ONTARIO ENERGY BOARD

FRAMEWORK FOR ENERGY INNOVATION:

Setting a Path Forward for DER Integration

JANUARY 2023

Ontario Energy Board

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1. Executive Summary

The Ontario Energy Board (OEB) initiated the Framework for Energy Innovation (FEI) consultation to clarify the regulatory treatment of innovative and cost-effective solutions, including distributed energy resources (DERs), and facilitate their adoption in ways that enhance value for consumers. The consultation included forming the FEI Working Group to provide advice to the OEB and inviting written comments from stakeholders on the scope of issues to be addressed and the FEI Working Group's recommendations to the OEB.

Considering input received from stakeholders, this Report sets out the OEB's policies and next steps with respect to the integration of DERs into distribution system planning and operations, as well as the use of DERs by electricity distributors[1] as non-wires alternatives (NWAs). This Report pertains only to the electricity distribution sector and is intended to provide sufficient clarity about the OEB's expectations to enable distributors, as well as other sector participants (such as DER solution providers) and customers, to take near-term action in response to the energy transition. The OEB is prepared to provide further guidance, when needed, as the energy transition unfolds.

A timeline of next steps for implementing the policies in this Report is shown in Figure 1.

OEB Expectations of Distributors

The prospect of widespread DER adoption may have significant implications for how the distribution system is used and the potential activities of distributors. To provide greater clarity and predictability for the sector, stakeholders told us the OEB should provide guidance on its expectations of distributors with respect to DER integration and use.

The OEB's Conclusions

The OEB expects distributors to modify their planning and operations to prepare for DER impacts on their systems, including integrating these resources cost-effectively, while maintaining reliable service for their customers. Distributors are also expected to consider DER solutions as NWAs when assessing options for meeting system needs.

Benefit Cost Analysis Framework for DER Solutions as Non-Wires Alternatives

To help distributors assess and deploy DER solutions as NWAs where appropriate, the OEB set out to develop a Benefit Cost Analysis Framework (BCA Framework) that distributors can use to develop business cases for DERs as NWAs and support

[1] Throughout this report "distributors" refers to rate-regulated electricity distribution companies and "utilities" refers to electricity distributors, electricity transmitters and natural gas utilities collectively (unless in a quote where "utilities" may not have been defined as such in the source document).

proposals in their rate applications. Stakeholders generally agreed that DER benefits and costs are often broader than traditional distribution investments and can include impacts for the whole energy system. While there was broad support for considering some or all impacts beyond the implementing distributor's system or customers, many stakeholders also emphasized the need for costs to follow benefits when deploying energy infrastructure.

The OEB's Conclusions

The OEB will adopt a BCA Framework that identifies the full energy system benefits and costs of DER solutions and allows different categories of costs and benefits to be considered separately. The costs and benefits for the implementing distributor and its customers will generally be the primary consideration for making decisions about cost recovery through distribution rates. However, a broad BCA Framework will assist the sector in developing mechanisms to ensure costs follow benefits, and will also enable distributors to propose DER projects based on a broader set of costs and benefits in circumstances when that may be appropriate. The OEB will launch a separate initiative to develop the components of the BCA Framework. The first phase of work, to develop guidance, methodologies and tools for distribution impacts, will be complete by the end of the 2023/24 fiscal year, followed by a second phase focused on the broader energy system impacts.

Utility Incentives for Third-Party Owned DERs as Non-Wires Alternatives

There are many potential barriers to the use of DERs as NWAs, including the various challenges that come with doing things differently and rethinking well-established processes and protocols. Uncertainty about the ability to recover DER-related costs and the perceived disincentive of forgoing the opportunity to earn a return when a DER solution displaces a capital project may also hinder the adoption of DER solutions by distributors. While there was broad stakeholder support for mitigating disincentives to DER adoption, there was disagreement about whether positive incentives are appropriate. Some stakeholders suggested that incentives are appropriate to ensure distributors give equal consideration to NWAs and traditional solutions; others suggested they are not necessary since regulated utilities should be obliged to adopt the most cost-effective solution.

The OEB's Conclusions

Prudently planning a distribution system that reliably serves customers in the context of broader DER adoption will become a core function for distributors, and associated costs will generally be treated the same as other distributor spending.

To alleviate uncertainty about the types of costs that may be recovered, distributors who need one are encouraged to apply for a deferral account to record material operations, maintenance, and administration (OM&A) costs related to DER integration and use, incurred in advance of their next rebasing application. Upon rebasing, DER-related costs should be fully integrated into distributors' overall spending plans.

Distributors may also propose an incentive tied to implementation of third-party owned DER solutions as NWAs. Adjudicating these proposals and observing impacts of any approved incentives will inform OEB consideration of any future incentives policies, applicable to all distributors. OEB guidance to facilitate applications for incentives will be issued by March 31, 2023.

DER Integration

To meet the OEB's expectations for cost-effectively integrating DERs in system planning and operations, distributors require detailed information about the pace and nature of DER adoption within their service areas. In addition to highlighting the need for clear guidance on the role and expectations of distributors, stakeholders expressed a need to foster greater information sharing among distributors, DER solution providers and customers, for the purpose of better understanding the value and availability of DER solutions.

The OEB's Conclusions

Several relevant activities that are underway or recently completed will result in the collection of new or more granular DER information. The OEB has therefore decided it would be premature to impose any further DER data collection requirements at this time. Going forward, the OEB may have a role to play in facilitating, standardizing, or providing appropriate oversight of arrangements for NWAs between distributors and third-party DER solution providers. Before the end of the 2023/24 fiscal year, the OEB will launch an initiative to identify any regulatory reforms that may be required in that regard, including requirements for information sharing about system needs and available solutions.

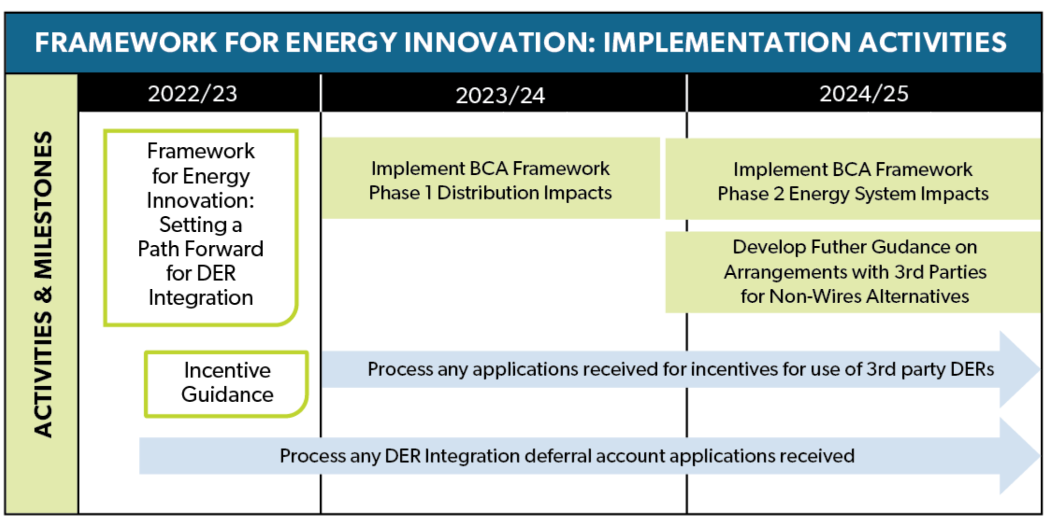

Figure 1: Framework for Energy Innovation Implementation Activities

2. Introduction

The OEB launched the FEI consultation to:

- Facilitate the adoption of innovative and cost-effective solutions, including DERs, in ways that enhance value for energy consumers; and
- Increase clarity on the regulatory treatment of innovative technologies and approaches.[2]

The OEB established a stakeholder-led working group (FEI Working Group) to provide recommendations to the OEB with respect to two priority workstreams:

- ***DER Usage:*** *to investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution needs.*
- ***DER Integration:*** *to ensure that utilities' planning is appropriately informed by DER penetration and forecasts.*[3]

This Report sets out the OEB's policies and next steps on these matters and some additional related issues, considering the recommendations of the FEI Working Group and stakeholder comments on those recommendations. This Report pertains only to the electricity distribution sector.

For each topic, this Report describes the opportunity or challenge the OEB is seeking to address, what we heard from the FEI Working Group, comments from stakeholders on the Working Group's recommendations, the OEB's policy conclusions, and its approach to implementation.

This Report is the culmination of the FEI consultation, which focused on a specific set of issues. However, the policy guidance and next steps it contains have been informed by the broader policy context, including the direction and outcomes of related OEB, Independent Electricity System Operator (IESO), and Ministry of Energy initiatives, many of which are referenced throughout this Report. The policies set out in this Report are intended to build upon and evolve the OEB's performance-based approach to regulation as the distribution sector responds to the energy transition.

In its May 2021 Letter confirming the priority workstreams, the OEB anticipated subsequent phases of the FEI consultation to address other issues identified by stakeholders at the time.[4] However, this Report marks the end of the FEI consultation. Next steps with respect to facilitating DER integration and use, as well as consideration

[2] OEB Letter Setting Out Proposed Priority FEI Workstreams, March 23, 2021

[3] OEB Letter Confirming Priority FEI Workstreams, May 10, 2021

[4] Ibid

of subsequent, related issues, as contemplated in the May 2021 letter, will be carried out through separate initiatives, many of which will be reflected in the OEB's Energy Transition Roadmap.[5] This change in approach is responsive to feedback from stakeholders about the most efficient way to tackle the many, interrelated, complex regulatory issues raised by the energy transition. It also recognizes that Ontario's energy and policy landscape continued to change since the FEI consultation began and the importance of adapting approaches accordingly.

