Innovation and Sector Evolution White Paper Series

Exploring Expanded DER Participation in the IESO-Administered Markets

PART II: OPTIONS TO ENHANCE DER PARTICIPATION

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Powering Tomorrow.

Contents

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Abbreviation	Description
BTM	Behind the Meter
CDM	Conservation and Demand Management
DACE	Day-Ahead Calculation Engine
DACP	Day-Ahead Commitment Process
DAM	Day Ahead Market
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DESN	Dual Element Spot Network
DNP	Distributed Network Protocol
DR	Demand Response
DRWG	Demand Response Working Group
DSO	Dispatch and Scheduling Optimization Tool
EMS	Energy Management System
FIT	Feed-in Tariff
HDR	Hourly Demand Response
HOEP	Hourly Ontario Energy Price
IAM	IESO-Administered Market
ICAP	Installed Capacity
ICCP	Inter-Control Centre Protocol

Abbreviation	Description
ICG	IESO-Controlled Grid
IESO	Independent Electricity System Operator
ISO/RTO	Independent System Operator/Regional Transmission Organization
LDC	Local Distribution Company
LMP	Locational Marginal Price
M&V	Measurement and Verification
mFIT	microFIT
MPLS	Multiprotocol Label Switching
MRP	Market Renewal Program
NYISO	New York Independent System Operator
OEB	Ontario Energy Board
OR	Operating Reserve
SCADA	Supervisory Control and Data Acquisition
T-D	Transmission-Distribution
TIR	Technical Interconnection Requirements
UCAP	Unforced Capacity
UPS	Uninterruptible Power Supply
VPN	Virtual Private Network

1. Introduction

Distributed energy resources (DERs) are transforming the electricity sector in Ontario and in other jurisdictions around the world. Traditionally, electricity systems have relied on large generators that transmit power across long distances into communities, businesses and homes. DERs are beginning to upend this traditional framework. Drivers like decreasing costs, enhanced functionalities, and emerging customer preferences are converging to make smaller distribution-connected resources an increasingly viable alternative to the status quo. In order to take advantage of the potential benefits provided by DERs, and to mitigate risks and negative impacts, these resources must be effectively integrated into the electricity system. A fundamental component of any approach to the integration of DERs into the electricity system involves determining if and how they should be permitted to participate in wholesale electricity markets.

In June 2019, the Independent Electricity System Operator (IESO) committed to developing a two-part white paper exploring expanded DER participation in the IESO-administered markets (IAMs) [1]. Part 1 – *Conceptual Models for DER Participation*, released in October 2019, provided a working definition of DERs, established a framework for understanding potential DER participation models, assessed the extent to which DERs are enabled to participate in the IAMs today, and identified barriers to enhanced DER participation [2].

As discussed in the first paper, these barriers exist largely because existing market rules and processes were designed for large-scale, transmission-connected resources, which limits the ability of new types of resources to participate and provide the products and services they are technically capable of delivering. Addressing barriers to market participation for DERs has the potential to improve competition and market efficiency, contribute to reductions in wholesale electricity prices, and enhance reliability and resiliency. These benefits were recognized by the Federal Energy Regulatory Commission (FERC) in its recent Order 2222, which obligates U.S. system operators to create participation models for DERs in their markets [3, pp. 6-7].

The first paper concluded that there are limited ways for DERs to participate in the IAMs today and identified the two main barriers to enhancing DER participation – the minimum-size threshold of 1 MW, and the restrictions for creating and operating aggregations of DERs. Other barriers include the cost of meeting the IESO's telemetry requirements and the lack of available information on upstream bulk system hosting capacity for resources. The first paper also highlighted that processes for communication and cooperation between the IESO and local distribution companies (LDCs) regarding the assessment, connection and operation of DERs (especially aggregations) could become a barrier in the future should the volumes of DERs participating in the IAMs increase.

This paper, Part 2 – *Options to Enhance DER Participation*, will explore options to address the barriers identified in the first white paper, evaluate the potential impacts of those options, and provide key insights and considerations to inform future market design work related to DERs.

1.1 Stakeholder Engagement

To help inform the second white paper, the IESO released a draft set of options in December 2019 for stakeholder feedback [3]. As part of this engagement, the IESO sought feedback on whether the options identified would enhance participation in the IAMs and on any additional challenges that should be considered when evaluating the potential impacts of these options.

Stakeholders confirmed that the draft set of options would enhance DER participation in the IAMs and supported exploring them further in the second white paper. Stakeholders also brought forward the need both to consider potential negative impacts to distributors and the distribution system that could occur from increased DER participation in the IAMs, and the importance of better understanding the scale of DER market participation that could occur if these options were implemented. Stakeholders were aligned on the need to ensure that the integration of DERs into wholesale markets results in a net benefit for electricity customers and ratepayers.

1.2 Structure of this White Paper

To better understand how various options could allow existing resources to participate in the IAMs once the terms of their contracts expire, section 2 of this paper begins with an assessment of DERs currently under contract to the IESO. This assessment includes information on the size and type of existing resources and their ability to participate under the IESO's existing market rules. The section concludes with commentary on the likelihood of these resources participating in the IAMs given alternative opportunities and considerations. The IESO understands that existing contracted resources represent a subset of the current and future potential DERs that could elect to participate in the IAMs if options to enhance their participation were implemented. As such, this paper will also identify opportunities for further analysis to explore issues that are outside its current scope, such as the scale of DERs that could be deployed in the future.

Following the assessment of existing contracted DERs, this paper will explore the options supported by stakeholders in December 2019:

1. Reducing the minimum-size threshold
2. Clarifying existing rules for aggregations
3. Modifying aggregation boundaries
4. Modifying aggregation compositions
5. Creating a participation model for aggregated non-dispatchable generation
6. Permitting alternative forms of telemetry
7. Identifying bulk system hosting capacity
8. Enhancing transmission-distribution interoperability

For each of the options explored, potential impacts and key considerations will be examined. Informed by the principles for DER integration identified in the first white paper of this series,[1] this paper will examine each option from the perspective of:

- Increasing the visibility of distribution-connected resources
- Enhancing competition in the IAMs
- Maintaining bulk system reliability
- Impacts to the distribution system and distributors
- IESO resources and costs required to implement
- Implementation time frame
- Ongoing administration requirements
- Interdependencies with other IESO initiatives
- Whether there are viable alternatives that can achieve the desired outcome more cost-effectively

Following exploration of the options and potential impacts, this paper will identify a subset of options that merit further consideration by the IESO and stakeholders. This white paper will also identify whether an option needs to be better understood or tested through a pilot project (e.g., to test concepts and better define potential benefits and challenges) or whether further consideration should be paused for the time being. These conclusions are further described in Table 1.

TABLE 1: CONCLUSION CATEGORIES

Merits Further Consideration	Pilot	Does Not Merit Further Consideration at this Time
Explore the implementation of the option in greater detail in future market design work in consultation with stakeholders	Test the feasibility of the option via a pilot project prior to making a decision on whether the option merits further consideration	The option does not merit further consideration at this time based on high-level net benefits or need

The insights and considerations resulting from this work will help inform future market design initiatives, associated tool changes, and stakeholder engagement related to DERs.

1 See [2, p. 15] for details.

2. Ontario-Contracted DER Analysis

2.1 Background

Better understanding the significant subset of DERs that exist today is key to exploring options to enhance DER participation in the IAMs in the future if changes were made to the current market design.

Since 2004, Ontario has made substantial investments in DERs through standard-offer programs, competitive procurements, and conservation incentives.[2] While the majority are under contract to the IESO and do not participate in the IAMs, absent a path for market participation once contracts expire, these resources could cease to operate. In that case, the IESO would lose both their capacity and energy contributions (that is, there would be fewer resources competing to provide capacity and energy in Ontario and electricity prices would be expected to reflect this reduced competition). If these resources continue to operate but do so outside the IAMs (e.g., as a retail-embedded generator or behind-the-meter load displacement), they may still provide energy and capacity that benefit Ontario's electricity system. However, because they would be operating outside of the wholesale markets, they would no longer be visible to or communicate with the IESO, which means that changes in their size, operations or technology could unexpectedly require actions by the IESO to maintain grid reliability (resulting in cost or reliability impacts for ratepayers).

It is important to note that this analysis includes only DERs currently under contract to the IESO. It does not include a forecast of future DERs that could be deployed.[3]

[2] These include the Feed-in Tariff (FIT), microFIT (mFIT), Renewable Energy Supply (RES) (I/II/III), Renewable Energy Standard Offer Program (RESOP), Combined Heat and Power (CHP) (I/II/III), Combined Heat and Power Standard Offer Program (CHPSOP), Hydro-Electric Contracting Initiative (HCI), and the Hydroelectric Standard Offer Program (HESOP).

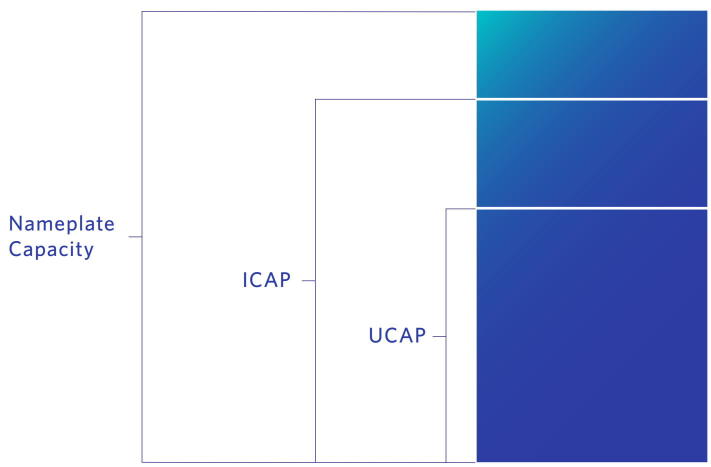
[3] A forecast of future DER deployment in Ontario, while out of scope for this paper, would help determine the potential impacts of the options discussed.

2.2 Nameplate Capacity, Installed Capacity and Unforced Capacity

To provide context to the analysis in this section, it is important to understand the differences between the concepts of nameplate capacity, installed capacity (ICAP) and unforced capacity (UCAP).[4]

- Nameplate capacity is the maximum rated capacity of a resource given ideal conditions
- ICAP is the maximum capacity of a resource taking into account the impact of seasonal and ambient weather conditions on equipment
- UCAP is the capacity expected to actually be provided to the system and includes derates for forced outages and other circumstances outside the operator's control, such as seasonal fuel supply

FIGURE 1: DIFFERENCE BETWEEN NAMEPLATE CAPACITY, ICAP AND UCAP



[4] For details in the context of the IESO's planned capacity auction, see [4, p. 40].

These concepts are important in the context of the IAMs, particularly for determining eligibility to participate and capacity qualification for the capacity auction. While the minimum threshold for participation in the IAMs is currently 1 MW of nameplate capacity, the capacity auction design plans to use 1 MW UCAP-qualified capacity to determine eligibility [4, p. 40]. Using nameplate or ICAP to determine eligibility enables smaller resources to participate though their actual qualified capacity, allowing offers smaller than 1 MW.[5] Using UCAP to determine the minimum threshold for participation would have significant negative implications for the ability of existing DERs, such as solar or wind, to participate in the capacity auction due to higher levels of de-rating that occur between nameplate capacity and UCAP. These derates are attributable to significant seasonal and intra-seasonal variations in fuel supply for these resources.

