ONTARIO ENERGY BOARD

DER Valuation Review

Stakeholder Consultation

November 24th, 2025

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Please note the supporting materials for Part 1 and Part 2 can be found in a separate document at the following link: Supporting Materials for DER Valuation Consultation

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DER Valuation Review

A. Introduction

Background

In June 2025, Ontario's Minister of Energy and Mines (MEM) released its Integrated Energy Plan (IEP). Along with the IEP, the Minister also issued implementation directives to both the Ontario Energy Board (OEB) and Independent Electricity System Operator (IESO). Implementation directive items 11 and 12 (provided below) require the OEB to deliver a report to the Minister on the valuation of distributed energy resources (DERs).

OEB Directive

Item 11

Review the valuation of DER, in consultation with the IESO, as appropriate, to identify recommendations or provide an update on actions by the OEB regarding the overall regulatory and compensation frameworks to appropriately reflect the system value of DER. The report back should be completed by March 31, 2026 and could include, but is not limited to, consideration of:

- *Compensation mechanisms that reflect the value of DER (e.g., value of DER tariff (VDER) tariff, adders to reflect differences in regional and temporal value).*
- *Demand/delivery charges for resources that provide grid services (e.g., DER and storage).*
- *Procurement and program mechanisms that support cost-effective DER deployment at local and bulk levels.*

Item 12

*Consult with the IESO, as appropriate, to **identify roles and responsibilities for implementing DER valuation recommendations** and explore opportunities for electricity distributor-led DER procurements[1]. This report back should be completed by June 30, 2026[1].*

This findings of the analysis and proposed recommendations conducted by the OEB in response to IEP items 11 and 12 are provided in this document for review by stakeholders. The OEB welcomes stakeholder feedback on this material presented here.

1. This document only covers the portion of IEP Item 12 regarding roles and responsibilities for implementing DER valuation recommendations (shown above in bold). The OEB will report on work conducted for the remaining portion of IEP Item 12 through other materials.

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Project Scope

For the purposes of this project, a DER is defined in accordance with the OEB's Benefit-Cost Analysis (BCA) Framework and includes *any resource or program, whether in front of or behind the meter, that could provide an alternative to traditional electricity distributor solutions to meet distribution system needs.* In this review, DER valuation was reviewed as two distinct components: DER compensation (i.e., compensation received by DERs for the services they provide), covered in Part 1 of this study, and the demand or delivery charges paid by DERs, covered in Part 2 of this study. A detailed description of each component is described below. The combination of DER compensation (payments to DERs or avoided costs from DERs) and demand/ delivery charges (costs DERs pay to use the distribution network) comprise the overall valuation of DERs.

Part 1. DER Compensation

Part 1 consisted of a review of compensation frameworks for DERs in Ontario and a qualitative analysis to identify potential misalignments in DER compensation relative to their estimated system value. In consultation with the IESO, the OEB developed recommendations to address the identified misalignments. Roles and responsibilities in the implementation of each proposed recommendation were also identified.

Part 1 of this document summarizes the analysis and findings of the study conducted on DER compensation.

Part 2. Demand / Delivery Charges

Most of Ontario's electricity resources (e.g., generators, storage) are located on the transmission system. The OEB established a transmission rates framework for electricity resources in 2000.

As more Ontario families, communities and businesses look to use, produce, and store electricity and manage it in real time, more electricity resources are expected to be located on distribution systems (i.e., DERs). There may also be more integration of bulk system and potential distribution system electricity markets. The report provides an opportunity to review delivery rates for DERs with the aim of ensuring suitability.

The report also provides an opportunity to highlight OEB activities related to facilitating DERs.

Part 2 of this document summarizes the analysis and findings of the study conducted on demand/delivery rates.

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B. Executive Summary

Summary of Part 1 DER Compensation

A summary of the analysis and findings from Part 1 are described below.

Part 1. DER Compensation

The system value provided by DERs was assessed based on the contribution of DERs to five system components (avoided capacity at the generation, transmission or distribution levels, avoided energy and avoided emissions). Compensation under existing mechanisms was assessed relative to system value, and potential misalignments between current compensation and system value of DERs were identified. The OEB is proposing the following recommendations to improve DER compensation relative to their system value and accessibility for DER providers:

- Consider transition from net metering to net billing, where injected electricity is compensated using a locational and time-specific tariff instead of the customer's retail rate. Allow for the development of new community net metering projects without an amendment to the regulation.
- Explore ways to make more efficient use of Industrial Conservation Initiative resources outside of bulk system peak periods, including consideration of opportunities to provide transmission and/or distribution capacity value where local or regional needs are identified.
- Implement dynamic pricing for Non-Regulated Price Plan (RPP) Class B customers to encourage efficient use of DERs. This is the subject of ongoing work by the OEB and has also been identified through this analysis to support enablement of DERs.
- To enable value stacking, establish a cost allocation and delivery framework for front-of-meter and market-participating DERs that have both distribution and bulk value.
- Other recommendations to enable stacking between IESO and LDC programs and procurements.

The OEB is requesting stakeholder feedback on the study, the findings of the gap analysis, as well as the proposed recommendations.

Summary of Part 2 DER Delivery Rates

A summary of the analysis and findings from Part 2 are described below.

Part 2. Demand / Delivery Charges

Electricity distribution rates were reviewed to assess whether changes might be warranted to DER-related connection costs, base rates, specialized rates and behind-the-meter rates. The review was informed by the rate design principles of cost recovery, fairness, efficiency and simplicity. The review also considered the policy objectives in the Ontario government's 2025 IEP and IEP implementation directive to the OEB. Opportunities to more closely harmonize distribution and transmission delivery rates frameworks for electricity resources were considered. The OEB notes that there are frameworks for delivery rates for electricity resources on transmission and distribution systems and they are generally consistent with each other. The OEB also notes that it is engaged in various public reviews of delivery costs that are or might be relevant to DERs (e.g., distribution and transmission connection costs responsibility reviews). The OEB proposes the following questions for discussion with stakeholders:

- Should the OEB consider exempting front-of-meter electricity storage from base distribution rates, consistent with how front-of-meter generation is treated on Ontario's distribution and transmission systems and how transmission-connected storage will be treated beginning in 2026? As a more immediate measure, should the OEB consider exempting front-of-meter electricity storage from paying Retail Transmission Service Rates?
- Should the OEB consider opportunities to facilitate consistency in how specialized rates for DERs are developed and applied by Ontario's electricity distributors, akin to how the OEB addressed monthly service charge for microFIT generators?
- Should the OEB consider reviewing standby rates best practices and applying lessons learned over time as distributors finalize their standby rates?
- Should the OEB consider reviewing opportunities for greater consistency in how Retail Transmission Service Rates are applied to distribution load customers with behind-the-meter generation, in terms of distinguishing between net load and gross load billing?
- What should the OEB consider when reviewing policies under Ontario Regulation 330/09 related to the treatment of distributed generation when powered by renewable energy sources - Renewable Enabling Improvement cost recovery, renewable energy expansion cost cap, Generation Connection Rate Protection, the scope of the Regulation - in light of changes in DER deployment and technology in Ontario since these initiatives were introduced?

