Ontario Distributed Energy Resources Impact Study

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The Ontario Energy Board

Submitted by:
ICF

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I. Executive Summary

1. Context

The pace of change in the electric utility sector is accelerating because of technological innovation, evolving customer expectations, and a changing policy landscape. Recognizing these trends and seeking to mitigate risks and maximize customer benefits, the Ontario Energy Board (OEB) has initiated two consultations: Utility Remuneration (EB-2018-0287) and Responding to Distributed Energy Resources (EB-2018-0288). The goal of these consultations is to investigate how Ontario may need to adapt current regulatory approaches, taking incremental steps to evolve the existing policy framework and proactively identifying and addressing emerging issues. ICF was engaged by the OEB to assist in these consultations.

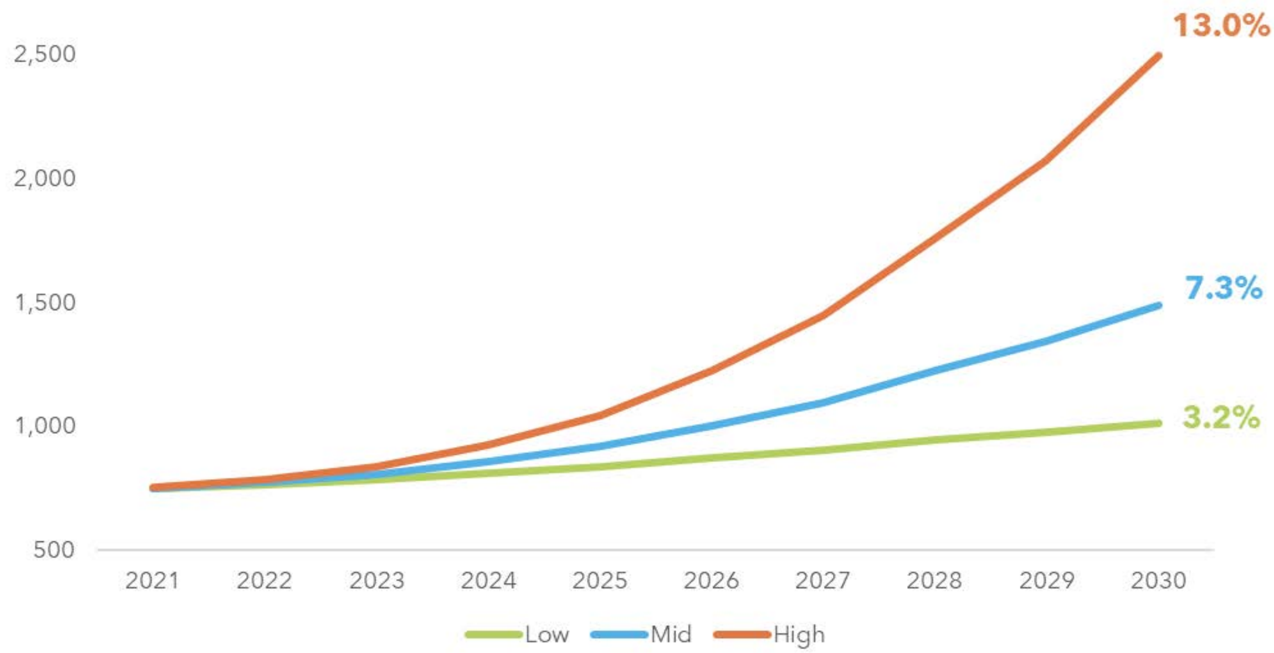
As part of this process, the OEB engaged ICF to conduct a Distributed Energy Resources (DER) Impact Study (Study) to forecast the adoption of distributed generation and storage in Ontario over the next 10 years and identify potential signposts for the timing of regulatory policy responses. The study considers two of the most common DER technologies that can inject power into the distribution system, solar photovoltaics (PV) and battery energy storage. The focus on solar PV and battery storage was driven by the fact that these technologies represent the greatest potential impact on distribution system reliability, DER-related integration costs, increased operational requirements, and impacts to the supply landscape at the distribution and bulk power system levels. The trajectory of these technologies' adoption and penetration is largely a function of changing technology costs, new or enhanced value streams, and changing customer preferences.

Given the vast number of uncertainties in the electric utility sector, this Study should be interpreted as a way to map out potential futures, identify critical considerations, and initiate new or augmented dialogues among key stakeholders. While the Study does include projections, they are indicative rather than predictive. And while the Study also includes recommendations for the OEB to consider, they are suggestive in nature and should not be viewed as conclusive or imperative to pursue in their exact composition here – or, indeed, at all. While the industry is rapidly evolving, it is still relatively early days as utilities, ratepayers/customers, service providers/project developers, regulators, and other stakeholders begin to grapple with the development of its future state, and this Study is intended as a tool in that journey.

2. Projections

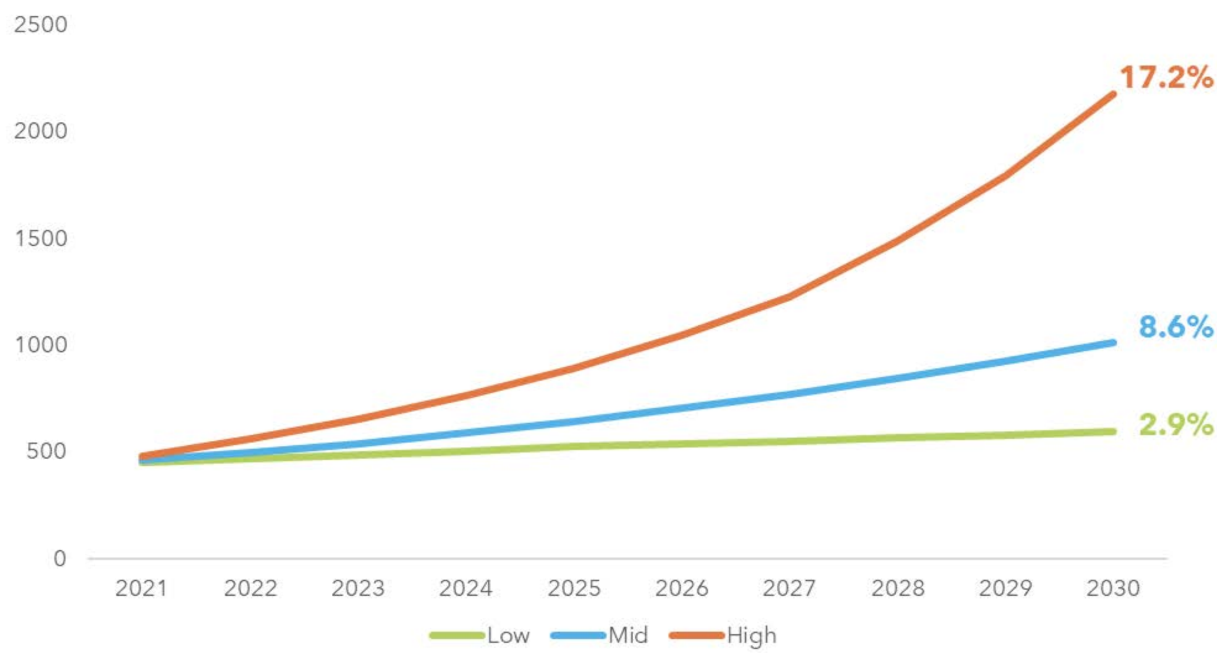
This Study develops projections of distributed solar PV and battery energy storage deployment in Ontario over the years 2021-2030. The Study takes a scenario analysis approach, which can help to inform the approach, pace, and sequencing of regulatory responses and supporting actions in Ontario by providing guidance on potential futures and their implied impacts. It includes three such Scenarios for each technology which were projected over the 10-year period from 2021 through 2030. The three Scenarios – termed Low, Mid, and High – portray a distribution of potential future outcomes of solar PV and energy storage adoption in Ontario; Low assumes higher technology costs and lower electricity prices, High assumes the reverse, and Mid assumes a middle path (please see Section II.2 for more detail). The key output metrics for each Scenario including capacity (measured in megawatts) and the number of installations. The cumulative capacity summaries and compound annual growth rate (CAGR) projections for each technology are shown below in Figure 1 and Figure 2.[1]

Figure 1. Solar PV – Cumulative Capacity (MW) and CAGR (%) Projections by Scenario



[1] Additional charts and tables that focus on other metrics can be found in Section III and breakdowns by customer class can be found in Appendix A

Figure 2. Energy Storage – Cumulative Capacity (MW) and CAGR (%) Projections by Scenario



3. Implications and Recommendations

This Study also examines potential implications and impacts of this increased solar and storage adoption and considers what the OEB could do in anticipation of them, depending on what kind of future emerges (i.e., whether the future aligns most closely with the Low, Mid, or High Scenario for each technology). Those future implications include impacts on processes, operations and planning, and markets, and, where possible, draw on case studies from outside of Ontario that can identify options and shine a light on what has (or has not) worked in those other jurisdictions. Tables 1-3 below include summaries of the key implications and recommendations. When viewing the recommendations in this simplified format, it is important to note that they are posed irrespective of:

- **Relevance**: Will solar PV and/or battery storage emerge to the extent that these implications come to pass and the recommendations become necessary to consider?
- **Timing**: If the recommendations are indeed relevant, *when* should they be explored and/or undertaken?

Notions of relevance and timing are, of course, crucial, but they are both the product of what future DER penetration actually looks like. As noted above, the Scenarios (Low/Mid/High) are intended to portray a distribution of potential future outcomes in Ontario, and therefore they are used in this Study as a way to provide insight on the relevance and timing of the implications and recommendations; please see Section IV for a more thorough exploration of that.

When considering the implications, it is important to note that DER penetration is non-uniform, that the timing and scope of potential OEB action will depend on impacts in high-penetration Local Distribution Company (LDC) pockets, and that therefore a blanket approach across the province is likely not appropriate. That being said, LDC planning outputs will enable the OEB to identify when and how to adopt the recommendations included herein. Calling on the LDCs to develop their own DER projections, requiring them to improve those projections over time, and sharing the results will provide the information that the OEB can use to turn what is now a range of possible actions to consider taking across the province depending on local conditions and local growth rates – and that this Study does not address – into a clearer picture of which recommendations to act on, and when.

3.1 Process Impacts

Given that the LDCs have an obligation to connect DER and to maintain reliability as required by the OEB, the OEB is in position to address barriers related to connecting growing numbers of DER projects. These barriers may stem from uncertainty around cost expectations or review timelines for projects that will increase in number and sophistication over time, as well as from the transition of existing processes as complex data requirements and operational guidelines emerge. In August 2019, the OEB initiated the DER Connections Review Working Group ("the Working Group") in order to identify any barriers to the connection of DER, and where appropriate to standardize and improve the connection process. The progress of the Working Group (which is separate from the Responding to DERs consultation) has been substantial to date. Additionally, the OEB Distribution System Code (DSC)[2] already addresses the potential for cost-sharing of connection-enabling infrastructure. So, while process impacts tied to DER connections are a key – and likely early – impact of increased solar and storage adoption, this Report is only focused on incremental recommendations beyond the current purview of the Working Group. The most pertinent of those recommendations at this point pertains to flexible connections, but the impact of such developments is not likely to be felt until the later years of this Report's study period.

Table 1. Summary of Process Implications & Recommendations

Implication	Associated Recommendations
Potential for the combination of more DER connection requests, increased DER complexity, and flexible grid operations to present new ways of handling connections	Investigate the feasibility of flexible connections that allow for dynamic adjustments of DER generator settings according to distribution circuit and system conditions

3.2 Operations & Planning Impacts

High DER penetration rates can prompt changes to distribution system operations and planning. Changes could include greater situational awareness, enhanced system monitoring and control capabilities, and advanced planning capabilities that enable the continued delivery of safe, reliable, and affordable service. Accordingly, it would be beneficial for some LDCs and the OEB to act early while DER penetration is still low. LDCs may need to make investments in new technologies to enable new operations and planning capabilities. LDCs should be encouraged to clearly enunciate the objectives of these investments and the enhanced functionalities they

[2] OEB, Distribution System Code §3.2.27, December 18, 2018. Available online: https://www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code.pdf.

will enable. The OEB may need new cost-effectiveness frameworks to assess the prudency of these investments. The OEB could also encourage LDCs to develop their own DER projections and improve them over time. Sharing these outputs with the OEB could help inform the timing and scope of prospective regulatory measures to ensure that timely action is taken to cost-effectively address DER impacts.

Table 2. Summary of Operations & Planning Implications & Recommendations

Implication	Associated Recommendations
Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into distribution operations	Assess new frameworks for LDCs to evaluate the prudency and cost-effectiveness of monitoring and control investments and grid modernization investments
	Organize technical workshops to generate discussion on implementation timelines and characteristics, share knowledge, and provide further support for LDC field pilots and projects on advanced capabilities
Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into planning practices	Convene stakeholders and hold discussions to develop frameworks to integrate DER into the fabric of electric distribution planning
	Formulate guidance for LDCs on enhanced distribution planning practices under high DER penetration
Inability to productively handle increased scale and complexity of data	Encourage the LDCs to coalesce around common reporting requirements and best practices for data from DER
	Advocate that the LDCs and IESO consider DER data-sharing initiatives within the context of ongoing activities in the IESO's Grid-LDC Interoperability Standing Committee and Grid-LDC Interoperability and Data Sharing Framework
	Work with DER developers, LDCs, and the IESO to assess the need for centralized data hubs, as well as the types of data housed in these repositories, to provide timely information to all parties

3.3 Market Impacts

Higher penetrations of DER in Ontario could result in growing complexities and potentially higher costs relative to current market design, planning, and operations due to the scalability of interactions between various market actors arising from emerging and forthcoming procurement, pricing, and programmatic efforts as well as changes to participation rules at both the distribution and wholesale market levels. The OEB has a role in continuing to collaborate with market actors to facilitate the pathways for ensuring that guiding principles such as regulatory effectiveness, transparency, safety, and reliability are maintained.

Table 3. Summary of Market Implications & Recommendations

Implication	Associated Recommendations
Opportunities for new or enhanced electric distribution market value streams for customers and utilities	Work with the LDCs to develop new programs that allow distribution-connected customers with DER to provide local grid value
	Work with the LDCs to determine how potential DER growth trajectories within their respective territories may impact which DER use cases provide the greatest system value at the distribution level
Opportunities for new or enhanced wholesale electric market value streams for customers and the system	Account for the diversity of LDC capabilities by developing guidelines and requirements that govern LDC performance in the coordination of DER participation in the IAMs that align with the OEB guiding principles
	Work with the IESO to identify how potential DER growth trajectories may impact which DER use cases provide the greatest system value at the bulk power levels
Heightened transmission-distribution coordination challenges	Convene a forum to provide guidelines on the design of a distribution-level market that can effectively coordinate with the IAMs on the prioritization of services and the allocation of roles and responsibilities
	Collaborate with the IESO and LDCs to explore ways to place appropriate measures on DER participation in IAMs that minimize the risks for duplicative compensation

II. Scope and Approach

1. Scope

1.1 Technology

This Study covers distribution-connected, grid-injecting solar PV and energy storage. While demand response (DR) measures and controllable loads impact load curves and load relief needs, their effect on resource integration and operational considerations is limited compared to PV and storage. These technologies were selected for this Study because their potential proliferation can have greater implications on system planning and operations given their ability to inject power into the grid.[3]

Both technologies included are assumed to be co-located with host customers, meaning that their primary function is to serve customers' loads. This is contrast to a community solar or storage configuration, where the generation technology and customer may be geographically distant from each other. From the Study perspective, the technologies are defined as follows:

- **Solar PV:** The Study considered solar PV installed and interconnected to the electrical distribution system at distribution voltages. Distribution-connected solar PV encompasses both front-of-the meter (FTM) and behind-the-meter (BTM) installations. Specifically, the analysis only considered rooftop mounted solar PV[4] for all customer classes.
- **Energy Storage:** The Study considered battery energy storage technology installed and interconnected to the electrical distribution system at distribution voltages. Distribution-connected battery energy storage encompasses both FTM and BTM installations.

