Assessment of Ontario's DER Compensation Mechanisms and Recommendations

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Executive Summary

As Ontario considers options to support the energy transition, distributed energy resources (DERs)[1] can present a cost-effective option to help meet growing electricity system needs. DERs can be deployed rapidly to meet fast-growing system needs, avoid siting challenges associated with larger infrastructure projects, and provide new opportunities for customers to manage costs and participate in the electricity sector. DERs can also optimize the use of grid infrastructure to support the demands of electrification.

This report reviews how Ontario's DER compensation mechanisms work together to drive the efficient adoption and management of DERs. In support of this review, we classify compensation mechanisms into three types:

- **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.
- **Procurement and wholesale market mechanisms** refer to IESO-administered mechanisms designed to meet reliability and resource adequacy in both the short and long term.
- **Programmatic mechanisms** include programs that compensate DERs through upfront and/or ongoing financial incentives tied to customers' participation and performance.

Results of the review, along with lessons learned from other jurisdictions, inform our development of a **principle-based DER assessment framework**. Centered on economic efficiency, the framework is used to assess Ontario's DER compensation mechanisms and identify potential ways to enhance them with the goal of maximizing the economically efficient adoption and operation of DERs. As requested by the report's sponsors, we provide recommendations for consideration by the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB), two of the Ontario bodies tasked with designing and administering the Province's many DER-related programs and initiatives.

Relative to other jurisdictions, Ontario already has many elements of cost-reflective electricity pricing. Ontario's retail electricity pricing stands out among its peers, with high fixed monthly

[1] For the purposes of this study, we define "distributed energy resources" broadly to include any customer-hosted load-modifying technologies or practices, storage technologies, or generating technologies, as well as any front-of-the-meter generation or storage connected at the distribution level. This definition includes load flexibility capabilities that are not associated with any particular technology, such as load shaving and load shifting driven by price signals and behavioral incentives, as well as energy efficiency. Note that we use the term "customers" here to refer to both transmission and distribution-connected customers.

delivery charges (used to recover a large share of fixed costs) and well-differentiated time of use rates (reflecting the daily and seasonal patterns of energy prices). The dynamic price signals in the wholesale energy market generally provide efficient incentives for DERs, and changes under the Market Renewal Program will sharpen those price signals. Where pricing alone falls short of providing sufficient signals for investment in and operation of DERs, Ontario leverages programmatic and procurement mechanisms.

We find that there are opportunities to further improve the economic efficiency of price-based mechanisms. We also identify opportunities for the IESO and OEB to modify existing compensation mechanisms to incentivize the efficient adoption and management of DERs to reduce system costs, and identify potential DER programs that can bridge the gaps among the three types of existing compensation mechanisms in Ontario. These recommendations include:

- **The OEB should continue to improve price signals to better reflect underlying system costs.** For non-Regulated Pricing Plan (non-RPP) Class B customers, time-invariant volumetric recovery of GA costs is inefficient and should be replaced with a mechanism that allocates costs based on their drivers. We note that the OEB is currently assessing alternative dynamic pricing options for these customers. For RPP Class B customers, more dynamic rates would offer greater customer choice and more efficient price signals. Alternative recovery mechanisms for transmission and distribution costs should be considered to more closely align what customers pay with underlying cost drivers. Implementing these recommendations would require the OEB to balance several objectives, including developing more efficient price signals, offering customers greater choice and more opportunities to save on their bills, and ensuring simplicity in the design of alternative rate structures.
- **Provide opportunities for DERs to participate in IESO's wholesale market and procurements mechanisms.** While some DERs can participate in request for proposal (RFP) processes and other procurement mechanisms, greater participation from smaller and/or aggregated DERs may be possible. Where DERs can fulfill a system need and meet participation and performance requirements, they should be able to compete on a level playing field with traditional resources. We note that in some cases procurement eligibility is predicated on wholesale market participation eligibility.
- **Reflect DER attributes consistently across DER compensation mechanisms**. Attributes such as visibility, availability, and flexibility can enhance the value of DERs to the system. All else being equal, a DER that delivers a lower value due to reduced visibility, availability and performance, or flexibility should also receive lower compensation, while higher DER compensation should be available for DERs with more desirable attributes. This approach helps minimize incentive shopping, drive more value out of DERs, and ensure that compensation is consistent and fair across all mechanisms. We recognize that defining

these attributes, determining their value to the system, and applying them consistently and logically across all compensation mechanisms may take time, and may require a full study and valuation of DER benefits. Further, the approach that Ontario will eventually select will evolve as the Province gains more experience with DER incentive mechanisms and as new mechanisms emerge.

- **Leverage DER programs to unlock DER value streams and increase their participation in the provision of grid services.** A DER program (or programs) can be established for market participants or for DERs that are not currently enabled because they do not neatly fit into an existing mechanism, but are still capable of delivering valuable and cost-effective services to the system. A DER program can also address gaps within existing mechanisms—whether due to unrecognized or underrecognized value streams or the complexity that DER participants experience when navigating different mechanisms. Such a program would help unlock and account for applicable value streams in the program design and compensation structure, generating granular signals that reflect system needs across time and location. In addition, the program could streamline and enhance the participant experience, presenting a centralized approach where DER participants can provide multiple services and where a system operator can acquire them. However, it is important that the IESO and OEB coordinate with key stakeholders to limit the number of these DER programs to avoid a patchwork of mechanisms available to DERs.
- **Continue to incorporate non-wires solutions (NWS) into distribution system planning and in regional planning.** Referring to approaches to address grid constraints without relying on traditional "wires" investments, cost-effective NWS can help optimize the use of both existing and new infrastructure, reducing the magnitude of wires needs and/or deferring the wires investment. The OEB and IESO should continue their efforts to incorporate NWS in different planning processes and develop standardized frameworks and mechanisms to enroll DER participants as needed.

Some of these recommendations may be implemented in the near term, and the IESO and OEB have already taken steps to implement some of them. Recommendations pertaining to the market structure likely will take more time to address. We also note that the adoption and implementation of some of these recommendations may be influenced by Ontario's public policy objectives that may be beyond the purview of the OEB and/or the IESO and would require further Government of Ontario direction or legislative changes.

1. Introduction

In this study, we examine whether and to what extent existing and potential compensation mechanisms work individually and collectively to drive the efficient adoption and cost-effective participation of distributed energy resources (DERs) in Ontario's electricity system. The study introduces a framework to assess how well different compensation mechanisms perform in advancing more cost-effective DER adoption and participation in Ontario's electricity system. The study involves four analytical tasks:

- In Task 1, we conduct an overview of existing Ontario DER compensation mechanisms, dividing these mechanisms into three distinct categories: price-based mechanisms, procurement and wholesale market mechanisms, and programmatic mechanisms (Section 2 of the report).
- In Task 2, we review and analyze DER compensation mechanisms offered in five markets with significant DER activity: New York, California, the PJM Interconnection, Hawaii, and Australia. We classify the compensation mechanisms available in these jurisdictions using the same categories as in Task 1 (Section 3).
- In Task 3, we develop a generalized assessment framework containing four principles that together can be used to assess or develop a DER compensation mechanism (or combination of mechanisms). These principles include economic efficiency, comparable compensation of DERs across mechanisms, simplicity, and predictable payoff (Section 4).
- In Task 4, we apply the assessment framework to existing DER compensation mechanisms in Ontario, evaluating the menu of mechanisms against the four principles established in Task 3. We also identify and analyze gaps in Ontario's suite of DER compensation mechanisms; outline recommendations to remedy those gaps; and provide consistent and effective signals for DER adoption (Section 5).

This report summarizes the results from the four analytical tasks. We note that the report is written from the perspective of an outside analyst and that some of the recommendations described herein may be superseded by policy considerations that are beyond the scope of this work. We further acknowledge that this analysis is retrospective by design and that past conditions can inform but do not predict the future. As Ontario's power system evolves, so will the most prudent approaches to compensating and incentivizing efficient adoption of DERs.

2. Overview of Existing DER Compensation Mechanisms in Ontario

In this section, we develop an inventory of Ontario's DER compensation mechanisms to inform the subsequent assessment of these mechanisms and to identify gaps and potential areas for improvement (see Section 5). We group the mechanisms into three categories: price-based mechanisms, procurement and wholesale market mechanisms, and programmatic mechanisms. These mechanisms are summarized in Table 1 below, and further details are provided in Appendix B.