The OEB requests stakeholder feedback on its approach to reviewing DER delivery rates, its observations and discussion questions, and any other matters that stakeholders feel are relevant and important to the OEB's report to the Minister Energy and Mines on IEP implementation directive item #11.

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Part 1: DER Compensation

1.1 Context & Approach

Overview of DER Compensation Mechanisms in Ontario

DER compensation mechanisms in Ontario assessed in this study are listed in Table 1.1. Compensation mechanisms are classified by mechanism type, as identified in a prior study on DER compensation mechanisms jointly commissioned by the OEB and the IESO[1].

Table 1.1 DER Compensation Mechanisms in Ontario

Price-based mechanisms: include all price signals experienced by customers in a given rate class, such as rates designed for the recovery of energy, Global Adjustment (GA), transmission and distribution costs.[1]		
Net Metering	**Energy Arbitrage**	**Industrial Conservation Initiative (ICI)**
Customers with renewable generation are compensated via bill credits for energy injected into the grid based on the retail rate they pay at the time of injection.	A strategy to optimize energy costs by shifting energy consumption to periods when the price of electricity is low from periods when the price of electricity is higher.	Customers who participate, referred to as Class A customers, pay GA based on their percentage contribution to the top five peak hours over a 12-month period.
Procurement and wholesale market mechanisms: refer to IESO-administered mechanisms designed to meet reliability and resource adequacy in both the short and long term.[1]		
IESO Capacity Auction	**IESO Wholesale Energy Market**	**IESO Long-Term Procurement Contracts**
Participants are paid a monthly capacity availability payment determined by the auction's settling price and their respective availability factor.	Participants submit bids and offer into the day-ahead and real-time markets. Participants are paid the wholesale energy price.	Contracts awarded through competitive procurements, each with different requirements. Compensation for the length of the contract is based on the contract price with adjustments for inflation.
Program-based mechanisms: programs that compensate DERs through upfront and/or ongoing financial incentives tied to customers' participation and performance.[1]		
eDSM Framework	**Distributor Contracts[3]**	
$10.9 billion funding program launched for 2025-2036 to support eDSM. Includes funding for a variety of existing and new programs, including Peak Perks and residential and commercial solar installation incentives.	Distributors may compensate local DER providers directly to address local system needs. Compensation varies by individual agreement. Examples of current agreements are limited.	

1. Brattle Group, 2025. *Assessment of Ontario's DER Compensation Mechanisms and Recommendations*.
3. Compensation by distributor can cover a broad range of payment types and may overlap with other mechanisms described here, such as participation in markets.

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Types of DERs

The types of DERs evaluated in this study were derived from the economic potential results of the 2022 DER Potential Study commissioned by the IESO and are listed in Table 1.2.[1]

Table 1.2 Types of DERs evaluated

Category	DER Type	Description
Distributed Generation (DG)	Solar Photovoltaic (PV)	Solar generation facility connected to the distribution system. Can be behind the meter (BTM) (i.e., connected through a meter shared with co-located load) or in front of the meter (FTM) (i.e., connected through its own exclusive meter).
Distributed Energy Storage (DES)	Battery Storage	Storage facility connected to the distribution system. Can be BTM or FTM.
Hybrid	Solar PV paired with storage	Solar generation facility paired with a storage facility connected to the distribution system. Can be BTM or FTM.
Managed Electric Vehicle (EV) Charging		Load shifting through controlled shifting of EV charging periods. *While the 2022 DER potential study[1] evaluated vehicle-to-building/grid, for the purposes of this study, managed EV charging was assessed.*
Demand Response (DR)		Heating, ventilation and air conditioning DR: Space heating or cooling equipment load reduction resulting from controlled thermostat adjustments. DR: load reduction during periods of high demand.

1. Dunsky, January 28, 2022. Ontario's Distributed Energy Resources (DER) Potential Study.

Summary of Jurisdictional Scan

DER compensation mechanisms in four jurisdictions were reviewed. The jurisdictions reviewed include New York State, Hawaii, Australia, and California. These jurisdictions were chosen based on levels of DER integration, DER policy goals and regulatory reforms related to DER compensation. One key finding is that each jurisdiction reviewed has made changes to compensation for electricity injected into the distribution system (mostly moving away from net metering to a compensation structure that values injected electricity at a different rate from consumed electricity). This is summarized below. The detailed scan is available in the Supporting Materials.

Summary of the evolution of compensation for injected electricity from DERs across jurisdictions

- New York transitioned from net metering to the VDER tariff in 2017 to provide a more precise price signal for DER products and services and to offer fair and accurate compensation for the value they create. The VDER tariff is a time and location-varying rate that applies to electricity injected into the distribution system, as opposed to net metering where electricity injected into the distribution system is valued at the retail rate.
- Australia has one of the highest penetrations of rooftop solar in the world, driven partially by high feed-in-tariff (FiT) rates. These high rates have been phased out and transitioned to retailer-set, locational-specific rates for net solar energy injected into the grid.
- Hawaii replaced net metering with a series of successive DER tariffs in 2015 after distributed solar capacity rose to approximately 12% of total generation. This shift was driven by grid reliability concerns, cost equity, and the need to better align DER compensation with system value. The DER tariffs that followed allowed customers to offset their own consumption and, in some cases, export electricity to the grid at rates below the retail price. Some tariffs restricted exports to specific times of day, while others allowed utilities to curtail electricity exports during periods of grid stress or saturation. The rates available today require customers to enroll in a time-of-use rate, which incentivizes shifting energy consumption to off-peak hours. This has increased the number of battery systems paired with customer-cited generation, with 96% of residential systems now paired with energy storage.
- After over two decades of net metering, California transitioned from net metering to net billing, which compensates electricity exports at hourly rates that differ from rates applied to consumed electricity. While typically lower than retail prices, the rates paid for electricity injected into the distribution system under net billing can exceed retail prices during peak demand periods. This transition was undertaken to address a 2021 report finding that solar customers often pay less than the actual cost to serve them, leading other ratepayers to cover the difference.

