Executive Summary

In January 2025, the Ontario Energy Board (OEB) launched a consultation to develop a policy framework to set expectations for electricity distributors regarding the development of Distribution System Operator (DSO) capabilities. In Alectra's view, this consultation and the outcomes that will follow are essential for the Province to advance its interests towards electrification and the energy transition currently underway. As the economic regulator, the OEB has a critical role to play in helping to design and develop the framework and governance that will move the sector forward in reaching the province's objectives. Alectra is a strong proponent for developing and instituting capabilities that will transform Ontario's electricity system into one that maximizes and optimizes the use of Distributed Energy Resources (DERs) to provide critical supply, flexibility, customer choice, and affordability for all of Ontario's ratepayers.

In Alectra's view, the importance for facilitating DSO capabilities is primarily concerned with maximizing the use of Distributed Energy Resources (DERs) to enable improved flexibility, choice, and affordability for customers. Thoughtful integration and coordination of DERs can significantly enhance system reliability and efficiency, while providing customers with access to additional value streams. Critical to this mission is a clear articulation of roles and responsibilities for various sector players, a robust governance framework, and investment in the tools, processes, and systems that will enable more advanced distribution operations to harvest the full stream of benefits that DERs can offer.

The benefits that DERs (such as distributed generation, storage, and demand response) can bring have the potential to enhance grid reliability, optimize costs, and support sustainability goals. For example, further integration of DERs can enhance sustainability and reduce system costs by helping to defer or mitigate capital costs for grid planning. Active local management can improve grid reliability and performance. Alectra believes that Local Distribution Companies (LDCs) should play a central role in managing, coordinating, and orchestrating DER activity through active grid management.

The OEB's consultation proposes three options to guide the evolution towards DSO capabilities for the sector. In order to address which proposal(s) different stakeholders prefer, the staff paper considers three design features for consideration, including the DER/A participation model, the degree of separation, and the distribution activation mechanism. Alectra's view on which options the OEB should pursue are grounded around its perspectives on each of the specific design features.

In short, Alectra submits the following preferences and positions:

- DER/A participation model: Market Facilitator (MF-DSO)
- Degree of Separation: No separation or Functional separation
- Distribution Activation Mechanism: Market-Based.

Accordingly, Alectra agrees with OEB staff's Proposal 1, which it sees as necessary for organizing and moving the sector forward in any event, and with Proposal 3 as this is the ultimate destination that Ontario should strive for. Alternatively, Alectra believes that adoption of Proposal 2 would create lost opportunities, result in sunk and irretrievable costs, and set Ontario on a path toward inefficient outcomes.

Alectra sees that the Market Facilitator Model (MF-DSO) is the optimal approach for integrating DERs. The MF-DSO model positions the DSO as a central facilitator that optimizes DER benefits at both the distribution level and also across the transmission and bulk systems as well. Under this structure, the DSO would maintain neutrality, provide transparency, and DER owners would be able to retain commercial independence. Key responsibilities of the DSO would include managing distribution networks, coordinating DER services, and ensuring efficient access to evolving market mechanisms, while simultaneously enhancing grid reliability and efficiency. For these reasons, in Alectra's view, the MF-DSO model facilitates optimal DER participation, ensuring fair access and transparency for all participants. The MF-DSO model encourages a transparent, integrated approach, fostering innovation and competition.

The one common element that all types of DERs have in producing these benefits is that with few exceptions, they are expected to be connected to the distribution grid. This has clear implications for the management of all aspects of distribution management. As a result, Alectra believes that no separation, or functional separation, of DSO and LDC activities would allow for cost savings and better resource planning. Alternatively, shifting planning away from LDCs or increasing structural barriers, risks introducing system fragmentation, operational inefficiencies, and delays. LDCs possess the detailed system knowledge, operational insights, and local context necessary for effective and reliable distribution system planning.

A local market for energy services will be essential for integrating DERs at the distribution level. This will require amending current laws and regulations to support the roles and obligations of distributors, as well as the creation, governance, and oversight of local markets. The establishment of clear market rules and processes is crucial for encouraging participation and ensuring fair competition within these emerging markets. Legislative reforms are likely to be required to enable market-based approaches for DER integration and to develop a robust governance structure. Appropriate oversight will be needed to monitor market operations and to amend market rules as necessary or required over time.

Moving forward, Alectra proposes the development of a clear roadmap to guide the evolution of DSO capabilities. A roadmap will allow sector players to understand the vision, direction, and key milestones along the journey to developing DSO capabilities and will assist in identifying the issues pertaining to establishing a robust regulatory framework.

Contextual Background & Introduction

In January 2025, the Ontario Energy Board (OEB) launched a consultation to develop a policy framework to set expectations for electricity distributors regarding the development of Distribution System Operator (DSO) capabilities. In Alectra's view, this consultation and the outcomes that will follow are essential for the Province to advance its interests towards electrification and the energy transition that is underway. As the economic regulator, the OEB has a critical role to play in helping to design and develop the framework and governance that will move the sector forward in reaching the province's objectives. Alectra is a strong proponent for developing and instituting capabilities that will transform Ontario's electricity system into one that maximizes and optimizes the use of Distributed Energy Resources (DERs) to provide critical supply, flexibility, customer choice, and affordability for all of Ontario's ratepayers.

Alectra wishes to emphasize several key principles regarding the integration and management of DERs across Ontario's electricity system to ensure system reliability, efficiency, and customer value. The desired end state is a fully coordinated framework for DER operations and investment across all system levels—not only addressing Local Distribution Company (LDC) needs, but encompassing the full range of DER and flexibility activities, including enhanced Demand Side Management (eDSM), local generation, local flexibility, Non-Wires Solutions (NWS), and related services.

At the core, the key principle is that all visibility, communication, and dispatch must be managed through the LDCs. This "path of least regret" is essential to preserving system integrity, as well as enhancing efficiency and cost effectiveness for ratepayers. DERs create value not just at the local distribution level but across the entire electricity value chain—supporting generation, transmission, distribution, and customer systems. The value to LDCs and customers spans several critical areas:

- Grid Planning: Enabling capital deferral or avoidance and managing capacity more efficiently.
- Grid Operations: Providing voltage support, reliability services, and outage mitigation.
- Asset Management: Improving utilization and extending the lifecycle of grid assets.
- Customer Engagement**:** Offering revenue opportunities, enabling customer investment participation, and reducing emissions.

LDCs are uniquely positioned to act as DSOs, orchestrating local megawatts (MWs) and optimizing flexibility across the grid. This orchestration must be LDC-led, ensuring that LDCs retain control over asset dispatch, including the ability to:

- Review dispatch signals before release,
- Assess system impacts,
- Apply overrides where necessary, and
- Relay approved commands to assets.

Alectra recommends that the OEB formally recognize LDC's central coordination role to ensure DER operations are safely, efficiently, and fairly integrated, maximizing benefits not just for local systems but across Ontario's entire electricity sector.

To achieve this vision, each of the Technical (Operations and Planning), Regulatory, and Market realms will need to be developed or evolved. How these evolutions move forward will depend critically on the direction arising from this consultative process. While further detail and context is provided below for the context of this consultation, Alectra sees that three enabling items will also have to coexist simultaneously while this consultation unfolds:

- Advancement and completion of technical coordination protocols to ensure that each of the Technical, Regulatory, and Market realms can exist; and
- The evaluation and deployment of enabling grid modernization tools, investments and infrastructure that will be necessary to evolve distributor capabilities;
- Establishment of a regulatory framework that defines roles and responsibilities along with the necessary oversight and governance protocols to ensure that consumers are protected and accountabilities are well understood.

On the topic of technical coordination protocols, the OEB and stakeholders will be aware that the Transmission-Distribution Working Group (TDWG) has been working to develop these. The TDWG's objective is to support the development of operational T-D coordination protocols for DER/As participating in the wholesale market as well as in distribution networks (in coordination with IESO wholesale markets). LDCs, DER Aggregators (DER/A), and the IESO will need to share information in a timely manner to ensure there is sufficient awareness concerning operational coordination. The TDWGs' work includes four deliverable streams, as follows:

- A: Coordination protocols: Develop implementation-ready protocols for three DSO coordination models (Total, Dual Participation, and Market Facilitator DSO)
- B1: Functional assessment: Analyze distributors' operational functions, capabilities, and costs across multiple dimensions
- B2: Communication Assessment: Map coordination interfaces and data exchanges
- for each coordination model
- B3: Shared Platform Concept: Conceptualize a shared platform that enables T-D coordination; document the requirements and functionalities.

The principles and T-D coordination protocols established by the TDWG will lay the foundation for the sector's DER enablement initiatives also. They should help inform the OEB's DSO Capabilities Consultation and the evolution of local flexibility markets in Ontario.