1.2 Customer Class

ICF projected solar PV and storage adoption for four customer classes in Ontario: residential, small business, non-RPP Class B commercial and Class A commercial and industrial. The segmentation aided in the determination of avoided energy costs for the solar PV economic analysis and payback periods for the storage economic analysis. ICF based the solar PV economic analysis on a PV-specific, modified Participant Cost Test[5] (PCT). ICF developed an

[3] Please see Appendix B for a description of why these specific technologies were included and why others were excluded.

[4] Upon analysis of the IESO's Active Contracted Generation List, ICF found that over 80% ground mounted PV cumulative installed capacity were of sizes larger than 5 MW and up to 10 MW. Such large investments are typically the work of standalone developers and not associated with individual customers. Given that there was no adequate indicator for determining which of the ground-mounted projects were load-serving, and to prevent accounting for generator-only projects, ICF removed ground-mounted PV projects from the list of baseline installs.

[5] The projection analysis applied a PV modified Participant Cost Test (PCT), a ratio of costs over benefits from the customer's perspective only, to predict the financial viability of PV projects and determine annual growth rates by customer class. The levelized cost of PV went to the numerator of the cost effectiveness ratio, and the avoided energy costs (such as bill savings and wholesale energy revenues) went into its denominator. According to the NSPM for BCA of DERs, the PCT can be used to provide useful information about the likelihood of customers adopting DER, with or without financial support from

installation baseline for each technology off which the projections were escalated at a rate as defined for each Scenario (see below). Projections at the individual customer class level can also provide clarity and inform future decisions that could be taken by various stakeholders.

The four customer classes used in this Study's projections are:

- **Residential:** Regulated Price Plan (RPP) based on Time of Use (TOU) rates as defined by the OEB.[6]
- **Small Business:** Based on recommendations from the OEB, the tariff structure of the small business segment is assumed to be the same as the residential described above – i.e., RPP TOU structure.
- **Non-RPP Class B Commercial:** General Service consumers with average monthly demand between 50kW and 999kW and not participating in the ICI program.
- **Class A Commercial & Industrial:** General Service consumers with an average monthly peak demand greater than 1000kW in addition to GS 500 – 999 kW customers that satisfy the NAICS code beginning with "31", "32", "33", "1114" and opt into the ICI program.

2. Approach

The approach that ICF took began with establishing a baseline and then building projections outward. Appendix D includes a full list of the publicly available sources and references used for this Study.

2.1 Baseline

Before projecting adoption, ICF established a baseline for the year 2020 of installed capacity and number of installations for both solar PV and battery storage technologies. To build the baseline inputs and assumptions for the projections for each of the three Scenarios, ICF reviewed Ontario-specific data provided by the OEB, the Independent Electricity System Operator (IESO), the Ontario Ministry of Energy, Northern Development and Mines, and the Government of Ontario, as well as broader North American data from publicly available datasets and reports.

2.2 Adoption Projections

ICF conducted 10-year projections of solar PV and storage adoption in Ontario, covering the years 2021-2030. In particular, the projections examined three Scenarios, termed Low, Mid, and High, which are intended to portray the distribution of potential future outcomes of solar PV and energy storage adoption in Ontario. The Scenarios are intended to be indicators of potential futures and do not represent definite outcomes or even predictions. The Scenarios are also

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distribution utilities (for instance, in the form of incentives), and help inform future deployment of DER. More information can be found here: NSPM-DERs_08-24-2020.pdf (nationalenergyscreeningproject.org)..

[6] For the sake of simplicity, the analysis does not incorporate the tiered prices billing structure net metered customers are subject to. The analysis also assumed that PV and storage only serve native load and do not export to the grid. According to the OEB RPP Roadmap published on November 16, 2015, most RPP eligible customers have smart meters and over 96% pay the TOU structure in the RPP. More information can be found here: RPP Roadmap - Report of the Board - November 16, 2015 (oeb.ca)

useful tools to help think through the potential implications of DER adoption in Ontario, which are explored in Section IV.

The three Scenarios are described at a high level in Table 4.

Table 4. Scenario Descriptions

Low	Mid	High
Low adoption scenario within an acceptable confidence interval for critical inputs. Features a growth curve below that of the Mid scenario due to high technology capital cost and operations and maintenance (O&M) cost estimates, no new or extended programs or incentives, and no new or extended enabling policy mechanisms in the study period. Assumes slow recovery from COVID-19 and extended pandemic impacts with extensive permanent demand reduction.	**Adoption scenario informed by average or neutral levels for critical inputs.** Features a middle-of-the-road growth curve due to moderate technology cost estimates and O&M cost estimates, and some implementation of new programs, incentives, and enabling policy mechanisms in the study period based on knowledge of current activities and plans. Assumes moderately paced recovery from COVID-19 and some pandemic impacts with some permanent demand reduction.	**High adoption scenario within an acceptable confidence interval for critical inputs**, informed by best-in-class adoption rates from other jurisdictions. Features a more aggressive growth curve due to rapidly dropping technology and O&M cost estimates, and implementation of a greater number of programs, incentives and policy mechanisms based on the knowledge of current activities and plans. Assumes best-case recovery from COVID-19 and limited pandemic impacts with little to no permanent demand reduction.

The Scenarios were characterized by differences in the following factors:[7]

- **Technology costs:** Capital costs are an important factor behind the decision to adopt a new DER technology. The Low Scenario assumes high technology costs, the Mid Scenario relatively lower technology costs, and the High Scenario the lowest technology costs.
- **Value streams:** The calculated value streams represented the potential range of revenues that PV and storage can earn, both theoretical and currently monetizable. The value streams were defined such that no overlaps exist between them. The key value streams, which were applied to specific technologies and customer classes,[8] were avoided energy costs, wholesale market energy revenues, and back-up power. Other value streams that were less readily quantifiable were incorporated via the Market Adjustment Factor or the Policy Adjustment Factor.[9]
- **Tariffs and prices:** Tariffs and rates provide an indication of the magnitude of each value stream that can be accessed by a customer adopting a certain DER technology. The Mid Scenario assumed that tariffs would continue to escalate at rates based on historical precedent and projections from Ontario's 2017 LTEP. The Study assumed that

[7] For more detailed descriptions of the ways that these factors were differentiated by Scenario, please see Appendix B, and for a detailed description of the methodology please see Appendix C.

[8] Please see Appendix B for details

[9] Please see Appendix C for details

the tariffs in the Low Scenario are lower than the Mid while rates in the High Scenario are higher.

- **Policy:** The core economic analysis at the heart of both the solar and storage projection models incorporated two key policy factors:
  - Variances in the timing of the integration of distribution-connected resources into the IESO Administered Markets (IAMs) as a result of the IESO addressing current participation barriers; and
  - Variances in net metering (NEM) compensation
  - Additional Policy Adjustment Factors were utilized to account for future policies yet to emerge and therefore difficult to quantify; see Appendix C for more information.
- **COVID-19:** ICF's projections included adjustments based on the economic impacts of the COVID-19 pandemic. ICF varied these adjustments by Scenario based on a likely timeline for vaccine development, distribution, and the inoculation of the provincial population.[10]

2.3 Metrics

The key metrics used across the technologies, customer classes, and Scenarios are described below.[11]

Capacity:

- The rated generating capacity of the systems installed in Ontario and measured in kW and MW. This is shown separately for PV and storage capacity for more detailed analysis.
- The cumulative generating capacity by technology is calculated in the projection models and presented in the charts below.

Installations:

- The number of systems (of both technology types) installed in Ontario over the projection period.
- This metric is calculated in the projection models and presented in the charts below on a cumulative basis.

[10] These assumptions were informed by insights from London Economics International, which produced a *COVID-19 Impact Study* for the OEB as part of the Utility Remuneration and Responding to Distributed Energy Resources initiatives and was published in December 2020; see https://www.oeb.ca/sites/default/files/LEI_COVID-19_impact_study_20201216.pdf

[11] A third set of metrics – energy output (solar) and net energy charging impact (storage) – were also calculated; an explanation of those metrics appears in Appendix C and projections of those metrics appear in Appendix A.

III. 10-Year Projections

The span of projected compound annual growth rates (CAGRs, as measured by cumulative MW capacity growth) over the ten-year period is both broader and has a higher upper end for storage (2.9-17.2% across Scenarios when including all customer classes) than for solar (3.2-13.0% across Scenarios when including all customer classes). This is expected, as solar is a more mature technology with considerably more installations already in place in Ontario. Storage, by contrast, is still evolving as a technology – both in terms of efficiency and use cases – and the starting base of installations in Ontario is relatively small. Generally, though, the adoption rates of the two technologies are not directly comparable, as they provide different use cases and draw on different customer motivations. Therefore, each technology's projections are examined individually, first by Scenario and then by customer class.

As noted above, the projections below should be interpreted as indicative rather than predictive. They are used to provide glimpses into what the future may bear, and the Scenario results in particular also contribute insights into the relevance and timing of the implications and recommendations in Section IV, but they should not be treated as gospel.

1. Solar Photovoltaics

While environmental or other concerns can play a role in the decision to adopt solar PV, for the vast majority of customers project economics is still critical, and as such the biggest drivers of solar PV adoption are technology costs and tariff rates. The Mid Scenario represents a business-as-usual case for solar PV adoption, with current technology cost decline trajectories, current Net Metering installation growth rates, and existing value streams (such as electricity bill savings) driving the bulk of the installations.

Low Scenario adoption levels are based on high technology costs (resulting in longer payback periods), lower bill savings, and slow market uptake of solar PV installations given that the lucrative FIT and microFIT programs have been canceled. By contrast, High Scenario adoption levels are based on low technology costs, higher bill savings, easier access to additional wholesale market revenues for select customers, and faster market uptake of solar PV installations with drivers such as a green premium (i.e., customers adopting solar PV because of its environmental attributes). Under the assumption that some of the critical market participation barriers (such as minimum size threshold and the registration processes) are addressed in the High Scenario, a larger number of solar PV assets owned by commercial and industrial (C&I) customers would likely begin participation in the IAMs during the study period. The High Scenario also assumes the full implementation of MRP initiatives early in the Study period.

The projections of solar PV by cumulative capacity (MW) across the three Scenarios are depicted in Figure 3 and detailed in Table 5.

Figure 3. Solar PV – Cumulative Capacity (MW) and CAGR (%) Projections by Scenario

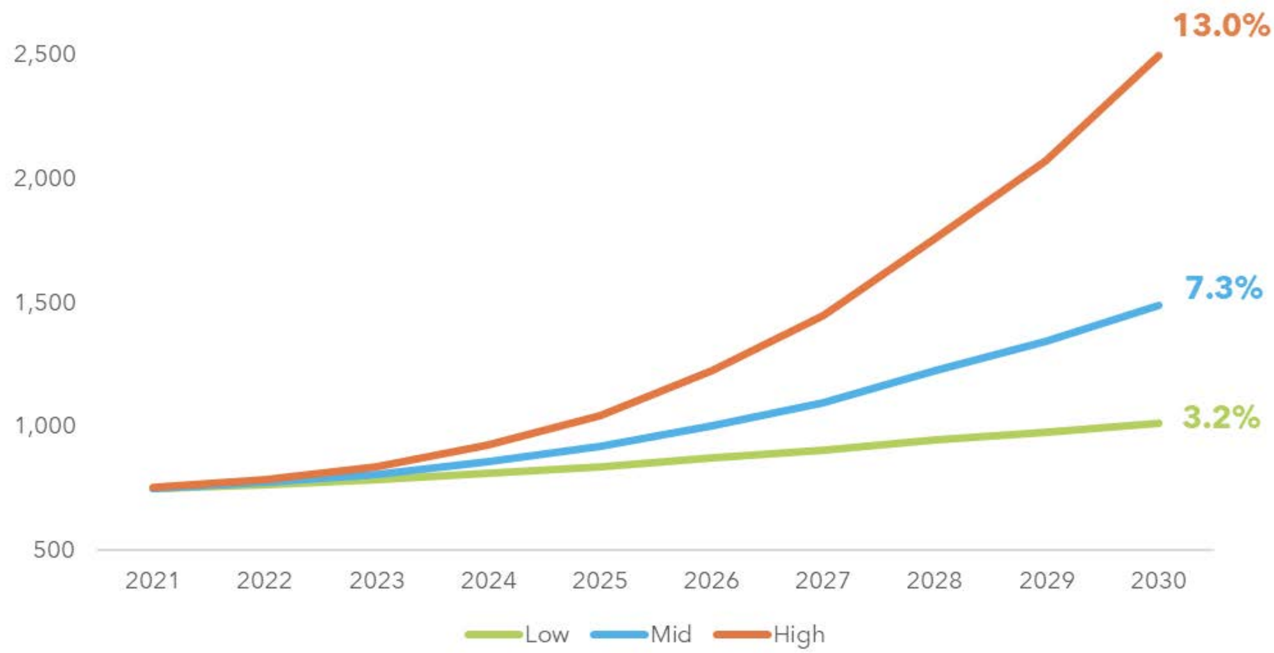


Table 5. Solar PV – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2021	748.4	751.6	755.1
2022	763.1	774.1	786.9
2023	783.4	807.4	839.3
2024	809.8	858.0	926.5
2025	837.9	918.7	1,042.0
2026	872.8	1,005.1	1,225.3
2027	906.1	1,098.0	1,445.3
2028	945.5	1,225.6	1,758.6
2029	977.8	1,344.2	2,073.8
2030	1,014.7	1,490.8	2,497.7

The span of annual solar PV growth rates (CAGRs, as measured by cumulative MW capacity growth) over the study period in these projections ranges from 3.2% in the Low Scenario up to 13.0% in the High Scenario. By comparison, from 2009 to 2017 the national CAGR for equivalent residential solar installations in the United States was 44.7%.[12] However, some U.S. states are, given their latitudes and climates, not close comparables for Ontario; for example, Georgia (77.6%), New Mexico (64.4%), Texas (60.2%), Arizona (51.7%), and Nevada (50.2%). Other U.S. states – such as Wisconsin, Oregon, Illinois, and Michigan – are significantly better proxies for Ontario, and their CAGRs for the 2009 to 2017 period were lower (29.6%, 33.5%, 34.9%, and 36.7%, respectively).

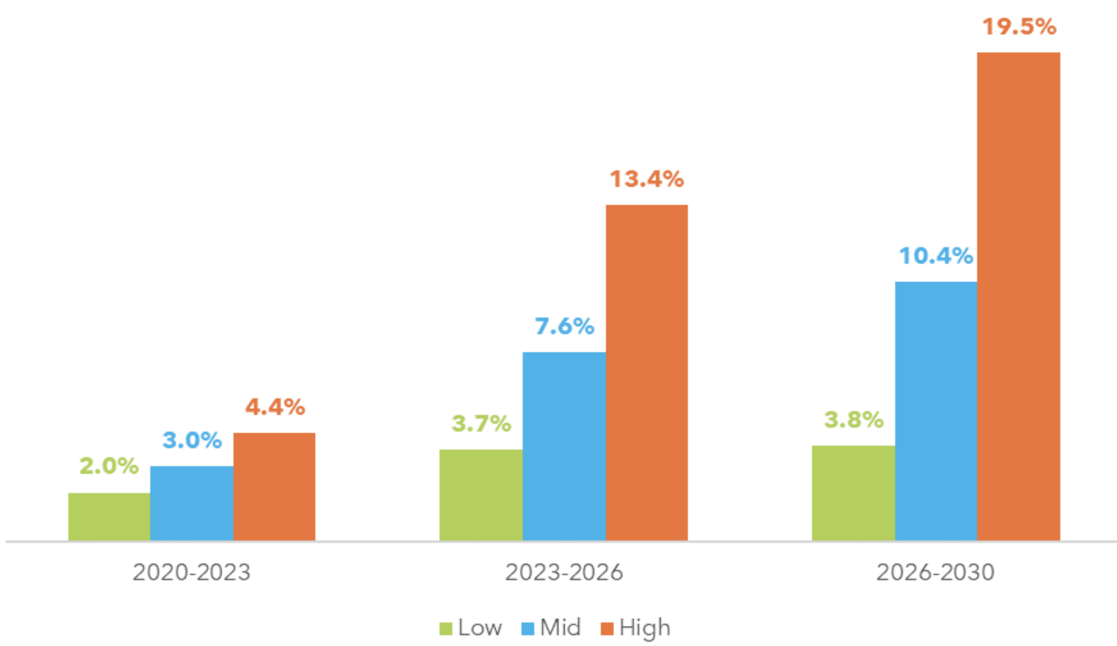
[12] All growth rates used as comparison derived from: Wood Mackenzie Power and Renewables and SEIA, US Solar Market Insight Full Report, March 2019.