The Value Stack Approach

The system value of DERs in Ontario was assessed for each DER type using the value stack approach outlined in Table 1.3 below, based on the value stack developed in the IESO-OEB joint study[1].

Table 1.3 Components of the value stack to assess system value for Ontario

Component	Description
Generation capacity value	Reduction in the generation capacity required to meet system coincident peak demand through distributed generation or reduced consumption during system peak hours.
Transmission capacity value	Benefit from reduction of coincident peak demand imposed on upstream transmission assets.
Distribution capacity value	Benefit from reduction of local peak demand imposed on upstream distribution assets.
Energy value	Reduction in energy required from centralized generation to meet load.
Emissions value[2]	Value of avoided emissions via reduction in energy consumption from centralized generation.
Ancillary services	Provision of ancillary services, including frequency, regulation and operating reserves. *Ancillary services are not assessed in this study[2].*

1. Brattle Group, 2025. Page 11. *Assessment of Ontario's DER Compensation Mechanisms and Recommendations*.
2. In the IESO-OEB Joint Study, the value stack included externalities which included emissions value and beyond. This component as excluded from the assessment conducted in the value stack. For this review, the component was limited to emissions value which allowed for the inclusion of this component when assessing compensation under current mechanisms against the value stack.
3. While critical to the power system, ancillary services make up a relatively small component of all power system costs. For this reason, ancillary service benefits were not included in the assessment.

Methodology for Assessing Value Stack Components

The system value of DERs in Ontario was assessed for each DER type using the value stack approach developed in the IESO-OEB Joint Study. Table 1.4 summarizes the assessment methodology used.

Table 1.4 Methodology for assessing value of DERs under each component of the value stack

Component	General Value Assessment	DER Type Assessment Methodology
Generation capacity	Value is **zero** if forecast capacity needs are met by existing generation resources. Value is **high** during coincident peak hours if forecast capacity needs exceed capability of generation resources.	Based on the resource's ability to reduce bulk system demand during coincident peak hours. This value varies according to the resource's unforced capacity (UCAP).
Transmission capacity	Value is **zero** in regions without constraints. Value is **high** during temporal constraint periods in regions with transmission system constraints.	Based on the avoided transmission capacity costs upstream of the resource's location on the regional transmission system.[1]
Distribution capacity	Value is **zero** in regions without constraints. Value is **high** during temporal constraint periods in regions with Dx system constraints.	Based on the avoided distribution capacity costs upstream of the resource's location on the local distribution system.
Energy	Value is equal to the locational marginal price at each time interval. This value fluctuates but is **typically much lower** than the generation, transmission or distribution capacity values during temporal constraint periods in regions with capacity constraints.	Based on a resource's ability to generate energy or modify consumption over a given period. The value also depends on the wholesale market price when the resource generates energy / modifies consumption.
Emissions	Value is based on the emissions rate of bulk generation assets at each time interval. This value fluctuates but is **typically much lower** than the generation, transmission or distribution capacity values during temporal constraint periods in regions with capacity constraints.	Proportional to the energy generated/consumption avoided by the resource. Value depends on the effective emissions of bulk generation assets at the time the resource generates energy/modifies consumption.
Ancillary services	Not included in assessment.[2]	

1. Dependent on the Transmission-Distribution (T-D) interface upstream of the DER. Often, there are multiple T-D interfaces upstream of a DER, so this value varies dependent on the flow of electricity through these interfaces.
2. While critical to the power system, ancillary services make up a relatively small component of all power system costs. For this reason, ancillary service benefits were not included in the assessment.

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Part 1: DER Compensation

1.2 Summary of Findings

DER Value & Rationale

The value of each type of DER included in the study was assessed for each component of the value stack using the methodology described in Table 1.5. The results of the assessment are provided in Table 1.6. Generally, it was found that DES, DR and hybrid resources provide high to medium generation capacity due to the high UCAP value and/or availability of these resources during coincident peak demand hours.

Table 1.5 Assessment of DER types against value stack components

System Value Component	Front-of-the-meter & Behind-the meter			Behind-the-meter	
	Distributed Generation	Distributed Energy Storage	Hybrid	Managed EV Charging	Demand Response
Generation capacity	*Value is **medium** since variable generation resources (e.g., solar) have low UCAP values and do not always generate during peak demand periods.*	*Value is **high** due to battery resource's high UCAP and availability during coincident peak demand periods.*		*Value is **medium** due to resource's availability to reduce demand during coincident peak demand periods, subject to user override.*	*Value is **high** due to resource's availability to reduce demand during coincident peak demand periods.*
Transmission capacity / **Distribution capacity**	*Value is **medium** in regions with Tx/Dx system constraints due to lower UCAP values and the non-dispatchable nature of solar DG leading to limited availability during peak demand periods. **Value is zero in regions without constraints.***	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.** Ability to stack with Gx value needs to consider timing of each system peak.*		*Value is **high** in regions with Tx/Dx system constraints if charging is shifted away from bulk/local system peak demand periods. **Value is zero in regions without constraints.***	*Value is **high** in regions with Tx/Dx system constraints if events coincide with bulk/local peak demand hours. **Value is zero in regions without constraints.***
Energy	*Value is **medium**, based on the wholesale market price at the time of generation.*	*Value is **low**, based on the difference in wholesale market price between charging and discharging, accounting for losses.*	*Value is **medium** as energy generated can be stored and used during peak periods when wholesale market prices are high.*	*Value is **low**, based on the difference in wholesale market price between managed charging and default charging behavior.*	*Value is **low**, based on the wholesale market price during events. For HVAC DR, energy consumption may not be reduced due to snapback effects.*
Emissions	*Value is **medium** as generated energy is emissions free. The energy displaced by DG includes energy from emitting resources. As emitting resources are currently used during both peak and non-peak periods, the value is medium regardless of the time at which the energy is available.*	*Value is **low** as current emission rates do not vary significantly between battery charge and discharge to make up for battery losses. If emitting generation resources were only used during peak demand hours, this value could be higher.*	*Value is **medium** as generated energy is emissions free. If emitting generation resources were only used during peak demand hours, this value would remain high since energy can be stored for consumption/injection during peak periods.*	*Value is **low** as current emission rates do not vary significantly between battery charge and discharge to make up for battery losses. If emitting generation resources were only used during peak demand hours, this value could be higher.*	*Value is **low**. Consumption during peak demand periods is reduced but emission rates do not vary significantly between peak and off-peak periods. If emitting generation resources were only used during peak demand hours, this value could be higher.*