Resources in capacity auctions are assessed based on UCAP in order to determine how many MW they are permitted to offer into the auction. This approach ensures uniformity of the product being delivered regardless of the resource providing it. Qualified capacity[6] (in units of UCAP) is based on the resource's ability to meet resource adequacy.

Resource adequacy analysis is a way of determining a power system's ability to meet expected demand. In order to determine a resource's contribution to resource adequacy for planning purposes, the IESO probabilistically simulates resources to account for such factors as time-varying energy availability, outages, and locational constraints. As a result, a resource's contribution to resource adequacy may be substantially lower than its nameplate capacity.

As with much of the IESO's reporting on capacity in Ontario, the figures listed in section 2 are stated in terms of nameplate capacity. As discussed above, the nameplate capacity of a resource does not represent either the capacity value its owner could offer into a capacity auction (UCAP), or the capacity the IESO would use to determine that resource's contribution to resource adequacy during system planning. In other words, the capacity value of DERs installed in Ontario is less than the ~ 4,000 MW of nameplate capacity identified.

[5] IESO Market Rules, Chapter 7, section 3.5.6 specify that "the largest quantity in any energy offer or energy bid for any dispatch hour must be at least 1.0 MWh"; see [13].

[6] Qualified capacity means a quantity in megawatts representing the maximum capacity auction offer that a capacity auction participant may provide for an applicable obligation period, and which corresponds to an amount submitted to the IESO by the capacity auction participant for qualification during the pre-qualification period of a relevant capacity auction; see [4, p. 37].

2.3 Population of DERs

Table 2 shows the population of DERs in Ontario accounted for in the IESO's resource adequacy planning, as well as those currently providing services under contract, but not the load-modifying resources connected behind a load customer's meter (see section 2.7). The population of DERs in Table 2 includes IESO-contracted resources, resources that are rate regulated by the Ontario Energy Board (OEB), and resources that are contracted by the Ontario Electricity Financial Corporation (OEFC). The following sub-sections will discuss DER operational parameters, size and other relevant considerations that would impact the ability of these resources to participate in the IAMs post-contract expiry.

TABLE 2: EXISTING OEB-REGULATED, OEFC AND IESO-CONTRACTED DERS BY TECHNOLOGY TYPE[7]

Technology	Number	MW
Bioenergy	76	123.72
Natural gas	31	379.90
Solar[8]	3,182	1,935.76
microFIT solar	30,189	259.61
Storage	16	45.05
Water	136	459.00
Wind	65	590.46
Total	33,695	3,793.50
Total minus mFIT solar	**3,506**	**3,533.89**

[7] Included in these numbers are OEB-regulated resources, OEFC-contracted resources, and merchant generation resources, which will not be included in the following analysis on resources with IESO contracts.

[8] Excludes microFIT solar.

2.3.1 Intermittent Generation

About three quarters (2,786 MW) of existing contracted DERs are solar and wind generators, which generally have limited ability to be fully dispatchable because of their reliance on the sun and wind for fuel. These resources can be dispatchable down (i.e., curtailable) through the use of smart inverters and other control systems (e.g., spilling wind). The participation of intermittent generation in the IAMs would be limited due to this lack of dispatchability, unless flexibility could be added through, for example, the addition of energy storage.

2.3.2 DERs Less Than 1 MW

Some of the resources in Table 2 (2,905 MW) are greater than 1 MW and could theoretically directly participate in the IAMs today. As such, Table 3 focuses on resources that cannot participate directly in the IAMs because they do not meet the 1 MW minimum-size threshold. Table 4 then categorizes these DERs into capacity ranges to describe both the number of resources and the MW within each range.

TABLE 3: EXISTING OEB-REGULATED, OEFC AND IESO-CONTRACTED DERS (< 1MW) BY TECHNOLOGY TYPE

Technology	Number	MW
Bioenergy	51	16.08
Natural gas	3	1.18
Solar[9]	3,036	603.28
microFIT solar	30,189	259.61
Storage	0	0
Water	48	21.14
Wind	11	4.08
Total	**33,338**	**905.38**
Total minus mFIT solar	**3,149**	**645.76**

[9] Excludes mircoFIT solar.

TABLE 4: CLASSIFICATION OF EXISTING CONTRACTED DERS BY CAPACITY RANGE

Capacity Range	Number	MW	% Total < 1 MW
10 kW-1 MW	16,410	778.40	86%
100 kW-1 MW	2,266	593.71	66%
250 kW-1 MW	1,176	428.89	47%
500 kW-1 MW	382	196.66	22%
750 kW-1 MW	10	8.32	0.92%
1+MW	366	2904.88	
Total < 1MW	**33,338**	**905.38**	

As resources smaller than 500 kW comprise the majority of the 905.38 MW of contracted DERs less than 1 MW, the IESO would need to substantially lower the minimum-size threshold in the IAMs to permit their direct participation. For example, lowering the minimum-size threshold to 500 kW would only enable 196.66 MW (~22%) of existing DERs that are less than 1 MW to participate directly; lowering the threshold to 250 kW and 100 kW would enable 428.89 MW and 593.71 MW respectively, or roughly 47% - 66% of existing DERs less than 1 MW. This indicates that unless the minimum-size threshold was lowered significantly (i.e., to 10 kW), most existing DERs would still face barriers to participating in the IAMs once their contracts expire. Additional considerations with regard to reducing the minimum-size threshold are explored in section 3.1. Another potential path to IAM participation for these resources is through aggregation, which is further explored in sections 3.2 through 3.5.

2.3.3 microFIT

Many of Ontario's existing DERs are small-scale solar facilities contracted through the microFIT program. These resources are among the smallest in Ontario today and may face additional challenges to participating in the IAMs relative to other types of DERs. For example, microFIT facilities are often owned by individuals or other entities not familiar with energy markets or the complexities of participation. While these resources make up a relatively small portion of the province's total DER MWs (~260 MW), their capacity is not insignificant.

All resources less than 1 MW (including microFIT) may have opportunities to continue operation after their contracts expire that do not involve direct participation in the IAMs. For example, they could potentially participate in the IAMs as part of an aggregation, provide local value to the distribution system, convert their connection to behind the meter (BTM) and proceed under a net metering agreement with their LDC, or simply continue to operate and receive the Hourly Ontario Energy Price (HOEP) as a retail-embedded generator.

2.4 Contract Expiry Timelines for Existing DERs

The timeline for DERs coming off contract is an additional consideration in IESO decision-making about when and if market design changes would need to be made to enhance DER participation. Most of the existing contracted DERs were acquired over a relatively short period of time, and through standard-offer programs with fixed-length contracts, many of which will expire within similar time frames.

Figures 2 through 7 show when IESO-contracted DERs will come off contract. This analysis will help inform timelines for the options explored in the rest of the paper.

FIGURE 2: IESO-CONTRACTED DER CAPACITY EXPIRING PER YEAR (CUMULATIVE MW)

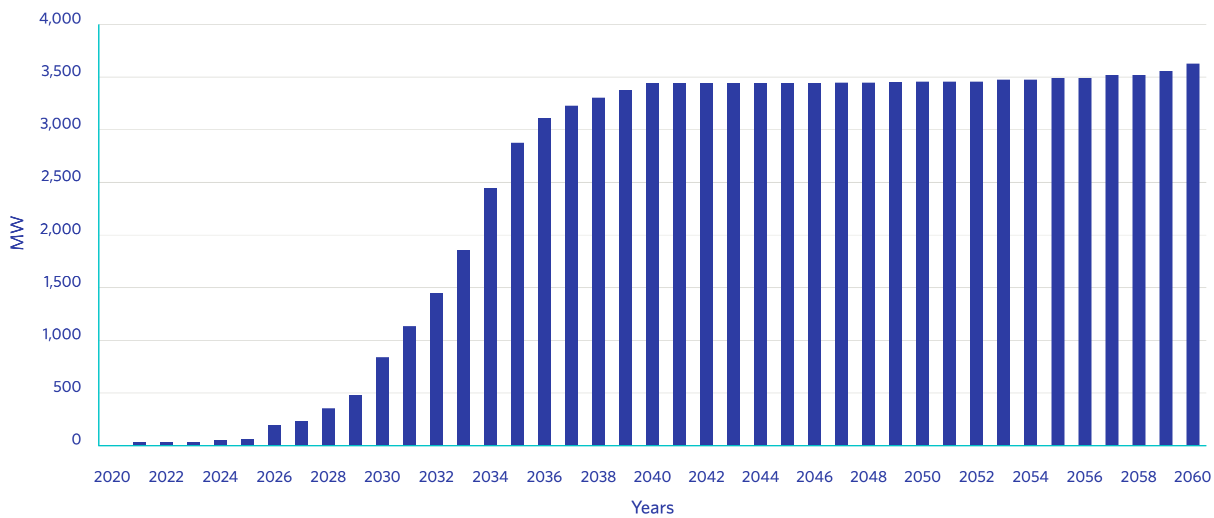


FIGURE 3: IESO-CONTRACTED DERS WITH EXPIRED CONTRACTS PER YEAR (ANNUAL BY NUMBER OF CONTRACTS)

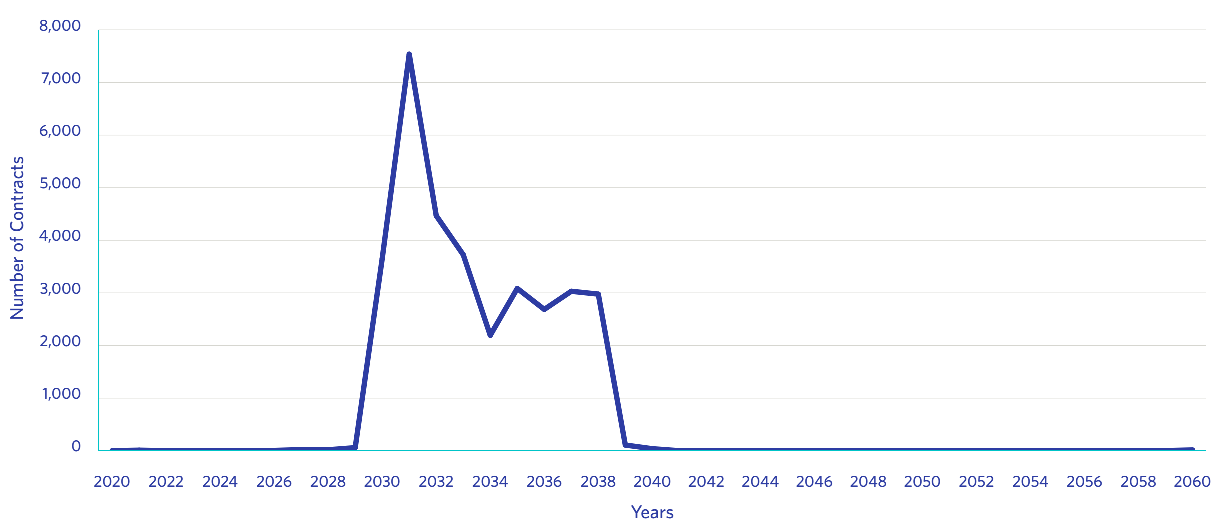


FIGURE 4: IESO-CONTRACTED DERS WITH CAPACITY <1 MW EXPIRING PER YEAR (CUMULATIVE MW)