[5] The OEB is mapping its priorities for responding to the energy transition (Engage with Us: Energy Transition).

3. Background

Widespread DER adoption and energy sector innovation have extensive implications for the provision and regulation of energy services. The spectrum of issues the OEB may need to address was initially identified in consultation with stakeholders in the OEB's Responding to DERs and Utility Remuneration[6] consultations, predecessors of FEI.[7]

Recognizing that the OEB and the sector cannot address every issue at once, two priority workstreams were identified for the FEI consultation, with the expectation that other priorities would be addressed in future work. The OEB established the FEI Working Group to review the priority workstreams and prepare policy options and recommendations for the OEB's consideration.[8]

With 22 members representing 24 organizations, the FEI Working Group was comprised of representatives of residential, commercial, industrial, and Indigenous customers, electricity and natural gas utilities, DER solution providers, electric vehicle (EV) owners, environmental groups, and the IESO.

The FEI Working Group met from June 2021 to June 2022 to carry out the tasks in its Terms of Reference.[9] It established three subgroups to delve more deeply into key topics:

- Benefit Cost Analysis (BCA) for DERs
- Utility Incentives
- DER Integration

Consultation Timeline

- **2019/20:** Precursor consultations explore & identify issues to be addressed
- **December 2020:** Consultant studies
  - DER Impact Study
  - COVID Impacts Study
- **March 2021:** FEI consultation launched
- **June 2021-2022:** FEI Working Group & subgroup meetings
- **June 2022:** FEI Working Group Report & subgroup reports
- **September 2022:** Stakeholder comments on FEI Working Group Report

Figure 2: Consultation Timeline

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[6] EB-2018-0288 and EB-2018-0287, respectively.

[7] OEB Letter Setting Out Proposed Priority FEI Workstreams, March 23, 2021

[8] OEB Letter Confirming Priority FEI Workstreams, May 10, 2021

[9] FEI Working Group Terms of Reference, May 26, 2021, p 1-2

Each subgroup prepared a report to the FEI Working Group, which informed the development of the main Working Group's Report to the OEB.[10]

The FEI Working Group's Report, along with the subgroup reports, were delivered to the OEB on June 30, 2022. The OEB then invited stakeholders to provide comments on the Report and advice as to how the OEB should respond.[11]

FEI Working Group Terms of Reference

Workstream # 1 - DER Usage: This workstream is intended to investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution needs. The near-term activities will focus on:

- Establishing a working definition of DERs.
- Developing a number of high-value, non-utility-owned DER use cases as alternatives to traditional solutions to meet distribution system needs, based on relevant players' knowledge of needs and alternative solutions.
- Defining an approach to measure the benefits of these DER use cases relative to costs and assess the value of DERs relative to traditional distribution investments.
- Developing appropriate incentives for distributors to adopt DERs for distribution uses that do not require equity investment by the utility.

Workstream # 2 - DER Integration: This workstream is intended to ensure that utilities' planning is appropriately informed by DER penetration and forecasts. The near-term activities will focus on:

- Identifying information distributors require regarding existing DERs to effectively operate and make future system plans.
- Establishing appropriate reporting requirements.

The progress made on these near-term priorities will inform subsequent areas of focus, issues to be addressed and activities to be undertaken, consistent with the incremental approach to work.

Figure 3: FEI Working Group Terms of Reference

Documentation related to the FEI consultation, including materials produced for and by the FEI Working Group in the course of its work, the FEI Working Group Report and subgroup reports, and subsequent stakeholder comments are available at Engage with Us: Framework for Energy Innovation.

[10] Framework for Energy Innovation Working Group Report to the OEB, June 30, 2022

[11] OEB Letter Inviting Comments on FEI Working Group Report, July 6, 2022

Guiding Principles

In developing the policies set out in this Report, the OEB considered its legislative objectives, its strategic goals[12] and the guiding principles listed below. Originally identified in consultation with stakeholders,[13] the guiding principles have been aligned with the OEB's four strategic goals and were used to compare potential policy options:

1. **Protect the Public (Customer Focus)** – Does the policy encourage positive outcomes for customers including cost-effectiveness and demonstrable, long-term value; customer choice and control; and increased consumer confidence in the sector?

2. **Evolve Towards Becoming a Top Quartile Regulator (Regulatory Effectiveness)** – Is the policy practical to administer while enabling appropriate oversight? Does the policy contribute to a regulatory framework that is clear and predictable but also adaptable and sustainable in the context of the energy transition?

3. **Drive Sector Performance** – Does the policy promote economic efficiency and cost-effectiveness? Does it support a level playing field for DER solutions? Does it enable utilities to act in the near term?

Nothing in this Report should be construed as the OEB promoting DERs for their own sake or preferring DERs to other solutions for providing distribution service. Beyond facilitating a level playing field and driving value for customers, it is not the role of the OEB to increase or accelerate DER adoption or to choose technology winners and losers. Balancing its statutory objectives to "promote economic efficiency and cost effectiveness" in distribution service and to "facilitate innovation,"[14] the OEB is aiming to ensure that regulated distributors prepare for the impacts DERs will have on their systems, integrate these resources cost-effectively and without negative impacts to their customers, and, where appropriate, secure benefits of DERs for their customers, given emerging options for delivering energy services and meeting system needs.

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[12] OEB 5-Year Strategic Plan 2021/22 to 2025/26, April 30, 2021, p 19-27

[13] OEB Letter Re: Utility Remuneration and Responding to Distributed Energy Resources, July 17, 2019, and OEB Staff Presentation on Sector Evolution: Utility Remuneration & Responding to DERs, February 20, 2020

[14] *Ontario Energy Board Act, 1998*, s. 1(1)

4. OEB Expectations of Distributors

4.1 Defining the Issue

The energy transition and widespread DER adoption have significant implications for how the distribution system is used and the potential activities of distributors. Stakeholders have told us that the OEB should clarify the role of distributors and its expectations of them with respect to DERs. Doing so will not only assist distributors in making long-term planning and business decisions but will also inform decisions of other energy sector participants and customers. Since this is a cross-cutting issue, making the OEB's views explicit can also inform other initiatives underway in the sector to integrate and coordinate DERs.

The FEI Working Group observed, "it may not be possible, or necessary, to determine the role of distributors definitively or exhaustively in an evolving sector."[15] The role of distributors is a complex issue and not something that the OEB solely defines. The role, activities, and responsibilities of distributors are defined in legislation and regulations, as well as in OEB codes, decisions, and policies. Distributors' activities and responsibilities may be further shaped through the expectations and requirements imposed by other entities such as the IESO, transmitters, and the Electrical Safety Authority.

By plainly articulating its expectations of distributors with respect to DER integration and use, the OEB can help provide greater clarity and predictability in the sector and facilitate near-term action by distributors and sector participants to secure benefits of DERs for customers.

4.2 FEI Working Group & Subgroup Recommendations

Although the OEB did not ask the FEI Working Group to consider the role of distributors in an evolving sector, the Working Group found that "uncertainty about the future role of distributors sometimes impeded the [FEI Working Group's] and subgroups' discussions."[16] This led to each of the subgroups recommending the OEB provide clarity in this area (see Figure 4), culminating in the FEI Working Group's recommendation that the OEB "provide further guidance on the role of distributors and the expectations of them".[17]

[15] Framework for Energy Innovation Working Group Report to the OEB, June 30, 2022, p 14

[16] Ibid, p 14

[17] Framework for Energy Innovation Working Group Report to the OEB, June 30, 2022, p 17

Subgroup Recommendations Related to the Roles and Expectations of Distributors:

"The Subgroup believes it would be worthwhile for the OEB to identify what utility actions that can affect DER implementation are currently a) required b) allowed, or c) prohibited in the various regulatory rules that govern the actions of utilities." (*Report of the Utility Incentives Subgroup*, p 28)

The BCA Subgroup recommended the OEB confirm "the scope of BCA to be applied for decision making regarding distributor deployment of DERs in the alternative to traditional distribution system solutions" (*Report of the BCA Subgroup*, p 33) which raises "the question of whether a distributor should have a role in considering the cost and benefit impacts of its DERs decisions on the electricity system as a whole or should only consider the impacts on its own distribution system customers." (*FEI Working Group Report*, p 14)

"The OEB should provide clear guidance on what distributors are expected to do vis-à-vis DER integration so that distributors can determine what information they have or need to deliver on those expectations." (*Report of the DER Integration Subgroup*, p 18)

Figure 4: Subgroup Recommendation Related to the Roles and Expectations of Distributors

4.3 Stakeholder Comments

Most stakeholders identified clarity in the OEB's expectations of distributors vis-à-vis DER use and integration as necessary for responding to the challenges of an evolving sector, including identifying changes to utility planning and operations. Some noted guidance would help define the extent to which distributors should consider DERs in system planning, including for local opportunities (e.g., NWAs), or to achieve broader energy system or societal benefits. Others suggested guidance would help identify DER enabling investments (e.g., increasing DER hosting capacity and dispatching capabilities) necessary for meeting the OEB's expectations.

Many stakeholders viewed OEB guidance as a necessary foundation before progress can be made on other FEI Working Group recommendations. For instance, some stakeholders commented that only once distributor roles have been clearly defined would it be possible to identify and appropriately mitigate disincentives or assess the appropriateness of providing positive incentives for meeting those expectations. Others suggested that it would be premature to establish additional information reporting and sharing frameworks prior to explicitly defining what activities distributors should (or should not) undertake.