Assessment of DER Compensation

Compensation available to DERs in Ontario today was assessed for a variety of common DER types and categorized into the components of the value stack as presented in Table 1.6 below. Gaps in compensation were identified and are further detailed in the Supporting Materials.

Table 1.6 Assessment of compensation under each mechanism relative to the value stack

	Front-of-meter			Behind-the-meter				
	Distributed Generation	Distributed Energy Storage	Hybrid	Distributed Generation	Distributed Energy Storage	Hybrid	Demand Response	Managed EV Charging
Generation capacity		LT1, LT2c, capacity auction		IESO eDSM, ICI~, IRP~, Class B GA rate†	Capacity auction, ICI~, IRP~	IESO eDSM, ICI~, IRP~, Class B GA rate†	Capacity auction, eDSM (Peak Perks* and *commercial HVAC program†*), ICI~, IRP~	ICI~
Transmission capacity							THESL LDR†~[1]	
Distribution capacity							THESL LDR†~[1], Hydro One *my*Energy Rewards[3]	Hydro One myEnergy Rewards[3]
Energy	LT2e, LGP, wholesale energy market	Wholesale energy market	Wholesale energy market	Wholesale energy market, retail rates[2], net metering	Wholesale energy market, retail rates[2]	Wholesale energy market, retail rates[2], net metering	Wholesale energy market, retail rates[2]	retail rates[2]
Emissions								

Legend

Procurement & market-based mechanisms
Program-based mechanisms
Price-based mechanisms
†Available to non-RPP Class B Customers only
*Available to RPP Customers only
~Available to Class A Customers only

Acronyms

eDSM – Electricity demand side management framework
ERP – Enabling Resources Program
GA – Global Adjustment
ICI - Industrial Conservation Initiative
IRP - Interruptible Rate Pilot
LGP – Local Generation Program
LT1 - Long-term request for procurement (RFP) 1
LT2e/LT2c - Long-term RFP 2 for energy / Long-term RFP 2 for capacity
THESL LDR – Toronto Hydro-Electric System Limited Local Demand Response Program

1. The THESL LDR program includes a capacity auction (i.e., administers a local market), but was classified as a program-based mechanism, as procurement and market-based mechanism are limited to those administered by the IESO, consistent with the definitions in the OEB-IESO Joint Study.
2. Note that Hydro One's MyEnergy Rewards program is not funded by ratepayers. Compensation was attributed to distribution capacity since participation is limited to residential distribution customers.
3. Dispatchable loads and resources >1MW are eligible to participate in the wholesale energy market.
4. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

Summary of Findings by Value Stack Component

This section provides a summary of the DER compensation findings, a list of misalignments or gaps identified in the qualitative assessment (shown in Supporting Materials). For each finding, the existing OEB and IESO initiatives that may address the misalignment are also provided.

Table 1.7 Summary of findings by value stack component

System Value Component	Misalignment or Gap	Existing OEB/IESO Initiative which may address misalignment
Generation capacity	1. **FTM DG and Hybrid DERs <1 MW are not compensated for generation capacity**. FTM solar resources larger than 1 MW can participate in the wholesale energy market and long-term and medium-term procurements (e.g. LT2e), subject to aggregation and location restrictions. Recent long-term procurements (eLT1 and LT1) were capacity focused and did not procure any FTM DG or Hybrid resources.	• IESO's ERP will allow aggregations of FTM resources to participate in IESO-administered markets. The IESO is also aiming to enable variable generation resources to qualify for participation in the capacity auction. This would allow aggregated FTM and single FTM DERs >1MW in size to be compensated for generation capacity according to the capacity auction settling price. • Corporate Power Purchase Agreements (PPA) under the recently amended O. Reg. 429/04 will allow FTM DG to receive compensation for energy which may be sufficient to also compensate for generation capacity. • IESO's Local Generation Program will offer to re-contract existing non-market participant, distribution connected, generation resources between 100 kW - 10 MW in size. As a competitive procurement process, LGP is expected to provide compensation to successful FTM DERs sufficient for energy and generation capacity value.

Summary of Findings by Value Stack Component

Table 1.7 – cont.

System Value Component	Misalignment or Gap	Existing OEB/IESO Initiative which may address misalignment
Transmission capacity	2. Compensation for **transmission capacity value** provided by DERs in regions with Tx system constraints is limited or unavailable.	• Future enhancements to Stream 2 eDSM may provide a funding mechanisms for LDCs to design and deliver BTM programs that consider the transmission capacity costs and benefits identified through the Energy System Test. • Through IESO's ERP, more DERs are expected to be able to participate in the IESO-administered markets and receive market price signals that reflect regional constraints. • IESO's Local Initiatives Program offers enhanced local energy efficiency programming to targeted areas of Ontario with transmission system needs. • The Non-Wires Solutions Guidelines for Electricity Distributors allow for non-wires solutions by distributors to be rate-funded and offer transmission capacity value. • IESO's Local Generation Program will offer to re-contract existing non-market participant, distribution connected, generation resources between 100 kW - 10 MW in size. The program will be designed to target procurement of DERs in areas where they can support transmission system needs.
Distribution capacity	3. Compensation for **distribution capacity value** provided by DERs in regions with Dx system constraints is limited or unavailable. Distributor contracts are the only available compensation mechanism and there are few examples.	• Stream 2 eDSM is expected to provide LDCs a funding mechanism to design and deliver BTM programs that consider the distribution capacity costs and benefits through the Distribution System Test. • The Non-Wires Solutions Guidelines for Electricity Distributors allow for non-wires solutions by distributors to be rate-funded and offer distribution capacity value. • Developing DSO capabilities may provide a more widespread opportunity for distributors to offer compensation where local constraints exist. • IESO's Local Generation Program will offer to re-contract existing non-market participant, distribution connected, generation resources between 100 kW - 10 MW in size. The program will be designed to target procurement of DERs in areas where they can support distribution system needs.