Furthermore, historical growth rates are not always good indicators of forward-looking growth rates because the state of the industry advances over time. While solar PV technology costs have fallen since the 2009-2017 period, matching the growth rates of the earlier era would be quite unlikely (mathematically) given the higher starting points today. Additionally, comparing regional developments is inherently fraught by differences in geography, climate, and regulatory policy, among other factors.

It is important to note the cumulative effect of annual growth rates over time. While the Low Scenario projects "only" a 3.2% CAGR over the study period, it still results in more than a 40% total increase in cumulative capacity over the study period. By comparison, cumulative capacity doubles in the Mid Scenario with a 7.3% CAGR while it more than triples in the High Scenario with the aforementioned 13.0% CAGR. So, while Ontario's projected growth rates for solar PV are lower than comparable historical rates, they would still result in significant increases in installed capacity, energy production, and the number of installations.

The projected solar PV CAGRs are presented in shorter timeframes in Figure 4 below.[13]

Figure 4. Solar PV – Compound Annual Growth Rate (%) Projections by Timeframe and Scenario



As indicated, there are not only differences in growth rates between the Scenarios across the full ten-year span of the Study, but also differences within smaller timeframes. In fact, the gaps between the scenarios, as measured by CAGR, widen over time. Additionally, adoption accelerates over time in all of the Scenarios (although much less so in the Low Scenario), which has ramifications for when the OEB might consider taking action, as described in Section IV.

[13] Please note that the three timeframes used here (2020-2023, 2023-2026, and 2026-2030) are very similar but slightly different than the ones used to assess the timing of impacts in Section IV (2021-2023, 2024-2026, and 2027-2030). That difference is due to the need for an "anchor" year in CAGR calculations (e.g., in order to measure a CAGR for 2021-2013, the calculation needs to be "anchored" in 2020), but in essence the two difference breakdowns of the 2021-2030 period are intended to be the same.

The projections of solar PV cumulative installations across the three Scenarios are depicted in Figure 5 and detailed in Table 6.

Figure 5. Solar PV – Cumulative Number of Installations and CAGR (%) Projections by Scenario

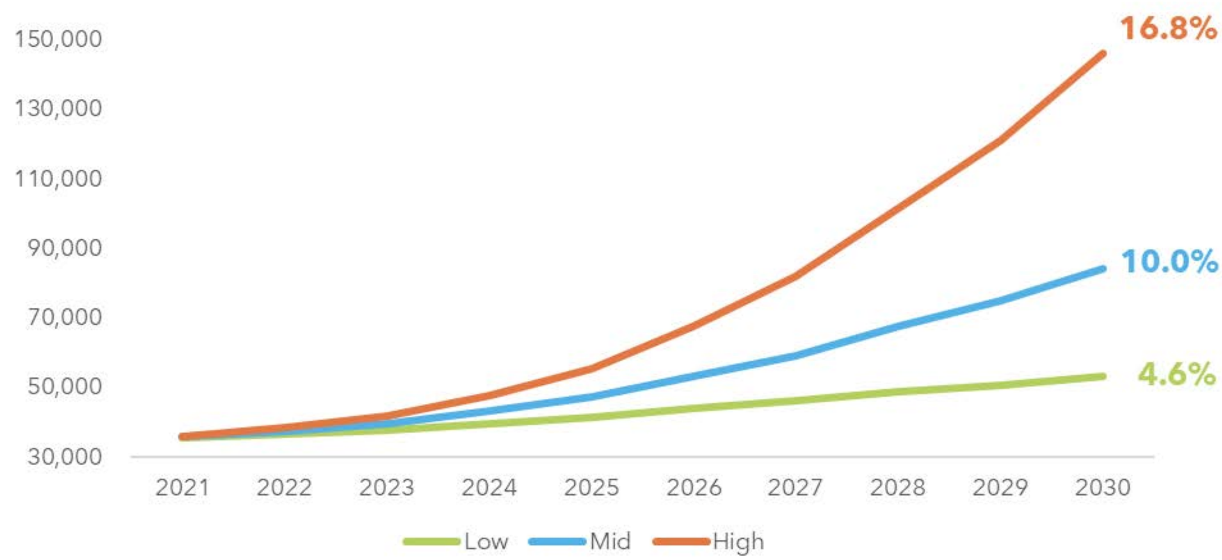


Table 6. Solar PV – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	35,540	35,775	36,029
2022	36,542	37,363	38,323
2023	37,930	39,745	41,929
2024	39,729	43,188	47,839
2025	41,617	47,369	55,600
2026	43,951	53,159	67,647
2027	46,153	59,303	81,825
2028	48,743	67,578	101,617
2029	50,844	75,158	121,178
2030	53,196	84,313	146,218

Across the three scenarios, the rate of solar installations is lower in the 2021-2023 timeframe compared to the 2024-2026 timeframe because of the dampening effects of the COVID-19 pandemic[14]. Compared to a no COVID-19 reference case, in the Mid Scenario, adoption growth rates were reduced by approximately 27% in the 2021-2023 period and 5% in the 2024-2026 period. The Low Scenario included a larger dampening effect, with adoption growth rates reduced by approximately 36% and 10%, respectively, during those same two periods, relative

[14] COVID-19 dampening effects were determined for each scenario based on: (1) the anticipated timeframe for the approval of somewhat, largely, or fully effective vaccines; (2) the rate for the roll-out, distribution, and completion of delivery of vaccines; and (3) level of persistence of the dampening effects and their impact on temporary or permanent demand reduction.

to a no COVID-19 reference case. Some permanent decline in growth rates persists for the Low and Mid Scenarios in the 2024-2026 timeframe and continues for the remainder of the study period, with the Mid Scenario seeing more moderate (i.e., relatively lower) levels of demand reduction compared to the Low Scenario. In the High Scenario, adoption growth rates were reduced by 15% in the 2021-2023 timeframe relative to a no COVID-19 reference case. Conditions were returned to pre-COVID-19 levels by 2023.

Recent policy developments related to GA rates also had a considerable dampening effect on the projections. Based on the illustrative examples provided in the 2020 Ontario Government Budget,[15] the projections were developed with a reduction in the baseline GA rates of 22% and 23% for Class A and non-RPP Class B rates, respectively; the reduction in GA levels were assumed to persist for the duration of the study period. The modeling methodology also incorporated these developments in the projection of RPP bills. With lower underlying rates, solar PV would not be as financially viable, and particularly not for non-RPP Class B customers. Further detail is provided in Appendix C.

2. Energy Storage

Significant differences exist between battery energy storage adoption trajectories for each Scenario. This is indicative of the technology's relative nascence and the different directions that market adoption could take in future years. The divergence in projection trajectories is driven by lower technology costs, enabling policy mechanisms and the usage of storage to serve a broader array of use cases. The Mid Scenario represents something akin to a business-as-usual case for storage adoption in Ontario, with current technology cost decline trajectories and existing value streams (such as arbitrage and global adjustment cost savings) driving the bulk of the installations.

The assumptions for the Low Scenario are based on high technology costs (resulting in relatively longer payback periods), lower global adjustment cost savings and slow market acceptance of storage as a resilience solution.

The storage projections in the High Scenario are substantially higher than those in the Low and Mid Scenarios. Relatively lower technology costs and project payback periods make storage financially attractive in this Scenario and the technology is viewed more favourably as a resilience solution and to provide cost savings. Low technology costs put storage technology within financial reach of a wider swathe of customers. The High Scenario also assumes the full implementation of MRP initiatives[16] early in the study period, when it is assumed that a larger number of storage assets begin participation in the IAMs (especially non-RPP Class B and

[15] In its 2020 Budget, the Government of Ontario announced that starting January 1, 2021, "a portion estimated at approximately 85 per cent of these high-cost wind, solar and bioenergy contracts, entered into under the previous government, will be funded by the Province, not ratepayers." (P.94). Illustrative billing examples were also provided for a non-RPP Class B and a Class A customer. More information can be found here: https://budget.ontario.ca/2020/pdf/2020-ontario-budget-en.pdf

[16] Any changes to market design rules to accommodate integration of DER in the IAMs are not likely to occur before the implementation of the MRP. More information can be found here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx.

Class A customers). ICF also assumed the greater use of storage for resiliency and back-up power and as a solution to localized grid needs by distribution companies.

The projections of energy storage by cumulative power capacity (MW) across the three Scenarios are depicted in Figure 6 and detailed in Table 7. Battery storage energy capacity (MWh) scales at a similar rate to power capacity as the kWh/ kW ratio and battery durations remain unchanged for each of the customer classes over the duration of the study period (4 hours for residential, small business and non-RPP Class B customers and 2 hours for Class A customers).

Figure 6. Energy Storage – Cumulative Capacity (MW) and CAGR (%) Projections by Scenario

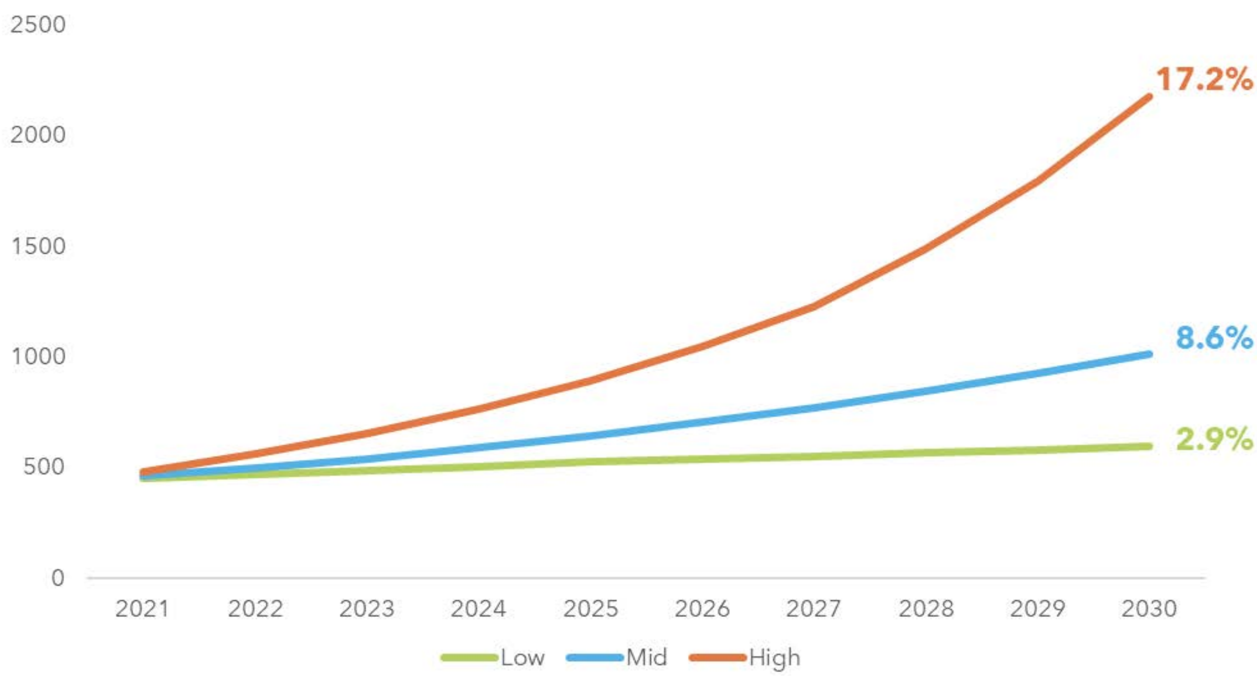


Table 7. Energy Storage – Cumulative Capacity (MW) Projections by Scenario

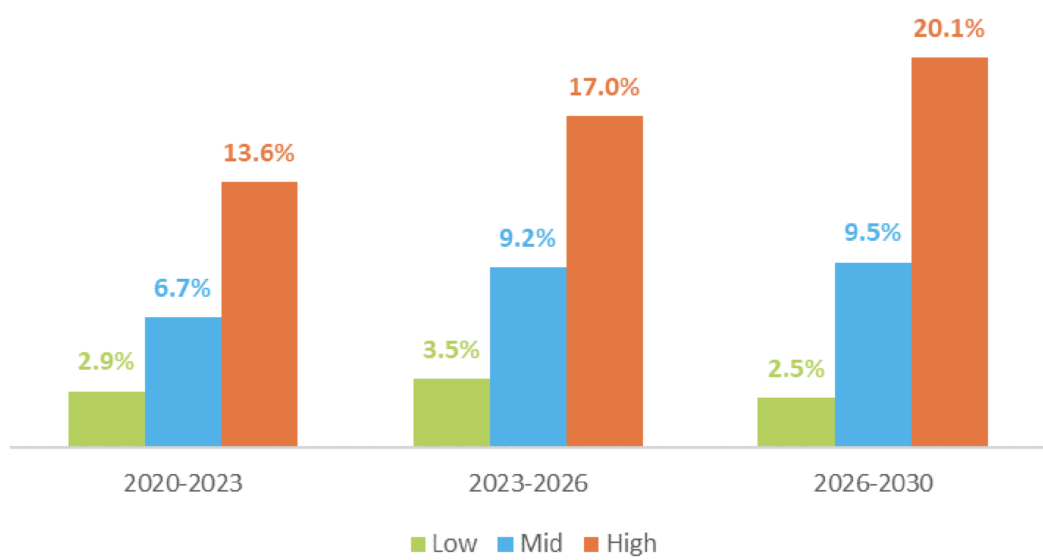
Year	Low	Mid	High
2021	453.8	463.2	481.0
2022	466.3	496.0	560.3
2023	485.1	541.3	653.5
2024	504.6	590.9	763.2
2025	524.9	645.4	893.4
2026	538.2	705.7	1047.5
2027	551.8	772.2	1229.1
2028	565.7	845.4	1485.6
2029	580.2	926.0	1797.1
2030	595.1	1015.4	2175.8

The span of energy storage CAGRs (as measured by cumulative MW capacity growth) in these projections ranges from 2.9% in the Low Scenario up to 17.2% in the High Scenario over the study period. By comparison, from 2012 to 2017 the national CAGR for equivalent residential storage installations in the United States was 140.2%.[17] However, there was wide divergence among U.S. states during that period, with CAGRs ranging from 72.6% (New York) up through 149.9% (Hawaii). It should be noted that extremely high CAGRs could also be indicative of very rapid DER growth from a relatively low starting value or baseline.

Furthermore, historical growth rates are not always good indicators of forward-looking growth rates because the state of the industry advances over time. While storage technology costs have fallen since the 2012-2017 period, matching the growth rates of the earlier era would be unlikely (mathematically) given the slightly higher starting points today. Additionally, comparing regional developments is inherently fraught by differences in geography, climate, and regulatory policy, among other factors. That being said, while lower than those historical comparables, the projected growth rates for storage in Ontario still result in large changes. Capacity is projected to grow by more than 30% in the Low Scenario over the study period and increase to more than two times current levels and nearly five times current levels in the Mid and High Scenarios, respectively.

The projected energy storage CAGRs for Ontario are broken down further into shorter timeframes in Figure 7 below.[18]

Figure 7. Energy Storage – Compound Annual Growth Rate (%) Projections by Timeframe and Scenario



As shown above, there are not only Scenario differences in CAGR across the 2021-2030 period, but also within shorter timeframes; the CAGR gaps between the three Scenarios generally widen over time. Additionally, adoption accelerates over time in both the Mid and High Scenarios (although less so in the Mid Scenario as time goes on), while it speeds up and then

[17] All growth rates used as comparison derived from: Wood Mackenzie Power and Renewables and SEIA, US Solar Market Insight Full Report, March 2019.
[18] Please see footnote 18 above

slows back down in the Low Scenario. These changing rates of adoption have direct implications for if and when the OEB might institute some or all of the recommendations included in this Study; this is explored more fully in Section IV.