TABLE 1. ONTARIO DER COMPENSATION MECHANISMS

Price-Based Mechanisms	Procurement and Wholesale Market Mechanisms	Programmatic Mechanisms
• Industrial Conservation Initiative (ICI) • Interruptible Rate Pilot (IRP) • HOEP Pricing • Regulated Price Plans (RPP) and Non-RPP for Class B Customers • Net metering • Distribution charges • Transmission charges • IESO uplifts (recovery of Capacity Auction and ancillary services)	• Energy market (bid/offer participants) • Expedited, medium, and long-term resource acquisitions and contracts (≥ 1 MW) • Capacity Auction • Ancillary services programs (e.g., operating reserves, frequency regulation) • Small Hydro Program	• Demand-Side Management (DSM) programs offer energy efficiency measures, residential demand response (DR), and targeted behind-the-meter (BTM) solar and storage incentives

Price-Based Mechanisms

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.

Ontario's largest electricity customers pay for energy through either the Hourly Ontario Energy Price (HOEP) or Market Clearing Price (MCP) and can opt to reduce their GA charges by participating in the Industrial Conservation Initiative (ICI) (e.g., Class A customers) and pay applicable transmission and delivery charges, among others. Smaller customers (e.g., RPP Class B customers) are exposed to different price signals, which in turn affect the degree to which those customers benefit from adopting DERs.

Ontario already has many elements of cost-reflective electricity pricing in place. However, some elements are not cost-reflective in real time, meaning that they do not represent the different underlying cost drivers for electricity services.[2] The extent to which the prices are or are not cost-reflective has implications for customer incentives to adopt or operate DERs in a way that benefits the electricity system.[3]

Procurement and Wholesale Market Mechanisms

Procurement and wholesale market mechanisms relate to IESO-administered mechanisms that are used to ensure resource adequacy and reliability across different timeframes. These mechanisms include: i) resource acquisition through request for proposals (RFPs), fixed-price contracts, and capacity auctions and ii) the energy and operating reserve markets (including day-ahead and real-time markets).

Historically, the majority of Ontario's generation capacity has been secured through rate-regulated supply and procurement contracts with a government entity. While DERs have been eligible to participate in the Independent Electricity System Operator's (IESO's) recent procurements, the eligibility requirements include market participation, which is currently restricted to stand-alone facilities of 1 MW or greater.[4,5] The IESO has indicated its openness to including stand-alone and aggregated resources of less than 1 MW in future procurements, contingent on their ability to participate in the wholesale market along with greater clarity of

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2 Specifically, for costs that vary in proportion to the amount of kWh of electricity consumed, customers should pay a $/kWh energy charge. Customers should pay a $/kW demand charge for costs that vary in proportion to the amount of kW needed to meet total demand. Demand-related costs include costs to procure generation capacity, transmission capacity, and distribution capacity. A more cost-reflective demand charge can be based on customer demand during system peak hours, which drive additional capacity investments. A fixed charge, also known as a customer charge, is used to recover remaining costs incurred to provide service to customers (e.g., metering, billing, customer service, maintenance of infrastructure, etc.). Fixed charges for low-volume customers may represent a relatively larger share of their electricity costs compared to other customers. However, aligning the remaining costs with cost drivers can still encourage DER adoption among low-volume consumers in ways that benefit the overall system.

3 The extent to which current prices are cost-reflective changes the economic viability of DERs. Cost-reflective prices ensure right-sized incentives for DERs, while costs that deviate from actual system costs can greatly under- or over-incentivize them.

4 "The LT1 RFP is expected to competitively procure year-round Contract Capacity from dispatchable New Build and Eligible Expansion resources, including New Build and Eligible Expansion facilities incorporating Electricity generation and storage, registered or able to become registered in the IESO-administered markets, larger than one (1) MW and which can deliver a continuous amount of Electricity to a connection point on a Distribution System or Transmission System during the Qualifying Hours for: (i) at least four (4) consecutive hours in the case of Electricity Storage Facilities; or (ii) at least eight (8) consecutive hours in the case of Non-Electricity Storage Facilities" (p. 5, IESO Request for Proposals for the Procurement of Long-Term Electricity Reliability Services Draft, June 30, 2023).

5 "Each Proposal must be specific to a single Long-Term Reliability Project which may be either a Large-Scale LT1 Project or a Small-Scale LT1 Project" (p. 7).

future participation uptake.[6] Separately, the IESO is re-securing existing distribution-connected hydroelectric capacity through the Small Hydro Program using a standard-offer contract. While Ontario intends to meet its long-term resource adequacy needs through rate-regulated supply and RFPs, the Province meets shorter-term needs using the Capacity Auction (CA) mechanism. In the 2023 Capacity Auction (which obtained capacity for Summer 2024 and Winter 2024/25), the majority of the cleared capacity was customer Demand Response. However, a large share of DERs still do not participate in Ontario's energy markets.[7] We note that the IESO is in the process of evolving its resource adequacy approach towards cadenced procurements to meet system needs on various timescales.

Programmatic Mechanisms

Programmatic mechanisms refer to programs that involve upfront and/or ongoing financial incentives or compensation that are tied to customers' DER adoption, participation, and/or performance.[8] Because of their ease of implementation from a customer experience and enrollment perspective, programmatic mechanisms are popular. They can also quickly deliver policy objectives, reduce market and cost barriers, and aid market transformation of newer technologies.[9] These mechanisms are typically used to incentivize efficient DER adoption and utilization when price-based mechanisms and procurement and wholesale market mechanisms do not send adequate price signals or have challenging technical requirements.[10]

In some instances, these categories of compensation mechanisms complement one another, while in other instances, they offer alternative avenues for DER owners to provide value to the system and internalize the value they provide. However, there are also instances in which some of these mechanisms overlap and potentially provide duplicative incentives for the provision of a given service. We discuss these interactions among mechanisms in Section 4.

6 IESO, Resource Acquisition and Contracts, December 11, 2023.

7 Virtual Hourly Demand Response (HDR), Physical HDR, and Dispatchable Load resources together provide 1,067 MW out of the total 1,867 MW cleared capacity for the Summer Obligation. The DER Potential Study estimates that as of 2022, there were 10,170 MW of DERs located in Ontario, of which 6,373 MW were demand response. *See* Dunsky Energy + Climate Advisors. "Ontario's Distributed Energy Resources (DER) Potential Study Volume I: Results & Recommendations," September 28, 2022.

8 Programmatic mechanisms have historically been delivered by the IESO, but per recent Ontario Energy Board (OEB) guidance, local distribution companies (LDCs) are beginning to experiment with programs to use DERs to deliver distribution non-wires solutions (NWS).

9 For example, a programmatic mechanism that provides rebates for new heat pump installations (provided that it passes the relevant cost-effectiveness test) can help accelerate heating electrification.

10 Please refer to Section 4 below for further discussion on tradeoffs among the different types of mechanism. Note that this study does not include an assessment of energy efficiency programs, as these are performed through IESO's Evaluation, Measurement and Verification (EM&V) Protocols.

3. Findings from a Jurisdictional Scan of DER Compensation Mechanisms

To inform our assessment of Ontario's existing DER mechanisms, we surveyed compensation mechanisms for DERs in five markets outside of Ontario with advanced practices for DER integration: New York, Hawaii, California, PJM, and Australia. Appendix A provides an overview of DER incentives offered in these jurisdictions and identifies successes and challenges. Below are the key findings from our jurisdictional scan.

- **DER compensation mechanisms are often used to promote specific technologies and/or policy goals**, **resulting in a patchwork of DER mechanisms that do not efficiently incentivize all DER types.** While mechanisms that promote specific technologies, such as using net energy metering (NEM) to support solar adoption, may still be tied to system needs and value, economic efficiency is not the primary objective. These approaches may succeed in spurring DER deployment, but they often do so to the detriment of non-participants who have to shoulder the mechanism costs. A consequence of the patchwork approach is the absence of a holistic framework to allow DERs to access the entire value stack in a streamlined fashion. In some cases, the lack of a framework can create barriers to future reforms.[11] Some jurisdictions have amended these patchwork policies to create more cost-reflective mechanisms. For instance, New York's Value of Distributed Energy Resources (VDER) tariff compensates electricity services that DERs provide based on their different value streams (e.g., energy, capacity, environmental value, among others). California launched the Distributed Energy Resource Action Plan, where the state will explore how to incorporate DERs into the grid in a way that maximizes their value and contributes to equity and affordability. In Hawaii, utilities investigated the technical, economic, and policy issues associated with DERs as part of a larger effort to integrate clean energy resources, modernize transmission and distribution grids, and reform rates.
- **Retail rate design continues to be the biggest barrier to—and opportunity for—promoting the efficient level of DER adoption and participation.** In many jurisdictions, fixed system costs are recovered through flat $/kWh volumetric charges, elevating the all-in electricity price during most hours to well above the marginal cost to produce electricity. As a result, customers are discouraged from adopting electrification technologies that increase

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[11] For example, some researchers note that in order to prevent creating entrenched interests, it is important to address issues with inefficient tariff design before large DER deployments. *See* Bo Shen, Fredrich Kahrl, and Andrew J. Satchwell, "Facilitating Power Grid Decarbonization with Distributed Energy Resources: Lessons from the United States." *Annual Review of Environment and Resources* 46, no. 1 (2021): 349–75.

consumption, such as electric vehicles (EVs) and heat pumps,[12] and over-incentivized to adopt technologies that reduce energy usage, such as distributed solar. Moreover, smaller customers' lack of exposure to real-time prices that reflect the marginal cost of energy hinders the adoption of technologies that could effectively respond to these signals, such as managed vehicle charging. Relative to traditional flat $/kWh volumetric charges, time-varying charges can better communicate system needs and generally benefit highly flexible DERs.[13] Some jurisdictions are moving toward changing their default rate structure to include a demand charge based on a customer's maximum power usage (e.g., Hawaii's Grid Access Charge) in part to ensure DER customers pay their fair share of the fixed system costs.