One stakeholder commented that the OEB has, in recent years, begun to provide industry guidance on DER-related investments (e.g., the *Conservation and Demand*

Management Guidelines for Electricity Distributors and guidance provided in response to the Regional Planning Process Advisory Report), and that this guidance has been sufficient to approve innovative and well-substantiated proposals.

4.4 The OEB's Conclusions

To support the cost-effective provision of distribution service that provides long-term value to customers, the OEB expects distributors to factor DER integration, consistent with the pace of DER adoption, into their planning and operations and consider DER solutions (NWAs) when assessing options for meeting system needs. Although these activities may be relatively new, or not yet routine for some distributors, the OEB expects that over time they will become business as usual.

DER Definition:

The FEI Working Group's working definition of DERs was intentionally broad:

> For the purposes of our work, we considered a DER to include any resource whether in front or behind the meter, which could provide an alternative to traditional utility solutions to meet distribution system needs or which could have a material positive or negative impact on the distribution system. *(FEI Working Group Report, p 7)*

The OEB is intentionally not defining DERs for the purpose of this Report, beyond the examples provided, because the appropriate definition is context specific and different definitions may be warranted in different regulatory instruments serving different purposes (e.g., a definition for the purpose of connection requirements may differ from the definition for the purpose of guidance on deploying NWAs).

Figure 5: DER Definition

DER is a broad term. Some DERs are new loads that are conducive to being managed so they can be served more efficiently, such as EVs paired with smart charging equipment. Some DERs are technologies that manage existing load or appear to the distribution system as fluctuating load, including forms of storage that shift consumption but do not inject into the system, load displacement generation, and demand management. Some DERs, specifically behind-the-meter generation and storage, inject supply into the distribution system creating a two-way power flow.[18]

[18] Amendments to the Distribution System Code arising from recommendations of the DER Connections Review Working Group recognize that DER adoption is blurring the line between load customers and generators and, since this distinction is less clear and meaningful than it used to be, connection requirements have been revised to focus on the impact each connection is expected to have on the grid. (Notice of Amendments to a Code to Facilitate Connection of Distributed Energy Resources, EB-2021-0117, March 22, 2022)

Historically, the distribution system has been designed to "passively" serve the needs of load customers by sizing network infrastructure to meet peak demand. Given the role DERs are expected to play in the energy transition, DER adoption is likely to become more widespread. Eventually, a significant proportion of customers may engage with the electricity system via some form of DER, whether through a demand response program, a net-metering arrangement, or a battery participating in an aggregation to provide services to a distributor or the IESO. These DERs will impact the distribution system directly, by injecting supply into a system that was not originally designed for a two-way flow of power, or indirectly, by significantly changing load patterns the system has been built to serve. Managing these impacts without building oversized, underutilized network assets will require distributors to engage in more active monitoring and management of their systems and approach planning differently.

The OEB expects distributors to plan, design, and operate their systems in a way that accounts for the anticipated impacts of DERs – informed by best available forecasts of DER adoption in each distributors' service area[19] – to ensure that distribution customers continue to receive reliable distribution service and that service quality is not degraded by DER integration. Doing so will also ensure that limitations of the distribution system do not pose an undue barrier to customers exercising their choice to adopt DERs. Customers would still be expected to pay for connection costs that are specific to their DER (for example, protection systems that are only required due to the existence of that facility). However, a distributor may propose system investments that enable DER integration, where the investments are not necessarily attributable to a given customer's facility or group of facilities and are justifiable in light of expected DER adoption and the benefits that may be conferred.

The OEB also expects distributors to consider DER solutions as NWAs when assessing options for meeting distribution system needs. The OEB has already provided some guidance on, and approved, distributor-owned, rate-funded DER solutions as NWAs (see Figure 6). Consistent with existing expectations that distributors consider options to identify optimal, least-cost solutions for meeting system needs, any proposals for a rate-funded, distributor-owned DER solution must demonstrate that a distributor has meaningfully explored contracting services from non-utility owned DERs – including providing sufficient lead time for third-party DER solutions to be identified and implemented – and doing so is either not feasible or less cost-effective in that instance.

[19] The OEB's Regional Planning Process Advisory Group 2022 Load Forecast Guideline for Ontario provides guidance to the IESO, transmitters and electricity distributors in the development of demand forecasts used in the various phases of the regional planning process. The Guideline is meant to enhance clarity, consistency and transparency in the development of demand forecasts, but also remain flexible to future sector evolution. Given how the system will continue to evolve (e.g., decarbonization, electrification, etc.), the Regional Planning Process Advisory Group plans to review this guidance document at least every two years, or as required to address emerging issues.

These expectations for DER integration and use are consistent with and build upon existing OEB guidance that distributors use an integrated approach to system planning and consider traditional and innovative options for meeting system needs.[20]

Figure 6: Distributor-Owned, Rate-Funded DER Solutions

Distributor-Owned, Rate-Funded DER Solutions
The OEB's 2021 Conservation and Demand Management (CDM) Guidelines support an approach to system planning, at the regional and local levels, that requires consideration of the role of CDM in meeting system needs. CDM activities potentially eligible for distribution rate funding include those that reduce instantaneous electricity demand on a utility's distribution system, or a portion of that system. Examples include demand response programs, energy storage and behind-the-meter generation. *Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021, p 6* An OEB Staff Bulletin (August 6, 2020) provided guidance on a set of circumstances in which the ownership and operation of behind-the-meter energy storage assets may be considered a distribution activity for the purposes of section 71(1) of the *Ontario Energy Board Act, 1998*. In a Decision and Order on Toronto Hydro's application for 2020-2024 distribution rates (EB-2018-0165) the OEB approved, among other things, rate recovery of a local demand response segment of the Stations Expansion program and the use of in-front-of-the-meter storage to meet distribution system needs.

[20] "…to have distribution plans that support the Board's performance outcomes approach to rate-setting, an integrated approach to infrastructure planning is required. Under an integrated approach, all categories of network investments will be planned together, including investments for the renewal and expansion of networks and, where applicable, investments for the connection of renewable generation facilities, investments for smart grid development and implementation, and investments identified in the course of regional infrastructure planning exercises. An integrated approach to planning will provide a foundation for the setting of distribution rates and lead to optimized investments that support the achievement of the outcomes identified by the Board." (Report of the Board: A Renewed Regulatory Framework for Electricity, October 18, 2012, p 31)

"Utilities are expected to develop plans that deliver lower cost solutions over the long-term through a Conservation First approach, integration with regional plans, and consideration of the evolution of the sector, including innovation and new technologies." (Handbook for Utility Rate Applications, October 13, 2016, p 13)

"Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term)." (Filing Requirements for Electricity Distribution Rate Applications, December 15, 2022, Chapter 5, s. 5.4.1.1, p 15)

The OEB recognizes that, to meet these new expectations, distributors need time to build internal capabilities and, more fundamentally, realign their business priorities around doing things differently. This may include, but is not limited to:

- Continuing to evolve and enhance load forecasting, considering DER adoption
- Making enabling investments such as system monitoring and data analytics
- Adjusting operational practices to incorporate and manage DERs on the system, including dispatching DERs being used as NWAs
- Modifying planning processes to identify, assess, and implement non-utility owned DER solutions
- Developing skills and knowledge, and acquiring new talent as needed

The OEB does not expect these capabilities to be acquired instantly. We also recognize the OEB has a role to play in supporting distributors on this journey, by continuing to be clear about our expectations and adapting the regulatory framework to accommodate new and evolving responsibilities and activities of distributors. Currently, Ontario distributors are at different stages of DER readiness, generally corresponding to DER adoption rates across the province. Thinking of DER readiness as a continuum, or growth curve, distributors should identify where they are currently and where they need to be in the future, considering anticipated DER adoption in their services areas.

As is the case with every other aspect of providing distribution service, the OEB expects that integrating DERs into distribution systems and building the necessary internal capabilities will be done cost effectively, with a strong emphasis on pacing and prioritizing investments.[21] The pace and nature of DER adoption will continue to vary across the province and distributors' plans for integrating and using DERs should reflect those local and regional differences. For example, while urban distributors may experience higher volumes of DER activity and find they need to focus on EV integration and support net-zero plans developed by their municipalities, rural and remote distributors may be looking at fewer, larger scale DER projects to provide more reliable service to communities that have historically experienced issues with reliability. These differences may appropriately impact how, and at what pace, a distributor responds from a planning and operational perspective.

The FEI Working Group observed, "as the sector is evolving, the role of distributors may also evolve, and may do so in ways that are not fully predictable today."[22] The OEB is aiming to provide sufficient clarity for distributors to begin acting on now, but is prepared

[21] "Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan." (Report of the Board: A Renewed Regulatory Framework for Electricity, October 18, 2012, p 37)

"… it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates." (Handbook for Utility Rate Applications, October 13, 2016, p 13)

[22] Framework for Energy Innovation Working Group Report to the OEB, June 30, 2022, p 14

to provide further guidance, when needed, as the energy transition unfolds. We will endeavour to provide ongoing clarity about our expectations of distributors, and our view of their role, as we carry out the initiatives identified in our Energy Transition Roadmap. Furthermore, the OEB will continue to engage in other activities underway in the sector that may impact the role of distributors going forward, such as the work of the Electrification and Energy Transition Panel,[23] positioning us well to provide further guidance, as required.