Regarding the grid modernization tools, investments, and infrastructure, and the establishment of a regulatory framework and all that entails, OEB staff have articulated many of the issues in their report. The discussion brought forward by OEB staff culminates in three potential proposals and a variety of specific questions that will help inform OEB staff's perspectives for the further development and direction of this essential consultation. The proposals themselves are action plans that will define the requirements regarding introduction, pacing, and scope of new functions for the distribution sector, including the role of distributors. The three proposals are summarized as follows:

- Proposal 1: require distributors to conduct two mandatory assessments to inform preparations to integrate DER/As into meeting system needs, including:
    - An assessment of current and future needs to identify applications for a DSO in their service area;
    - An assessment of current capabilities to identify what the distributor needs to develop, by when, and including such requisite grid modernization investments needed to support the use cases identified.

- Proposal 2: Develop a step forward that would allow time for consideration of a more sophisticated DSO model over time as DER penetration grows. Under the "Regulated DSO Model", DER/As would continue to directly participate in the wholesale market with DSO operational control. This proposal would see staff working with stakeholders to develop the Simplified DSO concept, as well as to define roles, rules, and responsibilities for a regulated- and program-based model. Once sufficiently advanced, this stream of work would turn to development of guidance for cost-recovery, conduct, consumer protection, and assessment of implications for existing processes and requirements.

- Proposal 3: Define an advanced model that best suits Ontario's conditions for the roles of distributors, other incumbents, and the design of current markets. This proposal would entail working with stakeholders to determine:
    - What capabilities and tools are required for distributors to develop and implement markets and procurement techniques;
    - What role should distributors play with respect to resources looking to provide service to the wholesale market;
    - What measures should be expected of distributors to ensure fairness and confidence in established markets;
    - What requirements should apply to the segregation of business functions and activities to support competition, minimize conflicts, and protect consumer interests; and
    - What arrangements are likely to provide optimal flexibility to adapt approaches and roles as conditions change.

In order to address which proposal(s) different stakeholders prefer, the staff paper further considers three design features, including the DER/A participation model, the degree of separation, and the distribution activation mechanism.

The DER/A participation model refers to the role of the DSO in facilitating DER/A participation in the wholesale market. The degree of separation refers to the degree to which DSO functions are separated from conventional distribution functions. Finally, the distribution activation mechanism refers to the way in which DER/As are curtailed or activated to meet distribution system needs. Together, perspectives on these will be the bedrock underpinning the foundational policy direction Ontario will need to make with respect to the evolution of the electricity distribution system.

As described by OEB staff, what is not covered in the scope of this consultation, at least for the time being, will be the following issues:

- Whether a DSO should be able to provide "DSO-as-a-service" to multiple distributors;
- Whether a DSO should be able to own DERs directly;
- Whether a shared platform should be used to facilitate DER/A service to the distribution system and participation in the wholesale market; and,
- Other matters that arise as DSO models are developed with greater levels of detail.
- Key planning enhancements and data requirements

These are expected to be addressed in later phases of this consultation.

For this phase of the consultation, addressing the critical task of assessing the definition of distribution service will inform the need and rationale for any legislative changes, if required, to enable implementation of DSO activities.

Below, Alectra addresses these topic areas and advances its own perspectives for how the OEB should move forward with this consultation. In short, Alectra submits the following preferences and positions:

- DER/A participation model: Market Facilitator (MF-DSO)
- Degree of Separation: No separation or Functional separation
- Distribution Activation Mechanism: Market-Based.

Accordingly, Alectra agrees with OEB staff's Proposal 1, which it sees as necessary for organizing and moving the sector forward in any event (many of these assessments have been undertaken by B1 deliverable in TDWG and we expect it will form the foundation for addressing this proposal), and with Proposal 3 as this is the ultimate destination that Ontario should strive for. Alternatively, Alectra believes that adoption of Proposal 2 would create lost opportunities, result in sunk and irretrievable costs, and set Ontario on a path toward inefficient outcomes.

<u>Organization of Submission</u>
Alectra's comments below are organized into the following topic areas and sections below:

A. The case for DER Integration and a DSO Model
B. Innovation and the York Region Non-Wires Alternative Project Experience
C. Degree of Separation Between DNO and DSO
D. Market Facilitation Model
E. DSO Activation Model & Governance Framework

F. OEB Proposals & Development of a Roadmap
G. Alectra Responses to OEB staff Questions

A. **The Case for DER Integration and the DSO Model**

Alectra believes it is critically important to reiterate the importance of this consultation, due to its potential impact on the electricity sector for generations to come. In Alectra's view, this consultation and its outcomes need to stay grounded in the perspective of what it is we are trying to achieve as this should foundationally impact the direction taken.

DERs – including distributed generation, storage, flexible loads, managed loads, and demand response—provide significant value across the electricity value chain, from generation and transmission to distribution and end-use customer systems. These resources enable more dynamic, localized solutions that can improve grid reliability, reduce system costs, and support decarbonization goals.

The key benefits of DER Integration can be summarized as follows:

Grid Planning

- Enable capital deferral or avoidance by using DERs (Distributed Energy Resources) as non-wires alternatives (NWAs) to address system needs without costly infrastructure upgrades.
- Improve capacity management by relieving local or regional constraints, optimizing grid design, and reducing peak demand pressures.
- Provide greater flexibility in planning by incorporating DER forecasts into load growth models, supporting more adaptive and dynamic system development.

Grid Operations

- Deliver voltage regulation and support at the local level, helping maintain power quality and reduce the need for central interventions.
- Enhance system reliability and resiliency by offering local balancing, and various backup services (e.g., load displacement, black start, or redundancy), particularly valuable during extreme weather or emergencies.
- Provide outage mitigation to keep critical loads energized during upstream outages.

Asset Management

- Improve utilization of existing grid assets by flattening load profiles, increasing load factors, and reducing asset stress during peak periods.
- Extend the lifecycle of infrastructure (e.g., transformers, feeders, substations) by reducing thermal loading and deferring replacements or reinforcements.
- Support targeted asset investment strategies through enhanced data on DER behaviors and their locational impacts, improving risk-based asset management decisions.

Customer Engagement

- Unlock new revenue streams for customers, to either curtail costs and/or assist with affordability, through participation in flexibility services, demand response programs, or local energy markets.
- Enable customer investment participation, allowing households and businesses to deploy DERs like solar, storage, EVs, or smart appliances to actively engage with the grid.
- Support emissions reduction and sustainability goals by facilitating local clean energy generation and community-level decarbonization efforts.

With more households and businesses generating their own energy through DERs (and able to provide load flexibility), LDCs need to take on a more active role in managing this two-way energy flow. The ability to use DER assets to drive system benefits requires effective integration for these local energy sources in order to maintain grid stability and to coordinate their participation in both local and bulk energy markets so as to maximize benefits and avoid unintended consequences. Sectoral change is required in order address the following drivers:

- Prepare for the future energy market: The Independent Electricity System Operator (IESO) is implementing new market rules that will allow small DERs to participate in wholesale energy markets by 2027/2028. LDCs need to be ready to facilitate this participation efficiently.

- Accommodate a growing number of DERs: As more DERs are deployed, LDCs need to ensure that these new resources can be connected to the grid in a way that doesn't disrupt the electricity system.

- Optimize grid operations: Effective use of DERs has the potential to reduce congestion, enhance grid resilience, lower operational costs, and improve reliability and system hardening as Ontario experiences more extreme weather conditions.

LDCs are uniquely positioned to coordinate DERs at the local level while aligning with system-wide needs due to several core competencies already in place . With deep knowledge of their distribution networks and a direct relationship with customers, LDCs are natural candidates to evolve into Distribution System Operators that can operate local electricity markets, manage DER dispatch, and support broader transmission-distribution coordination. LDCs have the deep technical knowledge and existing infrastructure needed to manage DERs. Their longstanding relationships with local customers and experience in handling dynamic grid operations give them a unique perspective in becoming DSOs. By acting as neutral market facilitators, LDCs can ensure smooth integration of DERs while optimizing grid operations to minimize costs. In other words, LDCs are natural candidates to lead the evolution towards effective use of distributed assets as it would be difficult or impossible for any other entity, which is otherwise removed from these particular core competencies, to bring to bear the same level of expertise, and focus on efficiency and cost effectiveness to grid operations.

Alectra has had direct experience operating as a DSO through its York Region Non-Wires Alternatives (NWA) Demonstration Project, which highlighted the success of this model. Acting as DSO, Alectra administered a local market to procure capacity from DER and enabled third-party participation, achieved strong local engagement, and proved that the benefits have significant potential to assist in deferring otherwise traditional infrastructure.

