December 12, 2025 By E-Mail

Mr. Ritchie Murray
Registrar
Ontario Energy Board
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Mr. Murray:

**RE: Review of the Valuation of Distributed Energy Resources, OEB File No. EB-2025-0268**

The Electricity Distributors Association (EDA) appreciates the opportunity to have participated in the Ontario Energy Board's (OEB) stakeholder meeting on November 24, 2025, and is pleased to provide this submission on behalf of Ontario's local hydro utilities. The EDA represents the province's local distribution companies (LDCs), the publicly and privately owned utilities that deliver electricity to residential, commercial, industrial, and institutional customers in every community across Ontario. Collectively, LDCs own more than $33 billion in electricity system infrastructure and invest over $3.1 billion annually to maintain and enhance a safe, reliable, and modern distribution grid.

The EDA recognizes the importance of the OEB's Review of the Valuation of Distributed Energy Resources (DERs). In June 2025, Ontario's Minister of Energy and Mines released the province's Integrated Energy Plan (IEP), along with implementation directives to both the OEB and the Independent Electricity System Operator (IESO). Directive items 11 and 12 require the OEB to review the valuation of DERs and to identify regulatory and compensation frameworks that appropriately reflect the system value these resources provide.

Ontario's LDCs are key implementation partners in the province's energy transition. The EDA looks forward to supporting the OEB in this important review and provides the following comments for consideration.

**SUBMISSION**

**Part 1: DER Compensation**

The OEB is seeking stakeholder feedback on its preliminary assessment of the system value of DERs. Specifically, the OEB requests input on whether the value stack is an appropriate methodology for assessing DER system value and whether its components are sufficient. The OEB also seeks views on whether the identified compensation mechanisms available to each DER type are exhaustive, and whether the noted misalignments between DER compensation and system value are comprehensive. The OEB invites stakeholder feedback to identify any additional gaps where DERs can provide value that have not been captured. Further, the OEB is seeking feedback on each of the proposed recommendations.

<u>EDA Feedback on OEB Assessment of System Value</u>

Overall, the EDA agrees that the OEB has identified the appropriate value attributes that DERs can provide across the electricity system. However, the assessment of these values can be strengthened to better reflect


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Ontario's system conditions, operational realities, and the full range of benefits DERs are capable of delivering. The following feedback highlights opportunities to refine and expand the current analysis.

The EDA notes that the OEB's assessment of distributed generation (DG) focuses solely on solar PV, without providing a rationale for excluding other DG technologies such as hydroelectric, bioenergy, wind, or combined heat and power (CHP). The OEB also defines hybrid resources exclusively as solar PV paired with storage, without considering other potential combinations. The EDA wishes to highlight that the IEP's reference to DG, when describing the DERs to be procured through the Local Generation Program (LGP), includes a broad range of technologies, identifying "small-scale electricity generation resources, such as biogas, wind, solar, and natural gas generators (including CHPs)."

The OEB notes that the distribution and transmission capacity value is high when system constraints exist and is "zero" when they do not. The reference to "zero" appears intended to illustrate a potential value range rather than a formal valuation. However, the EDA encourages the OEB to clarify how this value framework will translate into practical incentives to ensure that DERs remain available and responsive as constraints emerge.

With respect to the emissions value component, the OEB provides limited discussion of how such value should be defined or quantified in Ontario's context. We note that many IESO contracts historically retained environmental attributes. The OEB does not reference the Clean Energy Credit framework or explain how such instruments may interact with DER valuation under a net metering or value stack model. Ontario lacks a consistent methodology for identifying marginal emission reductions attributable to specific DER technologies. As a result, the EDA believes that additional guidance from the Ontario government is likely required for any consideration of an emissions value component to ensure alignment with the IEP and the province's energy and emissions policy more broadly.

More importantly, the OEB excludes ancillary services from its analysis, which represents a significant oversimplification of the potential system value that DERs can provide. While wholesale ancillary services such as operating reserve are already material opportunities for resources like energy storage, the analysis does not acknowledge that DERs can also provide a broad suite of distribution-level ancillary services. These include voltage regulation, volt-VAR optimization, power quality support, islanding or microgrid services that enhance reliability during outages, and flexible ramping capability to manage variability at the local level.