- **DER compensation mechanisms that provide reliable incentives with a high degree of certainty enjoy high participation levels.** Due to its highly attractive incentive, NEM 1.0 (where customers are compensated at the full retail rate) was instrumental in encouraging customers to adopt rooftop solar, especially in jurisdictions with high retail rates (e.g., California, Hawaii).[14] Likewise, Australia's generous feed-in tariff helped accelerate the country's deployment of rooftop solar. Demand response participation in the wholesale market skews toward reliability-based programs that offer significant capacity payments over the program period (e.g., PJM, New York Independent System Operator or NYISO, California Independent System Operator or CAISO). Large up-front payments with certainty can substantially increase customer uptake (e.g., the Battery Bonus program in Hawaii, with a one-time cash payment of $500–$850 per committed kW and lock-in 10-year period for export rates). Approaches with simple compensation designs with low risk and high convenience for customers also enjoy greater interest relative to more sophisticated designs. However, some of these implementations led to distortions in compensation and cost shifts at the expense of non-participants Therefore, as market conditions, technological

[12] Tim Schittekatte, Ilan Momber, and Leonardo Meeus. "Future-Proof Tariff Design: Recovering Sunk Grid Costs in a World Where Consumers Are Pushing Back." *Energy Economics* 70, (2018): 484-498. See also Elisheba Spiller, Ricardo Esparza, Kristina Mohlin, Karen Tapia-Ahumada, and Burçin Ünel. "The Role of Electricity Tariff Design in Distributed Energy Resource Deployment." *Energy Economics* 120 (2023), 106500; and Sanem Sergici and Long Lam. "Retail Pricing: A Low-Cost Enabler of the Clean Energy Transition." *IEEE Power and Energy Magazine* 20, no. 4 (July 2022): 66–75.

[13] For example, time-varying rates enhance the value of battery energy storage: customers can shift their demand for electricity from the grid from a high-price period to a low-price period. For additional discussion, see Andrew Satchwell, Peter Cappers, and Galen L Barbose. "Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources," July 24, 2019.

[14] However, it is also important to note that some of these compensation mechanisms lead to higher costs for non-participating customers and raise equity concerns.

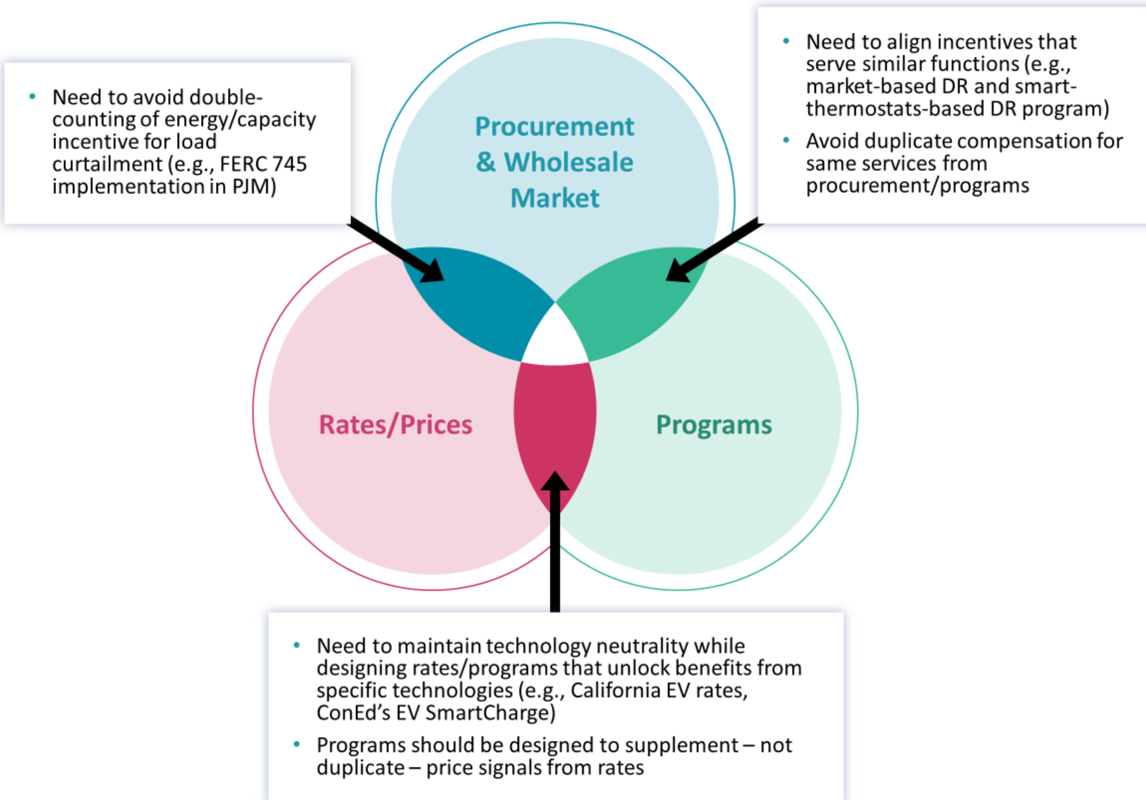
capabilities, and policy priorities have evolved, jurisdictions have accordingly evaluated and updated the structure of these compensation mechanisms, including incentive levels.

- **Challenges and opportunities emerge where alternative DER compensation mechanisms overlap.** Where rates alone are unable to provide efficient price signals, procurement and wholesale energy market mechanisms and programmatic mechanisms can be particularly useful to supplement the price signals. Further, non-rate mechanisms can also enhance the benefits of DERs by boosting their visibility to system operators, who in turn can schedule and dispatch DERs more reliably. However, coordination between regulatory bodies and system planners is required to incentivize the efficient deployment of DERs (e.g., California DER Action Plan and Australia OpEN) and to ensure DER compensation mechanisms provide complementary, rather than duplicative, price signals.

Drawing from experiences across the surveyed jurisdictions, we find that when transitioning from a fragmented system of DER mechanisms to a more holistic and consistent framework, it is important to first review existing mechanisms; evaluate how they interact with one another; and identify areas where they overlap (see Figure 1 below). Overlapping compensation mechanisms can create issues with double incentives on the value side and double-counting on the grid services side.[15] In general, it may be easier to identify and minimize instances of double compensation or double counting between programmatic and procurement and wholesale market mechanisms. Addressing inefficient interactions between rates/prices and other mechanisms may take a longer time, as it necessitates first making rates more cost-reflective before rebalancing the compensation available through other mechanisms.

[15] For instance, in the US, a customer bidding their demand response into an organized energy market avoids paying for that energy when activated, but subject to customer net benefits test, the customer is still eligible for payments for that same energy.

FIGURE 1: INTERACTIONS AMONG COMPENSATION MECHANISMS



4. Assessment Framework for Evaluating DER Compensation Mechanisms

We develop an assessment framework to aid in the evaluation of DER compensation mechanisms and the identification of potential gaps. Based on four key principles, the framework can be used as a guide to ensure that existing and future mechanisms deliver appropriate value to the power system and participants as intended.

Below, we define and describe these key principles in detail (see Figure 2 below). We note that it is often not possible to satisfy all four principles fully when designing compensation mechanisms; therefore, trade-offs among priorities and principles are necessary. In those cases, a qualitative assessment of policy priorities can help determine which principles should be elevated or de-emphasized.