The goal of the Distribution System Operator (DSO) is to transform the distribution network from a passive delivery channel into an actively managed, orchestrated grid platform that enables the efficient, reliable, and optimized the grid operations and planning to enable participation of Distributed Energy Resources (DERs).

The DSO provides active grid management and system orchestration to deliver value across transmission, distribution, and generation — while supporting customer participation, decarbonization, and market evolution.

1. **Optimize System Efficiency and Capacity Utilization**
    - Maximize the use of existing grid infrastructure by integrating DERs as non-wires solutions (NWS), reducing the need for capital-intensive reinforcements.
    - Improve load management and local flexibility through the orchestration of DER services, optimizing short- and long-term system performance
2. **Enable a Transparent and Accessible Local Flexibility Market**
    - Provide fair, non-discriminatory access for DERs to offer services that support both local (distribution) and system-wide (transmission or wholesale) needs.
    - Establish clear market signals and processes that allow DER owners and aggregators to participate efficiently and competitively.
3. **Enhance System Reliability, Resilience, and Power Quality**
    - Actively manage local voltage, frequency, and congestion using DER flexibility to maintain system stability.
    - Improve resilience to disturbances and outages by enabling local self-healing
4. **Support Decarbonization and Customer Empowerment**
    - Facilitate the integration of clean energy resources, such as solar PV, storage, electric vehicles, and demand response, to reduce emissions and align with climate targets.
    - Empower customers to become active participants in the energy system, not only as consumers but also as producers and flexibility providers.
5. **Coordinate Seamlessly with the Transmission System Operator (TSO/IESO)**
    - Provide visibility and coordination mechanisms between the distribution and transmission levels to ensure efficient use of resources and prevent operational conflicts.
    - Align local dispatch decisions with broader system needs to enhance overall system performance.
6. **Develop Future-Ready Digital and Operational Capabilities**

- Invest in data platforms, advanced grid analytics, control systems, and workforce capabilities required to operate a highly distributed, dynamic grid.
- Build scalable governance and regulatory frameworks that enable innovation while protecting system integrity and customer interest.

Alternatively, a failure to implement a distribution-led approach to DER integration could result in a variety of negative and costly outcomes. In particular, this would lead to missed opportunities for cost savings and avoided infrastructure investments, and would increase uncertainty among sector players, deterring innovation and investment in DERs. It would also produce a lack of visibility and control over the distribution system, which would put at risk reliability and redundancy, requiring further traditional type investments to be made to support these outcomes and targets. Finally, without direct distribution oversight, there could be several distribution level outcomes that would negatively (if not catastrophically) impact customer service and cost through additional system-specific outcomes, such as:

- Voltage Excursions: Uncoordinated load control increases voltage variability and risks over/under-voltage violations.

- Feeder Overloading and Peak Rebound: Uncoordinated demand response (DR) could potentially overload equipment, particularly during load restoration.

- Stress on Voltage Regulation Devices: Rapid demand swings could cause frequent operations of on-load tap changers and capacitor banks, leading to accelerated wear.

- Protection Miscoordination: Sudden load drops or reversals could trigger incorrect relay or fuse responses.

- Power Quality: Rapid device switching causing flicker and other power quality problems, could contribute to asset degradation.

- Thermal Stress: Repeated thermal cycling from DR events would shorten asset lifespan.

With this backdrop, an important body of work that should not be forgotten was the work of Energy Transition Network of Ontario ("ETNO"), which was a mission oriented task force made up of a group of senior leaders from across the energy sector, including utilities, DER providers, business and non-profit organizations, government agencies and universities, whose aim was to drive a more efficient, affordable energy system for Ontario. It's helpful to review the work by the ETNO, as it represents a group of sector experts from many key organizations with diverse perspectives, who were able to coalesce and make recommendations to inform policy development.

Three important elements can be derived from a review of the ETNO work. First, grounding perspectives through the filter of key principles is important so as to ensure direction remains sound. Second, developing an LDC led roadmap to guide a consistent and collaborative vision that addresses a complex and integrated set of outcomes will be of benefit to all stakeholders. Finally, through their work, analyses and principled approach, ETNO ultimately recommended that LDCs expand their role to take on the additional mandate of DSOs, while leaving room for DSO as a service available, which are recommendations that Alectra agrees with.

The ETNO's mandate was stated as follows:

> *ETNO's work is driven by a recognition that Distributed Energy Resources (DERs) and new structural models for organizing the sector are all challenging foundational notions of market boundaries, industry roles and responsibilities. Enhanced data and analytical capabilities, advanced transportation technology, environmental policy and other technological changes outside of the energy sector are also having an increasing impact on the energy system. To ensure that these innovations are integrated into existing energy systems in a way that enhances consumer choice, reliability and cost-effectiveness, new approaches to policy-making, regulation and energy markets will be needed.*[1]

The ETNO group looked at the evolving nature of the sector with a mind to how best to serve customers. They examined this perspective with ten critical principles in mind:

- Affordable – the best overall value of the price that is paid, while maintaining appropriate standards for system security and reliability, ensuring cost-effective integration of DERs;

- Customer Focused – decision making that is oriented towards evolving customer experience, communication and customer control;

- Accessible and Transparent – encouraging fair and equitable access to markets for all customers and resource types, including access to data and supporting infrastructure;

- Optimized and Efficient – ensuring the most cost-effective use of energy resources on a life-cycle basis and the seamless integration and operation of grid assets, regardless of ownership;

- Reliable and Resilient – ensuring that resources are available and deployable to provide continuous supply of energy;

- Competitive – the provision of an open, transparent, fair, and predictable market, essential for attracting capital and offering a level playing field for all participants;

[1] Energy Transformation Network of Ontario (ETNO), Principles Guiding the Transformation of the Energy System in Ontario, July 2021, p. 3.

- Collaborative and Innovative – encourages an integrated approach to planning and developing the end-to-end energy system;

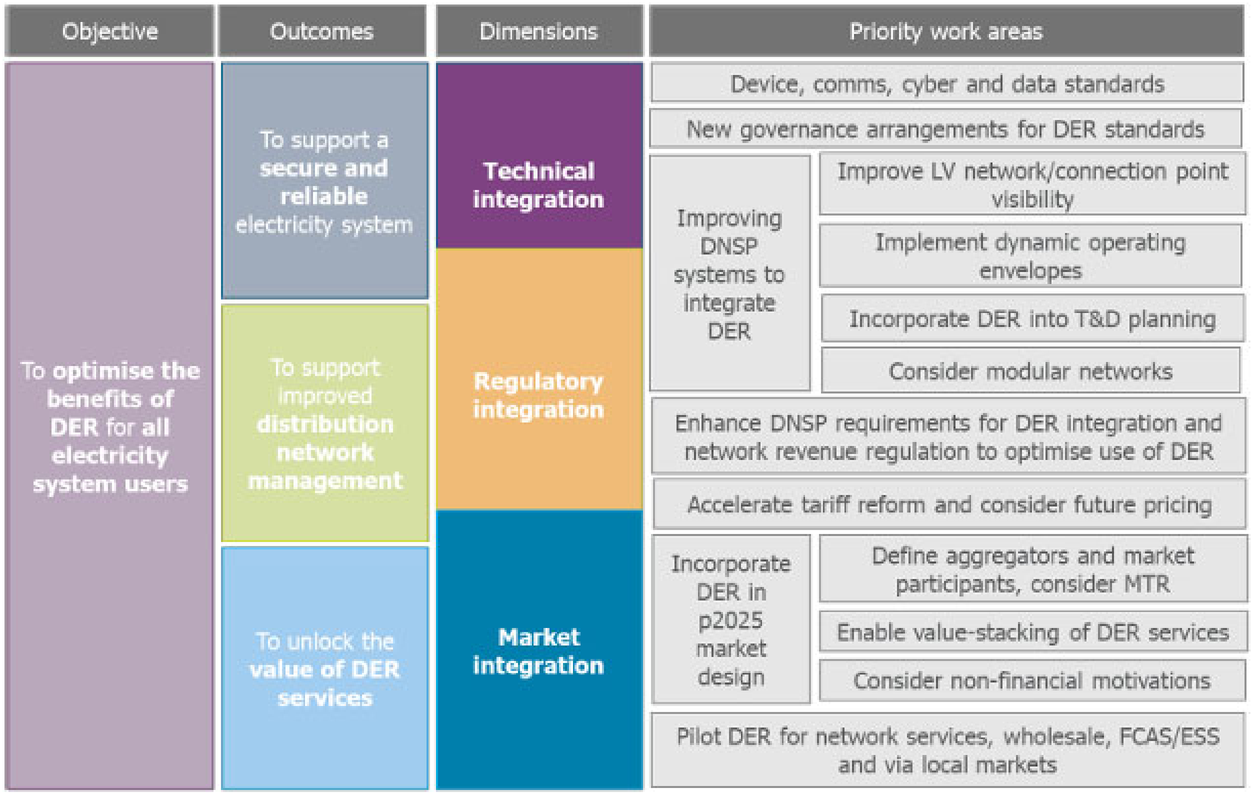
- Regulatory Evolution – aims to uphold the public interest, while meeting energy system needs and the attraction of investment in the face of transformative change;

- Just, Equitable, Diverse, and Inclusive - Improved outcomes derive from equitable access to energy and the associated societal benefits that come with it;

- Decarbonization – achieving Canada's commitment to achieve net-zero emissions by 2050 and reducing emissions by 40-45% compared to 2005 by 2030.

