Stakeholder Feedback and IESO Response

Distributed Energy Resources (DER) Potential Study – September 30, 2022

Following the September 30, 2022 publication of the Ontario DER Potential Study, the IESO sought feedback and questions in relation to the study.

The IESO received feedback from:

- Canadian Renewable Energy Association (CanREA)
- Distributed Energy Resources Stakeholder Initiative (DERSI)
- Electricity Distributors Association (EDA)
- Elson Advocacy
- Enwin Utilities
- Hydro One
- Hydro Ottawa
- Ontario Clean Air Alliance
- Ontario Power Generation
- Ottawa Renewable Energy Co-operative (OREC)
- Power Workers' Union
- Toronto Hydro

The presentation materials and stakeholder feedback submissions have been posted on the DER Potential Study webpage. Please reference the material for specific feedback as the below information provides excerpts and/or a summary only.

Notes on Feedback Summary

The IESO appreciates the feedback received from stakeholders. The first section below provides a summary of the key points included in the received feedback submissions, and is divided by sub-topic. The IESO will consider this feedback in the organization's future work, including but not limited to DER integration.

The second section below contains the technical questions received via the feedback submissions, including IESO responses with support from the project consultants.

Takeaways, Recommendations, and Additional Analysis

Does the report highlight the most relevant results and takeaways from the study?

Stakeholder feedback submissions indicate that the report does highlight the most relevant results and takeaways from the study. Results and takeaways highlighted in the report that were supported via feedback submissions are summarized below.

- Ensuring that solar net metering customers are able to access Time of Use rates, so that solar generation exported to the grid is compensated at summer daytime peak rates.
- Providing more options for Behind-the-Meter battery storage (Residential, Commercial and Industrial) to contribute to meeting system peaks, through market participation, IESO procurements, and access to enhanced Time of Use rates.
- Given the high system value, targeting new front-of-the-meter solar PV in future IESO procurements.
- Identifying lack of revenue certainty as one of the most significant barriers to DER adoption in Ontario.
- Utilities agree with the importance of a Transmission and Distribution (T&D) compensation and coordination framework and suggest that impending demand response programs should be leveraged to also meet distribution system needs.

What other results or messages from this study are of high importance?

While the majority of stakeholder feedback submissions indicated the report appropriately highlights key findings of the study, there were additional results, messages, or inferences from the study identified as being of high importance. These points are summarized below.

- Electrification, particularly at the rates described in the BAU+ and Accelerated scenarios, will require more generation.
- Residential and fleet EV charging and V2B/G/X is very prominent in this study, and necessitates addressing—and removing—regulatory barriers regarding compensation of charging infrastructure.
- The study's reference to gaining DER visibility through "alternative datasets" regarding EV locations is accurate and of high importance.

- DR capacity will increase despite increasing load due to electrification, and will accordingly require more reserve.
- DR capability may be underestimated.
- Taking into consideration that customers will implement DERs regardless of cost-effectiveness, is sound.
- Tailored DER programs and procurements administered by LDCs have the potential to improve adoption of economic DERs (i.e., drive DERs to connect at high-value locations).
- The high cost effectiveness of BTM DERs hosted by retail customers suggest a greater role for the OEB in establishing optimal TOU rates rather than IESO-led market solutions.

Based on the study results, are there other actions that should be considered to acquire DER potential?

The majority of stakeholder feedback submissions indicated that the recommendations capture appropriate actions to acquire the DER potential revealed in the study. Some stakeholder feedback submissions suggested considering other actions, and these points are summarized below.

- One important mechanism for incentivizing solar PV that was not included in the report would be Community or Virtual Net Metering (CNM/VNM). Changing net metering regulations to allow the sharing of credits among all customers in a "single pin" metered building or facility.
- Expanding net metering regulations to allow a customer to sell excess credits to other customers through virtual net metering or Power Purchase Agreements
- It is necessary to consider specific options for targeted DER procurements and how each could realistically be designed and implemented in the near future.
- System planning should support LDC investments, particularly regarding EV infrastructure.
- The provincial wholesale need is not coincident with every LDC asset peak. Thus, consideration should be given to the potential for detrimental effects of not coordinating DR with the LDC operations and asset loading conditions.
- Allowing LDCs to procure FTM renewable energy and storage to meet their needs, to include BTM solar in all CDM programming, and set Green Tariffs to help customers

Building on the work completed in this study, are there other areas of analysis that should be considered or undertaken that can provide meaningful insights for the IESO and others in the sector?