4.5 Implementation

Having confirmed the OEB's expectations for DER integration and use, distributors should have sufficient guidance to begin identifying steps they need to take to deliver on these expectations and make proposals in their rate applications, as needed. Consistent with the OEB's focus on outcomes, this Report is intended to shape *what* the OEB expects of distributors, without being unhelpfully prescriptive about *how* to get there. The OEB recognizes that further specificity and detail about what these expectations mean for distributor planning and operations, and which rate-funded activities and investments may be undertaken by distributors, will arise through the adjudication of specific proposals and supplementary guidance, such as bulletins, which the OEB is prepared to provide, as needed.

At the time of their next scheduled update, the *Filing Requirements for Electricity Distribution Rate Applications* will be revised to carry forward the OEB's expectations articulated in this Report. To the extent that supplementary guidance is provided, further detail and specificity will be added, where applicable, to the *Filing Requirements* as part of their regular updates. The expectations set out in this Report may also be carried forward into other regulatory instruments, as required, when those instruments are otherwise scheduled for housekeeping or other updates.

[23] The Ministry of Energy finalized the Electrification and Energy Transition Panel on November 17, 2022. The Panel will author a Report that reflects the cross-sector insights needed to develop an effective pathway to improved long-term planning to address increasing electrification and the transition to clean energy.

5. Benefit Cost Analysis Framework for DER Solutions as Non-Wires Alternatives

5.1 Defining the Issue

As discussed in section 4.4, the OEB expects distributors to use an integrated approach to system planning and consider options for providing reliable, cost-effective distribution service to customers. Accordingly, the OEB expects distributors to consider DER solutions as NWAs and deploy them when doing so is determined to be the preferred approach to meeting a system need.[24]

To support distributors in meeting these expectations, the OEB set out to develop a Benefit Cost Analysis Framework (BCA Framework) that distributors can use to assess DERs as NWAs and make a business case for such projects in their rate applications.

Establishing a common BCA Framework is intended to support consistent evaluation of DER solutions across distributors and reduce uncertainty about how DER proposals will be assessed by the OEB in rate applications. The OEB's goal in developing a BCA Framework is not to promote adoption of DERs or advantage them over other solutions; it is intended to assist distributors in making use of DERs where that is the most appropriate solution.

5.2 FEI Working Group & Subgroup Recommendations

The FEI Working Group created a subgroup (BCA Subgroup), including representatives of customers, DER solution providers, utilities, environmental groups, and the IESO, tasked with:

> *Defining an approach to measure the benefits of these DER use cases relative to costs and assess the value of DERs relative to traditional distribution investments.*[25]

The BCA Subgroup contextualized a framework for BCAs as part of the OEB's guidance

[24] The 2021 CDM Guidelines require distributors to make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. (Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021, p 8)

The Filing Requirements for Electricity Distribution Rate Applications states a distributor's DSP should describe how it has taken CDM into consideration in its planning process. (Filing Requirements for Electricity Distribution Rate Applications, December 15, 2022, Chapter 5, s. 5.3.5, p 12)

[25] FEI Working Group Terms of Reference, May 26, 2021, p 5

to distributors, explaining how the OEB would review distribution system plans (DSPs). The output of a specific BCA would inform distributors' planning decisions between DERs and traditional network investments.

In undertaking its work, the BCA Subgroup agreed that DER impacts are often much broader than those associated with traditional distribution investments and can include impacts to the whole energy system. In the absence of mechanisms to ensure costs of DER solutions always follow benefits, BCA Subgroup members differed about which costs and benefits should be considered when the OEB approves funding for DER solutions through distribution rates. In other words, while there was agreement on the potential for broader benefits, there was disagreement over whether those benefits to the broader energy system should be paid for by the implementing distributor's customers.

In recognition of the diversity of perspectives, the BCA Subgroup offered measures of cost-effectiveness for the OEB to consider[26] and recommended that the OEB provide direction on the scope of BCA to be applied for making decisions about distributor deployment of DERs as NWAs. The FEI Working Group referred the OEB to the BCA Subgroup's report and recommended that the OEB "establish an initial framework and template for Benefit Cost Analysis."[27]

5.3 Stakeholder Comments

Most stakeholders supported considering impacts beyond the implementing distributor's system or customers, such as broader system impacts and some societal impacts. However, many were clear that their support for considering broader impacts is conditional upon establishing mechanisms to ensure costs follow benefits. Others suggested that, to ensure consideration of broader impacts does not impede the adoption of the lowest cost solutions, robust metrics and Ontario-specific assumptions are needed to accurately quantify such impacts.

A minority of stakeholders advocated for a narrow scope. Some suggested that if the costs of implementing DER solutions to meet a distribution system need are recovered from the deploying distributor's customers, then a BCA must be limited to the costs and benefits to those customers. Others cautioned that a broader framework, involving a complex calculation of energy system and societal impacts, may be unduly cumbersome for distributors and may risk "double counting" DER benefits secured through other means (e.g., participation in IESO markets). One stakeholder also pointed out that many "non-financial" benefits (i.e., societal benefits) are inherent to many DER projects and so measuring and accounting for them in decision-making is not necessary

[26] Report of the BCA Subgroup, June 8, 2022, p 17, Table 4-1

[27] FEI Working Group Report, June 30, 2022, p 18

to realize such benefits.

Several stakeholders recommended a two-stage process for the development of a BCA Framework whereby a test for distribution costs and benefits is established in the short-term, with broader energy system and societal impacts added later. This approach would allow DER projects with clear benefit to the implementing distributor's customers to proceed in the short term. Some who supported this approach suggested that, in the longer term, a broader analysis may be undertaken in instances where DER and conventional solutions are close in terms of the distribution net-benefits, but the DER project can secure additional energy system benefits.

5.4 The OEB's Conclusions

A BCA Framework that identifies the full energy system benefits and costs of DER solutions, even those that are difficult to quantify, will best serve the sector. However, different categories of costs and benefits may be weighted differently when considering the costs of DER solutions in setting distribution rates. The costs and benefits for the implementing distributor's customers will be the primary consideration for assessing rate funding of a DER solution. The OEB will launch a separate initiative to develop the components of the BCA Framework. The first phase of work, to develop guidance, methodologies, and tools for distribution impacts, will be complete by the end of the 2023/24 fiscal year. A second phase, focused on the broader energy system impacts, will follow.

The BCA Framework will ultimately allow for consideration of all the categories of system impacts (distribution service impacts, DER host impacts, transmission service impacts, resource impacts, and general energy system impacts) identified in the BCA Subgroup's Report, where appropriate.[28] The OEB's approach may include considering some of these costs and benefits on a qualitative basis.

Including a broad set of impacts will allow the BCA Framework to be used for distribution system planning and potentially other integrated planning processes, such as regional planning. Having a complete picture, and a common understanding, of DER costs and benefits will also help the OEB and the IESO work together to confirm which layers of the DER value stack have a corresponding revenue stream, where there are gaps and where mechanisms are required to ensure costs follow benefits in relation to

[28] The Report of the BCA Subgroup includes impacts on other energy systems (gas, oil, propane, gasoline, water) in its list of energy system impacts; however, the Report's focus is almost exclusively on the electricity system. The OEB considers "energy system impacts" to include impacts on the natural gas system, however the approach and timing to assessing and incorporating these impacts will need to consider related work that is currently being undertaken through the Integrated Resource Planning (IRP)IRP Technical Working Group, which was established to assist in the implementation of the IRP Framework.

DER solutions.[29]

For the purpose of electricity distribution rate-setting, the OEB will be employing a multi-test approach, as described by the BCA Subgroup.[30]

The OEB will develop and require use of a test that assesses the distribution costs and benefits, similar to the Distribution Service Test described in the BCA Subgroup's report.[31] In most cases, the costs and benefits for the implementing distributor's customers will be the primary consideration for approving rate funding of a DER solution.

However, the OEB's intent is to encourage the development of solutions that are in the best interests of both a distributor's customers and Ontario's energy customers more broadly. For this reason, the OEB will also develop guidance on an additional test (part of the multi-test approach) that will consider appropriate energy system impacts. The results of the broader test can be used to identify an optimal solution for Ontario's energy consumers as a whole and inform appropriate levels of cost sharing between parties. Depending on the nature of a DER solution there may be limitations on cost-sharing arrangements. While the OEB's expectation is generally that costs should follow benefits, there may be limited circumstances when distribution rate funding based on broader energy system impacts is warranted, and distributors should have the tools to incorporate those impacts in the analysis supporting their investment proposals. Like the approach set out in the Natural Gas Integrated Resource Planning (IRP) Framework, this allows different categories of costs and benefits to be considered separately.[32]

In addition to supporting deployment of optimal solutions for customers and helping to level the playing field between DER and traditional wires solutions, adopting a broadly scoped BCA Framework also gives the OEB (and utilities) the tools and flexibility to respond more quickly to government policy changes. For example, having a tool for understanding the broader energy system benefits of DERs positions the OEB to respond swiftly in the event of changes to its mandate as referred to in the Letter of Direction from Minister Smith[33] or changes to the long-term energy planning framework

[29] OEB and IESO coordination in this space has already started with the initiation of a joint study on DER Incentives to "create a better understanding of how financial incentives for DERs function collectively to ensure that different incentives aren't working to cross purposes and are achieving the most efficient outcomes." (IESO-OEB Joint Engagement on DERs held on November 23, 2022, Joint Engagement Introduction, p 15)

[30] Report of the BCA Subgroup, June 8, 2022, p 17, Table 4-1

[31] Ibid

[32] Decision and Order on Enbridge Gas Inc. Integrated Resource Planning Proposal, EB-2020-0091, July 22, 2021, p 50-51

[33] "I am counting on the OEB, informed by the work of its Innovation Task Force, to provide the Panel with its best advice on potential changes to the OEB's mandate and operations, including any necessary

that may result from the work of the Electrification and Energy Transition Panel. The OEB will revisit the question of which societal impacts, if any, should be included in the BCA Framework once work related to developing guidance on distribution and broader energy system impacts is complete. By then, there may be more clarity about any potential changes to the OEB's mandate to better inform a decision.