Through the lens of these perspectives, the ETNO group endorsed and recommended the development of DSO capabilities within Ontario to manage this evolution.

Their "Sprint 1" report included an examination of DER deployment in other jurisdictions, including certain key features and guiding principles. In particular, in Australia, a "DER Integration Roadmap" was developed, which importantly included a plan to develop the three critical and enabling dimensions of the technical integration, regulatory evolution, and market integration and the associated critical path activities necessary to achieve the objective. Alectra believes that given the OEB has a similar objective and has already done much work in each of these dimensions, it would be advisable for the OEB to adopt a similar roadmap to help guide the sector toward achieving its objectives. Australia's DER Integration Roadmap was presented in the ETNO report as shown in the graphic below.



The ETNO recommendations made clear that success depends not just on expanding DER connections, but on embedding them within an integrated market design, technical framework, and regulatory environment that together form a clear roadmap to the sector's desired end state. Internationally, Australia's DER Integration Roadmap and the UK's ENA Open Networks program offer examples of how sector-led, principles-based roadmaps can guide the complex technical, market, and regulatory changes needed to unlock DER value at scale. These roadmaps have emphasized the importance of defining the advanced model first, rather than adopting "simplified" approaches that understate the operational and market complexities involved. Simplified models often fragment responsibilities, slow innovation, create stranded investments, and limit customer benefits by failing to coordinate across planning, operations, and markets.

Adopting an MF-DSO model addresses the critical cost dimension raised by ETNO and echoed in the OEB's consultation. Analysis by DNV and others show that a narrower separation between DNO and DSO functions enables better leveraging of staff expertise, grid knowledge, and operational insights, which in turn supports system reliability, resilience, and efficient planning. Moreover, DNV's findings confirm that greater separation between DNO and DSO roles tends to increase system costs. This evidence supports Alectra's view that DSOs should operate within LDCs, with clear functional separation but under a unified organizational framework, to preserve affordability while advancing innovation.

Finally, ETNO, like Alectra, emphasizes that no DSO transition can succeed without concurrent progress on market design, regulatory enablement, and technical standardization. Developing these elements together ensures that DER integration is not just technically feasible, but economically rational and customer centric. The MF-DSO model offers Ontario a path to achieve this: enabling DERs to deliver local and system-wide benefits, creating open and competitive market access, and equipping LDCs to manage the evolving demands of a decentralized, decarbonizing grid.

Building DSO capabilities will require LDCs to invest an estimated $65 to $90 million over 5 to 7 years[2]. These investments will be needed to upgrade grid management systems, improve real-time analytics, and support forecasting tools to integrate DERs better. While these costs are significant, they provide long-term benefits to consumers by enhancing grid reliability, reducing overall system costs, and preparing for future energy demands. Alectra does not focus more on this topic in this submission; however, it fully endorses and supports the perspectives offered by the EDA and consultant Power Advisory on this topic.

Alectra further elaborates on the importance of developing a coherent roadmap below. First, however, Alectra provides some commentary on its own experience with its DSO demonstration project (York Region Non-Wires Alternative) and then considers each of the three components raised by OEB staff in the context of this consultation: the DER/A participation model, the degree of separation, and the distribution activity mechanism.

[2] Assuming an optimal deployment of these capabilities across the province.

B. **Innovation and the York Region Non-Wires Alternative Project Experience**

Alectra Utilities, in partnership with the IESO and NRCan, established North America's first local electricity market and achieved groundbreaking results through the York Region NWA Demonstration Project. This initiative explored competitive market-based approaches to secure services from DERs to meet local energy and needs while maintaining coordination across the entire electricity system.

Acting as a DSO, Alectra administered and operated the local electricity market during a two-year market operation in the York Region from 2020 through 2022. In the fall of 2020, Alectra managed a local electricity capacity market auction, with 3 times the capacity target ultimately registering to participate. The local capacity auction successfully procured 10 MW of capacity from a diverse range of DERs participants, including manufacturers, supermarket operators, and residential participants through aggregators. DERs procured through the 2 capacity auctions committed to being available for a six-month period (May 2021 – October 2021 & May 2022 – October 2022) to help meet electricity system needs.

The Pilot had strong results, with participating DERs successfully reducing local peak demand by approximately 8MW while contributing 366 MWh of energy back to the grid during the commitment periods. Another critical achievement of the NWA Pilot was the procurement of 50% more capacity in the second year of the Pilot, including securing 6.8 MW of reserve-capable capacity at a price 38% lower than the previous year. This cost reduction demonstrates the potential for locally procured resources to be more cost effective than grid-scale resources over time. With effective regulation and incentives, DERs have the potential to defer, reduce, or avoid capital and operating costs associated with distribution, transmission, and/or generation infrastructure. DERs are clean and flexible; they do not require decades-long lead times to deploy, and they avoid the delays and cost overruns common with large energy infrastructure projects.

An additional achievement of the NWA Project was the customer journey, with positive feedback received through various focus group discussions. Participants consistently praised the NWA Pilot for its simplified, transparent, and streamlined process, resulting in an outstanding customer experience. Positive testimonials underscore the important role that Alectra played as an enabler of the local electricity market, and as a model for how competitive procurement and dispatching DERs should work as the province moves beyond pilot projects and seeks to harness the potential of these flexible resources at a larger scale.

C. Degree of Separation Between DNO and DSO

The ETNO group examined different options for evolving the distribution system structure and ultimately recommends moving forward with a DSO structure. To this end, they describe the key features of a DSO structure as follows:

- *Creation of a local market - energy, capacity, and ancillary services - for DERs connected at the distribution level or behind-the-meter (of a customer that is connected at the distribution level).*
- *DSOs facilitate the transaction of energy services across their networks (including between customers) and enable local DERs to provide grid services.*
- *DSOs can use the local markets to address network constraints, deferring grid investment. A DO [Distribution Operator] may take on the role of a DSO, however, it may also exist as a separate entity.*
- *Compared to the role of a DO, the DSO is an active manager of the distribution network that is able to harness the full potential of local DERs*[3]

ETNO recommended that LDCs take on the role of DSOs, as they are well positioned to manage DERs connected to the distribution sector. ETNO's examination revealed that DSO would be best able to leverage DERs and facilitate their usage for both distribution system management as well as bulk power market participation. This would be especially effective in a high-DER, capital constrained future because a DSO would be able to incent the efficient deployment of DERs to optimize multiple value streams and allow for the optimization of capital deployment by leveraging DER usage.

The fact that LDCs could have visibility into the operation of local DERs and that LDCs are responsible for conducting assessments to determine the feasibility of connecting at specific locations and to implement safety standards means that LDCs are well suited to the mandate of a DSO.

Alectra agrees with ETNO's recommendation. With its knowledge of the grid system characteristics, core competencies in customer service and engagement, and a mandate to optimize the efficiency of grid operations, customers can be best served by integrating DSO accountabilities into the traditional DNO functions that LDCs currently deploy. This will allow the full value staking of benefits available to customers through greater proliferation of DERs across the province.

As discussed below, the MF-DSO is the best suited to unlock the value creation brought about by the further integration of DERs into the electricity system. A DSO market structure would enable the sector to operate with consumer value in mind, rather than through an arbitrary and

[3] Energy Transformation Network of Ontario (ETNO), Distribution System Structures For A High Distributed Energy Resource (DER) Future - A Blueprint to Guide the Local Energy Transition in Ontario, December 2021, p. 15.

fragmented supply chain that intentionally separates the generation, transmission, and distribution aspects of a customer's supply of service from the grid. A DSO market model brings together supply side DER technologies to generate supply for load displacement at a customer's property or for export to the grid for distribution or bulk system supply, with the ability to address distribution issues. It allows for multi-faceted benefits using the same assets, producing potential benefits both up and down the supply chain. That is, they can be used to more effectively operate the grid, allowing for multiple other benefit streams to be realized, such as enhanced reliability, redundancy, peak management, asset replacement deferment, or in a variety of other ways.

