects undertaken by Alectra in 2024 involve a combination of non-standard installation approaches, 5 or 6 circuits, dedicated flagging personnel, a requirement to perform work in the evenings and weekends, lengthy spans, and atypical pole heights or strength requirements. Several 2024 projects involved work in tandem with Metrolinx and MTO contractors and occurred along rail corridors, river crossings or 400-series highways due to the urban nature of much of Alectra's service territory and its location within the Greater Toronto Area.

Another factor contributing to higher Poles CAPEX unit costs in 2024 relates to the evolution of design practices and increases in material costs. For example, pole installations require

adherence to the latest CSA Standard (CSA C22.3 No. 1, 2020 Edition), which includes climate change adaptation requirements that incorporate the use of stronger, more resilient designs and materials relative to the prior version, including the use of higher strength poles. Additional permitting and design complexities have also been required in some specific locations.

As a result of the conditions and circumstances outlined above, non-standard work was undertaken in order to enable the completion of certain public infrastructure projects as well as customer-initiated projects.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.54

Reference: 1-Staff-28

Provide an example of cost categorization in regards to the O&M line.

RESPONSE:

The Accounting Procedures Handbook for Electricity Distributors (APH) sets out regulatory accounting procedures and a USoA structure for the recording of utility costs. The Lines O&M APB program area encompasses the following USoAs:

- 5020 Overhead Distribution Lines and Feeders - Operation Labour
- 5025 Overhead Distribution Lines and Feeders - Operation Supplies and
- Expenses
- 5040 Underground Distribution Lines and Feeders - Operation Labour
- 5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses
- 5090 Underground Distribution Lines and Feeders - Rental Paid
- 5095 Overhead Distribution Lines and Feeders - Rental Paid
- 5125 Maintenance of Overhead Conductors and Devices
- 5130 Maintenance of Overhead Services
- 5145 Maintenance of Underground Conduit
- 5150 Maintenance of Underground Conductors and Devices, and
- 5155 Maintenance of Underground Services

Labour costs for certain activities may be tracked within the above noted USoAs at some utilities, and in alternative USoAs at other utilities. Alectra does not have insight into the tracking practices of other utilities.

As an example of potential differences in cost categorization amongst utilities, costs tracked in USoA 5120 include *"the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1830, Poles, Towers and Fixtures."* A specific example provided in the APH is the movement of line or guy pole in relocation of pole or section of line, which some utilities may record as a Lines OM cost under USoA 5020.

Generally, capitalization practices may vary across utilities. Differences in capitalization practices may impact the costs recorded in each USoA.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.55

Reference: 1-Staff-28

Clarify whether Alectra is suggesting that if the software limitations described in 1-Staff-28, Section A relating to poles, towers, and fixtures CAPEX did not exist, and cost allocation was standardized, unit costs could be reduced. Provide a comparison of this unit cost to a peer group with similar urban nature and load density to Alectra.

RESPONSE:

Alectra is not able to confirm, or to clarify, that if cost allocation was standardized, unit costs would be reduced. If such changes were implemented, it is probable that changes to the Poles CAPEX program area would also include an opposite impact on the Lines CAPEX program area, and vice versa, as the cost categorization issue impacts the tracking of overhead and underground work. As indicated in Exhibit 1, Tab 6, Schedule 3, Alectra has committed to further developing and enhancing the production of program-based benchmarking results going forward.

Alectra also reiterates that it does not record or report the quantity of fixtures. It is unclear how many, or which, utilities do capture and report this data in their APB results. The inclusion of fixture quantities could significantly impact the scale variable, which would impact comparability among firms if not applied consistently.

As a result of the foregoing, Alectra is not able to uniformly indicate whether the use of a standardized cost allocation would result in lower or higher unit costs for Alectra or comparative utilities under the Poles CAPEX APB program area.

In Alectra's assessment there is no suitable comparative peer group of Ontario utilities for Alectra Utilities with respect to load density and urban nature. In 2024, Alectra's average peak load with embedded generation was 4,248,733 kW and total quantity of circuit kilometers of line was 51,137, resulting in a load density of 83 kW per circuit kilometer of line. Alectra's service territory is 99% urban. Developing a peer group of Ontario utilities similar to Alectra in respect of urban intensity and load density is further challenged as any such candidates are not alike Alectra in terms of other important characteristics, such as service territory size, total line circuit kilometers, or customer count. Differences in these characteristics could have a material impact on the results, calling into question whether the cost comparison yields meaningful results.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.56

Reference: 1-Staff-28

Advise what percentage of the increase in Alectra's five-year average unit cost was driven by supply chain versus cost tracking practices.