5.5 Implementation

To reduce the complexity and effort of carrying out BCAs in system planning (and reviewing BCAs provided as supporting evidence in rate applications), the BCA Framework will include all the components identified by the BCA Subgroup, including tools for distributors.

The OEB will launch a new initiative to develop the components of the BCA Framework. This will include developing guidance on methodologies, establishing standard inputs and assumptions where possible, and creating a template to standardize project-specific BCAs across distributors.

Work will be sequenced to provide guidance and tools for assessing impacts on the implementing distributor's customers first (to facilitate distributor proposals sooner), and broader energy system impacts later. Once that work is complete, the question of societal impacts will be revisited.

Components of a BCA Framework

1. **Purpose and use:** identifies when a BCA is required and the BCA's intended use
2. **Information requirements:** lists the impacts that should be considered for assessment in a BCA
3. **Cost-effectiveness test:** sets out how the BCA impact assessment will be used to inform which solution should be deployed by the distributor, all other planning considerations being equal
4. **Standardized methods:** provides standard methods, assumptions, and tools for carrying out assessments
5. **Reporting requirements:** establishes the format for presenting BCAs

Figure 7: Components of a BCA Framework

The OEB will retain an expert consultant to support the development of draft guidance and tools for stakeholder comment. The OEB may hold stakeholder meetings on specific issues. To ensure the BCA Framework is implemented in a timely manner, existing and well-established methodologies and content that can be borrowed from "off

legislative amendments. This advice should include, but need not be limited to, opportunities to incorporate environmental and economic development benefits into the OEB's regulation of the sector…" (Letter of Direction from Minister Smith, October 21, 2022) the shelf" cost-effectiveness tests, or economic evaluations already in use for other purposes in Ontario (e.g., assessing NWAs in regional planning,[34] CDM, etc.), will be leveraged to develop appropriate guidance and tools.

Further details will be provided in a separate letter initiating this work.

Distributors should not wait until after the OEB has finalized its BCA Framework to consider DER solutions and seek OEB approval for distribution rate funding, where appropriate. Distributors may choose to use a conventional discounted cash flow analysis to compare the costs and benefits of a DER solution for their customers against a traditional wires approach and make the business case in a rate application. Until the OEB provides additional guidance, distributors should explain how they have considered those costs and benefits as part of the information provided for material investments proposed for recovery in rates.[35] Distributors may also give consideration to broader energy system impacts, as appropriate.

[34] The OEB understands the IESO intends, for the purpose of supporting Integrated Regional Resource Plans, to "publish guidelines for the evaluation of non-wires alternatives; this document could be helpful to LDCs as they look to support applications to the OEB by proposing a consistent methodology for the assessment of opportunities." (*2021-2024 Conservation and Demand Management Framework Mid-Term Review*, IESO, December 2022, p 55). The OEB has been engaging with the IESO on this work and any guidance provided by the IESO will be considered in the development of the components of the OEB's BCA Framework but will not be determinative for the purpose of setting distribution rates.

[35] The *Filing Requirements for Electricity Distribution Rate Applications* provides guidance on how distributors should demonstrate consideration of the costs and benefits of material investments proposed for recovery in rates. (Filing Requirements for Electricity Distribution Rate Applications, December 15, 2022, Chapter 5, s. 5.4.1.1, p 15)

6. Utility Incentives for Third-Party Owned DERs as Non-Wires Alternatives

6.1 Defining the Issue

As discussed in section 4.4, the OEB expects distributors to consider third-party owned DER solutions as NWAs for meeting system needs. The OEB recognizes that, in deploying these solutions, distributors will forgo an opportunity to earn a return by adding to their rate base, since "DERs will often, from a utility point of view, be non-capital in nature."[36] This misalignment between utilities' interests (to earn profits by building assets) and customer interests (to have the most cost-effective delivery of reliable energy services) may be a barrier to DER solutions. Providing incentives for distributors to deploy third-party owned DERs as NWAs is a way of addressing this barrier in the near term, without revisiting the fundamental approach to how utilities are remunerated and the overall rate-setting framework. That exercise, while warranted in the context of the energy transition, is also lengthy and complex. By addressing the more narrowly scoped issue at hand, the OEB is evolving the current framework to facilitate near-term progress that will inform a broader reconsideration of remuneration.

Uncertainty about the potential recovery of new types of DER-related OM&A costs can be another barrier for distributors. As described by the Utility Incentive Subgroup, this can include administrative costs, DER procurements costs, and the costs of payments provided to third-party DERs for the services they provide to the distribution system.[37] Addressing this uncertainty can assist distributors in meeting the OEB's expectations with respect to DER integration and use.

6.2 FEI Working Group & Subgroup Recommendations

The Utility Incentives Subgroup, comprised of individuals representing customers, utilities, and DER solution providers, provided analysis and recommendations related to:

> *Developing appropriate incentives for distributors to adopt DERs for distribution uses that do not require equity investment by the utility.*[38]

In completing its work, and consistent with the FEI Working Group's Terms of Reference, the Subgroup focused on incentive options that can be adopted within the OEB's current rate-setting framework. The Subgroup recommended the OEB test different incentives to understand their effectiveness and consequences for customers

[36] Report of the Utility Incentives Subgroup, June 8, 2022, p 5

[37] Ibid, p 7-8

[38] FEI Working Group Terms of Reference, May 26, 2021, p 5

and distributors. In developing an incentives policy, the Subgroup suggested the OEB consider the effectiveness of incentives in motivating desired utility behaviour and achieving intended outcomes, the cost to customers, any unintended consequences, and regulatory simplicity.

Table 1: Options Identified by the Utility Incentives Subgroup

Options Identified by the Utility Incentives Subgroup	
Capitalization of DER Spending	Closest to utilities' current business model as it allows distributors to earn a return on DER solutions as if they were capital assets.
Fixed Incentives	Opportunity to earn fixed fees for DER solutions (predetermined amount built into rates at rebasing, performance-based amounts or a Return on Equity premium).
Margin on Payments	Allows distributors to add a margin on spending to compensate DERs owned by customers or third parties for providing capacity, reliability, etc.
Shared Savings Mechanisms	Calculates the savings for customers from DER solutions and allocates a formula-based portion of savings to utility shareholders.
Scorecard-Based Financial Incentives	Allow distributors to earn fees based on their performance against scorecard metrics.
Non-Financial Tools	Require distributors to adopt DER solutions as NWAs or use DER-related scorecard metrics as a reputational incentive.

In addition to considering positive financial incentives, Subgroup members also recommended the OEB consider mitigating disincentives to DER solutions. Specifically, it was recommended that the OEB address uncertainty or barriers to recovering new types of DER-related costs (e.g., additional planning activities or procurement of third-party services).

In considering the analysis of the Utility Incentives Subgroup, the FEI Working Group provided two recommendations to the OEB:

1. *Remove DER Disincentives including Cost Recovery Uncertainties*
2. *Establish an Initial DER Incentives Policy including Testing Possible Incentive Structures*

6.3 Stakeholder Comments

Stakeholder comments on the need for and appropriateness of utility incentives varied significantly, however there was broad support for removing disincentives to DER adoption, including addressing uncertainty regarding cost recovery of DER-related investments.

Some stakeholders suggested incentives are appropriate to ensure distributors give equal consideration to NWAs and traditional solutions. Among these stakeholders, there was no majority support for a specific incentive option. Some expressed support for performance-based incentives, including a shared savings mechanism, citing their potential to ensure adoption of the most cost-effective solution. Another stakeholder suggested that a performance-based scorecard would be optimal within the OEB's existing regulatory framework. Others suggested that capitalization of DER spending is the only tool available to ensure equal consideration of NWAs, otherwise distributors will continue to prefer traditional solutions for their potential to earn a rate of return. A few suggested that the fundamental approach to utility remuneration should be revisited to make utilities fully indifferent to capital investments and operational expenses.

A few stakeholders suggested the OEB should consider testing incentive options, whether through pilot programs or by inviting distributors to submit proposals in applications. Proponents of this approach asserted that it would yield insights into how various incentives motivate utility behaviour, any unintended consequences and ultimately, whether incentives are necessary for ensuring a level playing field among NWAs and traditional solutions.

Some stakeholders, mainly consumer groups, commented that incentives are not appropriate since regulated utilities should be obliged to implement the most cost-effective solutions to serve customers. In other words, distributors should not receive additional compensation for making decisions that are in the best interests of their customers. In support of this position, some referenced recent OEB guidance and decisions that affirmed the importance of considering NWAs in system planning,[39] and argued that incentives are not appropriate because distributors are already expected to implement the most cost-effective solutions, irrespective of the impact on utility profits. Others suggested the OEB should use its authority to compel distributors, by licence condition or new conditions for approving DSPs, to implement DER solutions where they are the lower cost option.