FIGURE 2: ASSESSMENT FRAMEWORK PRINCIPLES

PRINCIPLE 1

Economic Efficiency / Cost-Effectiveness

A compensation mechanism should lead to societally beneficial outcomes in a cost-effective manner

PRINCIPLE 2

Comparable Compensation Across Mechanisms and Resource Types

Resources should receive similar compensation for similar services regardless of technology or mechanism type (after accounting for differences in important attributes across resource types)

PRINCIPLE 3

Simple and Accessible

Some participants have less sophistication and/or risk tolerance than others, and a mechanism's complexity should be appropriately calibrated to intended participant, technology, and compensation level

PRINCIPLE 4

Predictable and Acceptable Payoff

Participants should be able to predict payoff with reasonable accuracy, as this will result in maximal participation by cost-effective resources

a. Framework Principles

PRINCIPLE 1: A COMPENSATION MECHANISM SHOULD ADVANCE ECONOMIC EFFICIENCY IN A COST-EFFECTIVE MANNER

Economic efficiency is the overarching principle for the assessment or development of any DER compensation mechanism. A DER compensation mechanism advances economic efficiency if it encourages the adoption and participation of DERs that are less expensive than the traditional solution, resulting in lower total cost to provide energy services. To achieve this, a DER compensation mechanism should provide sufficient compensation resulting in the participation of all cost-effective DERs; at the same time, the compensation should not be so high that it causes a cost shift to non-participating customers. Over the long run, an economically efficient mechanism helps increase the participation of cost-effective DERs in the market, putting downward pressure on market prices and creating additional consumer benefits.

In general, marginal cost pricing can help achieve economically efficient outcomes. Under such a pricing scheme, where prices perfectly reflect costs, the amount that a DER earns from providing an energy service at a specific location at a given time should be equal to the value of that service to the system. That value may consist of multiple value streams, including the value of energy, capacity, transmission, distribution, ancillary services, and any externalities (see Figure 3 below).[16]

In practice, establishing the precise marginal cost at a given time and location is not always straight-forward. Moreover, requirements around the recovery of fixed costs, concerns about fairness, and the desire to provide mass-market participants with simple and accessible pricing (discussed more below) impose limits on how widely cost-reflective pricing can be applied.[17] Consequently, most participants are not exposed to marginal cost pricing, and so do not receive price signals reflecting accurate system value when making decisions to adopt and operate DERs. Even if locationally and temporally granular price signals were in place, smaller participants may not have the sophistication (or interest) to respond to such granular price signals without assistance from automation and enabling technologies.

Where pricing mechanisms alone do not support the participation of all economically efficient DERs, other types of mechanisms can help by providing supplementary price signals. Together, these multiple mechanisms through different revenue streams (realized through rate reductions, wholesale and procurement payments, and/or programmatic payments) send DER owners a *composite* price signal (i.e., a value stack), unlocking the value streams that DERs can provide to the system.[18] When designing these multiple mechanisms, care is needed to ensure that they work together to advance economic efficiency, while also addressing the other principles discussed below.

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[16] Unpriced positive and negative externalities may distort otherwise efficient pricing. Pricing those externalities is one of several policy measures that lawmakers use in multiple jurisdictions to correct for those inefficiencies. However, analyses in this report assume a system perspective, appropriate considerations of externalities are beyond the scope of this study.

[17] For a discussion concerning the limitations of accurately representing marginal costs to retail customers, see D. R. Biggar and M. R. Hesamzadeh (2014). *The Economics of Electricity Markets.* Wiley. Chapter 20.

[18] Only the relevant value streams that DERs are capable of providing should be unlocked. The composite price signal, or the value stack, should not double count and double compensate the values that DERs provide. See below for further details.

FIGURE 3: DER VALUE STACK

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 Value	Reduction in the transmission capacity required to meet system coincident peak demand through distributed generation or reduced consumption during system peak hours
Distribution Value	Reduction in the distribution capacity required to meet the local distribution network needs through distributed generation or reduced consumption during local network peaks
Energy & Losses	Reduction in energy required from centralized generation to meet load, achieved either through distributed generation or modified consumption
Ancillary Services	Provision of ancillary services, including frequency regulation and operating reserves
Externalities	Change in unpriced externalities (e.g., carbon emissions, health benefits, employment benefits). This report takes a system perspective, rather than a societal perspective, and therefore unpriced externalities are considered out of scope

PRINCIPLE 2: VALUE STREAMS SHOULD RECEIVE COMPARABLE COMPENSATION ACROSS DIFFERENT MECHANISMS AND RESOURCE TYPES

A portfolio of compensation mechanisms is often necessary to maximize the economically efficient deployment and participation of DERs, including mechanisms targeting particular DER technologies and participant types. When designing this portfolio, the different mechanisms should provide similar levels of overall compensation for similar value stream(s), independent of the specific technologies being deployed.

However, this does not imply that mechanisms should overlook differences in the value created by different DERs due to their attributes. For example, an EV managed charging program designed to unlock generation capacity value may provide greater year-round availability than a smart thermostat program that is only available in the summer. Indeed, the compensation level in each mechanism needs to account for the specific attributes of different participating resources that may mediate their value to the system. The attributes that may modify a DER's value may include:

- **Visibility.** The value that a DER offers is influenced by the extent to which it is visible to the system operator for planning and operational purposes. Visibility ensures the system operator can reliably utilize the DER and improve planning functions (as they would for traditional resources).[19]

[19] Mechanisms that require DERs to register and/or have robust telemetry tend to have higher level of visibility.

- **Availability and Performance.** This attribute reflects the extent to which DERs provide grid services over the course of a season, a year, or during certain extreme events, accounting for both inherent DER performance (including the certainty level of that performance) and enabling factors (e.g., availability of fuel supply).[20] Among the dispatchable resources, the duration of the offered service may alter its value of the service. For instance, 1 kW from an 8-hour battery is more valuable compared to 1 kW from a 4-hour battery. Also relevant to this attribute is the "firmness" level of a resource, or how much system operators, through performance obligations and penalties, can count on the resource's performance.
- **Flexibility.** Certain DERs can respond to dispatch signals from system operators in different time frames, from within five minutes up to multiple hours. Resources that can respond quickly are more valuable, and this value may be captured in the form of additional value streams (e.g., ancillary service values).

The appropriate decision-makers (e.g., regulators, system operators, policymakers) will need to develop methods to define, evaluate, and assess how these key attributes and characteristics, such as size and technology type, may mediate DERs' contribution to the different value streams. Such methods should evolve as system needs evolve. For example, in a future with a higher degree of variable renewable generation, a premium for quick response from DERs may help produce cost-effective outcomes. Whether the need for a new service emerges and how best to address it will be system-specific and should be developed as part of reviewing an existing compensation mechanism or proposing a new mechanism.

PRINCIPLE 3: A COMPENSATION MECHANISM SHOULD BE SUFFICIENTLY SIMPLE AND ACCESSIBLE TO INDUCE PARTICIPATION

The degree of complexity for any compensation mechanism should be calibrated based on the administrative capacity of the participant groups it targets.[21] For example, a smart thermostat program targeting residential demand response should involve relatively simple eligibility and verification requirements in order to minimize barriers to participation. The Capacity Auction, which targets larger commercial and industrial (C&I) customers and front-of-meter (FOM) generators, may have more complex terms governing eligibility, performance, measurement, verification, telemetry, and compensation.

[20] Some DERs complement each other and provide more value when combined or aggregated, often enhancing their availability. A good example is a combined solar plus storage system.

[21] Administrative capacity refers to the participant's ability to understand and meet rules and requirements of the relevant compensation mechanisms based on their expertise and available resources.

PRINCIPLE 4: A COMPENSATION MECHANISM SHOULD RESULT IN A PREDICTABLE AND ACCEPTABLE PAYOFF

Participants should be able to predict payoff with reasonable accuracy, given the compensation mechanism design, their compensation expectations, and ability to meet defined participation commitments. The compensation structure should be transparent—with clear connections between performance and payoff—and stable, providing some level of revenue certainty or aligning with the participant's expectation at the time of DER adoption and participation decisions. However, predictability does not mean that the compensation structure and level remain unchanged over long periods. As market conditions and grid needs evolve, it is natural to expect that the value streams will evolve as well. Alternately, if long-term revenue stability is essential for the deployment of economically efficient DERs, then the levelized value of the DER reflecting the market outlook over that duration can be used to establish the compensation levels.