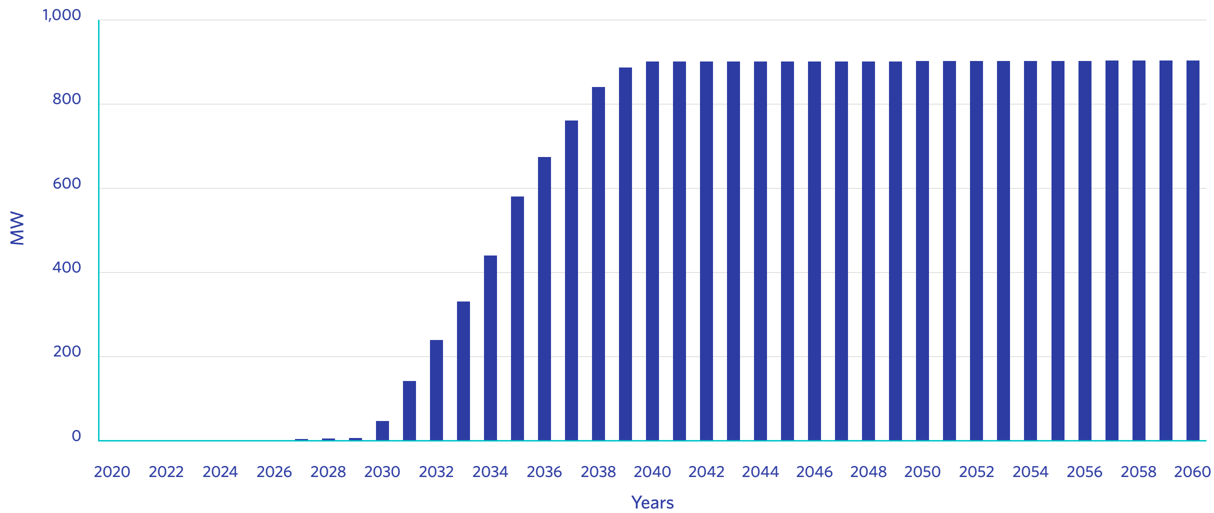


FIGURE 5: IESO-CONTRACTED DERS <1 MW CAPACITY WITH EXPIRED CONTRACTS PER YEAR (ANNUAL BY NUMBER OF CONTRACTS)

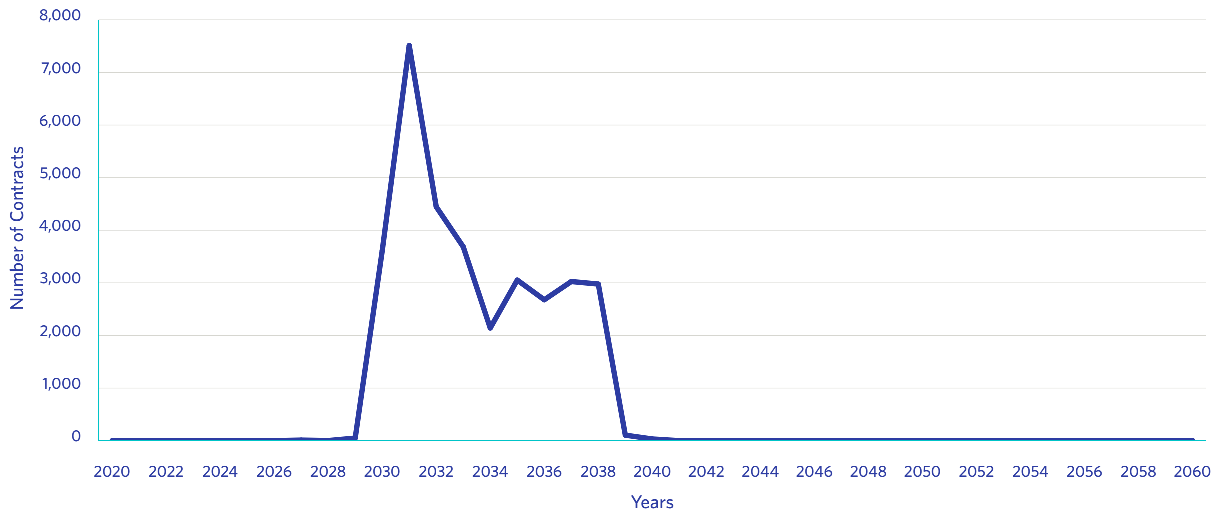


FIGURE 6: IESO-CONTRACTED DERS WITH CAPACITY ≥1 MW EXPIRING PER YEAR (CUMULATIVE MW)

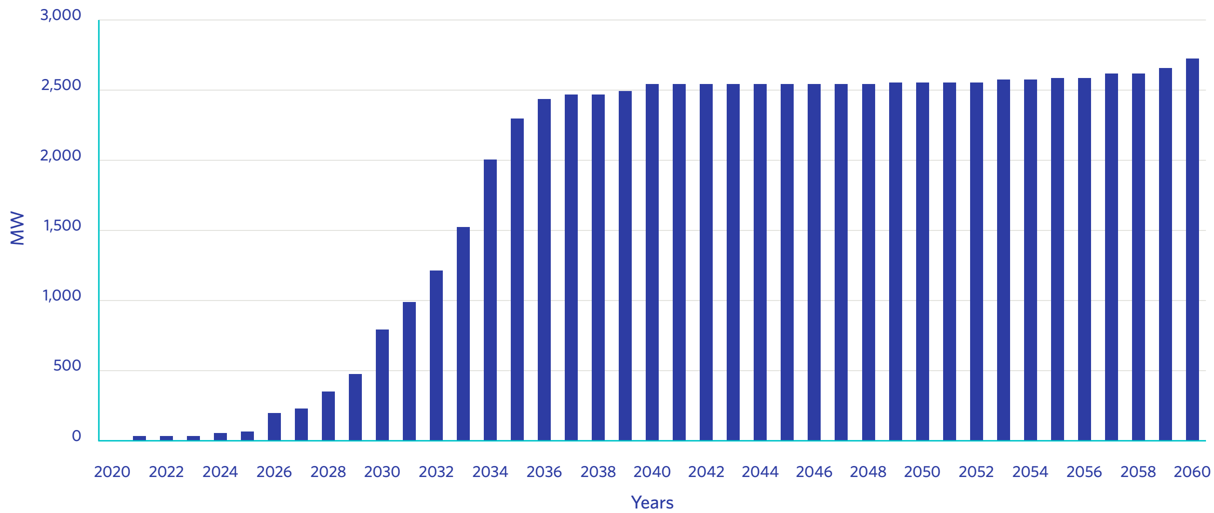
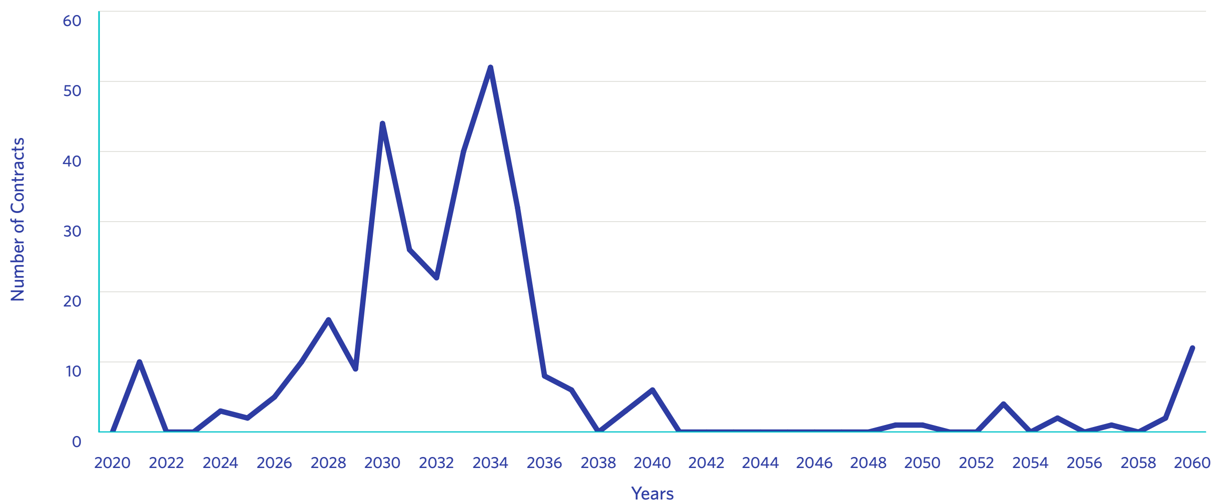


FIGURE 7: IESO-CONTRACTED DERS ≥1 MW CAPACITY WITH EXPIRED CONTRACTS PER YEAR (ANNUAL BY NUMBER OF CONTRACTS)



DERs that are less than 1 MW begin to come off contract in large numbers around 2030, with expirations peaking in 2031 and tapering off after 2040. DERs larger than 1 MW start expiring earlier, in the mid-2020s, but expiries also substantially increase in 2030. These larger resources can potentially already participate directly in the markets if they meet the other requirements; smaller DERs (less than 1 MW) could only participate through a new aggregation model or if the minimum-size threshold was lowered.

Based on the timelines shown in figures 2 through 7, any measures to enable the majority of these resources to transition seamlessly from contract expiry to participation in the IAMs would have to be in place before 2030. The timeline for contract expiries of resources that are less than 1 MW is especially important in making decisions with respect to the minimum-size threshold and enhanced aggregation. The earlier contract expiries for larger DERs represent more MWs and would impact the timing of other options, such as allowing alternative sources of telemetry and enhancing interoperability with distributors.

2.5 Potential to Aggregate Under Existing Market Rules

Estimating the number and type of resources that might choose to aggregate is difficult, given current unknowns, including business models, government programs, equipment-replacement decisions, or owner interest. That said, the maximum number of existing resources that could aggregate under current market rules (i.e., same technology, greater than 1 MW, and connected below a single connection point to the IESO-controlled grid or ICG) can be estimated.

It should be noted that this analysis does not take into account the wide variety of connection types, existing system conditions or limitations that may prevent resources from aggregating. Instead, the intent is to provide a high-level estimate of the maximum number of existing resources that could aggregate to participate in the IAMs in the future under existing rules.

TABLE 5: SAME-TECHNOLOGY IESO-CONTRACTED DERS (<1 MW) CONNECTED TO THE SAME CONNECTION POINT[10]

Technology	Number of Connection Points	Number of Resources	Megawatts
Bioenergy	2	7	2.47
Gas	0	0	0.00
Solar	222	27,661	790.56
Wind	0	0	0.00
Storage	0	0	0.00
Water	6	24	11.48
Total			**804.51**

[10] Connection information is unavailable for some small resources.

This analysis shows the theoretical potential for bioenergy, solar, and water facilities less than 1 MW to aggregate to meet the 1 MW participation threshold. Solar resources, which comprise the majority of DERs under the minimum-size threshold, have significant potential (~800 MW) to aggregate under most existing rules, though absent a participation model for non-dispatchable aggregated resources (section 3.5), or participation models for hybrid resources or mixed aggregations, this potential may be lost.

Total aggregation potential could increase if resources below and above the minimum-size threshold were to aggregate at the same connection point.

TABLE 6: SAME-TECHNOLOGY IESO-CONTRACTED DERS (TOTAL) CONNECTED TO THE SAME CONNECTION POINT[11]

Technology	Number of Connection Points	Number of Resources	Megawatts
Bioenergy	4	12	13.57
Gas	6	14	179.66
Solar	230	28,151	2,120.23
Wind	13	38	356.53
Storage	0	0	0.00
Water	22	79	224.78
Total			**2,894.77**

This analysis shows the broader potential for DERs of the same technology to aggregate at their current upstream connection point if those aggregations are formed with resources that are both smaller and larger than the current minimum-size threshold.