Some indicated that mitigating major disincentives, including cost recovery

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[39] Recent OEB decisions have affirmed the importance of adequately considering non-wire or non-pipe alternatives in system planning. See Decision and Orders: Hydro One Application for leave to construct: upgrade of a high voltage electricity transmission line in the townships of Iroquois Falls, Black River-Matheson and Kirkland Lake, EB-2021-0107, December 2, 2021; Enbridge Gas London Lines Replacement Project, EB-2020-0192, January 28, 2021; St. Laurent Ottawa North Replacement Project, EB-2020-0293, May 3, 2022.

uncertainties, may be sufficient to encourage greater uptake. To this end, these stakeholders argued the OEB should prioritize the development of a BCA Framework, as well as mechanisms for allocating costs to broader energy system beneficiaries. Ultimately, these stakeholders suggested implementing incentives should not be prioritized because their need has not been established.

6.4 The OEB's Conclusions

Prudently planning a distribution system that reliably serves customers in the context of broader DER adoption will become a routine function for distributors and related costs will generally be treated the same as other capital and OM&A spending. However, to alleviate uncertainty regarding the potential for cost recovery, distributors who need one are encouraged to apply for a deferral account to record material OM&A costs related to DER integration and use incurred in advance of their next rebasing application.

To test the effectiveness of incentives at securing benefits for customers of using third-party owned DERs as NWAs, distributors may propose an incentive in their rate applications that include material projects of this kind. The outcomes of these proceedings, combined with observing the impacts of any approved incentives, will inform the OEB on any broader review of utility remuneration and any future incentives policy that may be applicable to all distributors. OEB guidance to facilitate applications for incentives will be issued by March 31, 2023.

Removing Disincentives

Cost-effective DER integration and making use of DERs as NWAs to meet system needs are relatively new activities for distributors, but ones that will eventually become business as usual. Associated capital and OM&A costs will be treated in the same manner as costs for other distribution activities, such as network expansion and renewal, asset maintenance, ongoing planning work, and vegetation management programs. Consistent with expectations for integrated planning, set out in the Renewed Regulatory Framework, distributor rebasing applications should demonstrate how expenditures related to DER activities are integrated and balanced against all other distributor spending priorities, to support optimized outcomes for customers.

The OEB recognizes that some distributors will not be rebasing for up to five years, potentially longer if a merger has been recently approved, and may start incurring material costs associated with DER integration and use in the interim. Especially in the near term, the implications of these activities, and the magnitude of associated costs, will vary across distributors depending on the nature, pace, and extent of DER penetration experienced within their service area.

The Incremental Capital Module is available to address qualifying and material capital costs incurred during a rate term, which can be used to facilitate any urgent DER-related investments that may be required. Since many DER-related costs distributors will incur are expected to be OM&A expenses rather than capital,[40] distributors may apply for a deferral account, with a draft accounting order, to record material expenses related to DER integration and use. The account may include costs incurred until the distributor's next rebasing, at which point such costs should be forecast and integrated into the distributor's overall spending proposal and business plan. The requested deferral account should meet the OEB's criteria of causation, materiality, and prudence for establishing new accounts. Disposition of this deferral account (and its discontinuance) would be addressed at the next rebasing. At the time of the rebasing application, a distributor may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy. The amounts recorded in the deferral account and how they were calculated, including alignment with the BCA Framework or other policy guidance available at the time, will be considered as part of the distributor's rebasing application.

By making a deferral account available to distributors who need it, the OEB intends to mitigate uncertainty about the kinds of DER implementation costs, such as administrative costs for new DER-related activities, distributors may seek to recover (provided they are determined to be prudent and meet all the other requirements for account disposition). The OEB also intends to encourage distributors to start taking immediate steps to integrate and use DERs, consistent with the expectations it has laid out in this Report. This in turn should support distributors in adapting to meet the demands of the energy transition and help level the playing field for DER solutions. This account is not meant to be a long-term substitute for good utility planning; it is a transitional mechanism until integrated planning for DERs is reflected within DSPs at each distributor's next rebasing.

Testing Incentives

The OEB invites distributors to file a proposal for an incentive mechanism to accompany the deployment of third-party owned DER solutions as NWAs.[41] Proposals may be filed as part of a rebasing application or as a standalone application. Distributors may

[40] The Utility Incentives Subgroup Report identified OM&A costs that distributors may incur from integrating DERs, including, for example, hiring new personnel and procurement costs. (Report of the Utility Incentives Subgroup, June 8, 2022, p 7-8)

[41] This approach is consistent an OEB decision allowing Enbridge to propose incentives along with an IRP Plan filed under the First-Generation IRP Framework: "As more is learned though the pilots, the FEI, or experience in other jurisdictions, consideration of incentives may be part of the assessment of an IRP Plan on a case-by-case basis." (Decision and Order on Enbridge Gas Inc. Integrated Resource Planning Proposal, EB-2020-0091, July 22, 2021, p 76)

choose from one of the following incentive options:

- Shared savings mechanism
- Performance-target or scorecard-based incentive
- Margin on DER payments

Once some incentives have been in place for sufficient time to assess implications and outcomes, the OEB will use that information, as well as lessons learned from adjudicating the proposals, to inform any broader review of utility remuneration and determine if any future incentives policy applicable to all electricity distributors is warranted. To facilitate this, the OEB may seek to undertake interim assessments of incentive impacts within the first 24-36 months of their implementation, in addition to considering the outcomes of incentives during review of implementing distributors' next rebasing applications. If appropriate, lessons learned may also inform any incentives available under the next generation natural gas IRP Framework.

As shown in Table 1 above, the Utility Incentive Subgroup identified six incentives that could be implemented within the OEB's current rate-setting framework. The OEB is selecting three to test further. The OEB is selecting the shared savings mechanism and performance-target or scorecard-based incentive because, in both cases, the financial incentive is tied to a specific outcome that benefits customers. Ontario has some experience with these approaches through natural gas Demand Side Management Frameworks, which should contribute to a more reasonable level of regulatory effort (for all involved) to assess and implement these approaches. Additionally, the calculation of savings under a shared savings mechanism may be simplified by the presence of a standard BCA methodology, once the BCA Framework is complete. As a third option, the OEB is selecting to test a margin on spending. Although this option does not tie the financial incentive to a desired outcome (it still ties distributor earnings to more spending), it is one of the simplest incentives to administer. Given the value of regulatory simplicity, the OEB believes it is worth giving distributors the option to test it.

Testing distributor incentives for third-party owned DER solutions is warranted to gauge their effectiveness at aligning utility and customer interests and overcoming barriers to DER solutions (i.e., potential utility preference for capital investments and doing things the way they have always been done instead of realigning internal business practices to accommodate new approaches). Indeed, this step is a natural progression of the OEB's performance-based approach to rate-regulation. The Renewed Regulatory Framework Report envisioned eventually building on the foundation it established through "development of incentives to reward superior performance, encourage innovation, [and] encourage asset optimization."[42]

The potential for utilities to prefer capital solutions is not a new feature of the prevailing approach to rate regulation. The FEI Working Group and some other stakeholders

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[42] Report of the Board: A Renewed Regulatory Framework for Electricity, October 18, 2012, p 61

suggested the OEB will need to reconsider the fundamental utility remuneration paradigm, in light of the impacts of the energy transition. The Letter of Direction to the OEB from Minister Smith also identified the need to reconsider utility remuneration, among other things, to support distribution sector resiliency, responsiveness, and cost efficiency.[43] Identifying new or modified approaches to utility remuneration has extensive implications for utilities and customers. It requires careful and thorough consideration, and effective stakeholder consultation is essential to success. Testing incentives for third-party owned DER solutions is an important step towards OEB consideration of the broader, more fundamental remuneration question, while also facilitating more immediate progress on the use of DERs. Overall, testing incentives will help the OEB develop effective tools for driving sector performance, and ensure the regulatory framework and distributors are positioned to meet the demands of the energy transition.

6.5 Implementation

The OEB will, by March 31, 2023, issue guidance on information distributors should include to support incentive proposals in their applications. Guidance will be tailored, as required, to each type of incentive distributors may propose, to facilitate effective and timely regulatory review.

Guidance for DER deferral account applications has been provided in this Report. Since distributors are ultimately better positioned to specifically define the types of DER-related costs they will incur, the OEB will rely on distributors to do so in their applications seeking an account so a decision can be made about which specific costs may be recorded.

[43] Letter of Direction from Minister Smith, October 21, 2022, p 3

7. DER Integration

7.1 Defining the Issue

Distributors will need information about DERs to inform their system planning and operations in order to meet the OEB's expectations set out in this Report. By understanding the specific information that may be necessary or beneficial for distributors to have, the OEB can help identify and fill gaps in data collection or provide clearer guidance regarding the information the OEB expects to see in support of DER-related spending proposals.

7.2 FEI Working Group & Subgroup Recommendations

The DER Integration Subgroup was tasked with "identifying information distributors require regarding existing DERs to effectively operate and make future system plans."[44] In addition to determining how planning and operations may evolve to prepare for increased DER penetration, the Subgroup determined that distributors require information about DERs to develop inputs for a BCA, as well as business cases for DER-enabling investments. Information is also needed to develop internal processes to procure and manage non-utility owned DER solutions.[45]

With respect to what information is needed, the Subgroup identified three main categories:

1. **DER adoption forecasts:** There may be benefit in developing a common forecast and/or set of planning assumptions, but information must also be sufficiently granular and specific to a distributor's service area to inform planning decisions.

2. **DER usage data:** Distributors require information about how their customers will use DERs connected to their systems. Existing load monitoring methods may be sufficient for understanding the impacts of some DERs, but distributors may require higher visibility of others interacting directly with the system (e.g., injecting supply).

[44] FEI Working Group Terms of Reference, May 26, 2021, p 5

[45] Unlike the BCA and Utility Incentives Subgroups which focused on the use of DERs as NWAs to meet distribution system needs, the DER Integration Subgroup was tasked with considering information distributors require to plan for DER adoption broadly (i.e., DERs adopted by consumers for their own purpose and those deployed to provide services to the IESO-administered markets, as well as DERs used as NWAs to meet distribution system needs).