Acceptable payoff can be gauged by comparing the incremental cost and/or level of effort required to provide system value against the level of monetary compensation. For example, if the compensation leads to a reasonable rate of return for DSM programs (e.g., by shortening the payback periods) given the risk/potential inconvenience of participation, this may be an indication that the mechanism leads to an acceptable payoff.[22]

b. Interactions Among Compensation Mechanisms

In the same way that DER value streams can be stacked, different types of compensation mechanisms can be stacked to unlock the full value of a DER. For example, a TOU rate that promotes off-peak vehicle charging year-round may not provide an adequate signal to discourage participants from charging their vehicles during a heat wave. In this instance, it may be more effective to augment the TOU rate with a demand response program that compensates participants for responding to a certain number of curtailment events.

Consistent and fair compensation levels across mechanisms help minimize incentive shopping. While stacking different types of compensation mechanisms can effectively unlock the full value of different services that DERs can provide, it is important to avoid double counting and double compensating for DER values. For example, if a rate design already fully reflects the

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[22] This principle does not call for increasing compensation levels beyond the value the resources provide to the system, to ensure acceptable payoff. Setting the compensation level too high may lead to violating the economic efficiency principle and impose costs on other participants. Therefore, acceptable payoff and economic efficiency goals should be carefully balanced when developing compensations mechanisms.

value of energy produced by a behind-the-meter (BTM) generation facility, that facility should not receive additional energy value through a programmatic or a wholesale mechanism, as this would amount to double compensation.

Likewise, it is important to evaluate how simple and accessible the compensation mechanisms are collectively. A remuneration pathway consisting of multiple mechanisms that are, on their own, simple and easy to access may not necessarily be simple and accessible when combined. Further, we note that while the mechanisms themselves may be simple and easy for participants to access, it may not be straightforward for them to determine which mechanisms are available in the first place, which mechanisms make more economic sense, and how to coordinate their DERs across the mechanisms. Therefore, it is important to identify appropriate systems and participation models (i.e., DER aggregators or programs) that will enhance the experience for participants, particularly those with limited administrative capacity, and that reflect their system value.

5. Application of the DER Assessment Framework and Recommendations

When analyzing Ontario's DER compensation mechanisms using the proposed assessment framework, we find that there are already several ongoing initiatives to leverage DERs to meet system needs cost-effectively. In addition, we identify opportunities to improve the economic efficiency of price-based mechanisms and potential areas to bridge the gaps among wholesale/procurement mechanisms and programmatic mechanisms (please refer to Appendix B for a detailed summary of the gap analysis).

Below, we discuss these recommendations, noting that some may be implemented in the near term while others (most likely those pertaining to the market structure) may take more time to address. We also note that the adoption and implementation of some of these recommendations may be influenced by Ontario's public policy objectives that may be beyond the purview of the OEB and/or the IESO and would require further Government of Ontario direction or legislative changes.

Price-based Mechanisms

Introduce further rate improvements and rate options for RPP Class B customers.

Supply pricing for RPP TOU customers has been reformed to be more cost-reflective. During the summer and winter, the TOU pricing curves follow the general shape of the supply cost curve.

However, on the peak summer days, the TOU price understates the true cost of supply, while in the colder season, the TOU price overstates the true cost of supply. With a higher price ratio and later peak period, the Ultra-Low Overnight TOU rate is more cost-reflective than the default TOU rate. The OEB can take the following actions to create more efficient price signals for RPP Class B customers and encourage a more efficient level of DER adoption and utilization:

- **Offer more dynamic rates on an opt-in basis.** Dynamic rates, such as critical peak rates and real-time pricing, can communicate real-time system conditions more clearly, and customers can leverage their DERs to respond accordingly. When designing these alternative rates, it is important to account for the interaction between GA cost recovery and HOEP.[23] The OEB would need to balance several objectives, including creating efficient price signals (e.g., all-in price is lower during hours of abundant supply), providing customers with meaningful opportunities for bill savings, and considering simplicity in the design of the alternative rates.
- **Periodically review system TOU periods vis-à-vis system conditions.** As Ontario's electricity system continues to evolve, the relationship between TOU periods and the system load curve should be periodically reviewed. Definitions for pricing periods should be updated accordingly to ensure that customers receive the strongest price signals to reduce energy consumption during those hours with the greatest generation constraints. As variable renewable generation grows across the Province, net system load—rather than gross system load—may become a more important determinant of capacity constraints and, consequently, cost-reflective prices.[24]

Introduce further rate improvements and rate options for non-RPP Class B customers.

Current GA cost recovery for non-RPP Class B customers is not cost-reflective because costs are recovered through a flat volumetric charge that varies on a monthly basis. Because of the inverse relationship between the GA costs and HOEP, non-RPP customers pay a higher GA charge during months when the average HOEP is low and a lower GA rate when the average HOEP is high. The combined volumetric energy supply charge effectively mutes the energy

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[23] We note that Ontario's regulation specifies how the GA is to be recovered from different classes of consumers. *See* O. Reg. 429/04: Adjustments under section 25.33 of the Act. Therefore, implementation of this recommendation would require further government direction and legislative changes.

[24] Even in the presence of fixed costs, revising TOU periods to better align with changes in system load profile can still help incent efficient DER adoption. However, we note that Ontario's regulation specifies the time for the off-peak period. *See* O. Reg. 95/05: Classes of Consumers and Determination of Rates, Section 6(1).4. Therefore, implementation of this recommendation would require further government direction and legislative changes.

market price signal that would otherwise communicate to customers when to increase or decrease energy usage.

The OEB should explore additional energy supply rate structures for non-RPP Class B customers, where each cost component is recovered using its own appropriate billing determinant.[25] To that end, we note that the OEB is undertaking steps to explore alternative methods and implementation options.[26] Finally, the OEB should review GA cost allocation between RPP and non-RPP Class B customers and provide recommendations to the Government of Ontario on alternative options; while the GA costs are primarily driven by capacity and fixed costs, GA costs are currently split between the two customer groups on a volumetric basis.

Examine alternative transmission cost recovery methods that align with system needs.

The OEB could consider wider use of cost-reflective billing determinants for recovery of transmission and distribution costs that could encourage participants to shape their loads in more grid-beneficial ways. RPP Class B customers currently pay for transmission costs via a $/kWh volumetric charge, which can distort the energy price signal. A peak-coincident $/kW demand charge sends a more efficient price signal but may raise concerns about simplicity for smaller customers. As another option, the OEB could examine whether and to what extent transmission costs can be integrated into the existing TOU tariff for the RPP Class B customers, providing one set of cost-reflective price signals while minimizing bill complexity and volatility.[27]

The two-part demand charge to recover transmission costs for transmission-connected customers sends an appropriate and efficient price signal, and similar cost-reflective designs should be available for distribution-connected Class A and non-RPP Class B customers. Toward this objective, the OEB is considering a low-load-factor delivery rate for public EV charging stations, which would better align what the charging stations pay with the transmission system

[25] For example, a "demand-shaped" rate provides dynamic price signals that are correlated with system conditions. *See* OEB, Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario, February 28, 2019.

[26] The OEB is taking a consultation-based and research-driven approach that will result in a Price Design Report with recommendations to the Ministry of Energy and Mines on proposed price plan(s). *See* OEB, Dynamic Pricing Options for Non-RPP Class B Electricity Consumers.

[27] We note that Ontario's regulation specifies that low-volume customers are required to receive separate charges for delivery and commodity costs. *See* O Reg. 275/04: Information on Invoices to Certain Classes of Consumers of electricity Classes of Consumers and Determination of Rates, section 1(2). Integration of transmissions costs into the existing TOU tariff for Class B consumers may also require amendments to O. Reg. 95/05: Classes of Consumers and Determination of Rates. Therefore, implementation of this recommendation would require further government direction and legislative changes.

costs to serve them.[28] We also note that the OEB is reviewing various issues related to transmission charges,[29] and the OEB should continue with similar efforts to explore and implement alternative methods for recovering transmission costs.

Examine alternative distribution cost recovery methods that align with system needs.

Peak-coincident demand charges provide an efficient price signal to minimize consumption during the hours when the local distribution system peaks. For Class A and non-RPP Class B customers, the OEB could explore recovering allocated distribution costs in part through a "coincident" peak demand charge that recovers the cost of their contribution to the common/upstream facility requirements, with the remainder recovered through a "non-coincident" peak demand charge that recovers the cost of their contribution to local facilities. In theory, a similar two-part demand charge structure can be used to recover distribution costs from RPP Class B customers, but we understand that it is the OEB's policy to recover distribution costs through a fixed monthly charge, in large part because the majority of costs are related to connection and customer service for smaller customers and are fixed.[30]

In principle, transmission and distribution charges should be designed to be as cost-reflective as is reasonable (i.e., based on the cost of the assets used to deliver electricity to each individual customer, proportionate to their usage of those assets). However, fully reflecting locational differences in such charges can create equity issues among similar customers located on different circuits within a local distribution company's (LDC) service territory. An alternative approach is to apply reasonably cost-reflective prices to all customers within a service territory, and use programmatic mechanisms (such as non-wires solutions, or NWS[31]) to incent additional DER deployment and operations on capacity-constrained circuits.