The projections of cumulative energy storage installations across the three Scenarios are depicted in Figure 8 and detailed in Table 8.

Figure 8. Energy Storage – Cumulative Number of Installations and CAGR (%) Projections by Scenario

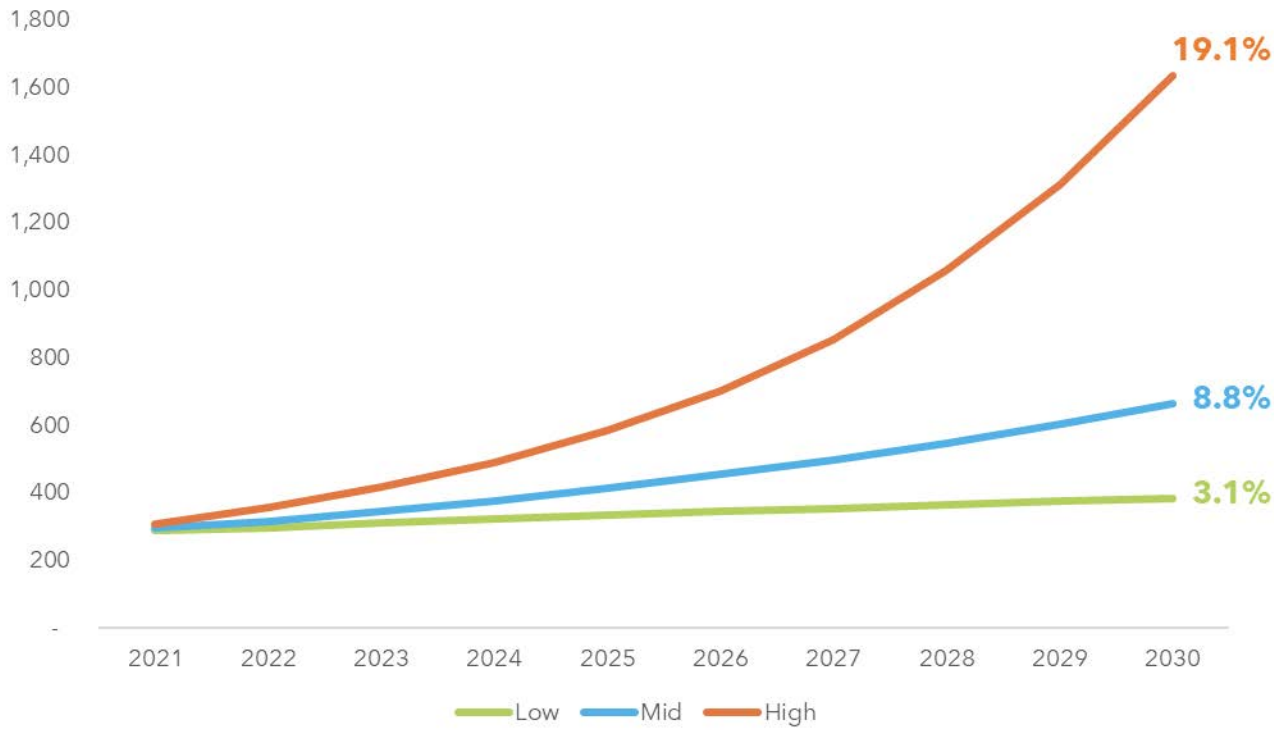


Table 8. Energy Storage – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	291	295	308
2022	299	317	357
2023	310	346	418
2024	322	377	492
2025	335	414	585
2026	345	455	703
2027	354	500	855
2028	364	549	1,058
2029	375	603	1,313
2030	385	665	1,633

Storage adoption is projected to proceed at a relatively low rate across scenarios in the 2021-2023 timeframe due to the ongoing economic impacts of the COVID-19 pandemic. The installation rate increases slightly in the Mid and High Scenarios in the 2023-2026 period due to technology cost reductions and the potential reduction of wholesale market participation barriers. These trends persist in the 2026-2030 timeframe, although the adoption rates are not significantly changed from the 2023-2026 period.

IV. Implications and Recommendations

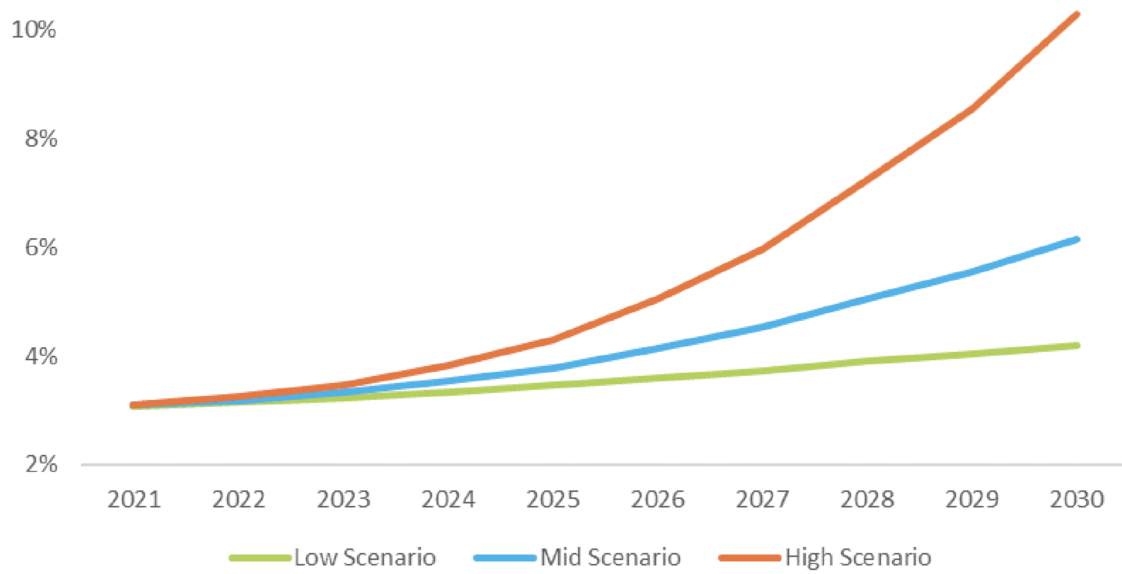
The projections above provide a sense of the levels at which solar PV and battery energy storage might be adopted in Ontario. It is just as important for the OEB to consider the implications of increasing distribution-connected solar and storage penetration in the context of lessons learned or best practices in other jurisdictions. The OEB's Responding to DERs initiative has recognized the need for assessing the impacts from DER growth trajectories in order to identify the need for and aid in the crafting of new policies or modification of existing ones. For instance, it has identified the importance of clarity and appropriate oversight of the evolving roles of the distributor as DER penetration grows. Ideally, any new or augmented regulatory framework resulting from the Responding to DERs consultation should align with the guiding principles of consumer-centrism, regulatory effectiveness, economic efficiency and performance, and a balance between stability and evolution.[19]

The impact of adoption rates of DER extends to institutional processes, distribution system operations and planning, and both distribution and wholesale markets. Because these three dimensions of DER impacts are strongly interrelated, it is important to consider them collectively as well as individually to identify the impacts associated with individual elements or sub-elements. These relationships also impact the timescales and magnitude of the implications in the Ontario context. Additionally, the different trajectories of the solar PV and battery storage projections and the varying policy, market, and technological factors pertinent to each resource type are key considerations.

Some potential impacts are a matter of scale. As such, it is useful to express projected solar PV and storage penetration across scenarios as a function of system peak load to gauge the relative magnitude of resource adoption.[20] For example, Figure 9 below displays the projected cumulative solar PV capacity (across all customer classes) in Ontario as a fraction of the province's projected summer peak load.[21]

[19] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020.
[20] Expressing DER capacity as a fraction of peak load is a common technique to demonstrate the relative magnitude of DER penetration. For example, see: NREL, The Future of Energy Storage: A Pathway to 100+ GW of Deployment, October 16, 2019. Available online: https://www.energy.gov/sites/prod/files/2019/10/f68/EAC_Storage_Denholm.pdf
[21] Projected summer peak load values are from the IESO's 2020 Annual Planning Outlook. Available online: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Figure 9. Cumulative Distribution-Connected Solar PV Projections as a Fraction of Ontario Peak Load



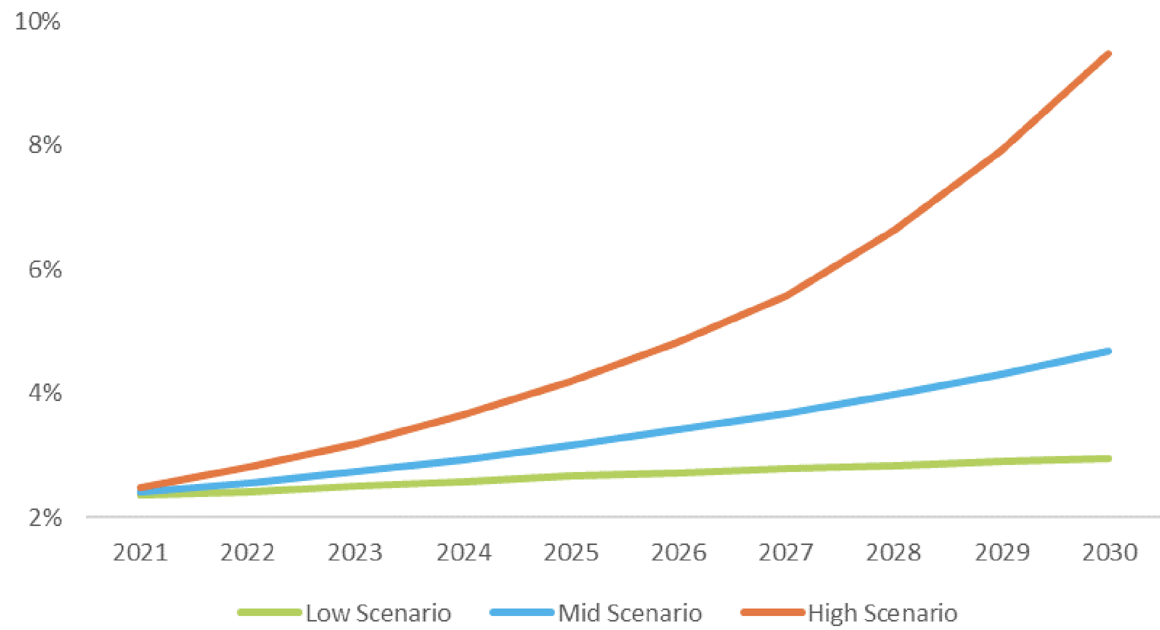
As noted here, while current solar PV penetration levels are slightly above 3% and projected to climb to approximately 4% in the Low Scenario, the High Scenario projects a tripling of penetration to around 10% – a level at which significant operational challenges might begin to emerge.[22] But the Mid Scenario – or even the Low Scenario – could present such challenges if adoption is particularly geographically uneven; this Study was conducted at the province-level, but local growth rates are likely to remain heterogeneous, and if certain utility service territories or sub-areas (feeders and substations) see higher adoption, impacts might be felt in localized pockets of rapid adoption comparatively early . For instance, more than 46% of solar PV installations among FIT projects were in the Toronto, GTA, and Central regions, 39% in the Southwestern region, and 13% in the Ottawa and Eastern regions. The Northern region (both Northeastern and Northwestern) had limited solar PV installations from FIT contracts.[23] If they continue, these trends imply that operational impacts would be substantially non-uniform across the province.

The same penetration trends are also true of battery storage. Figure 10 below displays the projected cumulative distribution-connected storage capacity (across all customer classes) as a fraction of Ontario's projected summer peak load. Such a representation provides an effective means for understanding and comparing the relative magnitude of resource adoption to a system's peak demand requirement. It should be noted that the majority of storage assets are

[22] For example, a commonly used criterion allows PV systems with a peak output that is 15% of a feeder's (or section thereof' s) peak load to be interconnected without a detailed supplemental study. Increased PV penetration on the same feeder or feeder section may lead to a rapid increase in the number of new impact studies required, which would in turn decelerate the pace of new PV connections. For more information, see:
NREL, Maximum Photovoltaic Penetration on Typical Distribution Feeders, July 2012.
Rylander et. Al, Alternatives to the 15% rule, November 2015.
[23] IESO's Active Contracted Generation List. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.ashx

likely to discharge energy and not charge from the grid during peak hours. In addition, the metric (connected storage capacity as a fraction of peak load) also provides an illustrative estimate of the storage capacity available during peak demand periods. However, to replace peaking capacity from conventional generators (such as gas plants), a storage asset must be capable of operating for the same number of consecutive hours as the conventional generator. Hence, the available duration of the storage technologies is important as well. While storage could replace gas generators that operate for one or two hours a few times a year, only long-duration storage technologies can replace plants that run, for example, for more than ten consecutive hours.

Figure 10. Cumulative Distribution-Connected Storage Projections as a Fraction of Ontario Peak Load



While storage performs differently from solar as a resource – it can both draw and inject power – different magnitudes of penetration could still result in varying types and levels of impact. In particular, because battery storage is more nascent than solar PV, there is a steeper curve to the High Scenario adoption, with the potential for a more than four-fold increase in penetration as a percentage of peak load. And as with solar PV, assuming that storage adoption will occur more intensively in some geographic areas than others, system operation and planning practices may need to be adapted.

In addition to exploring the various impacts and suggesting actions that the OEB might take in relation to them, each section below also examines the potential timing and level of each impact. These are displayed in a series of tables, each of which covers the three Scenario projections for each technology. The ten-year Study period is subdivided into three sub-periods – 2021-2023, 2024-2026, and 2027-2030 – which are assigned levels of impact, the key for which is in Table 9 below.

Table 9. Level of Impact Key

	High Impact
	Moderate Impact
	Low Impact

It should be noted that these levels of impact are inferences informed by ICF's exposure to similar issues in other jurisdictions, but there are many factors involved and a high level of uncertainty in any consideration of future developments, and therefore these should be regarded as guidance for consideration rather than predictions.

Furthermore, these indicators are only of the level of impact should the developments come to pass, and not of their probability of occurring. The probability of each occurring is implied by the Scenarios themselves: that is, the Scenarios depict variations on the future, but the extent to which the future will resemble one (or any) will be the result of many different factors and is open to a great deal of interpretation.

The recommendations below span all three projection Scenarios (Low, Mid, and High) and the accompanying text is meant to explore the variability across them. In the Summary of Recommendations section at the end, the recommendations are viewed through the lens of the Mid Scenario to simplify the presentation.

The recommendations are suggestive in nature and should not be understood to be conclusive or essential to pursue in their exact composition here – or, indeed, at all. While the industry is rapidly evolving, it is still relatively early days as utilities, ratepayers, service providers, regulators, etc. begin to grapple with the development of its future state, and this Study is intended as a way to map out potential futures, identify critical considerations, and initiate new or augmented dialogues among these stakeholder groups.

Finally, because DER penetration is inherently non-uniform, the timing and scope of potential OEB action will depend highly on impacts in high-penetration LDC pockets; a blanket approach across the province is in all likelihood not appropriate. The outputs from LDC planning practices can enable the OEB to identify when and how to adopt the recommendations below. Therefore, calling on the LDCs to develop their own DER projections, requiring them to improve those projections over time, and sharing the results with the OEB could prove a critical component of mapping out Ontario's DER future. With that kind of information on local conditions and local growth rates – which was not within the purview of this Study – the OEB could evolve the following range of possible actions to consider taking across the province into a clearer picture of which recommendations to act on, and when.

1. Process Impacts

Given that the LDCs have an obligation to connect DER and to maintain reliability as required by the OEB, the OEB is in position to address barriers related to connecting growing numbers of DER projects. These barriers may stem from uncertainty around cost expectations or review timelines for projects that will increase in number and sophistication over time, as well as from the transition of existing processes as complex data requirements and operational guidelines emerge. As previously noted, the progress of the Working Group in the DER Connections

Review consultation has been substantial to date. Additionally, the OEB Distribution System Code[24] already addresses the potential for cost-sharing of connection-enabling infrastructure. So, while process impacts tied to DER connections are a key – and likely early – impact of increased solar and storage adoption, this Report is only focused on incremental recommendations beyond the current purview of the Working Group. The most pertinent of those recommendations at this point pertains to flexible connections, but the impact of such developments is not likely to be felt until the later years of this Report's study period.