3. **Market relevant information to enable the use of third-party DERs as NWAs:** To enable NWAs, distributors require information about DER presence and availability. Market relevant information (i.e., price, quantity, term, and location) must be exchanged between distributors and third-party providers or customers.

In considering the analysis of the DER Integration Subgroup, the FEI Working Group provided two recommendations to the OEB:

1. *Establish an Initial Policy for the Sharing of Information between LDCs, DER Providers, and Customers to support distribution planning and operations*
2. *Develop Regulatory Reporting Requirements for DERs, including RRR Filings, Applications, and other OEB Reporting*

7.3 Stakeholder Comments

With respect to updating regulatory reporting requirements, some stakeholders said the OEB should identify the information distributors must provide to demonstrate they have adequately considered NWAs in applications. Others suggested the OEB undertake a review of how previously filed DSPs were assessed to identify how the OEB's DSP filing requirements could provide clearer expectations of how distributors are to address and incorporate DERs.

Many stakeholder comments also highlighted a need to foster greater information sharing among distributors, DER solution providers and customers. Information flows should be bi-directional so distributors are aware of existing and proposed resources available to meet system needs, and so DER developers and "prosumers" (i.e., consumers who provide energy services for themselves and potentially to the energy system as well) understand what DER services would be of most value to the system. Other stakeholders advocated for exploring opportunities to share greater information between distributors and the IESO to better understand and evaluate non-distribution system impacts of DERs.

Some stakeholders said additional reporting requirements should be considered only after the OEB has addressed other priority issues related to DER integration, including providing clear guidance on the role of distributors, establishing a BCA framework and mitigating DER disincentives. One stakeholder pointed out that new information gathering and reporting requirements are already being considered by the OEB through other initiatives and consideration of additional requirements should be deferred until those processes have concluded.

7.4 The OEB's Conclusions

Mindful of new DER-related reporting and information-sharing guidance and requirements arising from other initiatives, the OEB does not, at this time, intend to establish additional regulatory requirements with respect to the information about DERs that the OEB collects from distributors or requires distributors to collect.

Distributors contracting with third-party owned DERs for NWAs require information to be exchanged about system needs and available solutions. The OEB can potentially help facilitate these arrangements by, among other things, providing guidance or standardizing information-sharing requirements, but further consideration is required. Therefore, before the end of the 2023/24 fiscal year, the OEB will launch a new consultation to explore arrangements between distributors and DER solution providers and identify any reforms to the regulatory framework required to facilitate, standardize, or provide appropriate oversight of these arrangements.

Information to Support DER Integration

Consistent with one of the DER Integration Subgroup's recommendations, the OEB anticipates that the articulation of its expectations of distributors with respect to DERs in this Report should help distributors consider how their planning and operations need to evolve to meet those expectations, including identifying information needed to inform their business decisions.

With respect to the information about DERs that the OEB collects from distributors or requires distributors to collect, the OEB is mindful of the Minister's focus on "Red Tape Reduction"[46] and the need to carefully consider the necessity of any new requirements. The OEB has concluded that the following activities recently completed or currently underway address needs for DER information and imposing additional requirements would be premature at this time:

- The OEB's Regional Planning Process Advisory Group developed a *Load Forecast Guideline*[47] for electricity distributors, transmitters, and the IESO to use to ensure greater consistency in preparing load forecasts, including consideration of the impact of electrification, for the purpose of regional planning across Ontario. Among other things, the Guideline has identified information that municipalities should provide to distributors, including any expectations or

[46] "I ask that the OEB propose aggressive targets for continuing to reduce the number and cost of regulatory burdens by the end of the current business planning period (i.e., March 30, 2026) …" (Letter of Direction from Minister Smith, October 21, 2022)

[47] Regional Planning Process Advisory Group, Load Forecast Guideline for Ontario, October 13, 2022

objectives regarding DERs. The Guideline will be revisited every two years – with the next review anticipated by 2024 – to address emerging issues, which may include availability of new information about DER adoption.

- The *Filing Requirements for Electricity Distribution Rate Applications* have recently been updated to include expectations about planning and preparing for EV adoption.
- The OEB is facilitating implementation of Green Button in Ontario. Green Button enables customer-authorized sharing of data that distributors provide to their customers in the normal course of business. This may include information useful to those interested in deploying DERs. Electricity and natural gas distributors are required to implement Green Button by November 1, 2023.
- The OEB's DER Connections Review Working Group recommended, and the OEB is implementing, updates to the *Reporting and Record Keeping Requirements for Electricity Distributors* to include additional data about the quantity of different DERs connected to distribution systems. Also stemming from this initiative, Distribution System Code amendments that came into force on October 1, 2022, implement a revised process for preliminary consultations on connections and require distributors to publish information about restricted feeders. Both measures are intended to aid potential DER owners in determining appropriate locations for connecting DERs to the distribution system.[48]
- Under its Reliability and Power Quality Review, the OEB has implemented changes to the *Reporting and Record Keeping Requirements for Electricity Distributors* to clarify and provide more detail with respect to reporting on loss of supply, major events and interruptions. This is a first step toward enhancing measurement and tracking of reliability and power quality, which may eventually be used to help identify opportunities for NWAs.
- The IESO's Transmission and Distribution Coordination Working Group[49] is tasked with identifying DER coordination protocols, including exchanging information. The outcomes of this initiative may inform the need for further guidance or requirements from the OEB.
- The IESO's DER Potential and Pathways to Decarbonization Studies, along with the Ministry of Energy's Cost-Effective Decarbonization Pathways study currently under development to inform the work of the Electrification and Energy Transition Panel, may help the sector arrive at a shared view of probable DER adoption scenarios to inform planning decisions.

[48] DER Connections Review, Final Notice of Amendments to the Distribution System Code regarding the connection of distributed energy resources (DERs) to local electricity distribution systems, EB-2021-0117, March 22, 2022

[49] Transmission & Distribution Coordination Working Group Terms of Reference, May 16, 2022

Information to Support Third-Party Owned DERs as NWAs

The OEB understands that distributors contracting with third-party owned DERs for NWAs require information to be exchanged. The OEB can potentially help facilitate these arrangements by providing guidance or standardizing information sharing about system needs and available solutions. However, further examination of this issue is required before the OEB can provide appropriate guidance that provides clarity and consistency, where appropriate, but is not unduly prescriptive and constraining.

The FEI Working Group (and subgroups) as well as other stakeholders identified other areas where OEB guidance or requirements may help facilitate these arrangements on a more widespread basis. This could include standard approaches for valuing and compensating DERs for the services they provide to the distribution system. It could also include examining the sufficiency of current rules to govern relationships between distributors, third-party DER providers, and customers. Considering the Letter of Direction from Minister Smith[50], guidance on shared-services arrangements between distributors with respect to NWAs may also be beneficial. Once again, further consideration of these issues is required before the OEB can provide appropriate guidance. Section 7.5 outlines the OEB's plan to examine these issues further.

7.5 Implementation

The OEB has concluded that activities recently completed or currently underway address needs with respect to the information about DERs that the OEB collects from distributors or requires distributors to collect. However, there is a need to further consider exchange of information between distributors and DER solution providers.

The OEB will launch a stakeholder consultation process, before the end of the 2023/24 fiscal year, to explore arrangements between distributors and DER solution providers (which can include customers) and identify any reforms to the regulatory framework required to facilitate, standardize, or provide appropriate oversight of these arrangements.

This will include consideration of:

- Information exchange requirements to facilitate DER services to the distribution system, including privacy and cybersecurity matters;

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[50] "To continue to provide high levels of reliability and resiliency to their customers, be responsive to changing consumer expectations and new government mandates, and to do it all at an affordable price ... LDCs will need greater capacity ... that can be enabled by aggressively pursuing efficiencies through consolidation or enhanced shared services, adoption of innovative technologies and processes, collaboration on responsibilities like cybersecurity, and changes to the utility remuneration and incentive structure that ensure LDCs make the right investments for their customers." (Letter of Direction from Minister Smith, October 21, 2022)

- Approaches for procuring and compensating DERs for the services they provide to the distribution system;
- Rules governing interactions between parties; and
- Standardization across distributors, where appropriate.

To help develop a more detailed scope and work plan, an early step in this consultation will be to review existing NWA projects, such as pilots funded through the IESO's Grid Innovation Fund, to understand different approaches and lessons learned.

The outputs of this work will be folded into the current CDM Guidelines, which the OEB intends to convert into consolidated Guidance on the Deployment of NWAs, covering distributor CDM and DER activities. New and modified requirements would also be incorporated into relevant codes (e.g., the Distribution System Code and Affiliate Relationships Code), as required.

The CDM Guidelines already provide "guidance on the role of conservation and demand management (CDM) for rate-regulated electricity distributors"[51] and "place a greater emphasis on the use of CDM activities by distributors to address system needs and avoid or defer investments in traditional wires infrastructure than previous iterations of the CDM Guidelines."[52] There is significant overlap between CDM and DERs. Both can be used by distributors as NWAs. Many organizations include CDM within the definition of DER, one form of many supply-side or grid-edge resources that can come together to deliver energy services. Conversely, the CDM Guidelines include energy storage and behind-the-meter generation, two forms of DERs, as CDM activities in which distributors may engage. For these reasons, repurposing the CDM Guidelines is appropriate. Refreshing and repurposing the CDM Guidelines in this way is another tangible step on our journey to adapt the regulatory framework to keep pace with the energy transition and better accommodate new responsibilities and activities of distributors. When it is complete, this new, consolidated guidance will be reflected in the *Filing Requirements for Electricity Distribution Rate Applications,* as required.