[11] Connection information is unavailable for some small resources.

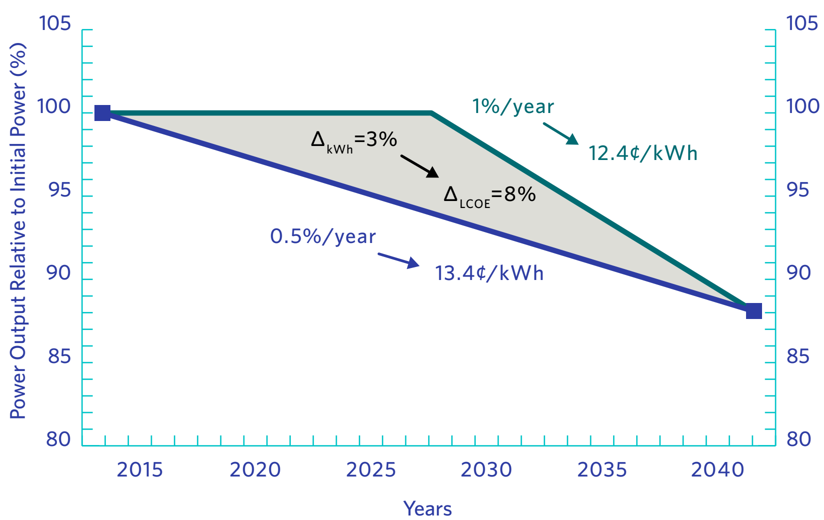
2.6 Useful Life After Contract

Estimating both the useful life of the equipment and the costs of continuing to operate DERs could help determine the potential for these resources to continue to operate after their contracts expire. For example, a resource that has useful life remaining post-contract expiry, and can recover its operating costs by participating in the IAMs or through other revenue streams (e.g., non-wires, LDC RFPs, customer services), could be expected to continue operating. Conversely, a resource that would incur significant capital costs in replacing equipment or that could not recoup its operating costs, would not reasonably be expected to continue operating.

2.6.1 Equipment

Solar panels generally have a degradation rate of about 0.5%/year[12] and are typically under warranty for 20-25 years, a period similar to the term for existing IESO contracts for DERs. Though warranties may expire around the end of the contract, many panels installed before the standard-offer programs are still in service today and would likely have significant useful life after the contracts expire. Research from the U.S. National Renewable Energy Laboratory (NREL) suggests average power output will remain at approximately 90% by the time the contracts expire and the actual useful life of photovoltaics to be between 25 and 40 years [5].

FIGURE 8: INDICATIVE AND AVERAGE SOLAR PANEL POWER OUTPUT DEGRADATION OVER TIME [5]



[12] Indicative degradation starts very low and then increases after approximately 12 years, meaning the efficiency of these panels will decrease more rapidly near the end of the contract and beyond [76].

Inverters generally have shorter life spans (closer to 10 years) than the panels, resulting in more costs for the resource to continue operating. This also means the inverter is likely to be replaced during the useful life of the resource, offering an opportunity to install newer smart inverters that may offer additional controllability and higher granularity and frequency of data transmission that could be leveraged by the resource owner, LDCs and the IESO.

NREL estimates the useful life of wind-turbine equipment to be 20 years, which aligns with the length of the majority of current IESO contracts for DERs [5]. This means that unless the majority of components are replaced when contracts expire – at a cost similar to the price of new resources – wind turbines would be less likely to continue operating. That said, the significant cost and challenges in siting and support infrastructure for wind resources may present an opportunity for these sites to be overhauled and continue operating.

As hydro power resources have the longest lifespans and contracts (generally 40 years), they are less likely to be the determining factor in making changes to enable participation of DERs in the IAMs. It should be noted, however, that ongoing operations and maintenance (O&M) costs can be substantial for smaller hydro resources [6].

Natural gas resources are more difficult to assess in this way. The variety of configurations, operating patterns, and economics based on fuel price make it more challenging to determine their behaviour post-contract though generally the effective useful life of most natural gas plants is approximately 20 years. After their contracts expire, these resources may still have useful life or be able to extend their useful life, but estimating this potential and its implications on participation goes beyond this high-level exercise.

2.6.2 Operations and Maintenance Costs

TABLE 7: 2019 O&M COST RANGES FOR SOLAR, WIND AND NATURAL GAS [7]

Technology	Fixed O&M (US$/kW-year)	Variable O&M (US$/MWh)
Solar rooftop (residential)	$14 - $25	–
Solar rooftop (C&I)	$15 - $20	–
Solar (utility scale)	$9 - $12	–
Wind (onshore)	$28 - $36.50	–
Natural gas (peaking)	$5 - $20.75	$4.75 - $6.25
Natural gas (CC)	$11 - $13.50	$3 - $3.75

As shown in Table 7, O&M costs vary dramatically by technology and size, with average solar O&M ranging from US$15 – $20/kW-year in 2019 – though this range is broader for the size of projects discussed in this paper (less than 1 MW). Wind O&M was higher at an average of US$32/kW-year, but the substantial capital costs for refurbishment of wind resources at end of contract may outweigh the O&M in decision-making.

Hydropower O&M also varies greatly by size and age of the facility. A 2017 hydropower report prepared for the U.S. Department of Energy indicated that hydropower facilities under 10 MW averaged US$113/kW-year [6, p. 58], though the DER hydropower resources used in the study population were significantly older than those in Ontario.

For natural gas resources, fixed O&M costs were generally in the US$5 – $20/kW-year range, depending on the size and configuration with variable O&M costs in the US$5/kW-year range. Biomass resource costs tended to be considerably higher, with fixed O&M near the US$110/kW-year mark and variable O&M around US$4/kW-year [8, p. 7].

2.7 Load-Modifying Resources

Ontario has an estimated 400 MW of behind-the-meter storage [86], more than 23 MW of net metering, and 67 MW of behind-the-meter gas generation for load displacement through past conservation and demand management (CDM) programs. CDM programs have also supported the installation of thousands of building automation and control systems throughout Ontario that are capable of modifying the loads of the buildings they serve, but do not currently participate in the IAMs.

Demand-response resources (~600 – 700 MW of which are distribution system-connected in Ontario) are generally connected to the distribution system, but many of these are aggregated and participating as Hourly Demand Response (HDR). As these aggregations can change over time, the IESO only has visibility into where they are modelled at one point in the delivery zone, rather than their actual location or where they deliver to the bulk system.

These resources currently enable customers to reduce their load and avoid energy costs and are generally sized to provide part or all of the load capacity. Some of these resources currently participate in the markets as demand response receiving additional capacity payments, but their future potential to participate is difficult to determine considering their size relative to their load and operation given current rules and incentives.

2.8 Conclusion

From a total of 3,765 MW of DERs under contract, 905 MW are less than 1 MW. Of these, 96% (867 MW) are intermittent and unlikely to be dispatchable, though there is potential for some controllability if smart inverters replace existing inverters at end of life, or energy storage is added.

Most microFIT installations are solar and ~200 MW are on roofs, meaning these could be used to net-meter and avoid residential rates rather than participating in the IAMs directly or as part of an aggregation. If feasible, the smaller ground-mount microFIT resources (~60 MW), or other small-scale DERs could also be moved or configured behind a load meter.

Solar resources likely have significant potential to continue operating post contract, though their ability to be dispatchable may be limited. Creating a participation model for aggregated non-dispatchable generation may enable continued operation of these resources (~800 MW). Based on their useful life and the significant costs for refurbishment, the potential to operate wind facilities after their contracts expire appears limited.

Current market rules for aggregations mean the potential to aggregate existing resources is low based on the diversity of technology types and location of existing resources. Changing the permitted aggregation boundaries and compositions could expand participation of existing resources, but the extent would depend on modelling the impacts of multiple connection points and diversified compositions.

3. Options

Section 3 of this paper will explore the following options to enhance DER participation in the IAMs:

1. Reducing the minimum-size threshold
2. Clarifying existing rules for aggregations
3. Modifying aggregation boundaries
4. Modifying aggregation compositions
5. Creating a participation model for aggregated non-dispatchable generation
6. Permitting alternative forms of telemetry
7. Identifying bulk system hosting capacity
8. Enhancing transmission-distribution interoperability

3.1 Reducing the Minimum-Size Threshold

3.1.1 Background

The minimum-size threshold determines the smallest nameplate capacity of a resource that is permitted to participate in any of the IESO-administered markets (IAMs) and also applies to the minimum initial offer/bid quantity submitted into the markets. Resources that are smaller than 1 MW,[13] cannot participate directly in the IAMs, but may be permitted to aggregate with other resources to meet the threshold.[14]

As discussed in section 2 of this paper, the nameplate capacity is not the amount of energy that will be delivered to the system in real-time or the amount of capacity that can be relied upon for the purposes of resource adequacy – rather it is the manufacturer's rated maximum potential output of the resource.

[13] The 1 MW minimum-size threshold applies to real-time markets for energy and all forms of OR, as well as procurement markets for ancillary services and is proposed for any future procurement markets for capacity.

[14] Other restrictions limit the ability to aggregate resources (e.g., resources must be hourly demand response, or the same technology, dispatchable, and connected to a single connection point to the IESO-controlled grid).

Minimum-size thresholds are generally established to strike a balance between a number of factors, including the potential for resources to impact the system, the likelihood of resources to participate in the IAMs, and the complexities associated with administering their participation. For example, the IESO requires that generators and loads above 10 MW register and participate in the IAMs in order to provide visibility into their size, technology, and real-time operations. Participation in the IAMs is optional for resources between 1 MW and 10 MW; that said, the IESO may require resources between 5 MW and 10 MW to provide operational data for monitoring and forecasting purposes.[15] Market participation (and the associated provision of operational data) is mandated for larger resources, because it gives the IESO more visibility and certainty in monitoring and scheduling resources to balance electricity supply with demand in real-time. While having visibility and some measure of control over all resources on the system, regardless of size, would be ideal, the IESO must consider the capabilities of tools and systems to accommodate smaller resources. These tools must be able to account for a resource's operating constraints and associated data streams, while still being able to conduct and optimize modelling, scheduling and dispatch of all resources in the amount of time required to operate the day-ahead and real-time markets.

Further, historically, the participation of DERs in the wholesale market was not considered feasible for several reasons:

- The lower technical maturity and higher costs/MW of DERs relative to centralized resources
- The costs and complexity of market participation for small resources
- The uncertainty about whether integrating small resources (less than 1 MW) would result in net system benefits

However, improved capabilities, declining costs, and the emergence of new business and finance models have led other independent system operators/regional transmission organizations (ISO/RTOs) to review and reconsider their established minimum-size thresholds.

One of the main factors driving this focus in the United States to date has been the Federal Energy Regulatory Commission (FERC)'s Order 841 [9], which requires all FERC-jurisdictional ISOs/RTOs[16] to develop a participation model for energy storage resources that includes a minimum-size threshold of 100 kW. FERC has now also issued Order 2222, requiring ISO/RTOs to develop participation models for aggregated DERs that include a minimum-size threshold of 100 kW [3, p. 9].