For distributors, these services are increasingly important. As electrification accelerates and load patterns become more dynamic, LDCs will face greater needs for local flexibility, voltage control, and contingency support. DERs that can deliver these functions provide real operational and planning value by reducing the need for traditional infrastructure investments, mitigating localized constraints, and enhancing reliability and resilience for customers. Excluding these services from the value stack risks undervaluing the unique contributions DERs can make on the distribution system and could lead to compensation mechanisms that do not align with system needs.

While DERs offer the noted benefits, they also increase operational complexity and can impose costs on LDCs. The EDA encourages the OEB to explicitly incorporate both wholesale and distribution-level ancillary services into the valuation framework to ensure a more complete and accurate assessment of DER system value that accounts for all trade-offs. It may be helpful to establish a uniform approach to calculating benefits and a clear mechanism for capturing value. We believe that the OEB should adopt a scalable, repeatable methodological approach, rather than a case-by-case approach (as exists in the current BCA Framework).

Overall, the OEB's assessment remains largely qualitative. The report would be strengthened by including indicative quantitative analysis of the value stack and by more clearly distinguishing between the system value of DERs and the compensation mechanisms available to them.

EDA Feedback on DER Compensation in Ontario

The EDA generally agrees with the OEB's assessment of DER compensation in Ontario, but several nuances should be considered to more accurately reflect available mechanisms and practical limitations. For example, LT2-C eligibility extends beyond solar PV to other forms of distributed generation, including CHP. The OEB's framing of DG as only solar PV (noted above) understates the compensation pathways available to a broader set of technologies.

Similarly, electricity Demand Side Management (eDSM) is listed as applicable to generation capacity, but it may also provide value in terms of energy (e.g., traditional energy efficiency measures, behind-the-meter solar) and potentially emissions value where environmental attributes are included. The OEB references eDSM as a "dollars per kW" incentive for behind-the-meter solar installations, which conflates the incentive mechanism with the underlying system value the resource provides. A clearer distinction between value and compensation mechanism would improve the assessment.

The OEB also includes the Interruptible Rate Pilot, even though the intention to launch a new program was announced only recently, and results from the original pilot have not been made public. It is unclear whether the updated rate will be applicable to distribution-connected customers, as prior participants were primarily large transmission-connected customers. Similarly, the inclusion of Class B Global Adjustment rates assumes the availability of dynamic rate structures outlined in the Winter 2024 Dynamic Pricing Options report, which has not yet been made public.

The assessment of wholesale energy market compensation does not address the suppressing effect of the Global Adjustment on wholesale energy prices, which can limit the value DERs can realize through market participation or as embedded retail generators (per the OEB's Retail Settlement Code). At the retail level, the analysis omits discussion of the Ontario Electricity Rebate (OER), which subsidizes the Regulated Price Plan (RPP) and reduces customer price signals, thereby dampening incentives for investments in behind-the-meter solar or energy efficiency.

EDA Feedback on OEB's Identified Misalignment of DER Compensation and System Value

We note several areas where the OEB's assessment of gaps identified in the qualitative assessment between DER compensation and system value could be refined to better reflect the status and impact of current initiatives underway at both the IESO and OEB.

| Category | EDA Feedback |
|---|---|
| **Generation Capacity** | • Timelines for DER aggregation enablement and the IESO's ERP remain unclear, especially with post-MRP and storage rule amendment priorities.<br>• The EDA questions the OEB's reference to corporate power purchase agreements under O. Reg. 429/09, as participation requires both parties to be IESO market participants; eligible resources primarily provide energy value, and storage is excluded. These PPAs may also rely on the Clean Energy Credit value.<br>• It is also unclear whether the LGP provides explicit capacity compensation given its energy-focused design. |
| **Transmission Capacity** | • It is overly simplistic to assume that locational marginal pricing fully reflects transmission value.<br>• It is also uncertain whether distributors can include transmission value in non-wires solutions (NWS) compensation or whether LGP adequately captures transmission capacity needs in constrained regions, given its energy-focused design. |