RESPONSE:

This undertaking was raised with respect to the Lines Transformer CAPEX program area in 1-Staff-28 a) iii) c.

An in-depth review of each capital project would be required to ascertain precise percentage increases in Alectra's five-year average Lines Transformer CAPEX unit cost attributable to each of supply chain or cost tracking practices. While such precision is not available, Alectra can confirm that the increase stems primarily from supply chain related factors, as described below:

1. Three-phase transformers cost approximately five times more than single-phase transformers. The quantity of 3-phase line transformers installed annually in 2023 and 2024 was approximately double the average installed volume from 2020 to 2022. Large-scale condominium projects, industrial, commercial and institutional (ICI) facilities, and increased load density requirements in urban centres within the Greater Toronto and Hamilton areas contributed to the increased need for 3-phase transformers in 2023 and 2024.

2. Alectra's largest transformer offering is 3 MVA. Alectra supplies large scale transformers for condominiums and ICI projects within this threshold on a routine basis. Many utilities would require comparable large-scale transformers on a less

frequent basis and may require such installations to be customer-owned. The APB benchmarking methodology does not account for transformer size variations when comparing utilities or assessing a single utility's year-over-year performance.

3. A transformer supply shortage was observed in 2020-2022. Updates to Alectra's internal specifications for transformers were completed in 2022. Reserve inventory was utilized through the 2020-2022 period. Transformer supply began to stabilize in 2023 as reflected in reported costs.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-3.57

Reference: 2-CCC-12, page 12

Provide a revenue requirement version of the Table at 2-CCC-12, page 12, related to AMI.

RESPONSE:

Please see the updated Table below that includes revenue requirements for each deployment option for 2027-2031:

Table 1 – Revenue Requirements for each Deployment Option

Capital Expenditures ($MM)	DSP: 2027 to 2031	DSP: 2032 to 2033	Total Project and Project Dependent Costs	DSP Quantities
3-Year Mass Deployment Alternative				
AMI Renewal	257.4	0.0	257.4	950,000
AMI 1.0 Reactive Meter Failures	14.7	0.0	14.7	74,944
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 3-Year Deployment	277.6	-	277.6	
Accelerated Depreciation	25.6	(9.2)	16.4	
Revenue Requirements	150.0	63.1	213.1	
5-Year Mass Deployment Alternative				
AMI Renewal	261.9	0.0	261.9	950,000
AMI 1.0 Reactive Meter Failures	23.6	0.0	23.6	89,173
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 5-Year Deployment	291.0	-	291.0	
Accelerated Depreciation	25.6	(9.2)	16.4	
Revenue Requirements	137.2	66.0	203.3	
5.5-Year Mass Deployment Alternative				
AMI Renewal	247.6	14.3	261.9	900,000
AMI 1.0 Reactive Meter Failures	23.6	0.0	23.6	89,173
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 5.5-Year Deployment	276.7	14.3	291.0	
Accelerated Depreciation	25.2	(8.8)	16.4	
Revenue Requirements	134.7	66.3	201.0	
7-Year Mass Deployment Alternative				
AMI Renewal	193.2	69.5	262.7	650,000
AMI 1.0 Reactive Meter Failures	35.5	6.2	41.7	132,546
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	19.2	2.9	22.1	32,680
Total 7-Year Deployment	247.9	78.6	326.5	
Accelerated Depreciation	15.7	0.7	16.4	
Revenue Requirements	122.7	94.5	217.2	

Please note that the above Table reflects the updated accelerated depreciation amounts. The initial amounts submitted in response to IR 2-CCC-12 only included accelerated depreciation up to the end of each deployment period. To provide a complete comparison of each deployment scenario, the full financial impact for the period from 2027 to 2033 has been presented, since the 7-year deployment ends in 2033. Please refer to JT-3.57_Attach 1_AMI 2.0 Deployment Alternatives.xlsx for the details on the revenue requirement calculations.

JT-3.57

Attachment 1
AMI 2.0 Deployment Alternatives

Please see live Excel