[51] Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021, p 3
[52] Ibid p 3

8. Conclusion

This Report sets out the OEB’s expectations of electricity distributors for DER integration and use, as well as a concrete plan for facilitating routine use of DERs as NWAs, when doing so is cost-effective and benefits customers. The policies set out in this Report are intended to build upon and evolve the OEB’s performance-based approach to regulation and support the electricity distribution sector as it responds to the energy transition. This Report aims to provide sufficient clarity for distributors to begin acting now and the OEB is prepared to provide further guidance, when needed, as the energy transition unfolds.

The OEB is grateful to the members of the FEI Working Group for their tremendous contributions and to all stakeholders who participated in this consultation for sharing their perspectives and advice on these important issues.

Appendix A: Summary of OEB Response to FEI Working Group Recommendations

FEI Working Group Recommendation	OEB Response
1. Provide Further Guidance on the Role of Distributors and the Expectations of Them. While the evolution of the sector may mean that longer term changes to the role, responsibilities and activities of distributors cannot, and perhaps should not, be determined and implemented immediately, distributors would benefit from guidance on what is expected from them in the short term. This includes things such as their relationship to third-party DER providers and customers, and modifications to the planning and operation of their systems to reflect changes in the broader energy marketplace in which distributors operate. Like all guidance in these areas, this may change over time, but for right now distributors need assistance in determining practical things like how to modify the development of their next Distribution System Plan to be consistent with OEB expectations.	To support the cost-effective provision of distribution service that provides long-term value to customers, the OEB expects distributors to factor DER integration, consistent with the pace of DER adoption, into their planning and operations. Distributors must also consider DER solutions (NWAs) when assessing options for meeting system needs. Any proposals for a rate-funded, distributor-owned DER solution must demonstrate that a distributor has meaningfully explored contracting services from non-utility owned DERs – including providing sufficient lead time for third-party DER solutions to be identified and implemented – and doing so is either not feasible or less cost-effective in that instance. Although DER integration and use may be relatively new, or not yet routine for some distributors, the OEB expects that over time they will become business as usual. Having confirmed the OEB's expectations for DER integration and use, distributors should have sufficient guidance to begin identifying steps they need to take to deliver on these expectations and make proposals in their rate applications, as needed. The OEB is prepared to provide further guidance, when needed, as the energy transition unfolds. We will endeavour to provide ongoing clarity about our expectations of distributors, and our view of their role, as we carry out the initiatives in our Energy

	Transition Roadmap. Furthermore, the OEB will continue to engage in other activities underway in the sector that may impact the role of distributors going forward, such as the work of the Electrification and Energy Transition Panel, positioning us well to provide further guidance, as required.
2. Actively Engage in the Broader Energy Sector Policy Development Activities. The changes to the energy sector are being discussed, and policy changes are being made, by the OEB, IESO, government ministries and agencies at multiple levels, and by many non-governmental organizations. The OEB can play a valuable role by actively engaging in the many initiatives of those other bodies currently underway, and those coming in the near term (including and expanding its engagement with the IESO). Examples include continuing active coordination with the IESO, providing a forum, and establishing a communications hub to ensure that stakeholders, including regulated utilities, have regular and consistent information on the evolution of the sector and the policy changes being proposed or implemented by the various actors.	The OEB is developing an Energy Transition Roadmap in consultation with stakeholders. The Roadmap, a schedule of initiatives the OEB is taking or plans to undertake, will clarify the OEB's work priorities with respect to the energy transition, support coordination of interrelated initiatives within the OEB and across the sector, and support effective stakeholder engagement by providing clarity about where and when issues are being addressed. The OEB continues to coordinate with the IESO, exemplified this year through the: • Joint Targeted Call on DER Integration (IESO Grid Innovation Fund and the OEB Innovation Sandbox); • Joint Engagement Sessions on DERs; • Joint Study of DER Incentives; and • Mutual participation in respective stakeholder engagements. The OEB is also actively supporting the work of the Ministry's Electrification and Energy Transition Panel.
3. Establish an Initial Framework and Template for Benefit Cost Analysis. Developing the Framework involves policy decisions on what information on benefits and on costs should be	A Benefit Cost Analysis (BCA) Framework that allows for consideration of the full energy system benefits and costs of DER solutions will best serve the sector. For the purpose of electricity distribution rate-setting, the OEB will be employing a multi-test approach. The costs and benefits for the implementing

included, and for what purposes. It may involve distinguishing between factors that are used for decision-making purposes versus other purposes. Distributors would also benefit from a formal, OEB-developed template that implements the appropriate benefit cost analysis in a way consistent with the framework policy the OEB determines.	distributor's customers will be the primary consideration for assessing rate funding of a DER solution. However, the BCA Framework will allow for consideration of broader energy system benefits, where appropriate. The OEB will launch a new initiative to implement the BCA Framework, including developing methodological guidance for the calculation of costs and benefits, standardized inputs/assumptions, and a standard template for carrying out BCAs. The OEB will retain an expert consultant to support the development of draft guidance and tools for stakeholder comment. The OEB may hold stakeholder meetings on specific issues. Work will be sequenced to provide components related to the distribution costs and benefits first, by the end of the 2023/24 fiscal year, and broader energy system impacts after that.
4. Remove DER Disincentives including Cost Recovery Uncertainties. Separate from consideration of any positive incentives for distributors, it is important that the OEB ensure that DER-related disincentives and cost recovery uncertainties are removed. This would require a rigorous identification of those disincentives and uncertainties, and policy determinations by the OEB as to which of those, if any, are appropriate utility risks, and which should be adjusted or ameliorated to assist distributors and encourage the evolution of the sector.	Prudently planning a distribution system that reliably serves customers in the context of broader DER adoption will become a routine function for distributors and related costs will generally be treated the same as other utility capital and OM&A spending. To mitigate uncertainty about the kinds of DER implementation costs distributors may seek to recover (provided they are determined to be prudent and meet all the other requirements for account disposition), distributors who need one are encouraged to apply for a deferral account to record material OM&A costs related to DER integration and use incurred in advance of their next rebasing application. Deferral account applications may be filed immediately.

	By making a deferral account available to distributors who need it, the OEB is aiming to encourage distributors to start taking immediate steps to integrate and use DERs consistent with the OEB's expectations.
5. Establish an Initial DER Incentives Policy including Testing Possible Incentive Structures. The Report of the Utility Incentives Subgroup provides a list of potential financial and non-financial incentives for distributors to encourage DERs, and criteria for analyzing those incentives. The OEB should first make a general policy decision as to the extent, if any, to which positive incentives are appropriate. The next step would be to test any incentives that fit within that policy against actual use cases to determine the real-world consequences. This could be done by modeling, by pilot projects, or through utility applications.	To test the effectiveness of incentives at securing benefits for customers of using third-party owned DERs as NWAs, distributors may propose an incentive in their rate applications that include material projects of this kind. Distributors may propose one of the following: • A shared savings mechanism • A performance-target or scorecard-based incentive • A margin on DER payments Adjudicating proposals and observing impacts of approved incentives will inform any future incentives policy applicable to all distributors. By March 31, 2023, the OEB will issue guidance to distributors on the information incentive proposals should include, to facilitate effective and timely review of applications.
6. Establish an Initial Policy for the Sharing of Information between LDCs, DER Providers and Customers to support distribution planning and operations. LDCs, DER providers and customers each have information that would be of value to the others. Both the nature of that information, and the needs of the parties, will evolve over time. At least initially, regulated utilities would be assisted in	Before the end of the 2023/24 fiscal year, the OEB will launch a stakeholder consultation to identify any reforms to the regulatory framework required to facilitate, standardize, or provide appropriate oversight of arrangements between distributors and DER solution providers. This will include consideration of information exchange requirements to facilitate DER services to the distribution system. Other matters related to these arrangements

incorporating DERs into their planning and operations if the OEB established a transitional policy for information sharing (including with respect to pilots) in all directions, stipulating the types of information to be shared, and the timing and method of sharing (including among LDCs). While Green Button may provide some information sharing, more will be required, particularly by distributors.	will also be considered, including: • Approaches for procuring and compensating DERs for the services they provide to the distribution system. • Rules governing interactions between parties. • Standardization across distributors, where appropriate. To house new guidance arising from this work, the OEB will convert the CDM Guidelines into consolidated guidance on the use of NWAs, given the extensive overlap between CDM and DERs as alternatives to meet distribution system needs.
7. Develop Regulatory Reporting Requirements for DERs, including RRR Filings, Applications, and other OEB Reporting. Key to the OEB staying on top of the changes taking place in the energy marketplace relating to DERs will be the information that it receives. The two main information flows – RRR filings and Applications – should be revised so that the OEB has initial information on the impact of DERs on load, customer requirements, costs, forecasting, planning, and other aspects of the regulated utility's business. Distributors would be assisted if the OEB took a proactive approach to these information expectations.	Mindful of new DER-related reporting and information sharing arising from other initiatives, the OEB does not intend to establish further requirements with respect to the information about DERs that the OEB collects from distributors or requires distributors to collect, at this time. New guidance and requirements include: • The *Load Forecast Guideline* developed by the OEB's Regional Planning Process Advisory Group. Expanding the types of DERs tracked in the *Reporting and Record Keeping Requirements for Electricity*, recommended by the DER Connections Review Working Group.

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