Table 10 below summarizes the process implication described in the following section.

Table 10. Summary of Process Implications & Recommendations

Implication	Associated Recommendations
Potential for the combination of more DER connection requests, increased DER complexity, and flexible grid operations to present new ways of handling connections	Investigate the feasibility of flexible connections that allow for dynamic adjustments of DER generator settings according to distribution circuit and system conditions

1.1 Potential for the combination of more DER connection requests, increased DER complexity, and flexible grid operations to present new ways of handling connections

Description

A number of existing codes and requirements have already established effective connection practices in Ontario. These include the DSC,[25] which addresses connection rules for LDCs, including the Connection Impact Assessment (CIA) process (including situations in which a CIA is not required)[26], the requirement that projects seeking connection to an LDC system have their Electrical Safety Requirements reviewed by the Electrical Safety Authority (ESA),[27] and the potential for cost-sharing of connection-enabling infrastructure development through the concept of the investment horizon.[28]

In addition, the Working Group, which includes representatives from the LDCs, DER providers, other stakeholders, and is facilitated by OEB staff, is already tackling many of the key connection challenges associated with increasing DER adoption and development. In particular,

[24] OEB, Distribution System Code §3.2.27, December 18, 2018. Available online: https://www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code.pdf.
[25] OEB, Distribution System Code §3.2.27, December 18, 2018. Available online: https://www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code.pdf.
[26] The CIA process results in a technical report outlining project feasibility, technical specifications required for the project to connect, and an overview of the impacts the project might have on the distribution system.

[27] Applicants may request an initial consultation (free-of-charge) so that they and the LDC can review information on the proposed connection.
[28] If a customer is required to pay for the additional infrastructure required for DER connection(s), which would be facilitated over an "investment horizon," subsequent projects which come on-line and benefit from this additional capacity must pay back the original project while the investment horizon is still open.

the Working Group has been undertaking several efforts that emphasize the need for information-sharing across different LDCs on issues related to DER generator connection and integration, with an aim for both sharing of best practices and, where possible, greater standardization.[29] These efforts have included:

- Exploring mechanisms to equip applicants with information in the pre-consultation phase of the CIA.
- Recommending the development of the Preliminary Consultant Report from LDCs that indicates whether the proposed DER has any potential to connect to the LDC system in question.[30]
- Exploring the standardization of the CIA form across all LDCs such that, regardless of location, there is consistency in the form and the information that is collected.
- Developing checklist and guidance documents, including samples of completed applications, in order to help DER developers understand what successful applications should include and look like.
- Considering the opportunity to standardize technical requirements for connections, such as common technical interconnection requirements (TIRs) where feasible and updating for new standards such as the recommendation on adopting CSA 22.3 for inverter-based technologies.
- Providing templates and standard requirements of certain documents, including sample single-line diagrams (SLDs) reflecting approved methods and materials required for DER connections.
- Focusing on ways to improve the clarity of the cost estimates resulting from proposed DER connections.
- Promoting LDCs the adoption of a protection philosophy adapted from one developed by the Ontario Energy Association.
- Exploring and developing both a risk-based connections framework and a restricted feeder map, which strike the balance between complex connection requests and finite available capacity on LDC systems.

Traditionally, most DER connections are based on firm connection agreements, or those which assume uncontrollable DER output with limited visibility into the devices. The DER growth projections encapsulated in this Report indicate that Ontario faces the prospect of a significant increase in DER generator connections; but along with this comes the prospect of a commensurate rise in the operational sophistication of thousands of active systems at the grid edge. These systems may be configured in a variety of ways; for example, some PV systems could be configured as non-exporting, inverter-based (NE/I) while others could be designed to feed all output into the network. In addition to standalone PV and storage systems, customers may be interested in installing co-located PV+storage systems as well. The increase in

[29] *See*, OEB, ED-2019-0207 Information and Template Forms for Preliminary Consultations on DER Connections, November 26, 2020. Available online: https://www.oeb.ca/sites/default/files/OEB-Staff-Ltr-DER-Connections-Preliminary-Consultation-Forms-20201126.pdf.
OEB, EB-2019-0207 Guidance – Protection Philosophy for DER Connections, November 26, 2020. Available online: https://www.oeb.ca/sites/default/files/OEB-Staff-Ltr-DER-Connections-Protection-Philosophy-20201126.pdf.
[30] This report is provided in response to a Preliminary Consultation Application from DER customers and proponents.

variability in project configurations, coupled with a broader network of interacting devices over time, is likely to introduce new complexities to the connection process.

One approach to dealing with that complexity, and which largely goes beyond existing efforts in Ontario, is the emerging practice of flexible connections. This approach utilizes DER connection agreements that incorporate the ability to modify DER generator connection parameters based on the time-varying nature of grid constraints on the distribution system; in essence, controls are utilized to manage real-power output from the DER generator to remain within grid constraint levels. In a future power system, these connection arrangements could allow DER generators to respond to local system conditions (including commands to ramp-up and provide grid services at the bulk- or distribution level).[31] Given the flexibility of DER generator configurations – and most notably energy storage ones – it is critical that LDCs and DER applicants exchange information on expected operational modes and settings within the flexible connection framework and taking into consideration any other technologies with which the DER generator will be paired (e.g., PV+storage installations may be able to leverage combinations of non-export and export from the PV system, storage system, or the combined output).

Stakeholders have noted the need to differentiate generator operating characteristics, particularly those which are able to follow a signal versus those based on intermittent operation, as this can impose unnecessary caps on distributed generation deployment on distribution networks.[32] This focus should be maintained as DER generators proliferate, as LDCs can continue their work with DER applicants to tailor DER operation for different needs, such as settings adjustments which limit active power output during times of low native load or require provision of reactive power to address circuit voltage fluctuations. The parameters for DER generators can be adjusted over time as further applications are processed and approved across the LDC territory. This approach offers bespoke solutions for individual DER generator project configurations and lower costs due to the reduced need for infrastructure upgrades. Evolution to this type of interconnection paradigm would require consideration of the necessary enabling technologies (e.g., system and DER monitoring and control) and resulting impacts to the system (e.g., changes in load shapes).

Broader usage of flexible connection agreements has the potential to pose challenges for LDCs, DER proponents, and the OEB. LDCs will require capabilities that provide visibility into distribution-system DER, information on their operating configuration(s), the means to communicate with these devices, and some measure of control to change settings (see discussions in Section IV.2). DER proponents will need to study the financial risks associated with non-firm connection arrangements and build trust with LDCs that may have the ability to curtail DER output during select situations. For its part, the OEB will need to maintain open access for DER connections to LDC systems, enforce rules on compensation arrangements, and ensure that LDCs accommodate DER exports beyond local hosting capacity if the particular flexible connection agreement allows this outcome. Accommodating and resolving these

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[31] EPRI and NREL, Evaluating Dynamic, Flexible Interconnection Options for Distributed Photovoltaic Resources, Distributed Generation Integration Collaborative (DGIC) Webinar, February 27, 2020.
[32] QUEST Ontario Combined Heat and Power Consortium, RE: OEB Distributed Energy Resource Connections Review Initiative Board File Number: EB-2019-0207, November 11, 2019. Available online: http://www.rds.oeb.ca/HPECMWebDrawer/Record/658493/File/document.

challenges can ensure that flexible connections emerge as an enduring solution to connect complex DER to Ontario's evolving distribution networks.

Timing and Impact

Table 11. Potential for the Combination of More DER Connection Requests, Increased DER Complexity, and Flexible Grid Operations to Present New Ways of Handling Connections – Potential Level of Impact

	Solar			Storage			Period (Years)
Scenario:	Low	Mid	High	Low	Mid	High	
Impact Level:							2021-2023
							2024-2026
							2027-2030

LDCs commonly publish key connection information such as application forms and checklists, contact information, reference materials. and inspection requirements online to provide clarity to applicants.[33] At relatively low projected solar PV penetration levels and growth rates (such as those in all Scenarios for the 2021-2023 period) these practices – combined with resources that may emerge from the Working Group – are likely to be sufficient to manage the DER connection process effectively. At higher penetration levels and with increasing volumes and diversity in configurations of connection requests (the projected annual growth rates for solar PV for the 2027-2030 period in the Mid and High Scenarios are 10.2% and 18.9% respectively), LDCs may be required to curtail DER system outputs during times of system constraints, particularly when system capacity is limited. To mitigate this outcome, LDCs may want to start considering the applicability of flexible connections and what investments in data resolution and system control arrangements could be required.

The volume of annual storage connection activity is projected to be far lower than that for solar. As such, storage is unlikely to contribute to broader connection challenges (e.g., queue congestion) on the same timeframes and to the same extent as solar PV. Nonetheless, consideration of flexible connections, particularly when combined with PV as a hybrid plant, could help to leverage the unique characteristics of storage assets. Despite low projected growth rates in the near-term (the Mid Scenario projects roughly 20 new annual installations from 2021-2023), the exploration of revised connections for energy storage may be required in the long-term based on the unique characteristics of this technology, or even sooner in a future that resembles the High Scenario. For example, an applicant seeking approval for connection of an energy storage device may also need to describe how existing native load might be increased. Furthermore, applicants could be required to describe the export-import configurations of their systems (for example unrestricted, export-only, import-only, no exchange)[34] in the connection application so that the safety and reliability of the grid is maintained.

[33] For example, Alectra and Toronto Hydro have dedicated pages on their websites to guide customers who wish to connect DER. More generally, §6.2.3 of the DSC requires that LDCs make available a generation connection information package to any person who requests the package.
[34] Interstate Renewable Energy Council, Inc., Model Interconnection Procedures (2019), available at https://irecusa.org/publications/irec-model-interconnection-procedures-2019.

Recommendations

The OEB could consider:

- **Investigating the feasibility of flexible connections that allow for dynamic adjustments of DER generator settings according to distribution circuit and system conditions**
    - As penetration increases in later years, the ability to dynamically adjust DER generator settings could be a potent tool for enabling DER connections without unnecessary costs, system investments, or DER curtailment. Accordingly, the OEB should assess the feasibility of flexible connection arrangements that align dynamic adjustments of devices with the operational needs of the local systems.
    - Widespread use of this approach is likely to require significant investments from LDCs in visibility and control mechanisms. Flexible connections may entail sensitive issues related to DER curtailments during times of system constraints, and thus should be pursued in coordination with stakeholders from the DER developer and consumer advocacy communities. These dynamics underscore a role for the OEB, including review of the timeline and prudency of LDC investments as DER connections increase (see Section IV.2.1), enforcement of rules on compensation arrangements, and stakeholder engagement to address consumer protection or contract-related issues as they arise from broader use of the practice.
    - The distribution system is dynamic and the impact of frequent DER curtailment should be explored and better understood. The OEB and LDCs may determine that only a few resources can qualify for flexible connection arrangements based on interactive effects with other generators and the complexity of managing several discrete systems in the absence of larger control system investments. The OEB should work with LDCs to develop robust, replicable, and transparent methodologies to assess the risk of curtailment within flexible connection arrangements. Flexible connections may be a more suitable approach at higher penetrations of DER in the long-term (2027-2030) and especially under the High Scenario.

2. Operations & Planning Impacts

High DER penetration rates can prompt changes to distribution system operations and planning. Changes could include greater situational awareness, enhanced system monitoring and control capabilities, and advanced planning capabilities that enable the continued delivery of safe, reliable, and affordable service. Accordingly, it would be beneficial for some LDCs and the OEB to act early while DER penetration is still low. LDCs may need to make investments in new technologies to enable new operations and planning capabilities. LDCs should be encouraged to clearly enunciate the objectives of these investments and the enhanced functionalities they will enable. The OEB may need new cost-effectiveness frameworks to assess the prudency of these investments. The OEB could also encourage LDCs to develop their own DER projections and improve them over time. Sharing these outputs with the OEB could help inform the timing and scope of prospective regulatory measures to ensure that timely action is taken to cost-effectively address DER impacts.

Table 12 below summarizes the operations and planning implications described in the following sections.

Table 12. Summary of Operations & Planning Implications & Recommendations

Implication	Associated Recommendations
Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into distribution operations	Assess new frameworks for LDCs to evaluate the prudency and cost-effectiveness of monitoring and control investments and grid modernization investments
	Organize technical workshops to generate discussion on implementation timelines and characteristics, share knowledge, and provide further support for LDC field pilots and projects on advanced capabilities
Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into planning practices	Convene stakeholders and hold discussions to develop frameworks to integrate DER into the fabric of electric distribution planning
	Formulate guidance for LDCs on enhanced distribution planning practices under high DER penetration
Inability to productively handle increased scale and complexity of data	Encourage the LDCs to coalesce around common reporting requirements and best practices for data from DER
	Advocate that the LDCs and IESO consider DER data-sharing initiatives within the context of ongoing activities in the IESO's Grid-LDC Interoperability Standing Committee and Grid-LDC Interoperability and Data Sharing Framework
	Work with DER developers, LDCs, and the IESO to assess the need for centralized data hubs, as well as the types of data housed in these repositories, to provide timely information to all parties

2.1 Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into distribution operations

Description

Increasing DER penetration rates could require additional distribution system operational capabilities, increase situational awareness and control of grid parameters to maintain system safety and reliability. The necessity and timing for new capabilities and functionalities will depend on DER penetration within each LDC's service territory, each utility's unique characteristics and existing capabilities.

At higher DER penetration levels[35] and with a diversity of operating configurations (standalone or PV+storage), enhancements to monitoring and control capabilities may be required to ensure the continued safe, secure, and reliable operation of the grid.[36] This could include additional investments in advanced distribution management systems (ADMS), DER Management Systems (DERMS), advanced switches and protection devices, and power flow controllers to adjust real and reactive power flow.

The timing of these investments will vary and will depend heavily on their intended application and individual LDC parameters such as local DER penetration and policy objectives. For example, the Hawaiian Electric Companies (HECO), with residential PV penetration of 19% in 2017 and 80,000 privately-owned rooftop PV systems, adopted secondary VAr controllers in 2018.[37, 38] These fast-acting devices help control and maintain secondary voltages within an acceptable range and can also provide monitoring capabilities.

In addition to mitigating DER impacts, distributed devices could also provide grid supportive functions and respond to grid operating conditions. For example, in some U.S.[39] and international regions,[40] DER inverters are now commonly required to provide responses to deviations in grid frequency and voltage. Inverters are also required to be capable of receiving command and control signals from system operators. The IESO has also adopted new generator rules requiring inverter-based units to maintain their output current during system disturbances and provide reactive power support.[41]

Inverter requirements are codified in technical standards. In Canada, the Canadian Standards Association (CSA Group) standard C22.3 No. 9 pertains to the connection of distributed resources and electricity supply systems. While similar, C22.3 No. 9 takes a different approach

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[35] An installed DER capacity to system peak load value of 5% is an illustrative threshold for procuring advanced functionality. The value is intended to be a heuristic and was informed by experiences in California, Hawaii, and Australia. The purpose of the threshold is to help utility employees understand when engineering, business process, and policy issues are likely to arise because of increasing DER penetration. Also see: ICF, Integrated Distribution Planning – Prepared for the Minnesota Public Utilities Commission, August 2016.