Stakeholder feedback submissions included the following points and recommendations with respect to other areas of analysis that should be considered or undertaken.

- Examining obstacles to DER interconnection at the LDC level.
- Engage in pilot and demonstration projects for emerging DERs, including LDCs, to test and demonstrate technology applications and confirm the forecasted achievable potential and contributions of these resources.

- Power consumers, the industry, power system planners, and the market as a whole would benefit from a more specific understanding of the anticipated costs and benefits of the most realistic specific near term design options for targeted DER procurement.
- Gap analysis of economic vs. achievable potentials (including supply chain constraints) of DER measures selected in the study, and consideration of policy measures to unlock more economic potential into achievable potential of the same.
- Analysis of telemetry and metering requirements' impact on project economics to ensure those requirements are not a barrier to entry.
- Analysis of energy storage locations to examine their impact on storage potential (which is vastly different depending on where it is added to the system) and alignment with capacity constrained areas.
- One area that is important to consider is the fact that IESO contracts place must-take obligations on LDCs and transmitters. This is another limitation that must be considered prior to connecting a potential DER.
- The Study would benefit from analysis of the regional and local potential for DERs that appropriately consider both regional variabilities of viable technologies (e.g., solar potential) and Transmission and Distribution system constraints.
- An ad hoc review committee, which has access to a provincially developed framework that considers T&D benefits plus base capacity avoidance benefits, would be greatly beneficial in assessing DERs as a potential solution where timelines are prohibitive for traditional wired solutions to capacity constraints.
- Consider new Net Zero Community (NZC) builds and the capacity they will need.
- V2B/G, residential behind the meter storage, Front of the Meter (FTM) solar and FTM storage could emerge as significant growth opportunities. This could be addressed in the Ontario Energy Board's (OEB) DER Working Group Tranche 5.
- EV fleets should be leveraged early given that electrical service upgrade costs can be reduced if DR and other EV charging management regimes can be implemented.
- A standard approach to calculating the benefits attributable to improved resiliency or reliability should be developed and built into the cost benefit analysis.
- Recommend that the IESO work with the OEB and the Ministry of energy to immediately analyze current grid regulations governing local distribution to allow greater DER flexibility and choice by LDCs and customers. Changes can then be made in 2023 ahead of the 2026 market renewal in conjunction with the tailored procurement and program initiatives recommended in the Study.
- The analysis should be updated to account for procurement announcements.

General Comments/Feedback

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Stakeholder feedback submissions included the following general comments and feedback.

- Harnessing a variety of DERs (e.g., HVAC DR, BTM storage, V2B/G/X, FTM storage, preparing for residential and fleet charging programs) into a DERMS platform where some LDCs could orchestrate devices to serve as a virtual power plant (VPP) is a cost-effective alternative to investing in traditional poles and wires, and brings value to local as well as bulk system needs. LDCs have a unique knowledge and understanding of program design, due to their longstanding customer relationships. They should have a primary role in business development for DR and DER programmatic opportunities.
- Many LDCs are very interested in DR as a system resource and have experience in residential and commercial HVAC DR programs. To maximize benefits, customers (residential, commercial, industrial) should be able respond to calls from LDCs and be compensated accordingly, without having to choose participation in one program over another.
- LDCs need to be very involved in programs that curtail load as it impacts their ability to manage their distribution systems safely and efficiently. Short-term and long-term system planning requires this knowledge. Curtailing load would enable further program development and more widespread adoption of NWAs.
- The study's BAU+ and Accelerated scenarios anticipate high levels of electrification in transportation as well as in other sectors of the economy. Consequently, there will be increased demand on distributors' systems. System planning needs to support distributor investments to facilitate this transition, including and particularly those relating to EV infrastructure investments, DERs, NWAs and two-way power flows.
- It was suggested that the BAU and Accelerated scenarios are extreme ends and that the BAU+ scenario should be used to guide policy.
- The report does not appear to consider the limitations of the transmission and distribution system to accept the faults current contribution and thermal contribution that these new connections would add to the system.
- It would be helpful if research from this process were to provide near term guidance to planners, policy makers, and stakeholders on the most appropriate design features of a targeted procurement for DERs in Ontario featuring revenue certainty.
- This study does not address how LDC and transmitter resources and associated costs to manage DERs will be treated.
- The analysis omits the role that removal of non-market distribution system regulatory barriers could play in encouraging DER deployment. Nor is "removal of the barriers" included in any of the various scenarios.
- Hydrogen electrolysis and hybrid dual-fuel was not considered and should have been.