While lowering the minimum-size threshold is the most direct pathway to enhancing DER participation in the IAMs, system operators responding to FERC Order 841 pointed out that other barriers identified during the FERC proceeding would also need to be addressed to achieve this objective [11]. These include the high costs of adhering to telemetry requirements, the complexities of co-ordination between ISOs and distribution utilities, and the requirements to upgrade ISO/RTO dispatch systems and software – all of which can impede the participation of DERs in wholesale markets.

[15] The IESO also requires a System Impact Assessment (SIA) for any embedded generation facility larger than 10 MW.

[16] These include: California ISO (CAISO), ISO-New England (ISO-NE), Midcontinent ISO (MISO), the New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP). The IESO is not under FERC jurisdiction.

3.1.2 Overview of the Option

The first option under consideration to enhance DER participation in the IAMs is a reduction in the minimum-size threshold from 1 MW to a lower amount (e.g., 500 kW or 100 kW). It should be noted that this paper is not focused on determining the "right" size threshold, but instead on exploring the potential impacts associated with a reduction.

3.1.2.1 Consideration of a Phased Approach to Reducing the Minimum-Size Threshold

Should the IESO decide to reduce the minimum-size threshold, a phased approach to implementation could allow time to monitor and respond to expected challenges. This could involve:

- Permitting a limited number of resources below 1 MW to participate in the IAMs and increasing that limit annually[17]
- Applying a lower threshold to specific market products (e.g., energy only and not OR[18] or capacity), rather than a full-scale reduction for all resources in all markets

Implementing a phased approach to reducing the minimum-size threshold could enable smaller resources to participate, while helping the IESO ensure its systems and processes are capable of incorporating greater volumes of resources and their constituent operating constraints.

A phased approach would also allow the IESO to assess the performance of smaller resources in the market (e.g., to determine the degree to which specific weather conditions, locations or distribution system events would reduce their reliability), and develop options and market rule changes that may be required to enhance performance requirements or provide system operators with more confidence. At a more fundamental level, a phased approach would also allow the IESO to evaluate the extent to which smaller resources were capable of or even willing to participate in the IAMs. Limiting the initial participation of smaller resources would also allow for a structured review of other market rules and requirements that might be acting as barriers to these resources, while providing real-world examples and applications to use as test cases.

3.1.3 Potential Impacts to Visibility, Competition, Reliability, and Distributors

Reducing the minimum-size threshold would enable the IESO to maintain visibility into existing contracted resources below 1 MW,[19] while gaining new visibility into resources below 1 MW that may become market participants in the future.

3.1.3.1 Existing Contracted Resources

As discussed in section 2, the IESO currently administers contracts for a large number of DERs through a variety of programs. Table 8 shows the type, number and capacity of DERs currently under contract to the IESO that could potentially participate directly in the IAMs post-contract expiry, provided the minimum-size threshold was lowered. Contracts for the majority of these resources are expected to expire between 2030 and 2035.

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[17] This could involve a phased reduction of the minimum-size threshold (for example, from 1 MW to 500 kW), and/or limiting the number of sub-MW resources to participate each year, with the limit being reviewed and potentially increased annually.

[18] Providing OR requires that a market participant also participate in the energy market as these two markets are co-optimized. A market participant can only offer OR up to its energy market offer.

[19] This would be bolstered if the IESO were also to lower the threshold to reflect the reduction in the minimum-size threshold for market participation.

TABLE 8: CONTRACTED DERS VS POTENTIAL MINIMUM-SIZE THRESHOLDS

Capacity Range	Number	MW	% Total < 1 MW
10 kW-1 MW	16,410	778	86
100 kW-1 MW	2,266	594	66
250 kW-1 MW	1,176	429	47
500 kW-1 MW	382	197	22
750 kW-1 MW	10	8	0.92
1+MW	350	2,859	
Total < 1MW	**33,338**	**905**	

Under current DER contracts, the IESO is privy to static information, including a resource's physical location, connection point, technology, capacity, ownership, monthly production data (in limited cases) and auditing rights. However, since these DERs are not market participants, the IESO does not have direct visibility into how they operate in real-time or near real-time. When these contracts expire, the IESO will lose the ability to directly track whether these resources are still active, and may have to make assumptions about their continued operation. The IESO has accounted for these embedded DERs as reductions to transmission-level demand (this is the IESO's standard process for assessing the impact of embedded resources that are not market participants). If these resources were able, and elected, to participate in the IAMs following the expiry of their contracts, the IESO would maintain the current level of static information and could capture new real-time operating data. Increasing visibility has the potential to allow more accurate forecasting and dispatching, which can lower market prices.

Reducing the minimum-size threshold and encouraging smaller resources to participate in the IAMs is not the only way to increase visibility of resources less than 1 MW. Robust reporting requirements could be introduced for LDCs to report DER connections (and constituent static data, including technology, capacity, behind-the-meter status, and eventually operational data) to the IESO on a regular basis. These could also include a requirement for customers to report DER connections to their LDC, even when these are behind the meter and customers do not intend to inject energy into the distribution system.

3.1.3.2 New Resources

The opportunity to participate in the IAMs may encourage smaller DERs that would otherwise have gone behind the meter to become market participants, providing the IESO with operational data as a condition of participation.

A reduction in the minimum-size threshold would offer resources smaller than 1 MW an avenue for direct participation in the IAMs (i.e., as a single resource connected to a single connection point on the distribution system). Reducing the threshold would also simplify the process of aggregating resources by allowing aggregators to meet the threshold with fewer or smaller contributor resources. Both of these outcomes would enhance competition by increasing the number of resources and market participants within the IAMs.

While it is difficult to determine if this threshold reduction would have a significant impact on wholesale market prices, experience has shown that enhancing competition creates downward pressure on prices. Flexibility benefits are another outcome of diversifying the mix of market participant resources. That said, most resources smaller than 1 MW that could be available to participate in the IAMs once their contracts expire are intermittent generators. While these resources could offer energy and some capacity, they would not be able to provide the full range of market products (e.g., OR or ancillary services) absent the addition of new equipment, such as energy storage or smart inverters.

Benefits to competition from this option would depend, in part, on whether alternative opportunities for DERs are relatively more lucrative than market participation. These alternatives can include currently available net metering (or future adaptations, including virtual net metering),[20] or the use of advanced rate designs (such as those being piloted by the Ontario Energy Board and LDCs under the Regulated Price Plan Pilots[21]) that can draw DER development behind customer meters.

Bulk system reliability may be enhanced by greater market participation and visibility associated with a reduction in the minimum-size threshold. Conversely, bulk system reliability could be compromised if (1) DERs cannot be assessed and modelled to appropriately predict system responses and (2) the IESO's dispatch and scheduling optimization (DSO) tool cannot adequately process the volume of information associated with the increase in DERs. More details on potential impacts to the DSO are discussed in section 3.1.4.

3.1.4 Implementation Considerations

The IESO uses a number of systems and tools, including the DSO, to operate the wholesale electricity markets. The DSO uses specialized software to determine the optimal (reliable and lowest cost) schedule for the dispatch of resources – subject to resource and grid constraints. Through the DSO, the energy and OR markets are co-optimized. In order to optimize the dispatch schedule, the DSO incorporates offers from generators, bids from loads (and forecasts for non-market participant loads), as well as the constituent operating constraints of the resources themselves (e.g., ramp rates, run-times). If resources smaller than 1 MW were able to participate in the market, the volume of data from these parameters alone may increase dramatically, overwhelming the processing capabilities of the DSO, and disrupting dispatch efficiency and even bulk system reliability. This is the most material concern related to the implementation of this option.

[20] The provincial net-metering regulatory framework allows customers to use the electricity they generate from renewable energy (with or without energy storage) to offset their consumption, and receive credits on their electricity bill for the electricity they provide to the system; see [59].

[21] For details, see the OEB's Regulated Price Plan (RPP) Roadmap consultation [61] and list of rate pilots [60].

If smaller resources were permitted to make bids and offers in the energy market, the minimum bid/offer increment may also need to be reduced to account for their likely levels of output. Currently, IESO tools allow for bid/offer increments of 0.1 MW (100 kW). A 100-kW market participant, however, may expect to be able to submit price/quantity pairs in 10 kW increments – which, in adding data volume, significantly increases processing requirements for the DSO.

These increased operational requirements would likely require the IESO to upgrade the DSO to ensure it can perform scheduling and dispatch functions, including multi-interval optimization,[22] within established time limits (three minutes). The IESO is planning to upgrade the DSO platform as part of its Market Renewal Program (MRP), potentially minimizing the incremental costs and efforts required to implement this option. However, the DSO will require extensive testing to confirm this capability, and may require software and hardware upgrades beyond the scope of MRP, which could result in significant costs and delay implementation.

Even if initial assessments indicate the IESO's upgraded tools could accommodate a reduced minimum-size threshold, there are lessons to be learned from other jurisdictions. The New York Independent System Operator (NYISO), for example, is undertaking a significant upgrade to its Energy Management System/Business Management System – the platform for its market software. In conjunction with its technology vendors, the NYISO has discovered that the complexities associated with evolving market designs (e.g., energy storage and DER aggregation participation models) and a changing resource mix (i.e., larger numbers of DER and DER aggregations) will mean that market optimization for the day-ahead and real time markets cannot be conducted within existing time frames [12].

Consequently, the NYISO has initiated a project to study options for enhancing solutions to improve market efficiency, including data processing methods that result in shorter processing times. As the level of DERs and DER aggregations participating in the wholesale market increases, all ISO/RTOs – not just the NYISO – will likely need to assess whether they require computing/software enhancements to maintain market clearing time frames within an acceptable limit. The NYISO's experience reinforces the benefits of considering a phased approach to reducing the minimum-size threshold, if a reduction is pursued.

Owing to a much higher volume of market participants as a result of this option, the IESO would likely need incremental staffing resources to assess new connections, as well as register and integrate these DERs into the new systems and tools (including verifying telemetry and building supervisory control and data acquisition (SCADA) displays). Providing the customer support required to integrate these resources, and connect with owners who are likely less familiar with the IAMs and their requirements, would also require a major investment.

[22] Multi-interval optimization is a feature of the DSO software used to determine optimal dispatch schedules by looking ahead a number of intervals, rather than just a single interval.

3.1.5 Conclusion

3.1.5.1 Reducing the Minimum-Size Threshold

Reducing the minimum-size threshold for all market participant resources is the fastest approach to removing barriers to market participation for smaller-scale DERs. However, an abrupt reduction applicable to all resource types will increase the volume of market participants, risking an unmanageable administrative and technical burden on the IESO. This includes both requests to register and connect, associated modelling of resources, as well as the potential negative impacts on resource dispatching software, which must be able to solve dispatch algorithms in the required time frame for the efficient and reliable operation of the real-time energy markets. These issues are currently being experienced in New York as a result of the NYISO's decision to lower the minimum-size threshold for market participation. To avoid a similar situation in Ontario, this white paper does not recommend considering a full-scale reduction in the minimum-size threshold at this time.

Conclusion ⟶ Does not merit further consideration at this time

3.1.5.2 Reducing the Minimum-Size Threshold – Phased Approach

A phased approach to reducing the minimum-size threshold has several benefits over a complete reduction. This approach mitigates the risk of overwhelming the IESO's market registration processes, and allows the IESO to slowly increase the volume of resources being managed by the DSO – acting essentially as a pilot for a full-scale reduction – in order to assess and mitigate potential risks. As such, this option also allows the IESO to gauge the level of interest of resources less than 1 MW to participate in the wholesale markets and address unforeseen technical or rule-based issues as they arise. With this in mind, a measured and phased approach to reducing the minimum-size threshold merits further consideration.