The one common element that all types of DERs have in producing these benefits is that with few exceptions, they are expected to be connected to the distribution grid. This has clear implications for the management of all aspects of distribution management. Without the ability to manage both the intended and unintended consequences of these connections would otherwise put at risk system efficiency, at best, or at worst, result in large amounts of wasteful and avoidable spending by Ontario's consumers.

In their paper entitled, the Power to Connect, the EDA expresses the following:

> *LDCs are the incumbent owners and operators of Ontario's electricity distribution grid that interfaces with and integrates the transmission system and customers. By leveraging their existing customer relationships, expertise, brand recognition, and knowledge of their local distribution networks, LDCs are uniquely positioned as the most efficient and cost-effective- service provider to lead the transition to a cleaner, more distributed and more intelligent grid. […]*
>
> *LDCs are critical to enabling DER in Ontario's energy system and to cost effectively satisfy increased demand for electricity through electrification of transportation and fuel switching."*[4]

Finally, and critically, Alectra believes that a key and central conclusion noted by DNV, and reiterated by OEB staff speaks directly and centrally to the principle of keeping costs affordable:

> *At the same time, DNV's analysis also holds that a narrower separation between DNO and DSO activities may have offsetting benefits as a result of better access to DNO staff's knowledge and insights that may more effectively support reliability, resilience and planning services.*[5]; and

[4] Electricity Distributors Association, The Power to Connect: Advancing Customer-Driven Electricity Solutions for Ontario (Executive Summary), February 2017.
[5] Ontario Energy Board, Discussion Paper: Distribution System Operator Capabilities (EB-2025-0060), May 2025, p.42.

DNV's analysis concluded that costs increase with greater business separation between the DNO and DSO.[6]

Separation of Planning from LDCs

The Ontario Energy Board (OEB) has proposed transferring certain planning responsibilities from Local Distribution Companies (LDCs) to a Distribution System Operator (DSO), citing concerns that existing LDC incentives may inherently favour traditional capital-intensive "wires-and-poles" solutions over non-wires alternatives (NWAs).

However, shifting planning authority away from LDCs risks introducing system fragmentation, operational inefficiencies, and delays. LDCs possess the detailed system knowledge, operational insights, and local context necessary for effective and reliable distribution system planning.

Historically a core challenge hindering greater deployment of DER technologies has been uncertainty around how to properly evaluate DER value streams across a fragmented supply chain (i.e., generation, transmission, and distribution), and the ensuing regulatory treatment of such investments for both utilities and sector players alike. The development of tools such the Benefit-Cost Analysis (BCA) Framework and the NWS Guidelines will assist tremendously in helping to overcome these obstacles. As the sector gains experience with these methods, processes and tools, further deployment of DER technologies by utilities, aggregators, and other sector players will continue to advance. The accessibility and development of operational tools that assist with NWA modeling outcomes and the deployment of grid modernization technologies will further assist to reduce barriers. These structures, tools, and processes help bring clarity and reduce uncertainty for the business conditions surrounding such investments and, importantly, enhance the precision with which value streams can be estimated for investment decision making. To make further strides in addressing these barriers, the OEB should focus on enabling LDC investment in modern planning tools and recalibrating the regulatory framework to provide equitable returns for NWAs and capital solutions alike, ensuring objective, least-cost planning outcomes.

Alectra believes it is appropriate that there be no separation, or functional separation only, between the DSO and the Distributor. Alectra recognizes that a functional separation could work to assuage concerns with self-dealing or the operation of fair and responsible oversight. As a result, Alectra would expect that a functional separation would entail a set of compliance or Code rules outlining the appropriate and necessary touchpoints with DNO activity, and that such rules can be created and overseen through OEB compliance related oversight, similar to processes that already exist today.

[6] Ibid, p.41.

D. Market Facilitation Model

Alectra believes the optimal DER/A participation model is the Market Facilitator Model (MF-DSO Model). In the MF-DSO model, the Distribution System Operator takes on the responsibility of facilitating and optimizing the full range of benefits that DERs can provide—not only at the distribution level, but also across transmission and bulk system layers. The MF-DSO would serve as a single point of coordination for customer dispatch of DERs into both local and wholesale markets, while also providing greater operational visibility for DER owners and aggregators (DER/As).

LDCs operating as MF-DSOs would manage the distribution network, coordinate DER services, optimize system performance, and facilitate access to evolving market mechanisms. As the market matures, the MF-DSO would play a critical role in ensuring DERs deliver value to both the local grid and the broader provincial system. Importantly, DERs and DER/As would retain their commercial independence, maintaining full rights to contract directly with the IESO or other market participants.

Under the MF-DSO, two central functions define the DSO's role. First, the DSO acts as an intermediary between DERs, DER/As, and the IESO—gathering bids and offers, relaying schedules and dispatch instructions, and applying any necessary local operational constraints to protect grid stability. Second, the DSO optimizes the local distribution system to minimize DER curtailment, thereby improving the ability of DERs to actively and reliably participate in wholesale markets. At the same time, DERs would provide local services to the DSO, which would schedule and activate them to meet distribution system needs.

Crucially, the MF-DSO model is built on the principle of the DSO as a neutral market facilitator. This neutrality means the DSO must provide efficient, transparent, and non-discriminatory access to the network and balancing services for all market participants, regardless of their size, technology, ownership, or geographic location. The DSO must not favor any participant or block access based on competitive positioning. Transparency is equally critical: network conditions, service availability, prices, and technical parameters must be clearly communicated and publicly available to ensure fair and open participation.

Within this framework, the DSO's responsibilities would include animating both IESO-level and local grid services concurrently, or in a co-optimized manner, and articulating any technical or operational limits to market participants before bidding. Importantly, the DSO would not act as an aggregator or market participant itself, but strictly as an enabler and facilitator of DER participation within its service area. Core responsibilities would cover dispatching all assets, conducting measurement and verification, and managing settlement processes, thereby ensuring reliable, efficient, and fair participation in Ontario's evolving electricity markets.

Alectra views the integration of the Market Facilitator DSO (MF-DSO) model as the most practical and future-ready approach for Ontario. It is also aligned with the recommendations and principles developed by the ETNO. At its core, the MF-DSO model aligns with ETNO's recognition that the rapid rise of DERs challenges foundational assumptions about system boundaries, market roles, and operational responsibilities. LDCs would not act as aggregators or market participants themselves, and would instead focus on optimizing the grid to enable maximum DER participation while safeguarding system reliability and efficiency. This allows DERs and DER/As to retain full independence in their commercial decisions, while ensuring that the physical system is managed in a coordinated, secure, and transparent manner.

ETNO explicitly recognized that LDCs are best positioned to integrate DERs because they have unparalleled visibility into local grid conditions, direct operational control, and the expertise to manage technical constraints, safety standards, and customer relationships. By grounding the DSO mandate within the LDCs, the system can harness multiple value streams from DERs—including grid optimization, reliability services, peak management, and capital deferral—while ensuring these assets are integrated efficiently into both distribution and bulk market operations. Crucially, the MF-DSO model reflects the key design principles that ETNO highlighted: affordability, customer focus, accessibility, optimization, reliability, competition, innovation, regulatory evolution, inclusivity, and decarbonization. It creates a transparent, non-discriminatory framework where DERs can participate openly in both local and wholesale markets, with the DSO providing essential balancing, coordination, and network optimization services. This model also leaves room for evolution toward future "DSO-as-a-Service" options, as market needs mature and additional third-party services emerge.

As Ontario's energy markets expand and third-party provider services emerge, the MF-DSO model could eventually evolve naturally toward a Total DSO framework. In such a framework, market access extends seamlessly to third parties, such as retailers or aggregators, who may request MWs to manage their own market positions. By optimizing across all markets, the Total DSO model facilitates maximum DER participation and simplifies the addition of new services and markets. This creates a virtuous cycle: as more services are enabled, demand for DER participation increases, which in turn drives greater DER deployment. This pattern aligns with international experience, where advanced DSO frameworks have led to consistently higher DER penetration rates.

E. Distribution System Operator Activation Method & Governance Framework

The current legislative and regulatory frameworks were not designed to allow for market-based approaches to secure capacity and energy services from DERs for local needs. As a result, facilitating a DSO structure will likely require amendments to certain legislation, codes, or regulations. What form these amendments ultimately need to take will critically depend on the structure that the OEB sets out for the roles and responsibilities of the sector.

Currently, distributors are enabled to consider Conservation and Demand Management (CDM) activities for the purpose of addressing system needs. These may require an exemption and do require authorization from the OEB, and can take the form of:

- Energy efficiency programs;
- Demand response programs;
- Programs to reduce distribution losses;
- Energy storage (in front of, or behind the meter); and
- Certain generation permissions.