[36] Monitoring reflects the capability to observe the performance and develop situational awareness of system assets, including DER. Control refers to the capability to manage and supervise DER and other system assets to meet operational goals on short timescales. Joint Utilities of New York, Supplemental Distributed System Implementation Plan. Case 16-M-0411, In the Matter of Distributed System Implementation Plans, November 1, 2016. Available online: https://jointutilitiesofny.org/sites/default/files/Supplemental%20distributed%20system%20implementation%20plan%20nov%202016.pdf

[37] Hawaiian Electric Companies, Modernizing Hawai'i's Grid For Our Customers, August 29, 2017. Available online: https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf

[38] Asano, Marc and Rodney Chong, Modern Grids of Hawaii, T&D World, November 1, 2018. Available online: https://www.tdworld.com/grid-innovations/distribution/article/20971882/modern-grids-of-hawaii

[39] California Public Utilities Commission (CPUC), Rule 21 Interconnection. Available online: https://www.cpuc.ca.gov/Rule21/

[40] German technical standards, see:
Power Generation Systems Connected to the LV Distribution Network, VDE-AR-N 4105, Offenbach, August 2011.
Technical Guideline: Generating Plants Connected to the MV Network, BDEW, Berlin, 2013.

[41] IESO, Market Rule Amendment Proposal MR-00445-R00.

to grid supportive functions than IEEE 1547-2018, the dominant U.S. DER connection standard. CSA Group is in the process of updating the inverter standard, C107.1, which is expected to fully enable similar functionalities spelled out in IEEE 1547-2018. In the meantime, the Electrical Safety Authority in Ontario has given something of a dispensation such that inverters certified to IEEE 1547-2018 are considered to meet CSA C22.3 No. 9 until C107.1 is ready.

A focus on consistent standard implementation efforts, even when DER penetration is low, can yield flexibility for the OEB, LDCs, and consumers to utilize different grid-supportive capabilities as they are required or as DER penetration increases. The DER Connections Review Working Group has begun efforts in this regard and has recommended – and the ESA has accepted – CSA C22.3 No.9 for connecting to distributors' systems and that the DSC, as a result, be amended to reflect this.

In the longer term, new operational systems and tools should be evaluated both in the context of incremental system benefits as well as through an examination of – and possible changes to – existing tools and processes. In some instances, within a high DER environment, investments in foundational technologies and traditional tools and methods may be a prerequisite to the implementation of more complex systems and prove to be more cost-effective. For example, Pacific Gas & Electric (PG&E) highlighted the importance of foundational investments, stating that "investments in improved data quality, modeling, forecasting, communications, and a DER-aware ADMS are required to achieve any efficient dispatch of DER in the future."[42] Furthermore, PG&E recognized that systems such as DERMS help manage the grid in conjunction with traditional tools, and that "in some instances, it may be more efficient and cost-competitive to use traditional grid infrastructure investments, manual/automated settings changes, circuit reconfigurations, or existing field devices to maintain grid safety, reliability, and compliance."[43] Hence, a key takeaway is that new operational systems and tools may not immediately yield new use cases for DER, system benefits, or other advantages by themselves. Rather, maximizing the value of these systems requires an examination of – and possible changes to – existing tools and processes.

However, establishing clear objectives early and setting the technical standards and functional requirements that facilitate those objectives enables the near-term deployment of technology compatible with those long-term goals. Doing so also helps avoid costly retrofits or additional equipment to address prospective operational impacts as experienced in Germany and Hawaii. For example, German distributed PV installations were deployed with inverter settings designed to disconnect solar generation if the grid frequency exceeded 50.2 Hz. This setting could have led to a mass disconnection of PV because of frequency variation, resulting in system instability and the possibility of shedding load. Inverter retrofits to resolve this problem were estimated to cost nearly $300 million U.S. dollars.[44] Similarly, high rooftop PV penetration on some feeders in HECO's service territory created voltage fluctuations, which may have led to undesirable

[42] Pacific Gas and Electric Company, EPIC 2.02 – Distributed Energy Resource Management System, January 18, 2019. Available online: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf
[43] Ibid.
[44] EPRI, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources. Available online: https://www.energy.gov/sites/prod/files/2015/03/f20/EPRI%20Integrated%20Grid021014.pdf

outcomes, endangering utility field crews, damaging home devices, and tripping PV systems.,[45] Hence, and as described previously, HECO deployed voltage and reactive power controllers to mitigate this issue.

Timing and Impact

Table 13. Potential for Utilities to Not Be Fully Prepared to Incorporate Future, Significantly Greater Levels of DER Into Distribution Operations – Potential Level of Impact

	Solar			Storage			Period
Scenario:	Low	Mid	High	Low	Mid	High	(Years)
Impact Level:							2021-2023
							2024-2026
							2027-2030

Utilities gather information on DER and circuit parameters such as power factor, real power, reactive power, and phase current and voltage to enable operational decision-making.[46] In the near-term (2021-2023), at low DER penetration levels for both solar PV and battery storage, operational impacts are likely to be modest, however under the Mid Scenario, with solar PV installs growing at a CAGR of 10.6% and energy storage at a CAGR of 9.5% in the medium-term (2024-2026), could require incremental investments in equipment such as intelligent switches and voltage management devices.

In the long-term (2027-2030) the Mid Scenario projects more than 650 storage systems and nearly 90,000 solar PV systems in Ontario by 2030. This level of deployment could require additional information from DER, changes in metering requirements and enhanced control capabilities. However, the number and diversity of distributors in Ontario will require a flexible approach to managing operational impacts of DER and continual improvements in growth projections to inform future action. The operational requirements across distributors will vary significantly, but in all cases clear objectives can provide pathways for system evolution so that individual distributors and the province as a whole can take actions to manage system operations in a manner consistent with those objectives. To the extent that those determinations imply the need for specific inverter functionality, new technical standards, or system design considerations, action can be taken today to reduce prospective customer costs and obviate the need for costly retrofits and expensive fixes.

[45] Hawaiian Electric, Varentec Grid Optimization Project. Available online: https://www.hawaiianelectric.com/about-us/our-vision-and-commitment/investing-in-the-future/varentec-grid-optimization-project

[46] For example, see section 2.5 (Control and Monitoring Requirements): Hydro One, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50 kV and Below. Available online: https://www.hydroone.com/businessservices_/generators_/Documents/Distributed%20Generation%20Technical%20Interconnection%20Requirements.pdf

Recommendations

The OEB could consider:

- **Assessing new frameworks for LDCs to evaluate the prudency and cost-effectiveness of monitoring and control investments and grid modernization investments**[47]
  - LDCs could be encouraged to link proposed investments to system drivers, objectives, and functionalities required to meet a desired capability or business need. LDCs could be asked to develop performance metrics to assess the efficacy of the investments, benefit to customers, and any potential risks.
  - The OEB could develop new cost-effectiveness frameworks for LDCs to evaluate grid investments. For example, grid modernization investments that provide joint benefits and help comply with regulatory mandates could be subject to a best-fit, most-reasonable cost standard, wherein the investment that provides the highest value and meets the LDC's objectives at the most reasonable cost would be the preferred solution. Such a framework could support assessments of future investments plans under higher DER penetrations.

- **Organizing technical workshops to generate discussion on implementation timelines and characteristics, share knowledge, and provide further support for LDC field pilots and projects on advanced capabilities**
  - A focus on consistent standard implementation efforts, even when DER penetration is low, can yield flexibility for the OEB, LDCs, and consumers to utilize different grid-supportive capabilities as they are required or as DER penetration increases and help avoid costly retrofits or additional equipment to retroactively address operational impacts.

2.2 Potential for utilities to not be fully prepared to incorporate future, significantly greater levels of DER into planning practices

Description

In addition to real-time operational impacts, higher volumes of DER will begin to affect the strategies and approaches LDCs employ for distribution system planning. Increased adoption will drive the need for expanded planning processes and enhanced tools capable of considering a diverse resource mix, greater sources of uncertainty, and new metrics such as flexibility and resiliency (in addition to the traditional metrics of safety, reliability, and affordability). The planning challenges and requirements posed by increased DER penetration can be addressed via a framework incorporating the following broad components: current state assessment, DER adoption and output forecasting, hosting capacity analyses, revised connection procedures, and NWA and locational value assessments.

[47] The US DOE's Modern Distribution Grid Project provides one example of such a framework. Available online: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

The current state assessment establishes a baseline on which enhanced planning activities can be performed and compared against. A review of system status can include gathering of data on system and feeder reliability, equipment condition, load forecasts, and quantity and types of DER. As DER penetration grows, incremental system investments will be required to maintain grid safety and reliability. However, DER adoption within LDC territories is likely to be uncertain in terms of the locations, types, rate, and amount of deployment, making it difficult to arrive at specific timeframes for new investments. Probabilistic and multi-scenario DER and load forecasts can assist in this regard. This can be further supported through hosting capacity analysis to assess the amount of DER that can be accommodated safely and reliably on the distribution system without violating thermal, voltage, and protection limits. Developing multiple scenarios in the context of this analysis can help consider diverse planning inputs and assumptions, help evaluate the impacts of varying outcomes, and accordingly develop specific solutions.

This type of planning could also include evaluation of the ability of DER as non-wire alternatives to defer or obviate the need for investment. For example, DER could be used to provide load relief, addressing capacity concerns, deferring equipment expansion or reconductoring projects or increasing system hosting capacity.

These practices can help utilities better prepare for DER integration by identifying the proper system investments, informing changes to existing processes, and quantifying the benefits of DER to customers and the system. As noted above, the heterogeneous growth rates across the province, from distributor to distributor, from substation to substation, and from circuit to circuit imply the need for distributors to continually improve data and the geospatial granularity of that data to help inform the signposts for action. The continuous of these planning outputs will help shape the actions needed by all distributors as well as the regulatory measures undertaken by OEB to address DER growth in the most cost-effective manner for Ontario.

Timing and Impact

Table 14. Potential for Utilities to not be Fully Prepared to Incorporate Future, Significantly Greater Levels of DER into Planning Practices – Potential Level of Impact

	Solar			Storage			Period (Years)
Scenario:	Low	Mid	High	Low	Mid	High	
Impact Level:	Green	Green	Green	Green	Green	Green	2021-2023
	Green	Yellow	Yellow	Green	Green	Yellow	2024-2026
	Yellow	Red	Red	Green	Yellow	Red	2027-2030

At low adoption levels, DER can be accommodated within distribution systems without significant changes to existing planning processes, but as penetration rates increase enhanced capabilities can help maintain system reliability. As a representative guide, the trigger for these new capabilities is assumed to be reached when DER penetration reaches 5% of a system's peak load.[48] At the province level, solar PV penetrations are projected to approach 5% of Ontario's system peak load towards the end of the Study period in the Mid Scenario and before 2027 in the High Scenario, but pockets of higher penetration growth could emerge and it is therefore possible that some portions may reach these threshold penetration levels much sooner. For example, some of Alectra's transformer stations have already connected DER capacity above 40% of the station's maximum thermal capacity rating.[49]

Recommendations

The OEB could consider:

- **Convening stakeholders and holding discussions to develop frameworks to integrate DER into the fabric of electric distribution planning**
    - The OEB could consider convening stakeholder groups to discuss targeted issues and share best practices on distribution system planning.
    - These discussions could be convened within the context of the existing Responding to DER consultation, which has identified in scope the treatment of investments by utilities to enable and integrate DER and enhancements to system planning.[50]

- **Formulating guidance for LDCs on enhanced distribution planning practices under high DER penetration**
    - As DER penetration grows, utilities may need to proactively adapt their existing planning techniques to better inform prospective system requirements. These enhanced distribution system planning techniques will produce improved information that could include the provision of more detailed DER projections at the substation and circuit level to inform distributor planning as well as future regulatory action. The continual advancement of these DER projections in terms of temporal and geospatial granularity could further inform the scope and timing for pursuing the recommendations provided in this document.

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[48] An installed DER capacity to system peak load value of 5% is an illustrative threshold for procuring advanced functionality. The value is intended to be a heuristic and was informed by experiences in California, Hawaii, and Australia. The purpose of the threshold is to help utility employees understand when engineering, business process, and policy issues are likely to arise because of increasing DER penetration. Also see: ICF, Integrated Distribution Planning – Prepared for the Minnesota Public Utilities Commission, August 2016.

[49] Alectra Utilities, Distribution System Plan 2020 – 2024, May 2019. Available online: https://alectrautilities.com/sites/default/files/assets/pdf/AlectraUtilities_APPL_Ex-4-Apx-A_PUBLIC-VERSION_-v.-2-of-7.pdf

[50] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020.

2.3 Inability to productively handle increased scale and complexity of data

Description

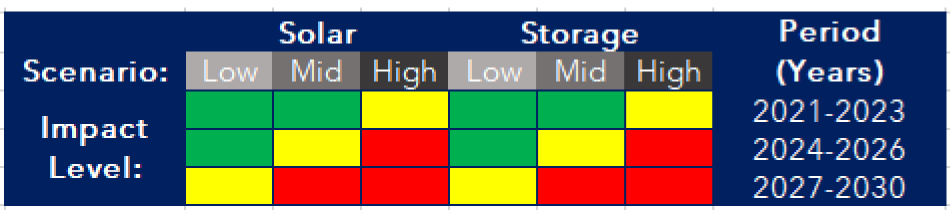
Communication pathways between DER owners/operators and the LDCs are critical to ensuring safe and reliable operation of the distribution system. As noted, the information that is exchanged across these channels is critical for providing situational awareness to system operators, and in the future could enable DER to respond to dynamic grid needs.

Data pertaining to resource characteristics, device status and operating condition will become increasingly important for functions such as local voltage management and system protection. Depending on the extent of DER penetration, bi-directional flows may involve several thousand devices ranging from the individual household on low-voltage secondary circuits to the sub-transmission substations operating at higher voltages.

A unified hub for sharing data from and between individual DER generators, aggregators, LDCs, and the IESO could allow both DER and larger central station generators to offer flexibility services to the bulk electric grid.[51]

Timing and Impact

Table 15. Inability to Productively Handle Increased Scale and Complexity of Data – Potential Level of Impact



LDCs should be encouraged to advance capabilities for data collection, analysis and increased situational awareness if DER penetrations are projected to increase significantly in local pockets. Doing this early while penetrations are still low will enable the LDCs prepare for future system conditions. As DER are better integrated into grid planning, grid operations, and wholesale markets, high-fidelity data will be needed on a timely and consistent basis for grid reliability and the management of transactions across the T-D interface and market orchestration.

The main drivers for DER integration in the IAMs is likely to emerge from the ongoing efforts associated with the IESO's Innovation and Sector Evolution White Paper Series, but may also require reviewing and updating market design rules for the Capacity Auction.[52] For instance, in

[51] IRENA, Innovation Landscape for a Renewable-Powered Future, February 2019.

[52] Any changes to market design rules to support new or revised DER or aggregation participation models are likely to occur after the implementation of the Market Renewal Initiative. More information can be found here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

its draft White Paper "Exploring Expanded DER Participation in the IESO-Administered Markets, Part II: Options to Enhance DER Participation," the IESO has identified creating a participation model for aggregated non-dispatchable generation, exploring alternative telemetry sources from LDC-collected operational data, and examining system needs and capabilities for hosting capacity as items that merit further consideration in the near term.[53] This implies the need for increased data-sharing and coordination of activities between the IESO and the LDCs to support these objectives.

Recommendations

The OEB could consider:

- **Encouraging the LDCs to coalesce around common reporting requirements and best practices for data from DER**, such as standardizing data needs and technical requirements, using consistent definitions for data fields, providing examples of required information, handling large datasets, and employing devoted resources to manage DER data.
  - This is in line with the Responding to DERs initiative's guiding principle of regulatory effectiveness, where the regulatory framework is predictable in the consistent application of its rules and requirements in similar circumstances – yet adaptable, flexible, and sustainable. Specifically, the OEB has identified "access to information" as a focus area of the Responding to DERs initiative, highlighting the need for "sufficient information sharing" to "lead to mutual benefits for host customers and ratepayers."[54]
  - Developing these capabilities soon (2021-2023) irrespective of the projected resource adoption Scenario is a no-regrets action that LDCs can take to streamline the DER connections process and provide timely information to developers.
  - This activity could also help lay the groundwork for building internal capabilities in preparation of more aggressive DER adoption as projected in the later years (2027-2030) of the Mid Scenario and the middle and later years (2024-2026 and 2027-2030) of the High Scenario.
  - The DER Connections Review Working Group is collaborating with industry stakeholders, including LDCs, to enhance existing checklists of requirements so that they reflect conditions at the proposed circuit location and the broader distribution system.[55] These steps can improve transparency for consumers regarding the time and cost implications for proposing DER projects in certain sections of the distribution system. As DER penetrations increase in the medium-term (2024-2026) in the High Scenario and long-term (2027-2030) in the Mid and

[53] IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part II: Options to Enhance DER Participation, 2020. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx
[54] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020. Available online: https://www.rds.oeb.ca/CMWebDrawer/Record/667330/File/document

High Scenarios, the OEB could work with stakeholders to refine the information available to DER installers.