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| **Distribution Capacity** | • The EDA emphasizes that DSO capabilities should support value capture across the full value stack, not just distribution capacity. DSOs are well-positioned to coordinate DERs to provide both distribution and bulk system services. A narrow focus risks undervaluing DSOs.<br>• Even where LGP targets distribution-constrained areas, it may not sufficiently recognize or compensate broader distribution-level contributions. |
| **Energy Value** | • Although the OEB recognizes that injected energy differs in value from retail rates, the analysis overlooks that RPP rates are subsidized through programs like the OER, which dampens customer price signals and reduces incentives for behind-the-meter solar deployment. |
| **Emissions Value** | • The OEB's analysis does not account for Clean Energy Credits or other environmental attributes embedded in IESO contracts, leaving emissions value largely unrecognized in compensation. Guidance from the provincial government is likely required to develop a compensation framework related to emissions value. |
| **Combined** | • The OEB notes that Class B GA rates do not compensate DERs for the full value they provide. Advancing dynamic rates for non-RPP Class B customers will require significant customer engagement and LDC investment in billing and CIS upgrades.<br>• The OEB also finds value stacking challenging due to complex interactions and compensation mechanisms, but its assessment appears limited to scenarios with local constraints. The EDA asserts that DSO capabilities should enable full value-stack capture, and that developing these capabilities could simplify DER participation by making compensation mechanisms more navigable and better aligned with system needs. |

Finally, while the OEB's analysis focuses on the value (i.e., benefits) of DERs, it excludes a detailed discussion on the costs and impacts of DER integration, for example, operational costs incurred by distributors and asset degradation. These costs and impacts should be considered alongside the benefits of DERs to ensure a comprehensive assessment of their value. Further, as more DERs are integrated, distributor updates to grid modernization plans and new investments will be required.

<u>EDA Feedback on OEB Recommendations</u>

***Recommendation #1, #2, #3: Net Metering vs. Net Billing***

The EDA recognizes the rationale for moving to net billing, and related updates to net metering and community net metering, as a way to better align compensation for injected energy with grid value. However, several practical, regulatory, and implementation challenges must be addressed before proceeding.

Jurisdictional experience shows that net billing requires a detailed regulatory process to define value-stack parameters, compensation levels, and billing rules, and it is at present unclear how to meaningfully establish locational and time value on a large scale. Developing these frameworks is time-consuming and often contentious, with the risk of misvaluing DER attributes or failing to capture system value comprehensively.

Further, we note the jurisdictions reviewed have very different institutional and market energy sector circumstances compared to Ontario. For example, in some jurisdictions (e.g., New York and California), DER policies and programs are, to some extent, driven by explicit emissions-reduction, decarbonization, and electrification targets and policies that do not currently exist in Ontario. As a result, adapting programs and policies from these jurisdictions requires careful consideration to ensure alignment and compatibility with Ontario's energy system policy and institutional context.

Transitioning to net billing would also require LDCs to make significant upgrades to billing and customer information systems, along with extensive customer communications to support the shift from existing rate structures. One advantage of net metering is its simplicity and universality. Without clear guidance and adequate lead time for net billing, customers may experience confusion or dissatisfaction.

While the Distribution System Code's 1% rule is frequently cited as a barrier, it is already optional for distributors. The more substantive challenge lies in expanding eligibility for community net metering, which would require establishing clear criteria, governance processes, and safeguards against unintended cross-subsidization.

Net billing may reduce concerns around GA avoidance and aligns with approaches in many jurisdictions, but any transition must also support the development of DSO capabilities and be compatible with future distribution system needs.

From a policy perspective, customer-facing solar programs should be kept as simple as possible to minimize barriers to participation. Customers are already navigating significant confusion stemming from interactions among Save on Energy program rules, net-metering eligibility, and restrictions on energy injection. A comprehensive rethink of how net metering, retail rates, and eDSM programs align is needed to provide a coherent, customer-friendly pathway for behind-the-meter solar adoption while reducing administrative burdens for all parties.

Overall, the objective should be to keep behind-the-meter solar straightforward for customers, enabling broad participation, while allowing LDCs to focus their efforts on controllable DERs that can be reliably integrated and coordinated to deliver distribution-system benefits.