As described in the OEB staff paper, over the past decade or so, the OEB has allowed circumstances in which behind the meter (BTM) storage assets may be considered a distribution activity. That is, certain investments made to address a distribution concern can be considered a distribution activity. The recent NWA Guidelines also now obligate distributors to consider DER solutions when assessing options for meeting system needs as part of their planning and operations. These obligations will require distributors to build and adopt advanced load forecasting capabilities, new planning tools and approaches (e.g. time series techno-economic modeling, risk management), implement system monitoring, controls, and data analytics, evolve operational practices to integrate and manage DERs as non-wires alternatives (NWAs), and update planning processes to assess and incorporate non-utility-owned DER solutions. In this context, it is a natural extension that refinement and/or evolution of market structures, as well as governance and oversight, would evolve to facilitate broader use of DERs to unlock the value stacking benefits they provide for the benefit of all Ontario's ratepayers, whether at the local or the bulk system level.

Establishing a robust regulatory framework and market structure will be vital to enable market participants and customers to recognize how to evaluate both outcomes and risks. To this end, having a clearly defined set of goals and guidance is crucial.

The OEB Act currently mandates that the OEB facilitate innovation and promote CDM in a manner consistent with Government policy and direction. A common refrain during the recent stakeholder consultation session was a question as to whether, "if we build it, will they come?". In Alectra's view, this is the wrong question. First, one thing that is certain is that if we don't build it, they will not come. And second, it has been well documented that the potential for a high DER future not only exists but should be vigorously pursued for the incremental value benefits and efficiencies that a high DER future can bring. As a result, the question the OEB should be addressing is how best to establish the conditions that will incent the right behaviours, protect public interest, and pursue further efficiencies that will preserve reliability, add flexibility and choice, and promote affordability. This will require an appropriate governance and oversight structure to govern the creation and operation of local electricity markets, including the creation of local market rules, as well as a process for amendments to market rules, as necessary. On this, Alectra agrees with OEB staff, where they indicate:

> *To combat these risks, rules would be required to stipulate how the market would operate and set the terms for participation. A review process would be needed to support the development of rules. A market oversight and monitoring function, similar to the functions in place to provide oversight of the wholesale electricity market, would also be required to oversee the market's operation, and to assess whether any individual participant could assert market power or engage in market manipulation to distort outcomes.*[7]

Further consideration will be needed to determine the most effective approach for administering market oversight, including the associated compliance and enforcement mechanisms.

Simultaneously, the legislative and regulatory frameworks should enable and support a core mandate for LDCs to develop or procure DSO services. At a high level, the primary activities of the DSO articulated in the core mandate might include the following:

- Permitting the DSO to interact with participating DERs to send both local and wholesale price signals and to coordinate with the IESO, as appropriate;
- Conducting market-based processes to register, secure, schedule and dispatch participating DERs for defined commitment periods;
- Leveraging existing and new DERs for distribution purposes, or customer participation in wholesale markets, as the case may be;
- Developing, managing, and executing participant service agreements;
- Developing new planning capabilities to enable the planning for NWAs;
- Providing for measurement and evaluation of DER provided services;
- Managing the settlement process with DER participants.

In Alectra's view, such a mandate would be consistent with otherwise currently existing permissible distribution activities in the same vein as OEB staff's description of providing services that may have ancillary wholesale level outcomes:

> *This arrangement and sequencing appear to fit with the concept of an incidental purpose, secondary to the distributor's predominant activity of administering its own market operations. Put into terms from the 2020 bulletin, the purpose driving*

[7] Ibid, p.33.

the activity is distribution; the ancillary benefits to the operation of the IESO's market appear incidental. In OEB staff's view, this form of arrangement would appear to be consistent with other permissible distribution activities.[8]

Taken together, the design and implementation of a core mandate to deliver DSO outcomes does not appear to be a distant leap from that which already exists and would allow policy formulation to establish the right foundations to evolve distribution system operations in Ontario.

In summary, the creation of local electricity markets will permit the ability to use DER aggregations to drive local or bulk level outcomes. An appropriate governance and oversight structure to oversee the operation of a local electricity market and the creation of market rules is essential. Simultaneously, a core regulatory mandate to permit DSO outcomes is necessary to facilitate the transition toward optimizing the use of assets, both distribution and customer owned, to unlock the full value stream of DERs for the benefit of all ratepayers.

Each of the steps necessary for creating a viable local electricity market, as well as giving LDCs a core mandate to operate as DSOs should be further evaluated and articulated in a roadmap defining critical issues and decision points necessary to advance DSO capabilities. Detailing these critical steps and decision points are necessary to ensure fairness, certainty, legitimacy, and transparency for DER owners, aggregators, and other market players.

[8] Ibid, p.36

F. OEB Proposals & Development of a Roadmap

Alectra supports the intent behind Proposal 1, which asks distributors to assess the need for DSO capabilities to address system needs, however emphasizes that this work should build upon the significant technical groundwork already completed by Ontario's TDWG, particularly the deliverable B1 document that outlines functional and technical DSO requirements. Leveraging this sector-developed foundation will provide the OEB with a consistent, credible, and efficient baseline for assessment, while avoiding duplication and fragmented efforts across the sector.

Alectra opposes Proposal 2, which suggests a simplified DSO model. While simplification may sound appealing on the surface, in practice it poses profound risks to Ontario's electricity system. The notion that DSO implementation can be "simplified" fundamentally underestimates the operational, regulatory, and market complexities involved. Building a functioning DSO is not simply an IT or operational adjustment; it requires deeply integrated changes across system planning, control room operations, market interfaces, and customer engagement. It touches every part of the electricity value chain, from capital planning to voltage management to price formation at the customer edge. Suggesting that the process can be reduced to a simple, light version risks creating a system with structural blind spots, fragmented roles, and a mismatch between responsibilities and accountabilities.

Moreover, while the sector should evolve progressively, evolution without a clear end goal is not advisable. It takes time—often years—to build, deploy, and integrate the infrastructure, systems, and processes needed for a fully functioning DSO. Without alignment on the desired end state, LDCs and the sector risk making incremental investments that do not fit together, leading to stranded assets, wasted capital, and grid solutions that are misaligned with long-term needs. Any evolutionary path must be intentional, with today's deployments architected in a way that they serve as foundational building blocks toward the final DSO model.

Furthermore, multiple European projects, including the EU SmartNet and CoordiNet projects, have shown the consequences of inadequate DSO models being developed. In SmartNet, DER aggregation for Transmission System Operator (TSO) needs aggravated local congestion when DSOs were not involved. In CoordiNet, flexibility services procured by the TSO had to be curtailed by the DSO in real time due to unexpected voltage issues—demonstrating the critical need for DSOs to validate dispatches and maintain real-time telemetry during activation. Both projects recommend establishing clear protocols requiring DSO pre-validation and active monitoring during any ISO/TSO dispatch to prevent local network violations.

Alectra fully supports Proposal 3, which presents the only viable path forward for Ontario. Advanced DSO models recognize that LDCs are uniquely positioned to manage local megawatts and optimize system flexibility—not only to meet local distribution needs but also to support transmission and generation-level operations. This approach does not equate to exclusion or closed systems; rather, it enables open, competitive, and non-discriminatory participation by DERs and aggregators through well-designed governance, interoperability, and market rules. A DSO framework, when properly designed, fosters inclusion by ensuring that both large and small market participants can access flexibility markets under fair and transparent conditions.

One of the most significant risks we see is the adoption of overly programmatic approaches that lock the sector into rigid, utility-administered programs. Programmatic models may appear to offer near-term deliverables, but they carry structural limitations that can entrench incumbent advantages, reduce service provider diversity, and stifle innovation. Under these approaches, existing players dominate service delivery, leaving little space for new entrants or aggregators to innovate or scale. Customers are left with a narrow set of utility-designed offerings that may not meet their unique needs, limiting flexibility and slowing the adoption of emerging technologies. In contrast, market-based models create price transparency, send clear value signals, and enable DER owners and aggregators to compete on the basis of service, price, and performance. They also provide the stable, consistent revenue streams that new technologies and business models need to scale effectively. Simply put, rigid programmatic approaches freeze the sector in today's paradigm, while market-based approaches unlock the innovation needed for tomorrow's grid.

The UK's ENA Open Networks serves as a powerful global example of why this approach is both necessary and effective, and why a simplified model was never seriously considered. The UK launched ENA Open Networks—a comprehensive, utility-led, multi-stakeholder programme designed to build DSO capability across nine electricity network operators, Ofgem, national system operators, and industry participants. Its creation was driven by three accelerating transformations in the energy landscape: decarbonisation, digitalisation, and decentralisation (the "3 Ds"). These changes demanded a system able to manage over 30 GW of distributed generation and rapidly growing electrification.