Summary of Findings by Value Stack Component

Table 1.7 – cont.

System Value Component	Misalignment or Gap	Existing OEB/IESO Initiative which may address misalignment
Energy	4. **The value of electricity injected onto the distribution system is not equal to the retail rate** which includes additional costs beyond energy supply. The resulting cost recovery imbalance shifts the financial burden of costs independent of energy volume onto non-net metered customers.	*No existing initiative addresses this gap*
Emissions	5. **Compensation for avoided emissions by DERs is unavailable** beyond limiting participation in mechanisms such as eDSM and net metering to non-emitting resources. The current price on industrial emissions from fossil fuel generation above the emissions intensity threshold may be reflected in the bid prices of fossil fuel generators in the wholesale energy market and thereby increase the market price when these resources are on the margin.	*No existing initiative addresses this gap*

Summary of Findings by Value Stack Component

Table 1.7 – cont.

System Value Component	Misalignment or Gap	Existing OEB/IESO Initiative which may address misalignment
Combined	6. **Compensation is limited for standalone storage resources less than 1 MW** (unless aggregated to participate in the capacity auction).	• IESO's ERP is expected to enable aggregations of DERs, with individual contributors less than 1MW, to participate in IESO-administered markets.
	7. **The Class B GA rate does not compensate DERs for value provided.** The rate is high during months when electricity is abundant and less expensive and low when electricity supply conditions tighten and prices rise. This means avoided energy from DERs is compensated at a lower rate when it has higher value, and vice versa.	• The OEB's work on Dynamic Pricing for Class B Non-RPP customers has identified price plans that would provide a more efficient price signal to better communicate when electricity is abundant, and prices are low and when electricity supply tightens and prices are higher. Implementing such a price plan would address this gap. • As part of the eDSM framework, the IESO is developing a commercial HVAC demand response program for Class B customers. This will provide compensation for generation capacity value to participants for load reduction during events coinciding with peak periods.

Summary of Findings by Value Stack Component

Table 1.7 – cont.

System Value Component	Misalignment or Gap	Existing OEB/IESO Initiative which may address misalignment
Combined	8. **DER value stacking can be challenging due to the complex interactions between different compensation mechanisms.** Since most mechanisms typically cover one or two components of system value, stacking requires participation in more than one mechanism.	• Stream 2 eDSM is expected to provide LDCs a funding mechanism to design and deliver BTM programs that consider generation capacity, distribution capacity and energy benefits and costs to determine the appropriate compensation level for DERs in locations with system constraints. These will be considered through the use of the Distribution System Test and the Energy System Test. Future enhancements to Stream 2 eDSM may also consider the transmission capacity costs and benefits. • The Non-Wires Solutions Guidelines for Electricity Distributors allow for non-wires solutions by distributors to be rate-funded as well as earn revenues through participation in the IESO's wholesale market. • Developing DSO capabilities may provide a more widespread opportunity for distributors to offer compensation where local constraints exist. • IESO's Enabling Resources Program will allow aggregated DERs to access IESO-administered markets and provide them with an opportunity to value stack with distribution level programs
	9. Many existing compensation mechanisms with different eligibility requirements and compensation methods make **DER compensation complex and difficult to navigate**.	*No existing initiative addresses this gap*

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Part 1: DER Compensation

1.3 Proposed Recommendations

Summary of Proposed Recommendations

This section provides the proposed recommendations that may address the gaps and misalignments identified in Section 1.2.

Table 1.8 Summary of proposed recommendations

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
1. Consider transitioning to net billing, in which electricity injected onto the distribution system is compensated at its market-reflective value. This value should be a function of the time and location electricity is injected to protect ratepayer equity and support the prudent expansion of DERs. This rationale has driven reforms in jurisdictions such as Hawaii, California and New York, which have adopted frameworks in which electricity injected is valued differently than electricity consumed. British Columbia is actively reviewing net billing. Net billing frameworks are often paired with TOU tariffs to encourage self-consumption and battery use to increase system utilization.	4. The value of electricity injected onto the distribution system is not equal to the retail rate which includes additional costs beyond energy supply.	• **Type:** change to existing mechanism • **Customer classes impacted:** All • **Responsible parties:** MEM for enacting amendments, OEB for rate design	***Improves value*** *because net billing would allow development of a specified rate for injected electricity that provides compensation that is more reflective than net metering*	***Maintains current levels*** *of accessibility as it does not impact ability of DER providers to participate in mechanism*	*May require legislative amendments*