Finally, we believe that alignment on the treatment of capacity-related charges would benefit the sector. Currently, LDCs differ in their approaches to Gross Load billing and standby rates, so changes to net metering, net billing, or related programs could have varying impacts depending on a utility's starting point. While we are not advocating for complete standardization of rates, there should be consistency in the parameters, methodologies, limitations, and application of these charges to ensure fairness and clarity across the province. This consistency would support transparent cost recovery for the infrastructure LDCs provide, even when DERs displace some load. Our comments on standby rates and considerations for consistent treatment are provided in Part 2 of this submission.

***Recommendation #4: Explore ways to make more efficient use of ICI resources***

It is unclear what the OEB is proposing beyond additional consultation. ICI resources are not necessarily excluded from LDC NWS programs; for example, Toronto Hydro's Local Demand Response (LDR) program already enables participation in the ICI. Any change to the approach would require the engagement of customers around their willingness to participate, as increased activations or load-reduction events could be disruptive to operations and may limit participation or program effectiveness.

***Recommendation #5: Encourage efficient use of DERs by implementing dynamic pricing for Non-RPP Class B customers.***

While the OEB has long advocated for expanding dynamic pricing, it remains unclear how supportive customers would be and whether such pricing would be optional.

In addition, LDCs would need to assess and implement considerable upgrades to billing systems and customer information systems to accommodate new dynamic rate structures. These systems must be capable of handling more granular interval data, new pricing algorithms, and more complex settlement processes. Enhancements may also be required to support new customer-facing tools to help customers respond effectively to dynamic price signals.

These system changes can be complex, costly and time-intensive, requiring vendor coordination and testing to avoid billing errors or customer confusion. Further, price signals must reflect actual system value, which requires moving to marginal pricing that captures true value and cost (for example, LMP+D). A static pricing model cannot accurately reflect the actual system value. A dynamic price cannot be established without clear, scalable quantification methodologies. For these reasons, any move toward dynamic pricing should be accompanied by clear implementation timelines, guidance on cost recovery, and a phased or optional pathway to ensure both utilities and customers can adopt the new structures successfully.

***Recommendation #6: Establish a cost allocation and delivery framework for front-of-the-meter and market-participating DERs that provide distribution and bulk system value, building on eDSM Stream 2.***

We strongly support exploring this recommendation. If LDCs acquire non-wires solutions that defer or avoid distribution investments, there should be a clear mechanism to "flow through" the associated bulk system benefits to LDCs and their customers. Without such a framework, DERs that provide multi-level system value may be undervalued, and LDCs may not have the right incentives to procure or integrate them.

We also note that the OEB's discussion omits the potential linkage to the LGP initiative. As the IESO moves aggressively toward DER procurement, it is increasingly important to consider how bulk-system procurement interacts with distribution-level needs. We maintain that there is a strong rationale for LDCs to take a lead role in DER procurement, given LDCs' visibility into local grid constraints, customer relationships, and operational requirements. A cost allocation and delivery framework must therefore contemplate the role of LDCs not only as facilitators but as active procurers of DER solutions that deliver both distribution and bulk system value in a way that leads to efficient system outcomes, empowers customer choice, and does not inefficiently bias investment decisions (e.g., regulatory treatment that favours IESO DER procurement over LDC DER procurement).

***Recommendation #7: Leverage procurements/programs within IESO's resource adequacy framework to secure NWS identified through the Regional Planning Process.***

We question whether the IESO should lead these procurements, and emphasize the case for LDC-led procurement, particularly since the resources in question are connected to the distribution system.

As with Recommendation 6, any procurement framework should include mechanisms to account for all value-stack components to ensure DERs are fully valued. Furthermore, alignment with evolving DSO capabilities is critical to enable integration, coordination, and dispatch of DERs to capture the complete value stack for both distribution and bulk system benefits. The approach for integrating NWS identified through the Regional Planning Process should also consider operational challenges and costs incurred by the distributor for integrating DERs, providing regional benefits.

***Recommendation #8: Incorporate a transmission avoided cost framework into DSM cost-effectiveness tests when a need is identified through the Regional Planning Process.***

We agree that this is reasonable.