- **Advocating that the LDCs and IESO consider DER data-sharing initiatives within the context of ongoing activities** in the IESO's Grid-LDC Interoperability Standing Committee and Grid-LDC Interoperability and Data Sharing Framework.
    - In the mid-term, DER data-sharing between the IESO and LDCs will be most valuable in the context of the High Scenario. This Scenario assumes that distributed PV and storage will be integrated into wholesale markets by 2024. As described previously, the main drivers for DER integration in the IAMs on this approximate timeline are likely to be the ongoing efforts associated with the IESO's Innovation and Sector Evolution White Paper Series and market design rules for the Capacity Auction. Data sharing initiatives between the IESO and LDCs could be pursued on a relatively delayed timeline for the Low and Mid Scenarios, which assume integration of DER into wholesale markets only by 2029 and 2026, respectively.
    - An important objective for the OEB would be to provide guidance on the data-sharing practices that provide "appropriate balance between information transparency and protecting consumer privacy, commercial sensitivity, and cybersecurity."[56]

- **Working with DER developers, LDCs, and the IESO to assess the need for centralized data hubs, as well as the types of data housed in these repositories, to provide timely information to all parties**
    - The OEB has some prior experience working with stakeholders on the development of technology platforms, having developed the standards for the EBT Hub.[57]
    - With a large number and diversity of LDCs in Ontario, defining and building the hub with unified technical standards, protocols, and requirements will be challenging. In other contexts, the shared datahub has been developed jointly by distribution system operators and the transmission system operator.[58] In Ontario, such an endeavour may require a few LDCs to serve as project sponsors, responsible for overall definition and implementation of the hub, with another group of LDCs serving as advisors. This mirrors the structure previously adopted for implementation of the Ontario EBT hub.
    - In a relatively low DER penetration environment and in the absence of DER participation in wholesale markets, as indicated by the projections in the Low

[56] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020. Available online: https://www.rds.oeb.ca/CMWebDrawer/Record/667330/File/document

[57] The Ontario EBT Working Group, Electric Business Transactions (EBT) Standards Document for Retail Settlement in the Electric Retail Open Access Industry, January 21, 2008. Available online: https://www.oeb.ca/oeb/_Documents/Regulatory/Ontario_EBT_Standards_v4.pdf

[58] Elia, Deployment of a Datahub Shared by All System Operators to Support Electrical Flexibility", March 8, 2018. Available online: http://www. elia.be/~/media/files/Elia/PressReleases/2018/20180308_SYN_Persbericht_Datahub_EN.pdf.

Scenario for both PV and storage, this activity would not be relevant. Centralized hubs to share meter data and information on market processes could be considered once DER have been fully integrated into wholesale markets and emerging retail markets: in the 2027-2030 period under the Mid Scenario, and as early as 2024 in the High Scenario.

3. Market Impacts

Higher penetrations of DER in Ontario could result in growing complexities and potentially higher costs relative to current market design, planning, and operations due to the significant growth in the level of interactions between various market actors. Over time, it will become more important to assess the system's ability to accommodate the scalability[59] of the interactions that will likely arise as a result of emerging and forthcoming procurement, pricing, and programmatic efforts and changes to participation rules at both the distribution and wholesale market levels. The OEB has a role in continuing to collaborate with market actors to facilitate the pathways for ensuring that guiding principles such as regulatory effectiveness, transparency, safety, and reliability are maintained. Importantly, given the diversity of LDCs in Ontario in terms of their functional capabilities to take on an increasing role for managing DER, the OEB could work with the LDCs and the IESO to ensure that any selected coordination framework aligns with specific LDC capabilities to minimize some of the pertinent scalability risks and ensure that distribution-level reliability is prioritized at all times.

Table 16 below summarizes the market implications described in the following sections.

[59] Scalability is defined as the ability of the system's processes and technology design to function effectively with very large quantities of DER on the system. More information can be found here: https://gridmod.labworks.org/sites/default/files/resources/Grid%20Architecture%202%20final_GMLC.pdf.

Table 16. Summary of Market Implications & Recommendations

Implication	Associated Recommendations
Opportunities for new or enhanced electric distribution market value streams for customers and utilities	Work with the LDCs to develop new programs that allow distribution-connected customers with DER to provide local grid value
	Work with the LDCs to determine how potential DER growth trajectories within their respective territories may impact which DER use cases provide the greatest system value at the distribution level
Opportunities for new or enhanced wholesale electric market value streams for customers and the system	Account for the diversity of LDC capabilities by developing guidelines and requirements that govern LDC performance in the coordination of DER participation in the IAMs that align with the OEB guiding principles
	Work with the IESO to identify how potential DER growth trajectories may impact which DER use cases provide the greatest system value at the bulk power levels
Heightened transmission-distribution coordination challenges	Convene a forum to provide guidelines on the design of a distribution-level market that can effectively coordinate with the IAMs on the prioritization of services and the allocation of roles and responsibilities
	Collaborate with the IESO and LDCs to explore ways to place appropriate measures on DER participation in IAMs that minimize the risks for duplicative compensation

3.1 Opportunities for new or enhanced electric distribution market value streams for customers and utilities

Description

Electric distribution markets can help source services such as capacity deferral, reliability, resiliency, power quality, and voltage management from DER. These DER services may provide alternatives to traditional LDC infrastructure investments. DER services are commonly procured via three mechanisms known as the three Ps - *Pricing*, *Programs*, and *Procurement*. Creating an optimal mix of DER sourced by these mechanisms and traditional investments requires a portfolio development approach and a common framework to assess the relative characteristics (output profile, cost, response duration etc.) of each investment type. Hence, increasing DER penetration necessitates a renewed focus on options within the LDC toolkit to guide and incentivize DER performance to align with system value and requirements, while also providing DER owners and/or operators with commensurate value for those services.

The first 'P', *Pricing*, involves the use of retail tariffs and/or rates to provide dynamic market signals to guide DER performance. The second 'P' is for *Programs* that could allow utility customers with DER to enroll in a systematic way to provide local value to the grid. Examples could include generic utility energy efficiency (EE) and demand response (DR) programs or more geo-targeted programs that focus on high-need areas such as localized constrained regions within the grid. The third 'P' is for *Procurement*, which involves competitive solicitation of

DER to address a targeted grid need. This section explores *Procurement* as the main vehicle for guiding and incentivizing DER performance in the province.[60]

The most common method of procuring resources is a competitive RFP, but it could also entail an auction process. Markets such as New York's Reforming the Energy Vision (REV) and California's Distribution Deferral Investment Framework (DDIF) show some of the practical challenges of competitive procurements such as project needs to meet cost, timeline, and project type requirements, as well as contentions over contractual obligations. The REV process initially required utilities to propose NWA solutions to grid constraints, including the solicitations from third-party entities.[61] The New York Public Service Commission collaborated with utilities to develop a benefit-cost analysis (BCA) test, segmented across issues (e.g., system constraints, reliability/resiliency, societal values) as a guide to assess NWA submissions.[62] Utilities have noted challenges with the reliability and system performance from third-party solutions; additional challenges related to the performance of NWA submissions (e.g., the operating characteristics associated with the proposed technologies) have complicated efforts to develop a routine approach to the solicitation of DER solutions.[63] The utilities noted prospective successful submissions tend to include a portfolio approach accompanied with granular information on the impact of resources encompassing the solution set.[64]

California was also an early leader in efforts to leverage DER like solar PV and energy storage in the context of distribution resource planning. In 2015 the state developed the DDIF (sometimes referred to as DIDF) decision framework to defer system infrastructure investments through targeted DER deployments on the condition they were cost-effective. Each of the state's investor-owned utilities (IOUs) would issue competitive solicitations for distribution deferral opportunities using DER like solar PV and energy storage, among a broader set of technologies. DDIF was part of a broader Distribution Resource Planning (DRP) process linking planning assumptions, assessment of grid needs and utility forecasts, approaches to grid modernization, general rate cases, and finally resource solicitation processes.[65]

Although the DRP process was designed to build on the IOUs' existing planning processes, each utility ran into trouble aligning the DRP timeline with their respective distribution capacity planning schedules. Each IOU has struggled to successfully procure DER-led deferral projects, due in large part to the finding that not every distribution need is well-suited for cost-effective

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[60] *Pricing* is covered through other initiatives such as the OEB RPP Pricing Pilots and the Electricity Distribution Rate Design. *Programs* may be less applicable to Ontario's context where the IESO has the sole responsibility for procuring supply to provide retail kWh and meet resource adequacy requirements.
[61] https://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities
[62] NYPSC, BCA Order: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016). Available online: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7D
[63] Lyons, Cristin, Non-Wires Alternatives: Non-Traditional Solutions to Grid Needs, T&D World, June 6, 2019. Available online: https://www.tdworld.com/overhead-distribution/article/20972703/nonwires-alternatives-nontraditional-solutions-to-grid-needs.
[64] Walton, Robert, New York utilities increasingly embrace non-wires alternatives as ConEd forges the path, Utility Dive, May 31, 2019. Available online: https://www.utilitydive.com/news/new-york-utilities-increasingly-embrace-non-wires-alternatives-as-coned-for/555762/.
[65] Cooke, Alan, Juliet Homer, and Lisa Schwartz, Distribution System Planning – State Examples by Topic, 2018. Available online: https://eta-publications.lbl.gov/sites/default/files/dsp_state_examples.pdf.

DER deferral. Specifically, each IOU encountered challenges related to technology feasibility given the long-duration needs of deferral opportunities, concomitant implications for cost-recovery,[66] program design complexity associated with combining multiple small offerings, and complications securing regulatory approval early in the process to reduce technology and cost-recovery uncertainty.[67, 68] As a result, to date the state has only seen one successful NWA procurement from the DRP proceeding, while the other two IOUs have yet to award a contract through the DDIF process.[69] There is still a view that tools like load growth scenarios and assessment of grid needs as part of the DRP process will be valuable for future grid modernization activities even with the mixed experience with solicitations under DDIF. Future activities may weigh the potential for DER-related tariffs to address procurement challenges and shore up disparities in cost-recovery needs for utilities, DER developers, and consumers alike.[70]

In Ontario, the IESO has recently partnered with Alectra Utilities on the York Region Non-Wires Alternatives (NWA) Demonstration, a two-year pilot project that is intended to explore market-based approaches to secure services from DER to meet local energy needs, while coordinating across the electricity system.[71] LDCs may also explore opportunities to define and compensate DER for provision of new types of distribution services such as ancillary services and local resource adequacy. Presently, the provision of these forms of distribution grid services by DER remains largely nascent and would need to be further studied and piloted.

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[66] Both for DER offerings on hour-based revenue opportunities spread across months or years, and for the IOUs given the disparity between depreciation schedules of traditional solutions versus the DER payment plans within 3- to 5-year contract structures. Generally speaking, higher depreciation costs of DER projects in short-lived contracts have not been able to compete with traditional solutions given the longer duration of deferral needs. For one project in the northern California area, the IOU also found "[t]he timing and magnitude of a forecasted capacity deficiency, as well as the scope and cost of the preferred wires alternative, are liable to change from year to year as system conditions and customer needs evolve. This uncertainty introduces risks to DERs' ability to fully meet the deficiency or to realize the projected deferral value." *See* Pacific Gas & Electric, Advice Letter 5435-E, February 5, 2019. Available online: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5435-E.pdf

[67] CPUC, Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), February 8, 2018

[68] Pacific Gas & Electric, Advice Letter 5435-E, February 5, 2019. Available online: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5435-E.pdf

[69] St. John, Jeff, California Struggles to Find Path for Solar and Batteries to Take Place of Traditional Grid Investments, GTM Squared, February 6, 2020

[70] GridWorks, Chapter Seven: Next Steps and Future Challenges, October 10, 2019. Available online: https://gridworks.org/2019/10/chapter-seven-next-steps-and-future-challenges/

[71] IESO York Region NWA Project. Available online: https://www.ieso.ca/Corporate-IESO/Media/News-Releases/2020/11/IESO-York-Region-NWA-Project

Timing and Impact

Table 17. Opportunities for New or Enhanced Electric Distribution Market Value Streams for Customers and Utilities – Potential Level of Impact

Scenario:	Solar			Storage			Period (Years)
	Low	Mid	High	Low	Mid	High	
Impact Level:							2021-2023
							2024-2026
							2027-2030

At present, the chief driver for PV and storage adoption by Ontarian residential, small business, and Class B non-RPP customers is the ability to save on energy bills. Storage assets have the additional capability of being able to provide backup power. The implementation of new rate structures and modifications to existing ones could modify adoption trajectories by encouraging customers to purchase resources that could help them better respond to price signals. Furthermore, price signals could also better align DER output and performance with system needs. As noted previously, the OEB has already initiated activities in this regard, and in the near-term (2021-2023) in a low DER environment, should continue building on these efforts.

Growing DER penetration will also bring additional opportunities to leverage DER within LDC programs and/or NWAs. The ability of DER to serve specific grid needs will be heavily dependent on the time and location of a grid need, as well as the cost and reliability of a solution. Specific to NWAs, these projects tend to be unique and with their own set of implementation challenges, including siting and permitting issues. For example, a recent report found that of 321 identified NWAs in the US, 59% have not been pursued, and only 16% have been implemented.[72] While a program such as the York NWA Demo is likely to provide useful insights, its results may not be broadly applicable to the entire province. While LDCs should be encouraged to find ways to integrate DER in the near- and mid-term, a common NWA cost-benefit framework or solicitation guide may be best suited for medium and high DER penetration environments in the long-term (2027-2030).

Recommendations

The OEB could consider:

- **Working with the LDCs to determine how potential DER growth trajectories within their respective territories may impact which DER use cases provide the greatest system value at the distribution level**
    - This is in line with the Responding to DERs initiative's focus on "enabling DER services to the distribution system."[73]

[72] Greentech Media, Where Are All the Non-Wires Alternatives?, August 27, 2020. Available online: https://www.greentechmedia.com/articles/read/where-are-all-the-non-wires-alternatives

[73] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020.

- o In the near-term (2021-2023) and mid-term (2024-2026), the OEB can support LDC pilots that explore innovative ways to integrate DER and maximize their potential system and/or local value. For example, pilots could focus on enhanced NWA planning frameworks, market mechanisms, or provision of local and flexible resource adequacy.
- o In the long-term (2027-2030) and under the Mid and High Scenarios, it may be prudent to develop standardized NWA cost-benefit and procurement frameworks for the LDCs.

3.2 Opportunities for new or enhanced wholesale electric market value streams for customers and the system

Description

With limited visibility into distribution systems, wholesale market operators are exploring ways to account for increasing DER penetration. In Ontario, the IESO has embarked on exploring options for expanding opportunities for DER to participate in its market.[74,75] Expanding these opportunities will require the IESO to make important decisions about a variety of topics including addressing barriers to participation such as aggregation eligibility and accounting for the functional diversity of LDCs. From a regulatory standpoint, it remains crucial to be informed about the challenges and opportunities that these changes present to ratepayers, and to facilitate the pathways for ensuring that the guiding principles of transparency, consumer-centricity, regulatory effectiveness, economic efficiency, and reliability are being maintained.[76]

In Ontario, there is currently no aggregation participation model for non-dispatchable resources in the IAMs. According to the IESO's draft DER whitepaper part II,[77] this prevents approximately 850 MW of existing distributed solar resources that fall below the existing minimum size threshold from participating in the IAMs. Creation of an aggregation model could allow for smaller resources that do not meet that threshold to have access to the wholesale market, which would gain them access to additional revenue streams and potentially provide grid value.