Summary of Proposed Recommendations

Table 1.8 Summary of proposed recommendations

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
2. **Review restrictions on net metering within the Distribution System Code** (e.g., requirement to connect up to 1% peak load threshold) to ensure DERs are enabled while protecting distribution customers from increased costs due to technical impacts of increased bi-directional electricity flow.	4. The value of electricity injected onto the distribution system is not equal to the retail rate which includes additional costs beyond energy supply.	• **Type:** change to existing mechanism • **Customer classes impacted:** All • **Responsible parties:** OEB for updated to Distribution System Code	***Improves value*** *because net billing would allow development of a specified rate for injected electricity that provides compensation that is more reflective than net metering*	***Maintains current levels*** *of accessibility as it would not change ability to participate in net metering*	*Requires code amendment(s) and adjustments to LDC billing practices*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
3. Amend Community Net Metering Regulation Subject to local distribution system conditions, consider the following amendments to O. Reg. 679/21: • Remove requirement that each community net metering project be explicitly listed in the regulation. • Reflect any changes made to net metering if a transition to net billing is made (see recommendation #1). The above amendments would require revised eligibility requirements for community net metering projects. These requirements should be developed to facilitate community net metering while not increasing costs for other customers. Examples of eligibility requirements may include local distribution system conditions as well as potential restrictions on components within a project (e.g., located on the same feeder).	1. FTM DG and Hybrid DERs <1 MW are not compensated for generation capacity.	• **Type:** change to existing mechanism • **Customer classes impacted:** All • **Responsible parties:** MEM for regulation amendment, LDCs for implementation	***Minimal impact*** *as proposed amendment does not change the compensation received under this mechanism*	***Improves accessibility*** *by allowing new community net metering projects*	*Requires regulatory amendments and changes to LDC billing practices*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
4. Explore ways to make more efficient use of ICI resources outside of bulk system peak periods, including consideration of opportunities to provide transmission and/or distribution capacity value where local or regional needs are identified.	2. Compensation for transmission capacity value provided by DERs in regions with transmission system constraints is limited or unavailable. 3. Compensation for distribution capacity value provided by DERs in regions with distribution system constraints is limited or unavailable. 8. DER value stacking can be challenging due to the complex interactions between different compensation mechanisms.	• **Type:** change to existing mechanism • **Customer classes impacted:** Class A • **Responsible parties:** MEM for design and IESO/LDCs for implementation, as appropriate	***Improves value*** *by allowing DERs to value stack where local constraints exist*	***Maintains current levels*** *of accessibility as it does not impact ability of DER providers to participate in mechanism*	*Requires DERs to be located where system constraints exist that are not coincident with bulk system peak periods.*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
5. **Encourage efficient use of DERs by implementing dynamic pricing for Non-RPP Class B electricity customers.**	7. The Class B GA rate does not compensate DERs for value provided. The rate is high during months when electricity is abundant and less expensive and low when electricity supply conditions tighten and prices rise.	• **Type:** Change to existing rate-based mechanism/new rate-based mechansim • **Customer classes impacted:** Non-RPP Class B • **Responsible parties:** MEM for regulation amendment, OEB for rate design, IESO for new settlement types, LDCs for implementation	***Improves value*** *by improving rate-based compensation for DER providers in this customer class*	***Improves accessibility*** *by providing improved price signals and encouraging efficient use of DERs*	*Requires regulatory amendments and development of rate by the OEB.*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility For DER providers	Implementation Considerations
6. Establish a cost allocation and delivery framework for front-of-meter and market-participating DERs that have both distribution and bulk value, building on eDSM Stream 2. Stream 2 eDSM is expected to address challenges in compensation mechanism stacking for BTM resources by providing a funding mechanisms for LDCs to design and deliver BTM programs. Stream 2 eDSM is expected to compensate for distribution capacity value, generation capacity value and energy value, through the Distribution and Energy System tests. Future enhancements to Stream 2 eDSM may also include transmission capacity costs and benefits identified through the Energy System Test.	2. Compensation for transmission capacity value provided by DERs in regions with transmission system constraints is limited or unavailable. 3. Compensation for distribution capacity value provided by DERs in regions with distribution system constraints is limited or unavailable. 8. DER value stacking can be challenging due to the complex interactions between different compensation mechanisms.	• **Type:** new or modified mechanism • **Customer classes impacted:** All • **Responsible parties:** OEB, IESO and LDCs.	***Improves value*** *as it improves ability of DER providers to value stack*	***Improves accessibility*** *by providing a new mechanism for DERs to participate and receive compensation*	*Requires collaboration between the OEB, the IESO, and LDCs to design a framework but can leverage learnings from eDSM Stream 2*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility	Implementation Considerations
7. Where appropriate, leverage procurements and/or programs within the IESO's resource adequacy framework to secure transmission non-wires solutions when they are identified as preferred solutions through the Regional Planning Process.	2. Compensation for transmission capacity value provided by DERs in regions with Tx system constraints is limited or unavailable.	• **Type:** change to existing mechanism(s) • **Customer classes impacted:** All • **Responsible parties:** IESO	***Somewhat improves value*** *as it may provide improved compensation for resources located in transmission constrained areas*	***Maintains current levels*** *of accessibility as it does not impact ability of DER providers to participate in mechanism*	*Requires coordination between the Regional Planning and procurement processes for implementation*
8. Incorporate a transmission avoided cost framework in demand-side management (DSM) cost-effectiveness tests when needs are identified in the Regional Planning Process.		• **Type:** change to existing mechanism • **Customer classes impacted:** All • **Responsible parties:** IESO, OEB	***Improves value*** *by including costs for previously unvalued system components*	***Maintains current levels*** *of accessibility as it does not impact ability of DER providers to participate in mechanism*	*Require changes to current frameworks*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility for DER providers	Implementation Considerations
9. **Enable value stacking** by developing consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework.	8. DER value stacking can be challenging due to the complex interactions between different compensation mechanisms. 3. Compensation for distribution capacity value provided by DERs in regions with Dx system constraints is limited or unavailable.	• **Type:** new or modified mechanism • **Customer classes impacted:** All • **Responsible parties:** OEB and LDCs to develop and implement with IESO input • **Further work needed:** Meet with LDCs to understand needs for standardized models	***Minimal impact*** *as it does not change compensation received*	***Improves accessibility*** *by improving ability of LDCs to offer programs*	*Requires standardization across different distribution systems*
10. Programs and procurements by the IESO and LDCs should **explicitly allow for future value stacking opportunities**, when resources are capable of providing multiple services.		• **Type:** change to existing mechanism • **Customer classes impacted:** All • **Responsible parties:** IESO and LDCs	***Improves value*** *as it improves ability of DER provides to value stack*	***Improves accessibility*** *to participate in IESO procurements*	*Requires coordination between the IESO and LDCs*

Summary of Proposed Recommendations

Table 1.8 – cont.