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[28] OEB, Draft Proposal: Adjusted Retail Transmission Service Rate for Low Load Factor Electric Vehicle Charging, May 30, 2024.

[29] OEB, Generic Hearing on Uniform Transmission Rates – Phase 2, Docket EB-2022-0325.

[30] In addition, the fixed charge was designed to reduce variability in how much customers pay for distribution services across different distribution systems in the Province. *See* OEB, A New Distribution Rate Design for Residential Electricity Customers, Board Policy, EB-2012-0410, April 2, 2015.

[31] Non-wires solutions (NWS), also known as non-wires alternatives (NWAs), refer to approaches that aim to address grid constraints without relying on traditional infrastructure investments like new transmission lines, substations, or other "wires" components. NWS can help optimize the use of both existing and new infrastructure, reducing the magnitude of wires needs and/or defer the wires investment. NWS can also be relied upon to mitigate the investment uncertainty surrounding the pace and locations of load growth on the grid (for example as it relates to greenfield development) until better information becomes available.

Wholesale and Procurement Mechanisms

Provide opportunities for DERs to participate in IESO procurement processes where they are capable of meeting service requirements.

Expanding procurement mechanisms to include DERs can increase competition that can, in turn, help meet system needs at a lower cost. This is particularly important in a high load growth environment where DERs may experience less barriers in connecting and delivering electricity services than large generation projects. In general, DERs that can provide the desired services (e.g., capacity service, energy service) should be allowed to participate in the RFPs, providing that they meet important and clearly defined participation and performance criteria. In the event that such necessary criteria would exclude cost-effective resources, other DER programs and mechanisms should be considered. Leveraging insights from existing mechanisms, the IESO can refine the terms and requirements for DERs and adjust participation requirements for future RFPs as needed.[32] We note that distribution-connected resources greater than 1 MW can participate in IESO procurements currently and that future IESO procurements may evolve as one pathway to include smaller stand-alone resources and/or aggregations of DERs. This is an example of how Ontario, through technology-neutral procurement mechanisms, can leverage DERs to meet system needs.[33]

Provide a pathway for customers with DERs to participate in and be appropriately compensated for in IESO-administered wholesale energy markets.

The dynamic price signals in the wholesale energy market generally provide efficient incentives for DERs, and changes under the Market Renewal Program will sharpen those price signals. However, DERs that are not exposed to wholesale energy market prices today do not have the incentives to respond dynamically to system conditions. As a step toward better enabling DER participation in the wholesale market, the IESO has committed to implementing new DER participation models over the coming years.[34] Through the new models, the IESO will enable aggregations of DERs to participate in the wholesale markets, improving alignment between incentives and location-based, real-time price signals. Meanwhile, it may be more pragmatic in the near-term to offer opportunities for the smallest customers to participate through rate-based or programmatic mechanisms. Over time, the IESO should continue to work with

[32] For example, for an RFP seeking to procure capacity, IESO can review rules governing the capacity auction and DER participation in the energy market. These rules can inform the calculation of the effective contract capacity and the penalty levels for underperformance.

[33] IESO, Resource Acquisition and Contracts, December 11, 2023.

[34] IESO, Distributed Energy Resources (DER) Market Vision and Design Project. Accessed August 6, 2024.

stakeholders to develop opportunities for wholesale market participation of residential and small commercial customers, where technology and/or aggregator capabilities allow for that level of sophistication.

Another point of inefficiency is that ICI participants can also participate in the Capacity Auction. The IESO should continue to examine the relationship between the ICI and the Capacity Auction to ensure that the correct incentives and charges are in place to avoid capacity payments to ICI participants for the capacity that may not be available due to ICI participation.[35]

Account for DER attributes consistently across DER incentives.

Attributes such as visibility, availability, and flexibility can enhance the value of DERs to the system. All else being equal, a DER that delivers a lower value due to reduced visibility, availability and performance, or flexibility should also receive lower compensation, while higher DER compensation should be available for DERs with more desirable attributes. This approach helps minimize incentive shopping, derive more value out of DERs, and ensure that compensation is consistent and fair across all mechanisms. We recognize that defining these attributes, determining their value to the system, and applying them consistently and logically across all compensation mechanisms may take time, and may require a full study and valuation of DER benefits.[36] Further, the approach that Ontario will eventually select will evolve as the Province gains more experience with DER incentive mechanisms and as new mechanisms emerge.

Programmatic Mechanisms

Leverage DER programs to unlock DER value streams and to provide important grid services.

Programmatic mechanisms can be used to incentivize DERs more efficiently when rates alone fall short of conveying all underlying costs, and/or when market participation is not suitable. In instances where existing mechanisms have gaps—whether due to unrecognized or

[35] Interruptible Rate Pilot has this restriction in place. The Pilot tests providing large electricity load customers with an interruptible rate for Global Adjustment charges in exchange for agreeing to curtail demand during interruption events as identified by the IESO. The rate structure in the Pilot includes a demand charge and a fixed charge that is paid regardless of the participating load's consumption levels. We note that enforcing ICI/Capacity Auction restrictions in practice may be cumbersome. As an alternative, the CA non-performance charges can be revised to be more directionally commensurate with the ICI value.

[36] Results from our jurisdiction scan show that currently no jurisdiction is applying consistent mechanisms to value DER attributes. However, jurisdictions such as California are making progress toward this goal.

underrecognized value streams or the complexity that DER participants experience when navigating different mechanisms—a DER program (or multiple DER programs) can bridge those gaps. In Ontario, for example, a DER program could be leveraged to offer a relatively simple and accessible way for DER customers across different levels of the system (bulk, regional, and distribution) to provide energy services. DER programs could also be established for market participants or DERs that are not currently enabled because they do not neatly fit into an existing mechanism (but can still provide valuable and cost-effective services to the system).

While there are a range of programmatic approaches that could be leveraged, it is important to streamline the participant experience as much as possible and to minimize the overhead of customer participation. A coordinated approach in which the IESO, OEB, LDCs, and other key stakeholders work in alignment to develop a focused set of high-priority, high-impact programs is likely to deliver positive results. Close coordination can also help to ensure that all perspectives are considered in the development of compensation mechanisms, improve administrative efficiency, and enhance the overall participant experience. More broadly, coordination and collaboration are needed to make sure that each individual compensation mechanism complements or enhances other available mechanisms rather than duplicating, conflicting with, or undermining them. For instance, the consideration and valuation of a distribution NWS would likely be more accurate when synchronized with regional planning cycles, allowing all applicable value streams to be considered together.

For customer-sited DERs, it is also important to consider the relationship between programmatic compensation and underlying tariff and rate structures. When DERs are installed and utilized at customer sites, they can offset supply, transmission, and distribution charges that customers incur for their grid use.[37] Programmatic compensation to participants should take into account these avoided costs to ensure the total incentive to the customer is commensurate with the value that they contribute to the system. Such an approach can support customer choice and bill savings for participating customers while limiting cost shifts to non-participating customers.

Continue to incorporate NWS in distribution system planning.

The OEB has taken a number of steps to facilitate the integration of cost-effective NWS into distribution planning to meet system needs. The NWS Guidelines require LDCs to assess the use

[37] Alternatively, a DER program could involve a new tariff if the underlying tariff and rate structures are found to be incompatible or too complex to harmonize with the new DER compensation mechanism.

of NWS and DERs where applicable as part of distribution system planning.[38] More recently, the OEB has prescribed the method that LDCs should use to evaluate the economic feasibility of NWS in distribution planning and is taking steps to refine input values and methods for calculating benefits and costs.[39] Furthermore, the OEB has invited LDCs to propose compensation mechanisms to use third-party (i.e., non-distributor-owned) DERs as NWS in lieu of distributor-owned solutions, which can further encourage DER deployment.[40]

In places where NWS has been a required part of distribution system planning (e.g., New York, California), NWS assessments have become a core business function within the capital planning process. As LDCs in Ontario become more familiar with NWS guidance from the OEB, and as NWS becomes a core part of LDCs' distribution planning, we recommend the OEB to build on existing tools and guidance and continue its work to support LDC's consideration of cost-effective NWS.

Continue to incorporate NWS in regional planning.