Conclusion ⟶ Merits further consideration

3.2 Clarifying Existing Aggregation Rules and Processes

3.2.1 Background

Resources that are unable or choose not to participate directly in the wholesale markets may be able to participate as an aggregated resource. Currently, the IESO Market Rules permit three types of aggregations:[23]

- Aggregations of dispatchable generation at a single transmission-distribution (T-D) node[24] (this includes compliance aggregations, referred to as consolidated resources[25] in Part 1 of this white paper)
- Aggregations of dispatchable load at a single T-D node
- Aggregations of non-dispatchable load within a transmission zone[26] (i.e., HDR), which is generally the only type of aggregation currently participating in the IAMs

The market rules for HDR are specific to that resource type and generally exist separately from those for other resource types.[27] Further, these rules already contemplate their application to DERs due to the distributed nature of most HDR contributor resources. As such, the focus of this section will be limited to the potential to clarify rules for aggregations of dispatchable generation and load at a single T-D node, as described in Chapter 7 section 2.3.2 of the Market Rules [13].

As market rules for aggregations of dispatchable generation and load at a single T-D node were written for larger transmission-connected resources, their application to aggregations of DERs is unclear with respect to identifying:

- The connection point to the ICG
- Factors that cause a proposed aggregation to compromise reliability (and be rejected by the IESO as a result)

In the absence of more significant changes to existing rules or processes, clarifying requirements and improving information-sharing along the lines described could be a relatively low-cost option for enhancing DER participation.

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[23] The market products aggregated resources are able to provide are discussed in Chapter 7 of Part 1 of this white paper series; see [2].

[24] A node is a single electrical connection point to the transmission system (the IESO-controlled grid or ICG).

[25] Consolidated resources consist of multiple facilities (whose operations are often interdependent) with the same owner, connected to the transmission system or distribution system at the same point or immediately adjacent points, such that they can be represented electrically as being connected to the same point.

[26] A zone is a defined area bounded by multiple points on the ICG. Specifically referenced are the 10 transmission zones the IESO defines for planning purposes [62].

[27] HDR resources aggregate for the limited purpose of submitting bids and are not settled by the energy market – an important distinction that separates this participation model from other aggregation models.

3.2.2 Overview of Option

3.2.2.1 Facilities, Connection Points & Switching Devices

The IESO's current rules for aggregations of dispatchable generation and load are intended for situations where multiple larger resources are connected to the same connection point to the transmission system. Examples include a single generation facility with multiple generation units, or multiple resources that are interdependent, such as co-generation or multiple run-of-river hydropower facilities that must operate in tandem due to water flow restrictions. Identifying the connection point to the ICG for facilities of this nature is relatively straightforward. Figure 9 shows a facility with two transformers that are not connected on the low-voltage side. The squares represent breakers (or some other switching device). In this example X could be a generator, directly connected load (e.g., large factory), or a distribution system. As mentioned, identifying the connection point for X is fairly straightforward: it is simply the upstream transformer. Anything aggregated below this point would then also, in theory, be straightforward (unless it was a distribution system that also connected to other transformers/connection points to the ICG).

FIGURE 9: SIMPLE EXAMPLE OF A TRANSMISSION-DISTRIBUTION INTERFACE

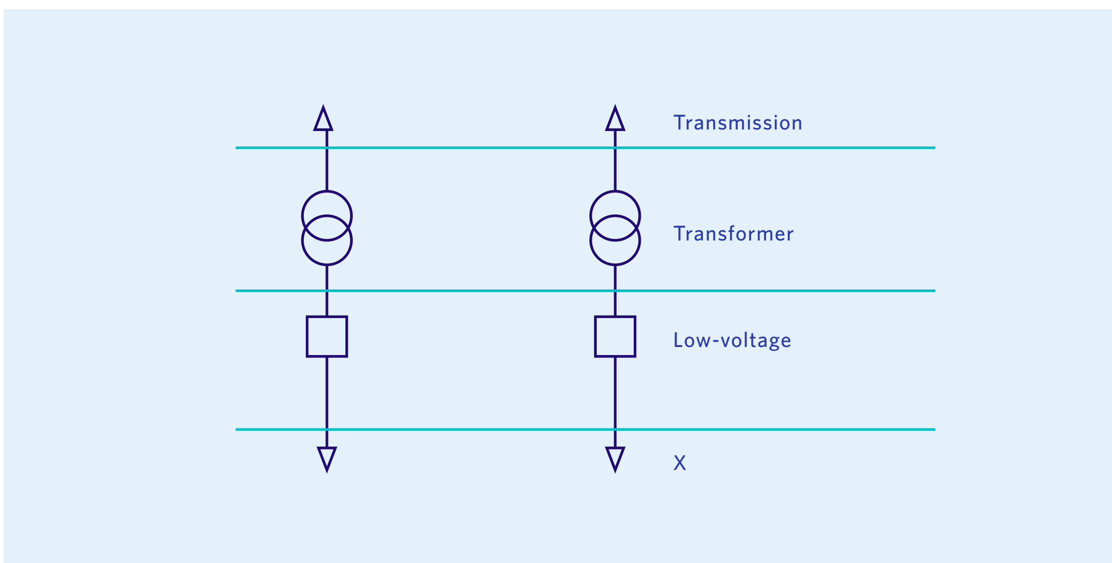
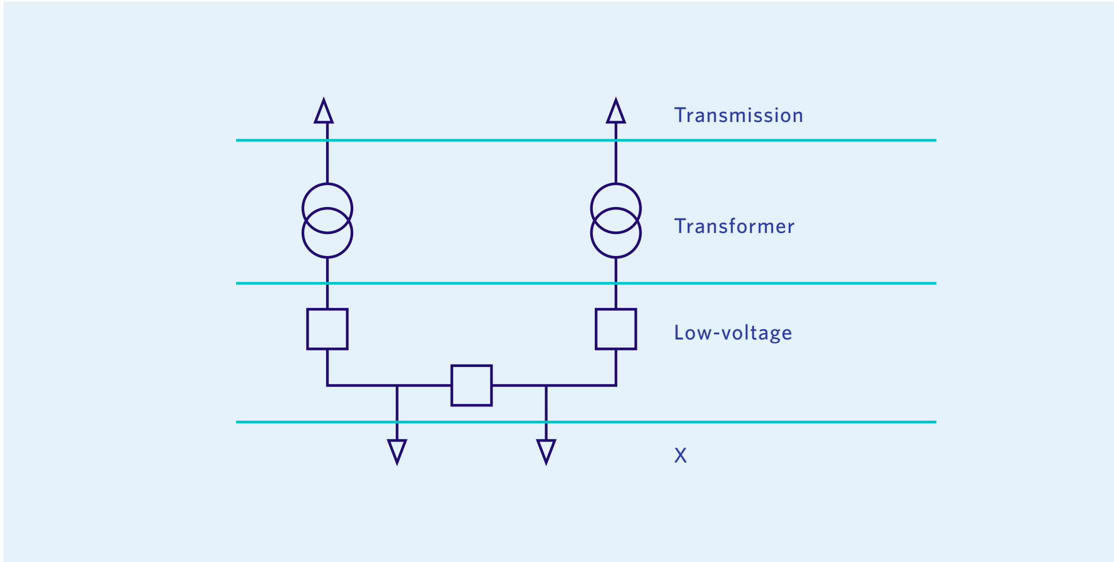


FIGURE 10: INTERMEDIATE EXAMPLE OF A TRANSMISSION-DISTRIBUTION INTERFACE



Now consider Figure 10, where two transformers are connected on the low-voltage side within the facility. In this case, the connection point to the ICG is less clear. For example, the connection point could change depending on whether the middle breaker was open or closed. Unfortunately, even equipment that shares a single bus poses challenges for aggregation. These pieces of equipment can have different characteristics that cannot be captured by current IESO models and that cause them to respond to system events differently. While the IESO has, in the past, approved aggregations in facilities similar to both figures, the challenges that result from planning and operating such resources poses a risk to the ICG. Due to the unique properties represented by each facility, each case generally has to be assessed individually based on potential impacts to grid reliability (which are discussed further in section 3.2.2.2).

To address this barrier, the IESO could provide clarity with respect to identifying:

- Where a DER clearly has a single connection point to the ICG
- The connection point to the ICG for DERs when an aggregation consists of contributor resources connected:
  - Downstream of a transformer station with multiple connections to the ICG
  - To a distribution network that is served by more than one T-D node
  - To a distribution network that can be served by more than one T-D node if/when the configuration of that distribution network is subject to change (i.e., when the connection point can be dynamic)

3.2.2.2 Factors Causing a Proposed Aggregation to Compromise Reliability

Chapter 4, section 2.1.5 of the Market Rules states that each new or modified connection, including both individual resources and aggregations, is required to undergo its own connection assessment. These assessments often take several months to complete because of the variety of connections and potential impacts to the system. In addition to the physical assets, reliability assessments take into account how the IESO models these assets to operate the system.

The processes for registering and approving aggregations were also designed for relatively smaller numbers of large resources and require significant modelling to ensure reliability would not be compromised. This means that while aggregations of dispatchable DER generation and load can be proposed to the IESO, the process for analyzing and approving the aggregation is time- and resource-intensive. These applications may also be denied for a number of reasons, including, for example, when contributor resources have different speeds of response,[28] or the IESO has reason to believe the aggregation would be physically incapable of following dispatch instructions.

In general, market rules, manuals and supporting information on the IESO website fail to clarify the reasons a proposed DER aggregation could or would be denied, creating inefficiencies for both potential market participants (which could propose aggregations that would be rejected due to reliability concerns), and for the IESO (which would be required to review those proposed aggregations, only to reject them).

To address this challenge, the IESO could identify the circumstances under which an aggregation would be more or less likely to be approved, enabling potential market participants to propose aggregations with a higher likelihood of approval. For example, the IESO could:

- Identify T-D nodes that would be higher risk (e.g., instability, approaching thermal limits) and lower risk (e.g., not near thermal limits, stability unlikely to be affected) to connect
- Communicate to potential market participants the considerations evaluated when approving an aggregation
- Determine and communicate the characteristics of aggregations that generally pose a low risk to reliability (i.e., have a higher chance of being approved)

3.2.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

One of the barriers to entry for smaller resources is the level of sophistication, time and effort required to navigate participation in the wholesale markets. Identifying and communicating the factors considered in approving an aggregation and the areas that are more or less likely to impact system conditions negatively, as well as connecting regional planning results to clear mapping of the transmission system edge, would allow potential market participants to propose aggregations that help meet system needs without exacerbating problems. Receiving applications for aggregations that are less likely to adversely impact reliability could increase the volume of new aggregated resources and the speed with which they could come online.

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[28] Two types of engineering data are used to assess reliability: steady-state and dynamic. The former is somewhat amenable to being aggregated, but the latter is not. For example, an aggregation's output can be said to be 15 MW when it is composed of a 10 MW and 5 MW device. However, when one device's response speed is 50 msec and another's is 100 msec, it is not possible to say the aggregate speed of response is 75 msec, or any other value.