Rather than defaulting to simplified, prescriptive models, the UK chose a coordinated, advanced roadmap. ENA Open Networks produced a living DSO implementation plan and technical architecture, embedding core DSO functions in a baseline by 2023, and targeting full adoption by around 2030. It intentionally skipped "simple first" frameworks because a DSO requires deep integration between planning, operations, markets, data systems, and customer engagement. The sector-wide, utility-led approach has delivered remarkable real-world results. UK Power Networks procured 1.5 GW of flexibility, avoiding about £91 million in reinforcement costs and delivering nearly £199 million in consumer savings. SP Energy Networks secured 300 MW of contracted flexibility, and Electricity Northwest scaled from 7.5 MW in early trials to over 1 GW in contracted capacity. These tangible benefits came from standardizing products, governance, and interoperable platforms—outcomes that would have been impossible with a fragmentation-prone, simplified model.

In sum, Ontario should convene an LDC-led, sector-wide roadmap framework grounded in advanced DSO design, interoperable market structures, and robust governance—modelled on the success of ENA Open Networks. That path would ensure alignment toward a clear final state, avoid stranded investments through gradual capability building, and create vibrant, scalable flexibility markets that deliver system value.

For Ontario, the path forward should be clear. Alectra recommends that the OEB support the formation of a sector-led, OEB-supported working group, led by LDCs, to co-develop the DSO model and a phased implementation roadmap. This roadmap should reflect Ontario's current capabilities, incorporate lessons learned from international markets, and establish clear regulatory and operational milestones to guide the sector's transition. The OEB's primary role should be to ensure interoperability, safeguard customer interests, and enable competitive market structures—not to predetermine winners or lock the sector into prescriptive programs. By taking this collaborative, future-ready approach, Ontario can build a DSO framework that delivers reliable, efficient, and equitable outcomes for customers and the electricity system as a whole.

Risks of a Simplified DSO Model Without a Long-Term Roadmap

In the alternative, Alectra sees that implementing DSO functions in a simplified or ad hoc manner without a clear long-term roadmap can expose the power system to significant risks. These risks span operational, technical, regulatory, and economic dimensions, potentially leading to system inefficiencies, underutilized DER capacity, uncoordinated operations, and even stranded investments. Alectra's views are informed by the global evidence and expert insights on why a comprehensive, phased DSO roadmap is critical, highlighting lessons from the UK, Australia, the EU, and the US.

Without a structured DSO roadmap, operational coordination between the distribution level and the broader grid are likely to suffer deleterious consequences. One major risk is conflicting or inefficient control signals to DERs when distribution utilities and the transmission system operator (TSO or wholesale market) act in isolation. In the UK, regulators have warned that without proper coordination, flexible resources might receive "inefficient or opposing instructions" from local vs. national operators. This lack of alignment can jeopardize reliability and nullify the value of DER flexibility. Western Power Distribution (WPD) in Britain similarly observed that as DER penetration grows, uncoordinated actions by the national grid operator (e.g., calling on DER for balancing without DNO input) would be inefficient and lead to unpredictable outcomes. In technical terms, experts describe pitfalls like "tier bypassing" and "hidden coupling" – i.e. control actions that skip over the DSO or simultaneous, unaligned dispatch by different operators – which create operational problems and must be avoided. These findings underscore that a clear framework for DSO-TSO coordination is needed in operations. Lacking a roadmap, operational procedures may develop piecemeal, increasing the risk of real-time imbalances, reliability issues, and even safety risks if different entities issue conflicting commands to grid assets.

Furthermore, a simplified DSO approach often means limited situational awareness and control at the distribution level. Insufficient real-time visibility and data sharing can hinder the DSO's ability to balance local supply and demand. In contrast, advanced DSO models call for *"unprecedented visibility, high-granularity monitoring and controllability"*[9] to actively manage flows. If such capabilities are not planned, operators may be forced into reactive decisions, and DERs might be curtailed or left idle during critical periods. Over time, this operational inefficiency can erode stakeholder confidence in DER integration. The absence of a coherent roadmap would create or exacerbate technical risk, regulatory risk, and economic risk.

Technical Risks: Inefficiencies and Interoperability Gaps

A major technical risk of not having a long-term DSO roadmap is enduring system inefficiencies due to suboptimal integration of DERs. A passive or overly simplistic DSO model tends to rely on traditional grid reinforcement for rising demand or back-feed, rather than leveraging DER flexibility. For example, WPD noted that continuing as a passive Distribution Network Operator (DNO) would require *"very substantial investments in grid infrastructure, which would be underutilised much of the time"*[10]. In other words, without active DSO functions, utilities might overbuild wires and substations that sit mostly idle, leading to inefficient capital use. This not only wastes money but also fails to use existing DER capabilities to relieve the grid. Technical inefficiencies also arise when DER potential is constrained by a lack of proper control systems – for instance, widespread rooftop solar may be disconnected during peaks because no mechanism exists to modulate their output intelligently. Australia's experience underscores this risk: high solar uptake poses "serious risks to our power system."[11] If not managed, it will prompt Western Australia's DER Roadmap to urgently plan new DSO-like capabilities.

Another technical concern is interoperability. In the absence of a common roadmap or standards, each utility or region might implement different technologies and communication protocols for DER management. This patchwork can inhibit DER providers from operating across systems and prevent seamless data exchange. The UK's Open Networks project stressed the need for alignment of data and IT systems to ensure interoperability between DSOs and the national grid. A clear roadmap typically sets out architecture and interface standards so that, as advanced DSO functions roll out (like real-time DER dispatch platforms or monitoring systems), they remain interoperable system wide. Without this foresight, technical silos emerge, making it hard to coordinate DER operations across neighboring networks or to scale innovations beyond pilot projects. Fragmented systems also introduce cybersecurity vulnerabilities and complexity. A cohesive, phased roadmap mitigates these technical risks by defining standard "rules of the road" (e.g., communication protocols, visibility requirements, control hierarchy) upfront.

Regulatory and Market Risks: Unclear Roles and Misaligned Incentives

Implementing DSO functions without a long-term vision can leave regulatory grey areas and misaligned incentives that hinder progress. One risk is that, in a simplified model, the

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[9] National Grid, *DSO Strategy December Update v17.*, 2017, Slide 9.
[10] Ibid, Slide 9.
[11] Government of Western Australia, Distributed Energy Resources Roadmap, 2025.

responsibilities and boundaries between the DSO and other entities (incumbent distribution utilities, TSOs, retail market players, etc.) remain unclear. This regulatory ambiguity can lead to jurisdictional disputes or duplication of efforts. A lack of unified direction can result in each entity optimizing for its own mandate without considering the whole-system outcome. The result may be overlapping or even conflicting market mechanisms at the local vs. wholesale level, confusing DER providers and investors.

Moreover, without clear regulatory guidance, utilities may default to legacy business models that underutilize DERs. Lack of a long-term DSO strategy exacerbates this, as utilities and regulators have no agreed end-state to aim for. This can slow the development of DER markets and limit third-party innovation. Regulators in the UK have responded by requiring DNOs to articulate DSO transition plans in their business strategies and to implement measures mitigating any conflicts of interest between their network ownership and DSO roles. The lesson is that without a roadmap setting expectations, such conflicts and uncertainty might persist, deterring new entrants and investments in DER services.

Inconsistent approaches across jurisdictions also pose market risks. The United States, for instance, has seen a state-by-state patchwork of DER integration efforts. Experts warn that if each jurisdiction pursues a different DSO model without coordination, it leads to a proliferation of terminology, concepts, and approaches that increases costs and dilutes the benefits of DERs. A common vision (or at least a harmonized set of standards) is needed to allow DER developers to scale solutions and to enable trading of services across regions. The absence of a national DSO roadmap in the U.S. is increasingly viewed as a barrier; industry groups (e.g. NARUC and ESIG) call for a "structured dialogue on solutions to longer-term issues" and a shared framework, drawing on international examples like Australia's OpEN and the UK's Open Networks project. In summary, a piecemeal, short-term approach breeds regulatory uncertainty, which can lead to stalled market development, lack of investor confidence, and suboptimal decisions by utilities and regulators.