The IESO has established a process for identifying NWS for transmission needs through the Integrated Regional Resource Plan (IRRP).[41] The multi-step process involves screening potential NWS based on the characteristics of the identified need and applicable option types (e.g., transmission-connected generation or storage, distributed generation, etc.). The process also includes an economic analysis of candidate NWS compared to traditional wires solutions, with results integrated into the broader IRRP. When transmission NWS options are identified as viable solutions, the IESO should continue to explore how existing mechanisms can be

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38 The NWS Guidelines build on the OEB's previous Conservation and Demand Management (CDM) Guidelines, which required 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. The NWS Guidelines require distributors to document their consideration of NWS when making investment decisions on electricity system needs with an expected capital cost of $2 million or more as part of distribution system planning, excluding general plant investments. *See* OEB, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024.

39 OEB, Benefit-Cost Analysis Framework for Addressing Electricity System Needs, May 16, 2024. For specific refinements that the OEB is considering, see OEB, Stakeholder Feedback and Webinar Invitation - Final Phase One Benefit-Cost Analysis Framework for Addressing Electricity System Needs (EB2023-0125), May 16, 2024.

40 These mechanisms are not in scope because the OEB announced this policy when analysis for this report was undertaken, and there was not experience with an approved mechanism available to consider their indirect impact on DER deployment. *See* OEB, Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, March 28, 2023.

41 IESO, Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives, May 26, 2023.

appropriately utilized to enroll transmission NWS participants.[42] Recently, the IESO used the Local Initiatives Program within the current 2021–2024 Conservation and Demand Management framework to deliver NWS that were found to be cost-effective based on bulk system value within the regional planning process. If new mechanisms are required, the OEB and IESO, along with other IRRP technical working group members (including LDCs and transmitters) where applicable, should coordinate to ensure these mechanisms can also address both transmission and distribution system needs as appropriate.[43] We note that as part of the Regional Planning Process Review, the IESO has been refining its approach to identifying NWS opportunities for transmission needs, developing NWS options, and evaluating how to procure resources to implement cost-effective NWS solutions to meet system needs.[44]

Adopting these recommendations will help improve the efficient deployment of DERs in Ontario. As the Province's energy system evolves, DERs can be quickly deployed to meet fast-growing demand for electricity services while avoiding siting and construction challenges that are often associated with larger infrastructure projects. In addition, DERs can also provide new opportunities for customers to manage costs and participate more fully in the electricity sector. Today, Ontario has a number of compensation mechanisms in place to leverage the existing DER capability in the Province. Enhancements to these existing mechanisms, along with introduction of new ones where needed, can lead to a higher level of cost-effective DER participation in Ontario's energy markets, including participation from the next generation of DER technologies. Many of the potential changes to the compensation mechanisms are already under development or in initial deployment stages. It is critical that the compensation mechanisms are economically efficient, designed to promote flexibility, and adaptable to evolving market conditions and technological advancements, together ensuring that the best technologies and business models succeed and help mitigate the pace of future system cost increases. Taken together, these recommendations would help further Ontario's policy goals to plan for electrification and the energy transition cost-effectively while continuing to maintain safety and reliability for all customers.

[42] For example, the IESO in previous RFPs awarded bonus points to resources located in transmission-constrained areas.

[43] For example, see the OEB's Non-Wires Solutions Guidelines for Electricity Distributors (formerly CDM Guidelines for Electricity Distributors) for consideration of NWS in distribution system planning. In addition, there is also a joint IESO/Electricity Distributors Association/Ontario Energy Association working group underway developing recommendations to the OEB for a regulatory process to establish a shared funding model for LDC-led DSM programs that provide both bulk system and distribution level benefits.

[44] IESO, Regional Planning Review Process. Accessed August 3, 2024.

Appendix A—Jurisdictional Scan Summary

TABLE A1: OVERVIEW OF DER COMPENSATION MECHANISMS IN OTHER JURISDICTIONS

	Practice	Jurisdictions	Successes/Challenges
Price-based Mechanisms	• Distributed generation tariff based on avoided cost	• New York State (Value of Distributed Energy Resources Value Stack), Hawaii (Smart DER Tariff)	• Recognize and unlock some DER value streams • Avoided cost calculations can be contentious
	• TOU tariffs with low midday rates for regions with high distributed solar adoption	• Hawaii, Australia (Solar Sponge Rate) • California (San Diego Gas & Electric 3-Period Rate)	• Greater acceptance and familiarity of time-varying rates among customers and regulators • Transitioning to a more cost-reflective design leads to pushback from rooftop solar groups
	• Time- and location-specific rates that reflect local distribution system constraints	• New York State (export only, Commercial System Relief Program), Australia (South Australia Power C&I Time of Use Rates)	• Enable demand-side resources to meet location-specific needs • Customer education continues to be challenging
Procurement & Wholesale Market Mechanisms	• DER participation in the wholesale capacity market	• California, New York State, PJM	• High DER participation level • Determining compensation based on DER's system value is challenging
	• DER participation in energy/ancillary services markets	• California, New York State, PJM	• Continuous effort to expand DER participation (e.g., FERC 2222 aggregation rules) • DER participation is low
Programmatic Mechanisms	• Utility-operated demand-side management focused on local system constraints	• New York State, Hawaii	• Programs are now part of larger planning processes • Some challenges with customer acceptance
	• Rebates for off-peak electric vehicle charging	• NY ConEd SmartCharge, California (Sacramento Municipal Utility District's 3-period rate)	• High enrollment and participation from EV owners • Technology neutrality remains a concern; more dynamic rates may be needed for higher adoption
All of the Above	• Integrated DER strategy across bulk power system and distribution systems	• California (DER Action Plan), Australia (Open Energy Network Project, Energy Demand and Gen Exchange)	• Increasing recognition of the importance of coordination across regulatory bodies overseeing wholesale and retail markets, but progress is slow

Appendix B—Detailed Gap Analysis

TABLE A2: SUMMARY OF GAP ANALYSIS ASSESSMENT BY PARTICIPANT TYPE

Participant Type	Key Gaps
All Participant Types	• Certain mechanisms can unlock the value streams separately, but there is no mechanism today that allows comprehensive “stacking” of the value streams • Some DER attributes (i.e., visibility, availability, flexibility) are defined and accounted for in some mechanisms, but they are not consistently applied across all mechanisms • Behind-the-meter DERs, directly connected DERs under 1 MW, and aggregated DERs are not currently eligible to participate in the current procurement contract process • Due to technical requirements (e.g. telemetry, metering, minimum size), some fast-responding DERs are not currently eligible to provide certain ancillary services (e.g., frequency regulation services and operating reserve)
Class A Customers	• High GA costs coupled with how GA costs are recovered from ICI customers create price signals that exceed the capacity value that DERs provide • Without proper compensation and charges in place, participation in both the ICI and CA can lead to payments for capacity that may not be available due to ICI participation • Transmission charge design is appropriate; mechanisms to activate DERs for location-specific transmission capacity needs are emerging
RPP Class B Customers	• Benefits from net-energy metering (NEM) participation do not reflect the underlying value streams separately; the total benefits to the participant exceed rooftop solar’s value to the grid • DERs participating in the capacity auction are not exposed to market prices (HOEP or MCP), and settlement based on RPP or retail rate creates inefficiency • While tiered rates may not provide a strong signal to adopt and operate DERs, they align with the Ontario government’s goal of offering options that accommodate customers’ diverse preferences and lifestyles • Some of the existing rate options are not cost-reflective under certain system conditions • More cost-reflective design to calculate transmission and distribution charges can signal system needs more efficiently (though certain designs, such as a flat $/month fixed distribution charge, are in place to meet policy objectives) • Mechanisms to activate DERs for location-specific transmission capacity needs are emerging
Non-RPP Class B Customers	• Benefits from NEM participation do not reflect the applicable value streams separately; the total benefits exceed rooftop solar’s value to the grid • $/kWh flat volumetric recovery of GA costs distorts the overall price signal • More cost-reflective design to calculate transmission and distribution charge can signal system needs more efficiently • Transmission and distribution charges are generally appropriate; mechanisms to activate DERs for location-specific transmission capacity needs are emerging • GA costs are split between RPP Class B and non-RPP Class B customers on a volumetric MWh basis, even though the GA cost drivers are primarily based on capacity needs and policy directives
Distribution-Connected DERs	• Distribution-connected DERs below a certain size threshold are exposed to HOEP and not the more cost-reflective MCP • DERs are activated based on size thresholds and existing contract structures; market signals are not sufficient for dispatchable DERs to be activated in response to distribution capacity needs or transmission capacity needs that are not reflected as a dispatch constraint (e.g., limitations at the transformer station)

FULFILLED SOME IMPROVEMENTS NEEDED NOT FULFILLED

Supply Cost Recovery for RPP Class B Customers

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff

A default TOU rate is in place in Ontario to recover energy (through the HOEP) and Global Adjustment costs from RPP Class B customers. Alternatively, customers can opt into the tiered rate or the ultra-low overnight (ULO) TOU rate introduced in 2023.