Diversity of LDC capabilities in facilitating DER participation in the IAMs is another important consideration for Ontario. Select LDCs with more advanced capabilities may be more ready to

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[74] IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part 1 – Conceptual Models for DER Participation, Innovation and Sector Evolution White Paper Series, 2020.Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.ashx

[75] IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part II – Options to Enhance DER Participation, Draft White Paper, Innovation and Sector Evolution White Paper Series, 2020. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

[76] OEB, Responding to Distributed Energy Resources (DERs). Available online: Responding to Distributed Energy Resources (DERs) | Ontario Energy Board (oeb.ca)

[77] IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part II – Options to Enhance DER Participation, Draft White Paper, Innovation and Sector Evolution White Paper Series, 2020. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

procure, integrate, dispatch, and operate DER, while the majority may still need the system operator to take a centralized role in the participation of DER in the wholesale market. The former group of LDCs may be more involved in the DER participation in the IAMs, minimizing some of the scalability risks that the IESO would otherwise be facing with increasing number of participants. However, if DER are required to submit bids to LDCs for wholesale market participation in a layered coordination model, there may be concerns over transparency and creating a fair and competitive market arena for DER, particularly if the LDC is allowed to bid its own resources into the wholesale market. The OEB might consider providing guidance and/or establishing requirements for LDCs to ensure that any selected coordination framework preserves principles of transparency, consumer-centricity, and regulatory effectiveness. For instance, the OEB could consider the establishment of open-access guidelines governing LDC performance that ensure that an LDC's own (or an affiliate's) DER is not given a competitive advantage in instances of layered coordination models, where the LDC acts as the single point of contact for participation of DER in the wholesale market.

Timing and Impact

Table 18. Opportunities for New or Enhanced Wholesale Electric Market Value Streams for Customers and the System – Potential Level of Impact

	Solar			Storage			Period (Years)
Scenario:	Low	Mid	High	Low	Mid	High	
Impact Level:	Green	Green	Green	Green	Green	Green	2021-2023
	Green	Yellow	Yellow	Green	Green	Yellow	2024-2026
	Yellow	Yellow	Red	Yellow	Yellow	Red	2027-2030

The IESO currently accounts for approximately 2200 MW of distributed PV (including microFIT) installations and 45 MW of storage installations in its resource adequacy planning processes. As a variable resource, the ability of solar PV to currently participate in the IAMs is limited. Storage resources can participate in the IAMs but currently do so on an ad-hoc basis.

As part of its Innovation Roadmap, the IESO is exploring options for integrating DER into IAMs.[78] Some of the considerations for addressing the barriers will be linked to the MRP timelines;[79] the MRP initiatives are expected to be in place by 2023. This study assumes integration of DER into the IAMs along the following timeframes: 2029 in the Low Scenario, 2026 in the Mid Scenario, and 2024 in the High Scenario. The OEB could benefit from taking actions ahead of these timeframes in consideration of provision of guidelines and/or establishing requirements for LDCs to ensure that any selected coordination framework for participation in

[78] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Innovation-and-Sector-Evolution-White-Paper-Series

[79] For instance, the IESO is exploring the potential for creation of a non-dispatchable aggregation model for participation in the energy market and eventually in the capacity auction pending a few changes that would be needed to market design rules. However, this will likely occur after the implementation of the MRP. More information can be found here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

the IAMs preserves guiding principles such as transparency, consumer-centricity, and regulatory effectiveness.

Recommendations

The OEB could consider:

- **Accounting for the diversity of LDC capabilities by developing guidelines and requirements that govern LDC performance in the coordination of DER participation in the IAMs that align with the OEB guiding principles**
    - LDCs with more advanced capabilities may be more ready to procure, integrate, dispatch, and operate DER while the majority may still need the system operator to take a centralized role in the participation of DER in the wholesale market.
    - One consideration could be the establishment of an open-access framework that governs LDC performance in instances where the LDC is the single point of contact for the DER participating in the wholesale market.
    - These activities could be undertaken in the long-term (2027-2030) in the Low Scenario, mid-term (2024-2026) in the Mid Scenario, and near-term (2021-2023) in the High Scenario.

- **Working with the IESO to identify how potential DER growth trajectories may impact which DER use cases provide the greatest system value at the bulk power levels**
    - Working with IESO and LDCs, the OEB can assist in identifying the most pertinent DER services that ensure beneficial outcomes at the distribution and wholesale levels. In keeping with the timeline for integration of DER into the IAMs, this issue is likely to rise to the fore in the long-term (2027-2030).

3.3 Heightened transmission-distribution coordination challenges

Description

The complexities that emerge with increasing numbers of DER on the system necessitate close coordination between the key players across a given Transmission-Distribution interface, including the IESO, LDCs, and the OEB. Scalability of DER participation in wholesale markets may raise concerns of tier bypassing and hidden coupling as well as introduce operational risks that may impact grid reliability. The OEB could work with the IESO and LDCs to ensure that the reliability of the distribution system is maintained irrespective of the selected coordination framework for DER participation in the wholesale market.

As distribution systems are more dynamic than the bulk power system, there is a higher risk for the occurrence of instances where existing or emerging distribution system conditions render DER unavailable to operate for wholesale market purposes as originally intended. A DER or an aggregator responding to an ISO dispatch that bypasses the distribution system[80] may be

[80] A grid architectural concept that is referred to as tier bypassing. More information can be found here: https://gridmod.labworks.org/sites/default/files/resources/Grid%20Architecture%202%20final_GMLC.pdf.

constrained due to current distribution system conditions such as a reconfigured distribution circuit that limits the capacity available for injection. In recognition of this risk, the recent FERC Order 2222 requires ISO/RTOs to create communication protocols that give distribution utilities the permission to override signals that could potentially compromise the reliability of the distribution system.

The technical ability for DER to stack multiple services across several domains can provide a significant opportunity for the distribution-connected resources to compete on an economic basis with traditional system infrastructure. However, allowing for stacking of services may result in unintended duplicative compensation for provision of a single service through multiple revenue streams. This would create an unfair and unintended advantage to DER in the market. The potential for stacking also introduces the risk for conflicting obligations rendering a resource unable to meet both the IESO and distribution obligation at the same time, a grid architectural principle known as "hidden coupling."[81] In the case of duration-limited resources like energy storage, the situation may arise due to insufficient time to recharge between two consecutive dispatch instructions.[82]

To facilitate effective coordination of a resource that is allowed to provide multiple services, the OEB, IESO, and LDCs could collaborate to explore options for tracking DER performance and compensation (such as updating of metering practices) and placing of measures (such as requirements on prioritization of services[83] similar to California's multi-use applications[84] and New York's 2018 storage order[85]) that would reduce the likelihood of duplicative compensation without imposing rules that unfairly prohibit DER from participating in both markets.

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[81] Taft, Jeff, Grid Architecture 2, Pacific Northwest National Laboratory, 2016.Available online: https://gridmod.labworks.org/sites/default/files/resources/Grid%20Architecture%202%20final_GMLC.pdf.

[82] The IESO covers considerations for State of Charge limitations as part of the Storage Design Project. More information can be found here: Energy Storage Advisory Group (ieso.ca)

[83] In January 2018, the California Public Utilities Commission (CPUC) issued a proposed decision to guide the ability of energy storage to provide multiple services based on prioritization of reliability services (such as: transmission and distribution, or T&D, deferral) over non-reliability services (such as: customer demand charge management) to the extent they result in competing obligations. More information can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K234/202234451.pdf.

[84] CPUC. Proposed Decision of Commissioner Peterman: Decision on Multiple-Use Application Issues, January 11, 2018. Available online: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K234/202234451.pdf

[85] NYPSC, Case 18-E-0130 – In the Matter of Energy Storage Deployment Program. Order Establishing Energy Storage Goal and Deployment Policy, December 13, 2018. Available online: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bFDE2C318-277F-4701-B7D6-C70FCE0C6266%7d

Timing and Impact

Table 19. Heightened Transmission-Distribution Coordination Challenges – Potential Level of Impact

Scenario:	Solar Low	Solar Mid	Solar High	Storage Low	Storage Mid	Storage High	Period (Years)
Impact Level:	Green	Green	Green	Green	Green	Green	2021-2023
	Green	Green	Yellow	Green	Yellow	Yellow	2024-2026
	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	2027-2030

Coordination challenges between LDCs and the IESO may arise as DER participation in the IAMs grows. As part of its Innovation Roadmap, the IESO is exploring options for integrating DER into IAMs.[86] Some of the considerations for addressing the barriers will be linked to the MRP timelines;[87] the IESO's MRP initiatives are expected to be in place by 2023. The suggested timeframes for development of rules for DER participation in the IAMs would follow the related assumptions for this Study – namely, 2029 in the Low Scenario, 2026 in the Mid Scenario, and 2024 in the High Scenario – although the OEB may want to initiate the activities described below well ahead of those particular years to adequately allow results to materialize and develop.

Recommendations

The OEB could consider:

- **Convening a forum to provide guidelines on the design of a distribution-level market that can effectively coordinate with the IAMs on the prioritization of services and the allocation of roles and responsibilities**
    - This is in line with the Responding to DERs initiative's focus on "enabling DER services to the distribution system" in alignment with bulk system activities and the "allocation of roles and responsibilities" for sector participants engaging in DER activities."[88]
    - Topics that could be covered:
        - A way for prioritizing the dispatching of signals to DER that may be conflicting in the case of multiple use applications.
        - Policy that affirms the responsibility of LDCs in maintaining the reliability of the distribution system at all times, particularly at the time of an IESO dispatch to a resource connected to their respective distribution systems.

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[86] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Innovation-and-Sector-Evolution-White-Paper-Series

[87] For instance, the IESO is exploring the potential for creation of a non-dispatchable aggregation model for participation in the energy market and eventually in the capacity auction pending a few changes that would be needed to market design rules. However, this will likely occur after the implementation of the MRP. More information can be found here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

[88] OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020. Available online: https://www.rds.oeb.ca/CMWebDrawer/Record/667330/File/document

  - This activity would be most pertinent in the long-term (2027-2030) given the nascency of distribution level markets in the province.

- **Collaborating with the IESO and LDCs to explore ways to place appropriate measures on DER participation in IAMs that minimize the risks for duplicative compensation** when DER can participate in both retail programs and IAMs to provide multiple wholesale services.
  - Given the nascency of distribution-level markets, it is assumed that these activities could be undertaken in the long-term (2027-2030) in both the Low and Mid Scenarios. However, in the event that pilots such as the York NWA demonstration start to become more prevalent, a trend that may be likely in the High Scenario to meet anticipated local or regional demand increases, the OEB may choose to begin working with key stakeholders on some of these pertinent issues sooner (in the 2024-2026 timeframe).

4. Summary of Recommendations

The implications of DER adoption chronicled above are organized thematically – i.e., process impacts, operations and planning impacts, and market impacts. Within each of those thematic categories, however, the corresponding recommendations vary in terms of when the OEB might consider taking each one. Therefore, this summary is organized around the timing of potential OEB actions: recommendations for the near-term (2021-2023), medium-term (2024-2026), and long-term (2027-2030). Because that timing is rather dependent on what levels of DER adoption emerge, and therefore varies widely between the Low, Mid, and High Scenarios that underly this Study, for simplicity's sake the recommendations below assume future outcomes in-line with the Mid Scenario; actual timelines for action will need to be adjusted for actual DER penetration and judged within the context of OEB's other initiatives and broader goals.

4.1 Near-Term Recommendations (2021-2023)

- **Encourage the LDCs to coalesce around common reporting requirements and best practices for data from DER**

  Developing these capabilities soon is a "no regrets" action that LDCs can take to streamline the DER connections process and provide timely information to developers. This activity could lay the groundwork for building internal capabilities and providing transparency to stakeholders regarding time and cost implications for DER connections as time progresses.

- **Convene stakeholders and hold discussions to develop frameworks to integrate DER into the fabric of electric distribution planning**

  The OEB could undertake this activity in the near-term within the context of the existing Responding to DERs consultation, which has identified in scope the treatment of investments by utilities to enable and integrate DER.

- **Organize technical workshops to generate discussion on implementation timelines and characteristics, share knowledge, and provide further support for LDC field pilots and projects on advanced capabilities**

  This effort could be initiated in the near-term. Such efforts can help LDCs to gain familiarity with and employ advanced capabilities and address operational impacts in a timely fashion.

- **Work with the LDCs to determine how potential DER growth trajectories within their respective territories may impact which DER use cases provide the greatest system value at the distribution level**

  In the near-term, the OEB could support LDC pilots that explore innovative ways to integrate DER and maximize their potential system and/or local value. Pilots could focus on enhanced NWA planning frameworks, market mechanisms, or provision of local and flexible resource adequacy.

4.2 Medium-Term Recommendations (2024-2026)

- **Assess new frameworks for LDCs to evaluate the prudency and cost-effectiveness of monitoring and control and grid modernization investments**

  LDCs could be encouraged to organize proposed investments to integrate DER according to the objectives and functionalities required and to state how the investments meet a desired capability or business need. The projections indicate a low DER environment in the near-term and new participation options and business models that require more active monitoring and control are relatively nascent. It would be prudent for the OEB to start exploring new cost-effectiveness frameworks in the medium-term.

- **Formulate guidance for LDCs on enhanced distribution planning practices under high DER penetration**

  As DER penetration grows, utilities may need to proactively adapt their existing planning techniques to better inform prospective system requirements. This activity could be undertaken in the medium-term so that LDCs are prepared for higher uptake of DERs towards the end of the decade. Enhanced planning frameworks that consider the role and value of DER could create clarity for LDCs, help identify new tools and processes, and ensure the continued safe and reliable operation of the grid.

- **Advocate that the LDCs and IESO consider DER data-sharing initiatives**

  Data-sharing initiatives between the IESO and LDCs with respect to DER participation in wholesale markets could be pursued on a slightly delayed timeline for the Mid Scenario. This scenario assumes that integration of DER into wholesale markets does not occur until 2026.

- **Account for the diversity of LDC capabilities by developing guidelines and requirements that govern LDC performance in the coordination of DER participation in the IAMs that align with the OEB guiding principles**

  LDCs with more advanced capabilities may be more ready to procure, integrate, dispatch, and operate DER while the majority may still need the system operator to take a centralized role in the participation of DER in the wholesale market. One consideration could be the establishment of an open-access framework that governs LDC performance in instances where the LDC is the single point of contact for the DER participating in the wholesale market.

4.3 Long-Term Recommendations (2027-2030)

- **Investigate the feasibility of flexible connections that allow for dynamic adjustments of DER generator settings according to distribution circuit and system conditions**

  This recommendation is better suited for higher penetrations of DER in the long-term and especially under a future that resembles the High Scenario. As penetration increases, the OEB could assess the feasibility of flexible connection arrangements that align the operation of devices with the needs of the local systems and potentially avoid the need for additional connection infrastructure in the future.

- **Work with DER developers, LDCs, and the IESO to assess the need for centralized data hubs**

  Centralized hubs to share meter data and information on market processes could be considered once DER have been fully integrated into wholesale markets and emerging retail markets. Hence, exploring the need for a hub would be most relevant in the long-term under the Mid Scenario, and slightly earlier in a future that resembles the High Scenario.

- **Collaborate with the IESO and LDCs to explore ways to place appropriate measures on DER participation in IAMs that minimize the risks for duplicative compensation**

  The emergence of distribution-level markets is anticipated to be relatively slow, following similar trends from other jurisdictions. Because of this, it is assumed that these activities could be undertaken in the long-term in both the Low and Mid Scenarios. However, in the event that pilots such as the York NWA demonstration start to become more prevalent, the OEB may choose to begin working with key stakeholders on some of these pertinent issues sooner.

- **Convene a forum to provide guidelines on the design of a distribution-level market that can effectively coordinate with the IAMs on the prioritization of services and the allocation of roles and responsibilities**

  This activity would be most pertinent in the long-term given the nascency of distribution-level markets in the province.

- **Work with the IESO to identify how potential DER growth trajectories may impact which DER use cases provide the greatest system value at the bulk power levels**

  Working with IESO and LDCs, the OEB can assist in identifying the most pertinent DER services that ensure beneficial outcomes at the distribution and wholesale levels. In keeping with the timeline for integration of DER into the IAMs, this issue is likely to rise to the fore in the long-term.