With the significant existing penetration of DERs under 1 MW in Ontario, and the potential costs of more substantial market changes to lower the minimum-size threshold or create new participation models, leveraging existing pathways, to the extent possible, is prudent. As discussed in section 2.6, under current rules, 12% of existing DERs (~800 MW) could theoretically be aggregated as these resources are downstream of single connection points to the ICG (though it should be noted the majority of these resources are wind and solar, limiting their ability to be dispatchable). This potential could increase with other options, including 3.3 Modifying Aggregation Boundaries, 3.4 Modifying Aggregation Compositions and 3.5 Participation Model for Aggregated Non-Dispatchable Generation. As it stands, however, this potential is limited to single-technology, dispatchable resources connected at a single connection point to the ICG.

The impact of this option on reliability is relatively minor. The changes proposed would still result in the connection of resources with low-to-no negative effect on reliability and, in the future, these resources may be able to provide services to improve reliability both at the bulk and local level. In clarifying the identification of connection points to the ICG and determining and communicating the parameters that would make a T-D node higher or lower risk for reliability impacts, the IESO could incorporate information from distributors with regard to the potential for downstream impacts from DER aggregations. This option could benefit distributors and reduce potential impacts to the distribution system resulting from an increase in the deployment of aggregated DERs.

With more DERs responding to signals from the bulk system, distributors will have to play a larger role in ensuring that meeting upstream needs does not cause downstream problems or, in the future, that a resource is not providing services at a local level that would conflict with dispatch to meet bulk system needs. While this increased involvement will result in larger costs for distributors, it may also lay the foundation for future T-D interoperability capabilities. Starting with the approval of aggregations and modelling of the T-D interface would help advance the capability of the IESO and distributors to build more collaborative and automated processes.

Currently all proposed aggregated resources must be assessed to determine their impacts before they are approved to participate in the IAMs. Based on type and location, identifying some of these aggregations as lower risk before they are proposed could reduce the modelling assessment required for each resource. This would require significant modelling and assessment effort upfront to determine the location of high- and low-risk nodes. To ensure the outcome is accurate and useful, this work can leverage existing aggregation modelling to build and regularly update a list of nodes by risk classification. While resource intensive at the outset, building this capability over time will help alignment at the T-D interface and support other activities, including regional planning.

There may also be a limit to how much can be modelled in advance, as different aggregations may have different operating characteristics and the dynamics of the system may reduce the amount of potential aggregations that can be pre-vetted. Communicating the results of this modelling assessment to the public will require engagement and education to help improve prospective aggregations before they are proposed to the IESO.

As mentioned, IESO coordination with distributors at the time of registration and approval would likely be required to determine the potential impacts of an aggregation. In some cases, the IESO and distributors could work together to identify where major issues at certain nodes are likely, but identifying the location of low-risk nodes may be more difficult. Distributors would have to conduct their own modelling to determine if resources aggregated below a single point of connection to the ICG may disrupt their system – work that could also be beneficial both in preparing for increased penetration of all DERs and in supporting regional and distribution system planning.

3.2.4 Implementation Considerations

Based on IESO initiatives that involved a similar scope (e.g., the review of market rules and manuals), the number of IESO staff required to clarify existing rules for aggregations would likely be relatively low. The extent of resource needs for identifying high- and low-risk aggregations, however, would be dependent on the approach to identifying T-D node risk. If this is done incrementally, as high-use T-D nodes are identified, the need for additional IESO resources would likely remain low; that said, if T-D nodes are assessed holistically across the ICG in a single effort, staffing and time requirements would increase significantly.

This option does not involve modifications to the IESO's tools and so could potentially be completed independently from market rule and manual changes that are being conducted as part of the market renewal process. Given the focus on leveraging existing rules and processes and enhancing information sharing, implementation of this option would not be expected to incur additional capital costs.

There may be some risk in sharing information about the likelihood of aggregation approvals where this information may benefit another participant causing localized market power issues. Sharing information to improve the approval process should be balanced with this potential risk.

There are no known interdependencies with other IESO initiatives. Clarifying the existing rules and processes for proposing aggregations would not rely on the completion of other IESO initiatives to move forward.

3.2.5 Conclusion

With the exception of HDR, there is insufficient clarity within the IESO's market rules and process documents on how DERs may be able to aggregate for the purposes of market participation. The IESO's existing rules were tailored to transmission-connected market participants and do not adequately describe acceptable approaches for aggregation for distribution-connected resources located at different connection points downstream of a single T-D node. Clarifying language within the market rules, and developing guidance documents, would enable the IESO to more clearly define requirements for prospective DER aggregators, as well as set expectations on how applications for aggregation will be vetted by the IESO. This option would represent a relatively low-cost and low-effort undertaking on the part of the IESO that could be completed within a short time frame. As such, the development of such clarifications and guidance merits further consideration.

Conclusion → Merits further consideration

3.3 Modifying Aggregation Boundaries

3.3.1 Background

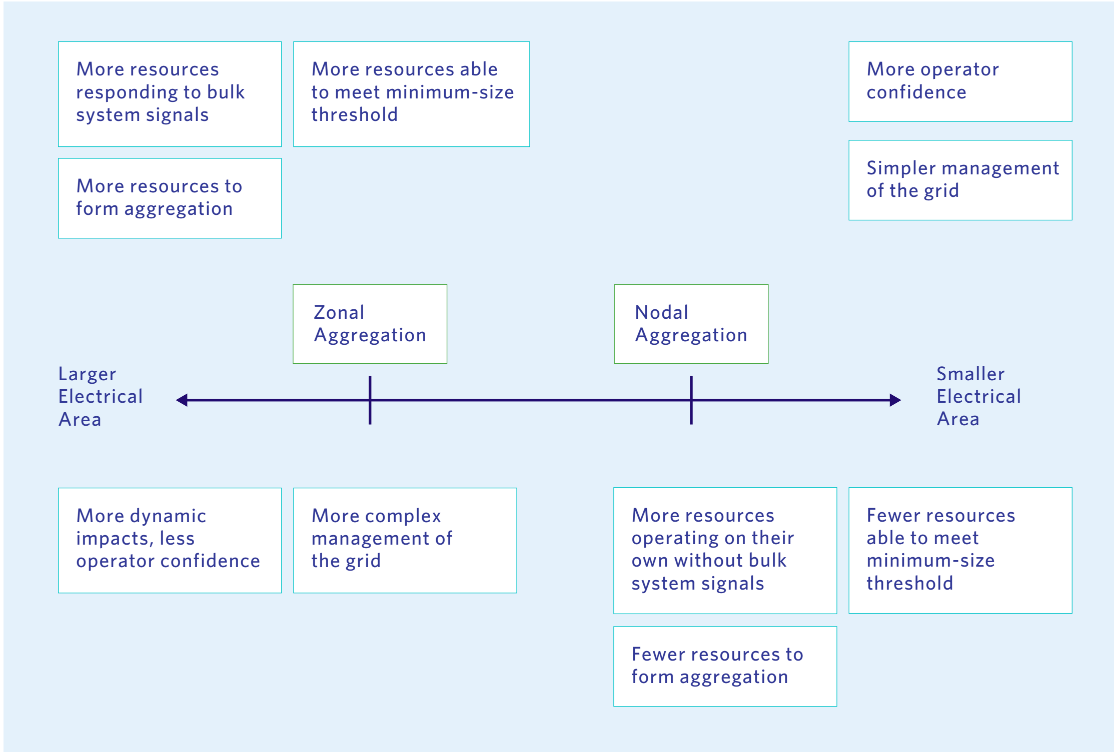
Aggregation boundaries define portions of the ICG within which resources can be reliably aggregated. These boundaries can vary widely in size, with those on the small end of the spectrum potentially set at a single T-D node (referred to as nodal aggregations). This would mean that an aggregation could only be formed by contributor resources connected to the portion of the distribution network served by that single T-D node. On the large end of the spectrum, aggregation boundaries could range from many T-D nodes, to an entire electrical zone[29] (referred to as zonal aggregation). With a suitable power system model, this would mean that an aggregation could be formed by contributor resources connected to distribution networks served by any of the T-D nodes within that zone.

Setting aggregation boundaries is based, in large part, on striking a balance between an aggregator's ability to find contributor resources for an aggregation, and an operator's ability to predict the performance and impact of the aggregation. The larger the electrical area used to define permitted boundaries, the less granularity and certainty operators have about the impacts of the dispatch of an aggregation, and the more difficult it will be for the IESO to use resources to meet local transmission reliability needs.[30] If the permitted boundaries are too narrow, though, aggregators may be unable to find the requisite number of resources to form an aggregation that meets the minimum-size threshold (and other requirements, such as restricting aggregations to a single resource type). Figure 11 summarizes these considerations.

[29] Ontario has 10 electrical zones corresponding to major transmission interfaces between the zones; see [62].

[30] In Ontario, this lack of surety is dealt with, in part, by modelling an aggregated HDR resource at the strongest bus within an electrical zone to ensure the least disruption to overall power flow.

FIGURE 11: SPECTRUM OF AGGREGATION BOUNDARIES AND OUTCOMES



As discussed in section 3.2.1 of this paper, the IESO currently permits HDR resources to aggregate on a zonal basis, and dispatchable generation or dispatchable loads to aggregate on a nodal basis at a single T-D node. Stakeholders have indicated it is challenging to find enough contributor resources to aggregate to meet the 1 MW minimum-size threshold under the current rules [14]. Some system operators in other jurisdictions have expanded aggregation boundaries, while others continue to limit aggregations to a single connection point to the bulk system.[31] Examples of different approaches currently used by system operators are described in section 3.3.1.1.

3.3.1.1 New York Independent System Operator (NYISO)

In New York, the NYISO is taking the single-connection-point approach to DER aggregations. All aggregated resources are required to connect below a single point on the transmission system to enable dispatch in a manner that both sends the correct price signals and effectively relieves transmission constraints on the system [15]. The NYISO has taken this approach in the belief that more effectively relieving transmission constraints will lower the overall cost of producing electricity. Currently the NYISO is working with distributors to define an approved list of transmission nodes for DER aggregations that accurately reflects intra-zonal congestion and locational price formation. The NYISO is also working with distributors to develop provisions that deal with situations where DERs may be electrically connected to more than one node because of changes to distribution system topology over time.

[31] FERC Order 2222 requires system operators to establish locational requirements for DER aggregations that are as geographically broad as technically feasible, and to provide detailed analysis on how they determined such limits [3, p. 161].

3.3.1.2 California ISO (CAISO)

California allows zonal aggregations and nodal aggregations for DERs. Specifically, sub-zones are defined within the larger default load aggregation points (DLAPs)[32] inside which DERs can form aggregations. DERs can aggregate at a single connection point, as is the case in New York and Ontario, or within a sub load aggregation point (Sub-LAP).[33] These sub-zones are defined by areas that limit the frequency of transmission congestion and minimize grid impacts based on reliability must-run studies, discussions with transmission planners and locational marginal price (LMP) study results [16]. This ensures the nodes that bound the sub-zone have similar grid impacts and that delivery to one or multiple points should not lead to significant differences in congestion or locational price. The CAISO then models each multi-node DER aggregation as a single resource located at a "weighted-average" pricing node location, using distribution factors (i.e., positive weights that add up to 100%) to represent the share of the aggregation's total capacity at each of the pricing nodes where some of its individual DERs are located.