- The report does not consider the role that Local Distribution Companies (LDCs) can play in deploying DERs within their distribution systems.
- Enabling wholesale market participation is only one element to unlocking full DER value streams, and additional efforts are required to unlock value associated with distribution system and other societal benefits.
- In continuing its market enhancement efforts, the IESO was encouraged to remain agnostic to the role of distributors in order to enable different paths that may emerge along different time periods.
- The Study's specific recommendations do not address the holistic and strategically sequenced approach needed to translate economic potential into achievable opportunity, and what is labelled as "other considerations" including steps to coordinate on and integrating DERs are in many instance prerequisites to enable and unlock full DER potential.

Technical Questions and Responses

The following section details the technical questions received, and IESO responses with support from the project consultants.

Hydro Ottawa

1. *Slide 24 of the June 22, 2022 Session 3 presentation: What are the "other DERs"? Are these only those listed in the report appendices, since they are in total equivalent to ~50% of the top six.*

Yes, a list of all DERs included in the study is provided in Appendix F on the Measure_Screening tab. Those with a "Yes" under column O (titled: Assessed in Study) were included in the analysis. The achievable potential for each of the assessed DERs are available in Appendix F in the Potential_Achievable tab.

2. *Near-term > Residential HVAC DR >: has consideration been given to the effectiveness based on NRCan studies and trials, in particular New Brunswick & Quebec? Hydro Ottawa had prepared a study with the City of Ottawa for supplementing fossil fueled boilers with electric heating elements and demonstrated both reduced operating cost and carbon footprint while avoiding Global Adjustment.*

No. The only heating electrification measures included in the study were associated with heat pump adoption, and assumptions for heat pumps were derived from the IESO's APO study.

3. *Was any consideration provided for timelines to achieve the capacity needs in the business case analysis? The opportunity cost of insufficient traditional capacity (distribution, transmission or base load) to meet customers' timelines could mean lost revenues, and should be contemplated in some form when evaluating alternatives.*

We did not include any analysis on the opportunity cost impact of insufficient supply or capacity in the analysis. The avoided costs of electric energy and capacity used in the study reflect the impact of increased demand and potential supply shortages on the market prices as modeled by Power Advisory.

4. *How much of the AP can be stacked? Meaning, will it add value to both winter and summer peaks?*

All of the achievable potential can be stacked, for both summer and winter peak capacities. Dunsky's DROP model (applied for the DER potential analysis) dynamically accounts for the combined impact of the DERs on the overall system load curve, and the achievable potential for capacity represents the total combined impact of all DERs when the achievable potential of each is applied simultaneously to the electricity system.

Many measures exhibit capacity benefits in both summer and winter, while others may only offer summer or winter peak benefits. The season specific (stackable) potentials for each measure can be found in Appendix G in the Potential_Achievable tab.

OPG

1. *Within the study, has there been consideration as to what entities would be interested in coordinating various DERs to support demand with sufficient economic benefits for competition amongst the entities?*

The study assumed that an aggregator or aggregators (which could take many forms) could coordinate DERs to deliver system services. The types of aggregation entities were not specified within the study.