Description of Recommendation	Identified gaps that may be met by this solution	Responsibilities	Solution Assessment		
			System Value	Accessibility	Implementation Considerations
11. Develop simplified process or tool for DER providers to easily understand and assess available mechanisms for their resources and identify best available pathways to compensation for the services they provide.	8. DER value stacking can be challenging due to the complex interactions between different compensation mechanisms. 9. Many existing compensation mechanisms with different eligibility requirements and compensation methods make DER compensation complex and difficult to navigate.	• **Type:** n/a (information tool, not a mechanism type) • **Customer classes impacted:** All • **Responsible parties:** *For discussion: Is this a possible role for industry associations?*	***Minimal impact** as it does not change compensation*	***Improves accessibility** by improving DERs providers understanding of how they may provide services*	*Requires further consideration to assess challenges with development and maintenance to ensure accuracy*

ONTARIO ENERGY BOARD

Part 1: DER Compensation

1.4 Request for Feedback

Areas for Stakeholder Feedback

OEB Staff have prepared this report to summarize the analysis conducted on DER compensation mechanisms in Ontario, and to recommend solutions to address identified misalignments. OEB Staff invite stakeholder feedback on the analysis and proposed recommendations and pose the following questions for discussion:

Analysis of DER compensation mechanisms

- Please elaborate on any feedback you may have on the assessment of the system value of DERs, specifically with regards to:
  - whether the value stack is an appropriate methodology for assessing the system value of DERs
  - are the components in the value stack sufficient to assess system value of DERs?
- Are the identified compensation mechanisms for which each DER type is eligible exhaustive? If no, please elaborate.
- Are the identified misalignments of DER compensation relative to system value comprehensive? Please describe any gaps in DER compensation where DERs can provide value that were not identified.

Proposed Recommendations

- For each proposed recommendation, please discuss:
  - Whether the recommendation is appropriate for the misalignment for which it is proposed.
  - the recommendation sufficiently address the identified misalignment.
  - Any unforeseen impacts of the recommendation on DER providers, ratepayers or Ontarians in general.
  - Whether the assessment of recommendation for system value, accessibility to DER providers and implementation considerations are appropriate.

ONTARIO ENERGY BOARD

Part 2: DER Delivery Rates

2.1 Context and Proposed Approach

Context and Proposed Approach

The OEB's review of DER Delivery Rates, informed by the policy objectives of the Ontario government's 2025 IEP and IEP implementation directive to the OEB, assesses whether changes might be warranted to DER-related connection costs, base rates, specialized rates and behind-the-meter rates.

Proposed Principles & Perspectives

- The OEB proposes four rate design principles for the purposes of this document – cost recovery, fairness, efficiency and simplicity. The principles will help inform the OEB's consideration of any gaps in Ontario's DER delivery rates framework and of options for addressing them.
- The OEB proposes to consider DERs from the perspectives of (a) their electrical location and (b) their function.

  (a) In terms of electrical location, we propose to consider both front of meter and behind the meter DERs.

  (b) In terms of function, we propose to consider front of meter generating technologies and storage technologies (i.e., DER technologies that inject electricity directly into the grid, and DER technologies that directly inject and withdraw electricity from the grid).
- For behind the meter DERs, we propose to consider generating technologies, storage technologies and dynamic load-modifying technologies or practices. We will also consider behind the meter DERs that provide load displacement only, as well as behind the meter DERs that displace load and inject into the distribution system (for example, through arrangements akin to net metering).

Proposed Considerations

- The OEB will remain open to considering opportunities for greater harmonization between transmission and distribution delivery rate frameworks where such alignment is practical and contextually appropriate. However, the OEB will also consider the importance of respecting legitimate differences in system design, service offerings, operational contexts and any other relevant considerations.
- The OEB also notes that it is engaged in various public reviews of delivery costs that are or might be relevant to DERs (e.g., distribution and transmission connection costs responsibility reviews).

Note: see Supporting Materials for greater detail.

ONTARIO ENERGY BOARD

Part 2: DER Delivery Rates

2.2 Summary of Draft Observations, Updates and Discussion Questions

A. Connection Cost Responsibility

A. Connection Cost Responsibility:

1. **Observation:** Connection cost responsibility frameworks exist for Ontario's distribution and transmission systems; they are consistent with each other.

2. **Update:** The OEB has initiated consultations to review some aspects of transmission and distribution cost responsibility (e.g., DER connections, review of the TSC to enhance and clarify the implementation of cost responsibility rules for connections). The OEB has identified additional aspects that it plans to review in the future.

3. **Discussion Question**: What should the OEB consider when reviewing policies under Ontario Regulation 330/09 related to the treatment of distributed generation when powered by renewable energy sources - Renewable Enabling Improvement cost recovery, renewable energy expansion cost cap, Generation Connection Rate Protection, the scope of the Regulation - in light of changes in DER deployment and technology in Ontario since these initiatives were introduced?

B. Base Distribution Rates, FTM Generation

B. Base Distribution Rates, FTM Generation:

1. **Observation**: A base distribution rate framework appears to exist for front of the meter generation: generators don't generally pay base distribution rates, loads do. This appears to be consistent with the framework that exists for the transmission system.

C. Base Distribution Rates, FTM Storage

C. Base distribution rates, front of the meter electricity storage:

1. **Observation:** A base distribution rates framework exists for front of the meter electricity storage: front of the meter electricity storage pays base distribution rates when it withdraws electricity. This is not consistent with the framework that will be in place on the transmission system beginning in 2026.

2. **Update:** The OEB is working with the IESO to co-ordinate the implementation of an exemption to transmission charges for transmission-connected energy storage facilities when these facilities are scheduled for operating reserve, providing reactive power support, providing regulation service, responding to a real-time IESO energy dispatch or responding to an IESO reliability directive beginning in 2026. This co-ordination and implementation activity is in accordance with the OEB's Decision and Order on Phase 2 of the Generic Hearing on Uniform Transmission Rates (EB-2022-0325).

3. **Discussion Question:** Should the OEB exempt front of meter electricity storage (i.e., storage that is directly connected to a distribution system) from base distribution rates? This would be consistent with how front of meter generation is treated on Ontario's distribution and transmission systems and how transmission connected storage will be treated beginning in 2026. Should the OEB leverage lessons from the work that OEB and the IESO are doing to co-ordinate and implement the exemption to transmission connected storage?

4. **Discussion Question:** Should the OEB consider exempting front of meter electricity storage from paying Retail Transmission Service Rates in the more immediate term? This would facilitate the integration of the distribution-connected front of meter electricity storage procured recently by the IESO.

D. Specialized Distribution Rates for DERs: General

D. Specialized distribution rates for DERs:

1. **Observation:** Ontario's distribution rate framework includes limited instances where DERs are charged specialized rates to recover the costs incurred by electricity distributors for processing DER metering information and settlement and DER account management and billing. While these types of charges are not applied by transmitters to transmission-connected electricity resources, the difference is appropriate in the context of DERs because the specialized rates recover the costs of services that electricity distributors (uniquely) provide to their DER customers.