***Recommendation #9: Enable value stacking by developing consistent approaches for distribution programs and procurement to support the bulk system within the IESO resource adequacy framework.***

The OEB's discussion does not clearly address who should lead DER procurement; in some instances, the OEB points to the IESO, while in others, it suggests LDCs. If the IESO continues to procure DERs under contract, the focus should be on ensuring mutual compatibility between IESO and LDC procurement and programs, rather than solely on achieving consistency across LDCs.

***Recommendation #10: Programs and procurements by the IESO and LDCs should explicitly allow for future value stacking opportunities.***

We agree with this recommendation. However, we suggest that the OEB explicitly link this element to the development of DSO capabilities, as these capabilities are critical to enabling the integration, coordination, and dispatch of DERs to capture full value-stack benefits at both distribution and bulk system levels.

Note that whether the DER assets are owned by the LDC or by a customer, their inclusion could also incur incremental costs for the LDC. Therefore, the OEB must ensure that such costs are appropriately accounted for.

***Recommendation #11: Develop a simplified process or tool for DER providers to identify the best pathway for compensation.***

We support this recommendation. However, the current approach appears primarily focused on customer communication and education. While this is useful, there are additional opportunities to more fundamentally simplify and streamline the process, reducing administrative complexity and making it easier for customers to participate in DER programs and access compensation.

**Part 2: DER Delivery Rates**

The OEB has requested feedback on a range of topics related to DER delivery rates, including its approach to defining DERs, characterizing the context for this work, assessing working rate principles, and evaluating potential harmonization between transmission and distribution rate frameworks. The OEB also seeks input on general rate categories, such as connection costs, base rates, specialized rates, and behind-the-meter rates, as well as specific questions related to connection cost responsibility, base distribution rates for front-of-meter generation and storage DERs, specialized DER distribution rates, and delivery rates for behind-the-meter DERs, including standby rates, bypass compensation, and retail transmission service rates.

From a distributor's perspective, the design of DER delivery rates is a particularly important and material issue. Distribution companies are directly responsible for planning, operating, and maintaining the local grid, and delivery rates affect their ability to recover costs, manage infrastructure investments, and provide reliable service to all customers. How DERs are compensated through delivery rates can significantly influence customer participation in DER programs, the deployment of controllable resources, and the efficient operation of the distribution system.

For LDCs, discussions around rate design are as important, if not more important, than broader policy or procurement considerations. Rate structures establish the financial and operational framework that guides customer behaviour, investment decisions, and utility planning. Ensuring that rates reflect system costs and values while remaining administratively feasible is central to enabling both fair customer treatment and sustainable distribution operations.

We recognize that the OEB has not yet put forward specific recommendations regarding DER delivery rates. This consultation represents an initial opportunity to provide input on principles, frameworks, and considerations. Distributors expect that this consultation will continue over time, with additional opportunities to comment and engage on specific recommendations as they are developed, allowing LDCs to provide detailed operational and implementation perspectives to support effective policy outcomes. Recognizing the importance of this initial discussion by the OEB, the EDA's response provides feedback on each of these discussion points.

**A: Connection Cost Responsibility - Should the OEB review policies under Ontario Regulation 330/09 related to distributed generation powered by renewable energy sources, considering changes in DER deployment and technology?**

We agree that a review is warranted. These rules were originally established under the FIT program and are now outdated. Revisiting them could provide a pathway to support incremental DER deployment, particularly for resources developed to provide local or bulk system benefits. Updating the framework would help ensure that connection cost policies reflect current technologies, operational realities, and the evolving role of DERs in Ontario's electricity system.

**B: Base Distribution Rates for FTM Generation – No discussion questions**

We agree that no action is required.

**C: Base Distribution Rates for FTM Storage - Should FTM electricity storage be exempt from base distribution rates, similar to FTM generation and transmission-connected storage? Should FTM electricity storage be exempt from paying Retail Transmission Service Rates in the short term to facilitate integration?**

We acknowledge that this is a concern raised by electricity storage customers, including those contracted through the recent IESO storage procurements, and that the cost of providing distribution services to electricity storage can differ from traditional load customers. That said, while electricity storage inherently offers operational flexibility, that flexibility must be managed in a way that aligns with the needs of the distribution grid, recognizing that bulk-system dispatch may not coincide with local system peaks or off-peak periods.