2. *Have previous customer program adoption data (example: HVAC control programs) been incorporated in the three study scenarios?*

Historic Hourly Demand Response participation data was applied to benchmark the model's DR program achievable potentials in the initial years of the study. Baseline DER data was also applied in the model as a starting point upon which future DER measure adoption was applied.

3. *Have the three study scenarios taken into account other programs IESO has in-progress or will commence within the next 3 years such as HIP.*

No.

EDA

1. *Does the study consider time to market for components needed in the listed DER measures, e.g., batteries?*

The study incorporates adoption lag (from when a DER becomes cost effective for customers to when it is adopted). However, the study does not incorporate the recent supply chain issues currently being experienced.

2. *Does the study differentiate between LDC or third-party owned FTM infrastructure, e.g., storage?*

No. The study assumptions do not make this distinction.

3. *Does the study allow other ways for BTM measures (besides BTM solar, per Vol. 1, page 57) to participate outside of a net-metering basis?*

For BTM solar, the study models host participation based on remuneration through a net-metering framework. For BTM storage measures, the study models remuneration based on capacity payments (through either a market or a program), energy arbitrage, and in some cases Industrial Conservation Initiative Global Adjustment savings and demand charge savings.

For more details, please see Figure E-2 on the Volume II: Methodology & Assumptions report.

4. *The study assumes the system operator will be able to access these DERs. Does the study contemplate if it will be able to connect to these DERs, particularly if they sit behind distribution constraints? What changes will be required to utility processes and operations in coordinating this?*

The study does not contemplate restrictions on dispatching DERs sited behind distribution system constraints. The changes required to utility processes and operations with respect to coordination of DER dispatch in consideration of distribution system constraints are being discussed through the IESO's Transmission and Distribution Coordination Working Group.

Elson Advocacy

1. *Could the IESO please provide a list of the renewable energy resources that are not covered in the study, and an indication of the MW potential for each of those excluded resources (e.g. per previous IESO studies)? For instance, I believe offshore wind was excluded. It would be helpful to have that confirmed, along with a reference to the IESO's previous estimate of the offshore wind potential in Ontario.*

The only renewable energy measures included in this study are distribution-connected behind-the-meter solar PV, and distribution-connected front-of-the-meter hydro and solar PV. The IESO has not conducted potential studies for other renewable energy technologies.

2. *Could the IESO please confirm whether the study included the potential arising from conversions of electrically-heated homes to ASHPs and/or GSHPs for space heating (or both space and water heating)? If not, can you provide any details on the potential arising therefrom? According to this report, this would be highly cost-effective and beneficial - https://www.cleanairalliance.org/wp-content/uploads/2022/01/Heat-PumpReport-2022-8.5x11-jan-11-v_01.pdf.*

Yes, the study assumed space heating electric load growth as a blended load of ASHPs and GSHPs. The study then determined the potential associated with applying demand response through the use of smart thermostats to the population of that blended ASHP/GSHP load. In the study, this measure was referred to as "ASHP/DMSHP Smart Thermostat."

Ontario Clean Air Alliance

1. *Could you please let me know the cost of capital assumptions embedded in Dunsky's September 28, 2022 DER report for the IESO. That is percent of DER capital costs that are financed by debt and equity respectively; and the cost of debt and equity capital.*

For assessing solar PV and storage capital costs, we used CAPEX projection assumptions from NREL's 2021 Annual Technology Baseline (ATB) workbook, and applied a 2.5% inflation rate (which we recognized may already be somewhat outdated).

Our solar adoption model does not break down CAPEX between equity and debt portions (that would entail a depth of detail which is not typically applied in broad, market-wide potential studies such as this one), and no cost-of capital is applied as the adoption curves used to assess solar PV uptake are based on empirical curves that equate residential adoption with simple payback, and commercial adoption with internal rate of return.

The DER potential model that determines DER participation in the market and DR programs applied a discount rate of 6% to future cash flows.