2. **Discussion Question:** Looking ahead, in the event of greater deployment of DERs across Ontario's distribution systems, should the OEB consider opportunities to facilitate consistency in how specialized rates for DERs are developed and applied by Ontario's electricity distributors? The OEB has done this in the past, when it established a provincewide fixed monthly service charge for microFIT generators (which are distribution-connected generators) based on nine cost elements specified by the OEB. The OEB reviews the microFIT charge annually.

E1. Behind-the-Meter DERs: Standby Rates

E. Distribution rates for behind the meter DERs: (Standby Rates)

1. **Observation:** Standby rates exist for 10 electricity distributors in Ontario. Of those, standby rates are interim for six distributors. The standby rate is recovered from customers that have load displacement generation and that require standby service from their electricity distributor. Standby rates are not applied to transmission-connected customers that have behind-the-meter resources. While this is a difference between Ontario's transmission and distribution delivery rates frameworks, the difference is appropriate, reflecting the specific circumstances of electricity distributors and reflecting a service that electricity distributors offer to their customers who want to use it.

2. **Discussion Question:** As distributors propose to finalize their standby rates over time, should the OEB consider reviewing best standby rates practices and applying lessons learned to facilitate the ongoing effectiveness of DER delivery rates in Ontario?

E2. Behind-the-Meter DERs: Bypass Compensation

E. Distribution rates for behind the meter DERs: (Bypass compensation)

3. **Observation:** The Distribution System Code provides the circumstances in which an electricity distributor must require bypass compensation from a customer. The Distribution System Code also sets out the circumstances in which bypass compensation may not be applied, including "any reduction in a customer's existing load served by the distributor's distribution system that the customer has demonstrated to the reasonable satisfaction of the distributor (such as by means of an energy study or audit) has resulted from embedded renewable generation, energy conservation, energy efficiency or load management activities." This is consistent with the bypass compensation rules that apply to transmitters per the Transmission System Code.

4. **Discussion Question:** Should the OEB consider reviewing its policy related to bypass compensation exemptions given the passage of time since the policy was first established and given the rapidly evolving context for DER deployment in Ontario? Areas for focus might include evaluating the continued suitability and scope of existing bypass compensation exemptions (e.g. should exemptions be extended to also include non-renewable DERs?), and opportunities for continued harmonization between applicable provisions in the TSC and DSC.

E3. Behind-the-Meter DERs: Retail Transmission Service Rates

E. Distribution rates for behind the meter DERs: (Retail Transmission Service Rates)

5. **Observation:** Some distribution-connected load customers that have behind-the-meter generation pay a portion of their RTSRs based on their gross load, and the other portion based on their net load. This is consistent with how transmission-connected customers that have behind-the-meter generation pay transmission rates, in accordance with Ontario's Uniform Transmission Rates. However, it does not appear that all distributors in Ontario distinguish between net load billing and gross load billing with respect to Retail Transmission Service Rates for distribution customers that have behind-the-meter DERs.

6. **Discussion Question:** Should the OEB consider reviewing opportunities to achieve greater consistency in how transmission delivery rates (Retail Transmission Service Rates) are applied to distribution load customers with behind-the-meter generation, in terms of distinguishing between net load and gross load billing? This could provide added predictability for load customers with behind-the-meter DERs. It could also enhance the existing alignment between Ontario's distribution and transmission rates frameworks for behind-the-meter resources.

F. Distribution Rates for DERs Providing Grid Services

F. On the matter of distribution rates for DERs that provide grid services:

1. **Observation:** The general basis for delivery rates in Ontario is that delivery rates reflect the costs of providing delivery service. They are not derived based on the grid services or values that the entities who require the delivery service (such as generators and loads) provide to customers (such as energy, capacity and ancillary services). Those grid services or values are reflected instead in planning decisions related to DERs, in DER procurements and compensation, and in DER participation in procurements and programs, and in government policies.

2. **Update:** As the OEB's report back to the Minister of Energy and Mines addresses DER delivery rates with a focus on the costs of providing delivery service to DER providers and customers who use DER services, it will also address the complementary issues of procurement mechanisms for acquiring DERs and compensation mechanisms for remunerating DERs for the grid services that they provide customers.

ONTARIO ENERGY BOARD

Part 2: DER Delivery Rates

2.3 Request for Feedback

Areas for Stakeholder Feedback

The OEB has prepared this report to summarize its research on delivery rates for electricity resources in Ontario, and to propose areas for further attention with focus on delivery rates for DERs. The OEB invites stakeholder feedback on its research and proposed recommendations. The OEB will consider feedback from stakeholders as it develops a report back to the Minister of Energy and Mines on IEP implementation directive item #11. The OEB would especially appreciate stakeholder feedback on the following areas:

A: The OEB's approach to addressing DER delivery rates:

1. Is the OEB's characterization of the context for this work appropriate?
2. Are the approximate DER definitions that the OEB has outlined for purposes of this work adequate?
3. Are the working rates principles that the OEB has outlined appropriate?
4. Is the OEB's approach to considering DERs from electrical and functional perspectives appropriate?
5. Has the OEB appropriately characterized and considered the potential advantages and limitations of greater harmonization between Ontario's transmission and distribution rates frameworks for electricity resources?
6. Are the general rates categories identified by the OEB appropriate? (i.e., connection costs, base rates, specialized rates and behind-the-meter-related rates)
7. Is the OEB's characterization of the matter of grid services appropriate as it relates to delivery rates?

B: The appropriateness of the OEB's analysis and observations, and draft discussion questions related to:

8. Connection cost responsibility
9. Base distribution rates for front-of-meter generation DERs
10. Base distribution rates for front-of-meter electricity storage DERs
11. Specialized DER distribution rates
12. Delivery rates for behind-the-meter DERs, specifically on:
    - i. Standby rates
    - ii. Bypass compensation
    - iii. Retail Transmission Service Rates

Areas for Stakeholder Feedback (Cont'd)

C: Any other matters that stakeholders feel are relevant and important to the OEB's report back to the Minister of Energy and Mines on IEP implementation directive item #11.

For example:

- What questions, concerns or ideas do you have about this work?
- What is your advice to the OEB as it seeks to develop its report to the Minister?