We also believe that the OEB's focus on "exemption" may be too narrow. A broader review of rate design options for energy storage, beyond simple exemptions from base distribution or RTSR charges, could better balance incentives for storage integration with the cost of providing reliable distribution services.

**D: Specialized Distribution Rates for DERs - Should the OEB consider opportunities to standardize specialized rates for DERs across Ontario's electricity distributors?**

Support for standardization may vary among LDCs depending on what specific "standards" are being proposed. While some level of consistency could simplify participation and reduce administrative complexity, LDCs may have legitimate operational, system, or customer-specific reasons to maintain flexibility in rate design. Any standardization effort should carefully consider these differences to avoid unintended consequences for local system planning or DER integration. Rather than establishing standardized rates, the OEB should standardize the methodology used to set them.

**E: BTM DERs: Standby Rates - Should the OEB review best practices for standby rates as distributors finalize them?**

The EDA considers this a reasonable approach. We strongly suggest that at this stage, the focus should be on identifying and sharing best practices, rather than imposing standardized standby rates across distributors. A review of best practices could lead to a more streamlined approach for LDCs when applying to introduce standby rates, particularly benefiting utilities that do not currently have them. In general, LDCs would support a consistent framework that allows access to standby rates in a fair and predictable manner.

As mentioned in Part 1, we believe that the sector would benefit from greater alignment on the treatment of capacity-related charges. Currently, LDCs differ in their approaches to Gross Load billing and the application of standby rates, which means changes to these items could have uneven impacts depending on a utility's starting point. While full standardization is not necessary, there should be consistency in the parameters, methodologies, limitations, and application of these charges to promote fairness and clarity across the province. Clear guidance would help ensure that LDCs can recover costs for infrastructure they build, even when downstream DERs reduce some load, while providing customers with a transparent and equitable rate structure.

**F: BTM DERs: Bypass Compensation - Should the OEB review bypass compensation exemptions to include non-renewable DERs and ensure alignment between transmission and distribution frameworks?**

We believe it is reasonable for the OEB to clarify the treatment of behind-the-meter storage within bypass compensation rules. Such clarification would help ensure consistency between transmission and distribution frameworks and provide more certainty for storage customers.

**G: BTM DERs: RTSRs - Should the OEB review opportunities for greater consistency in applying RTSRs to distribution load customers with behind-the-meter generation?**

We believe that this is a reasonable approach. Reviewing and enhancing consistency in the application of RTSRs can help provide clarity and fairness for customers, whether connected to the transmission or distribution systems.

**H: Distribution Rates for DERs Providing Grid Services – no discussion questions**

The OEB notes that delivery rates reflect the cost of providing delivery service, rather than the grid services or other values provided by DERs and intends to address complementary issues of procurement mechanisms and DER compensation in its report to the Minister. The EDA observes that the OEB provides limited detail on recommendations in this area and believes further discussion and clarification are needed to ensure that delivery rates and procurement mechanisms appropriately recognize the value DERs contribute to both distribution and bulk systems.

**CONCLUSION**

In conclusion, the EDA appreciates the OEB's efforts to advance a comprehensive framework for valuing and compensating DERs and supports continued collaboration to ensure alignment with Ontario's unique system needs. A robust approach must incorporate the full value stack, including ancillary services, emissions considerations, and distribution-level benefits, while enabling practical and transparent compensation mechanisms. Clear guidance on implementation timelines, cost recovery, and customer engagement will be essential to avoid confusion and ensure the successful adoption of new programs such as net billing and dynamic pricing. Finally, the development of DSO capabilities and harmonized procurement frameworks will be critical to unlocking the full potential of DERs and delivering efficient, reliable, and customer-focused outcomes for Ontario's electricity system.

We respectfully request that the OEB consider the EDA's comments in its review of the valuation of DERs. If you have any questions, please do not hesitate to contact Rudra Mukherji, Senior Regulatory Affairs Advisor, at rmukherji@eda-on.ca.

Sincerely,

Teresa Sarkesian

Teresa Sarkesian
President & Chief Executive Officer