<u>Economic Risks: Stranded Assets and Lost Value</u>

Perhaps the most tangible risks of an ill-defined DSO strategy are economic. Investments made without a long-term plan can turn into stranded assets or yield poor returns. For instance, if a utility adopts only a minimal DSO model (focusing on a few near-term fixes) and fails to anticipate the end-state, it might invest in stopgap infrastructure or one-off IT systems that later become incompatible with a more advanced framework. The Ontario Energy Board, in plotting an evolutionary DSO path, explicitly noted that a phased approach *"minimizes the risk of stranded investment"*[12] by avoiding over-build of costly systems before they're needed. Conversely, lacking a roadmap can swing the pendulum the other way – some utilities might delay necessary investments for fear of stranding them, resulting in under-investment and degraded service. Both outcomes are costly to consumers.

[12] Ontario Energy Board, Discussion Paper: Distribution System Operator Capabilities (EB-2025-0060), May 2025, p.54.

An inadequate DSO model also means underutilization of valuable DER assets, which is an economic loss to both owners and the system at large. DERs like rooftop solar, batteries, or flexible loads represent capacity that, if orchestrated, could defer expensive grid upgrades and provide services (energy, capacity, ancillary support) more cheaply. If there is no framework to tap these resources – for example, no marketplaces or programs for DER to participate in – those assets sit idle or operate purely for self-consumption, leaving system benefits on the table. A clear example is the "non-wires alternative" concept: in regions with a DER integration roadmap, utilities actively procure DERs to alleviate grid constraints instead of automatically building new lines. Where such processes are lacking, networks may keep over-investing in traditional assets. Utility WPD re-designed its planning strategy upon transitioning to DSO, noting it would *"blend more active energy management with targeted infrastructure upgrades"*[13], rather than simply build out copper that would sit underutilised much of the time. This shift is aimed at providing the best outcomes for electricity ratepayers, because it avoids both needless capital spend and missed opportunities to use cheaper flexible solutions.

Finally, without sector-wide alignment on the DSO end-state, there's a risk of duplication of investments and stranded capacity. Australia's Open Energy Networks consultations examined various frameworks – from minimal to fully independent DSO models – and found that the most complex (fully independent DSO) approach could cost billions more due to duplicated systems and roles, whereas more integrated models reusing existing structures could achieve the same with less spend. Crucially, their analysis recommended implementing new DSO functionality in an incremental way, scaling with DER uptake, to ensure net benefits. This kind of economic prudence is only possible if a roadmap is in place to sequence investments over time. In summary, the absence of a long-term DSO roadmap can lead to either over-investment (stranded assets) or under-investment (bottlenecked DER value), and generally higher total system costs due to inefficient resource use.

[13] National Grid, DSO Strategy December Update v17., 2017, Slide 4.

G. Alectra Responses to OEB Questions

With the aforementioned context and positioning in mind, Alectra turns now to direct responses to each of OEB staff's specific questions.

Defining Opportunities and Objectives

- **What are your views on the opportunity and policy objectives for DSO capabilities?**
  Alectra views DSO capability development as essential to Ontario's energy transition. With the rapid growth of DERs, the province is moving from a one-way electricity system to a dynamic, two-way grid. The DSO model creates the operational and market framework needed to harness DERs for system-wide benefit—enhancing affordability, reliability, system efficiency, and customer participation. The policy objectives should prioritize unlocking local energy value, reducing system costs, improving grid resilience, and positioning Ontario to meet decarbonization goals. Critically, this is not just an operational change; it is a structural transformation requiring intentional design and coordination.

- **What are your views on the use cases and value of DSO capabilities for Ontario, including the importance of DSO capabilities in capturing more of the benefits DERs can provide?**
  DSO capabilities open up multiple value streams for Ontario. At the grid level, they help reduce congestion, optimize system operations, and defer or avoid capital investments in infrastructure leading to greater cost effectiveness and affordability. At the customer level, they unlock revenue opportunities for DER owners—allowing customers to provide services like demand response, voltage support, and market participation. Without DSO functions, DERs remain isolated and underutilized, limiting their contribution to both local and system-wide objectives. To fully capture DER value, Ontario must coordinate across technical, market, and regulatory dimensions.

- **How should the OEB's objectives (as set out in section 1 of the OEB Act) be balanced and reflected in the development of a DSO policy framework for Ontario?**
  The OEB's mandate to protect consumer interests, ensure reliability, promote economic efficiency, and support innovation should be fully embedded in DSO policy. Affordability should guide the prioritization of DERs as non-wires alternatives that reduce system costs. Reliability must be safeguarded by ensuring LDCs, as DSOs, retain operational oversight of distribution networks. Efficiency and innovation should be enabled through open, transparent markets that allow broad participation. Importantly, these objectives can only be balanced effectively if the province defines a clear end goal for DSO development and designs a roadmap to get there—avoiding piecemeal efforts that risk stranded investments or system inefficiencies.

Evaluating Proposals and Approaches

- **Is an evolutionary approach to developing DSO capabilities appropriate for Ontario to pursue in order to achieve the policy objectives set out in the Staff Discussion Paper?**
  Yes, an evolutionary approach is appropriate—but only if it is anchored in a clear end-state vision and a structured, sector-led roadmap. Internationally, the UK's ENA Open Networks program provides a proven example. The UK did not pursue simplified or ad hoc approaches but instead created a collaborative, multi-stakeholder roadmap led by distribution network operators (DNOs) to define advanced DSO capabilities and then phase in implementation. This approach ensured that near-term pilots and system changes aligned with the long-term vision, avoided duplication, and created interoperable market and technical frameworks. Ontario should adopt a similar LDC-led, OEB-supported roadmap, building on work by groups like ETNO and the TDWG, to progressively and purposefully develop DSO capabilities across the province.

- **What are your views on each of the three proposals presented in the Staff Discussion Paper?**
  Proposal 1 (distributor-led assessments) is a reasonable first step but should leverage existing technical outputs, such as TDWG's Deliverable B1 and ETNO recommendations, to ensure efficiency and consistency.

  Proposal 2 (simplified DSO model) is not viable, as it underestimates the operational, technical, and market complexities involved in DER integration. Simplified approaches risk fragmentation, stranded assets, and uncoordinated system development.

  Proposal 3 (advanced models) is the only viable path. It positions LDCs as neutral market facilitators, ensures full value stacking of DER services, enables customer participation, and safeguards reliability. Crucially, it mirrors the approach taken in successful international programs like ENA Open Networks, where the sector first defined what "advanced" looks like and then designed an evolutionary path to get there.

<u>Balancing Standardization and Flexibility</u>

- **How should the OEB best balance the benefits of a standard approach relative to the innovation and insights that could be gleaned from enabling greater flexibility and diversity through experimentation?**
  Ontario should adopt minimum standards where system-level consistency is essential—such as data protocols, interoperability, and market access rules—while leaving space for regional flexibility and innovation. Within this framework, LDCs should have the flexibility to trial local market designs, test new services, or pilot innovative DER coordination models under a regulatory sandbox approach. This balanced approach—standardization combined with structured experimentation—mirrors the ENA Open Networks experience, where a sector-wide roadmap defined common goals and frameworks, but local actors had room to innovate, test, and scale solutions before broader adoption. This would allow Ontario to combine the stability of standardization with the creativity of local experimentation.

Conclusion

Alectra appreciates the opportunity to contribute to the OEB's consultation on DSO capabilities. As Ontario navigates a rapidly evolving energy landscape, the development of a clear, coordinated, and future-ready DSO framework is essential to unlocking the full potential of DERs, ensuring a reliable, affordable, and sustainable electricity system. To that end, Alectra recommends that the OEB prioritize the articulation of a clear vision, direction, and delineation of roles and responsibilities among sector participants. Establishing this foundational clarity is a critical first step toward building a robust regulatory framework.

Alectra further emphasizes the importance of aligning the DSO implementation roadmap with the sector's evolving maturity and the progressive development of planning and market coordination roles. This alignment will ensure that investments in grid modernization and operational capabilities are both strategic and scalable, avoiding stranded assets and enabling a smooth transition toward a more decentralized and dynamic grid.

It is probable that current legislative and regulatory frameworks must evolve to accommodate new market structures, operational models, and customer participation mechanisms. Alectra urges the OEB to provide the necessary guidance and oversight to ensure that DER integration is not only technically feasible but also economically rational and customer centric.

Finally, Alectra strongly encourages the OEB to facilitate a collaborative DSO development and implementation framework by establishing a formal OEB/LDC working group. This group would serve as a platform for developing the DSO model, identifying key decision points, and coordinating implementation efforts across the sector. A sector-led, OEB-supported approach, grounded in shared principles and informed by existing best practices from other jurisdictions, will be critical to ensure that Ontario's DSO framework is both effective and enduring.

By taking these steps, Ontario can position itself as a leader in DER integration and grid modernization, delivering long-term value to customers, enhancing system resilience, and supporting the province's broader electrification and decarbonization goals.