- TOU rate improves price signal over flat volumetric pricing (where the $/kWh price does not vary with time) because it better reflects the marginal cost of energy consumption, but price signal can deviate from underlying costs during system peak hours
- With a high price ratio of 10:1 and later peak period, the ULO TOU rate is more efficient than the TOU rate as the former's shape more closely follows HOEP; the tiered rate is less efficient
- TOU rates are generally understandable and accessible to mass market customers, who are familiar with dynamic pricing in other contexts in daily life
- Because RPP pricing is driven by **wholesale market prices** and **GA costs**, pricing structures that better reflect those cost drivers are more efficient (e.g., TOU + Critical Peak Pricing)
- Customer response to TOU and ULO TOU price signals also depends on the structure and level of **transmission** and **distribution charges** as customers respond to the all-in rate

Supply Cost Recovery for Non-RPP Class B Customers

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff

Non-RPP Class B customers pay HOEP for their energy usage and a $/kWh volumetric charge that varies on a monthly basis for GA charges. Alternative cost recovery options that have been proposed include a demand-based hourly rate (where the GA charge varies hourly as an exponential function of demand), a flat GA + CPP rate, and a TOU rate.

- The current rate is simple and accessible with some monthly price volatility for Non-RPP Class B customers, but it is not cost-reflective due to the time-invariant method to recover GA costs
- The higher variable energy price observed by customers promotes DERs that curb volumetric consumption but discourages technologies that increase consumption, such as beneficial electrification
- Potential inefficiency in splitting GA costs with RPP Class B Customers on a volumetric (MWh) basis
- Pricing structures that better reflect **GA cost** structure such as demand-based hourly rate, critical peak peaking, and other time-varying rates are more efficient; the overall customer response to price signals also depends on the structure and level of **transmission** and **distribution charges**

Industrial Conservation Initiative

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff

The ICI was designed to incentivize eligible C&I customers to reduce their demand during the top five coincident peak hours. Because participants pay their GA charge based on their share of consumption during those hours, they can reduce their GA payments by predicting when the five coincident-peak hours will occur and reducing their electricity demand accordingly, potentially with the help of DERs.

- When participants correctly identify the CP hours and reduce their energy usage, they lower their GA payments– a benefit that can exceed the value of generation capacity to the system. Resulting costs are shifted to Class B customers
- The benefit from the ICI program can exceed the price paid for similar services procured through other mechanisms, such as the Capacity Auction and RFPs
- Cross-participation with ICI risks payments for capacity that may be unavailable on ICI days. ICI participants may benefit from lower **transmission** and **distribution charges** if their ICI response also reduces their demand billing determinants
- The capacity benefit to the system over the planning timeframe is real, but its value in the operational timeframe is reduced by the lack of *visibility* into what the participating resources are and how they respond to real-time grid conditions
- The mechanism is sufficiently simple and accessible to large customers with dedicated energy management resources, though with some policy risks and uncertainty (e.g., having to chase the high five hours)

Interruptible Rate Pilot

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff

Per the Ontario Ministry of Energy's request, the IESO in 2024 introduced the Interruptible Rate Pilot (IRP). Intended to bring more certainty and visibility for demand reductions during periods of system stress and improve system planning, the three-year pilot requires participants to reduce their usage to an agreed-upon firm contract demand level during IESO-determined events communicated in advance.

- Similar to the ICI program, the IRP compensates participants more than the value they provide to the system; however, the IRP provides greater visibility and certainty to system operators and greater certainty in payoff to participants
- The IRP involves a fixed price component that IRP participants pay, which better mirrors the GA cost structure relative to traditional GA cost recovery methods
- Eligibility and participation rules coupled with the involved application and contract process can be cumbersome; however, participation is simpler as participants only have to respond to advance notifications. This results in more predictable payoff than the ICI, which requires customers to accurately forecast peak hours.
- The prohibition on cross-participation in the **Capacity Auction** eliminates concerns about double payments. IRP participants may benefit from lower **transmission** and **distribution charges** if the response to called events also lowers their demand billing determinants.

Energy Market

Five-minute market clearing price (MCP) signals are set based on the bids and offers that are settled in the wholesale electricity market. The HOEP is the hourly average of the MCP for energy in the wholesale electricity market. Market Renewal will introduce day-ahead and real-time Locational Marginal Pricing (LMP) and the Ontario Zonal Price.

Economic Efficiency

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- The mechanism is efficient for market participants who experience wholesale market price signals, and LMP will be more efficient
- While larger customers can respond to energy market prices, it may not be the same for smaller customers (though improvements in automation technologies will facilitate and enhance how customers respond to advanced prices)
- DER owners respond to all-in price signal (**GA payments** + energy price), so (in)efficiency in GA cost recovery structure contributes to the price signal's overall effectiveness

Procurement Contracts

The Province intends to meet its *long-term* resource adequacy needs through rate-regulated supply and request for proposals (RFP). While DERs have been eligible to participate in recent procurements, the eligibility requirements include market participation, which is currently restricted to facilities of 1 MW or greater. The IESO has indicated its openness to including DERs that are less than 1 MW in size in future procurements. A competitive procurement process with broad participation across different resource types provides an indicator of marginal generation capacity value.

Economic Efficiency

Comparable Compensation

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Acceptable & Predictable Payoff

- The capacity price resulting from the procurement contracts is higher than the Capacity Auction price but lower than the Industrial Conservation Initiative's capacity value (each of these mechanisms is designed to accomplish different goals, and compensation for comparable services across should be commensurate)
- Procurement contracts offer some of the highest levels of payoffs and predictability over the contract terms and includes commensurate complexity level for participation requirements
- It is appropriate that participants cannot enroll in other procurement mechanisms (e.g., **Capacity Auction**)

Capacity Auction

Ontario relies on the annual Capacity Auction to help meet its *shorter-term* resource adequacy needs. The mechanism allows demand response, existing (but uncontracted) generation and storage facilities, and imports to participate. Resources that clear the auction receive payments for making their capacity available for dispatch by the IESO.

Economic Efficiency

Comparable Compensation

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Acceptable & Predictable Payoff

- Capacity Auction reflects the short-term, market-based capacity value for a group of eligible resources based on their attributes
- Same capacity payments are provided for all resources that clear the auction; payments are lower than capacity value under other mechanisms (e.g., procurement contract, ICI) and net cost of new entry, in part because of the short-term commitment period, which tends to attract existing facilities and resources with low investment requirements
- Participation requirements are complex for some but may be warranted given the transaction size; payments are predictable over the relatively short commitment period but less predictable from one auction to the next
- Cross-participation with **ICI** risks payments for capacity that may be unavailable on ICI days

Ancillary Services: Operating Reserve & Regulation

Ontario operating reserve (OR) requirements are competitively scheduled through a real-time market and co-optimized with energy. Frequency regulation service is procured through medium-term contracts.

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff

- The OR mechanism is efficient because the clearing price incorporates the economic trade-off between being scheduled as OR versus energy. With Market Renewal, OR prices will be determined locationally considering transmission congestion
- OR market price signals are transparent, and the pricing is consistent and transparent; the pricing level fluctuates
- Frequency regulation service is procured through contracts (though the volume is small)
- Payments for regulation services are predictable over contract terms
- The mechanism accessible to IESO market participants, who can participate in the OR market and frequency regulation service contracts

Non-Wires Solutions

Distribution and transmission NWS leverage a portfolio of DERs to defer or avoid distribution and transmission capacity expansion projects (e.g., major substation upgrades). Ontario has a few active demonstration projects and pilots and has established a process of creating a standardized framework to incorporate NWS into distribution planning.

- Existing pilots, such as Toronto Hydro's Local Demand Response (LDR) Pilot program, leverage BTM DERs from commercial or institutional customers to address short-term capacity constraints
- Learnings from pilots may assist in identifying potential updates to the guidance and tools within the existing NWS framework
- Locational marginal cost studies, which evaluate the cost of load growth within different parts of a utility service territory, will be important for identifying opportunities to defer or avoid costly investments. These marginal cost values can inform compensation for NWS and can be used to determine the appropriate compensation level for participating DERs
- IESO conducts studies and has ongoing processes and initiatives to evaluate and deploy transmission NWS as needs arise

Economic Efficiency

Comparable Compensation

Simple & Accessible

Acceptable & Predictable Payoff