3.3.2 Overview of Option

Moving away from either end of the spectrum, this section will explore two middle-ground approaches to aggregation: sub-zonal aggregation and multi-nodal aggregation. Both types of aggregation are meant to balance predictability of impacts with the formation of economic aggregations. These two sub-options build upon existing IESO constructs, addressing the challenges of both and expanding the variety of connection types that the IESO can effectively leverage, while maintaining system reliability and effective market outcomes. While these measures are intended to incrementally improve capabilities to use aggregations starting with dispatchable resources, in the future sub-zonal and multi-nodal aggregations could benefit other types of aggregations, including non-dispatchable aggregations. Figure 12 shows where the sub-zonal and multi-nodal approaches fall on the aggregation boundary spectrum.

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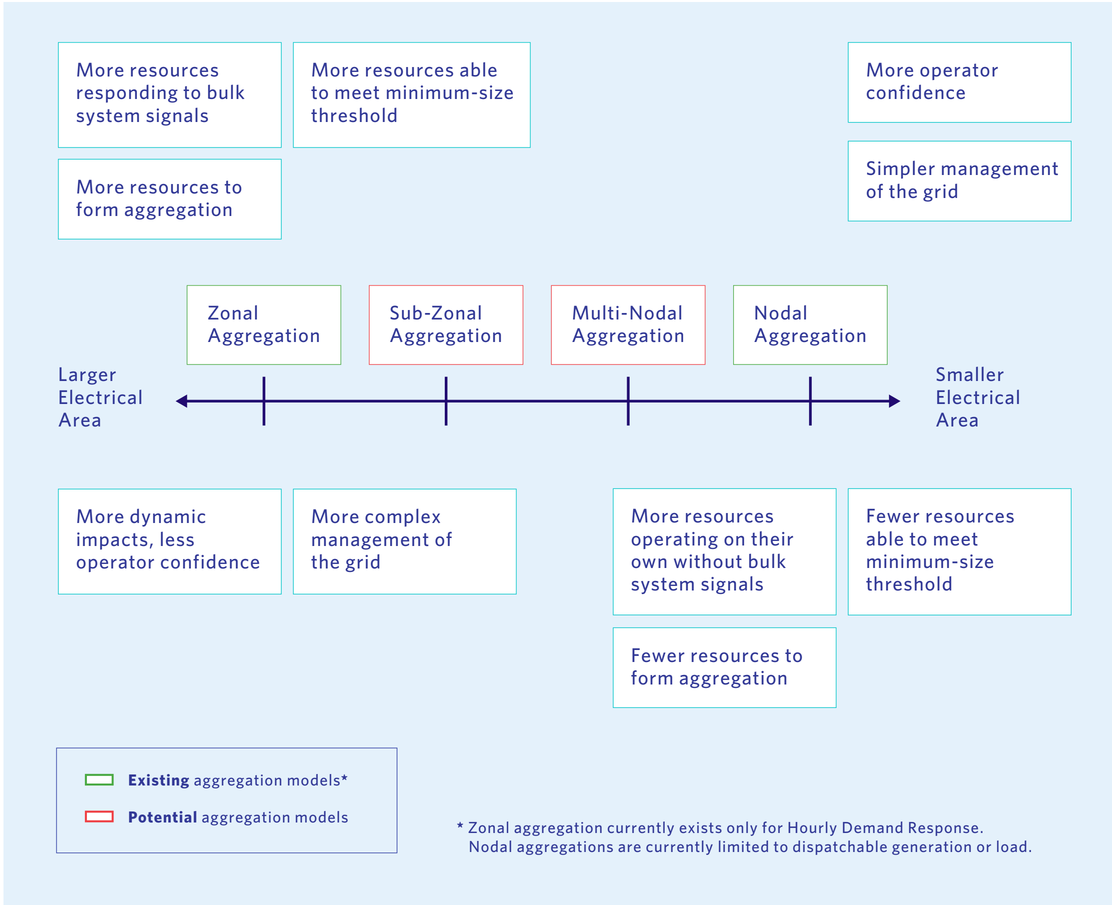
32 DLAPs are a set of pricing nodes used for the submission of bids and settlement of demand; for definition see [63].

33 To view an example of a CAISO PG&E Sub-LAP map, see [64].

FIGURE 12: SPECTRUM OF AGGREGATION BOUNDARIES AND OUTCOMES WITH POTENTIAL NEW AGGREGATION MODELS



3.3.2.1 Sub-Zonal Aggregation

Sub-zonal aggregation boundaries are essentially smaller transmission zones established for the purposes of DER aggregations. These zones can be defined by groups of T-D nodes with similar system conditions (minimal internal congestion) or the same or similar LMPs. Aggregations could be modelled as a single resource with a weighted average at a series of single nodes based on the location and size of its contributor resources, or virtually modelled to a single node within the sub-zone, similar to the way HDR resources are modelled today.

To improve accuracy, the IESO could develop distribution factors to represent the impact of the distribution system on the resource's ability to deliver services to the grid. Distribution factors can represent the proportion of an aggregation's capacity that is expected to deliver to each T-D node. In California, DER aggregators have a default set of distribution factors, but can submit updated factors with their day-ahead and real-time market bids and offers to reflect short-term changes in the availability of their contributor resources. Larger variations, such as a substantial change to the population of contributor resources, can require the aggregated resource to be reassessed for system impact before it can continue to participate in the wholesale market. The ISO/RTOs and distributors determine whether a change is substantial, based on a number of factors, including the aggregation's overall size, location, composition or other operating characteristics.

While smaller zones increase confidence that the resources will impact the system as expected, they have their own challenges, including the ability of aggregators to find contributor resources to form an aggregation.

To address these barriers, the IESO could:

- Perform studies on existing nodes and zones to identify pockets where the boundaries have similar system conditions or LMP. The definition of sub-zones should be:
  - Incremental (i.e., based on the rolling schedule of regional plans and opportunities to meet identified system needs)
  - Co-ordinated with affected distributors and transmitters
  - Thoroughly explored with stakeholders to balance sub-zone size with predictability of impacts
- Determine if new power system models or an upgrade to existing models would more effectively handle DERs with multiple or dynamic connection points required for sub-zones
- Develop a process for when and how to re-define sub-zones and what happens to affected aggregated resources
  - Determine the threshold for differentials in LMP at the bounds of sub-zones
  - Revisit sub-zone boundaries when issues in dispatching aggregated resources arise, e.g., inability to deliver or bulk system congestion
- Review market rules for required changes to connection requirements and aggregation for dispatchable resources
  - Formalize requirements for Chapter 7 section 2.3.2A, which governs discretionary approvals for multiple connection points
- Evaluate the potential for arbitrage if a differential in LMP between nodes emerges
  - Define sub-zones to minimize differentials in LMP, recognizing that variation may arise and rules should be in place to prevent aggregations from exacerbating congestion or gaming LMP differentials

3.3.2.2 Multi-Nodal Aggregation

Multi-nodal aggregation would allow contributor resources in an aggregation to connect to more than one connection point to the ICG. This could be multiple contributor resources connected to more than one T-D node, a contributor resource that is within a distribution system served by more than one T-D node, or a connection point that has multiple electrical connections, such as a dual element spot network (DESN), which is actually two electrical connections to the transmission system with a tie-breaker in between.

Allowing for multi-nodal aggregations increases the contributor resource pool for aggregators, but creates challenges for operators. These could occur, for example, when a resource delivers to one T-D node when dispatched to alleviate an issue at another. The IESO power system models currently do not allow a resource to have more than one connection point to the ICG, so the initial approach would focus on identifying an upstream node to model the aggregation without significantly impacting reliability, as described in Chapter 7, section 2.3.2A of the Market Rules.

To address this barrier, the IESO could:

- Determine if new power system models or an upgrade to existing models would more effectively handle DERs with multiple or dynamic connection points
- Evaluate the capabilities of systems being developed for its Market Renewal Program to process multi-nodal aggregation
- Review the market rules for necessary changes to connection requirements and aggregation for dispatchable resources
- Co-ordinate with distributors on registration approvals and identification of multiple nodes with the potential for aggregation
- Determine settlement for resources with multiple connection points and the potential for LMP arbitrage

3.3.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

The sub-zonal option aims to improve the visibility of DERs by narrowing the aggregation area relative to the current zonal approach for HDR. This would lower the likelihood of resources delivering to an unexpected location on the ICG. Additionally, depending on the information requirements on the contributor resources, the IESO may gain visibility into all or the majority of an aggregation's resources. Multi-nodal aggregation rules could enable more resources to form aggregations and participate in the IAMs, improving visibility over non-participation, but potentially lowering visibility compared to direct participation.

In reducing the size of zones, operators can rely more on aggregations to reliably provide a wider set of services. Currently zonal aggregations are restricted to hourly (non-dispatchable) demand-response resources, which means they can only provide capacity. With smaller zones, where operators can be more confident of the impact of dispatching a resource, sub-zonal or multi-nodal aggregations may be able to provide real-time services like OR and energy.

Modelling and dispatching resources at sub-zones, rather than at the larger transmission zones used today, would allow the IESO to better manage the error introduced by aggregation. If the sub-zones are defined to minimize negative system impacts, the downsides of the current approach to zonal aggregation could potentially be mitigated. Modelling and dispatching resources at multiple nodes, or potentially at an upstream node rather than a T-D node, could adversely impact reliability. These potential negative impacts could be alleviated, however, by coordinating with distributors during registration, and limiting multi-nodal connections to T-D nodes with similar system conditions/LMPs.

An increase in the number of aggregated resources dispatched by the wholesale market would increase the complexities of managing the distribution system. This could be mitigated by, for example, enhancing interoperability and including distributors in connections approvals, as well as defining the sub-zones, and sharing dispatch schedules as is explored in section 3.7. Thanks to the narrower area, sub-zonal and multi-nodal aggregation would have fewer impacts on the distribution system than zonal aggregation, but significantly more than nodal aggregation, where delivery would be to a single point on the ICG.

3.3.4 Implementation Considerations

IESO staff time and effort would be required to model nodes, review market rules and manuals, interface with distributors, and communicate information to prospective market participants. This option would also require significant work upfront to define sub-zones, though existing and scheduled work in regional planning could be leveraged to identify local needs and constraints that could inform sub-zone boundaries. Distributors would also need to be involved in the definitions of zones, as well as connection assessments and registration. Sub-zone definitions would have to be reviewed on a regular basis to ensure sub-zones continue to exhibit similar conditions at the boundaries of the zone. This would require ongoing engagement with affected distributors and stakeholders.

This option would involve modifications to tools, and require the completion of certain initiatives (e.g., LMP determination, regional planning review[34]) prior to initiation. As such, and given the volume of changes and interdependencies, development would have to be delayed until after implementation of the Market Renewal Program (MRP) in 2023. LMP is a key element of the single-schedule market initiative under MRP. To take the LMPs into account when establishing boundaries for this option, the IESO would need to implement some form of LMP for both loads and generators in advance of establishing sub-zonal aggregation areas. Implementation of multi-nodal or sub-zonal aggregations would also likely need to follow MRP to ensure that upgraded capabilities for network modelling and dispatch tools could facilitate this more complex and potentially dynamic form of aggregation.

This option would also require the results of the IESO's real-time visibility project[35] to determine the level of visibility required of DERs and the value of the real-time visibility of these resources over static data or distributor reporting. Existing contracted resource analysis could also be expanded to these sub-zones (or multiple nodes) when and if each is identified.

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[34] For details on the Regional Planning Review, see [58].

[35] For a description of the project, see "Recommending appropriate real-time visibility of DERs" in [65].

3.3.5 Conclusion

3.3.5.1 Modifying Aggregation Boundaries: Sub-Zonal Aggregation Boundaries

Sub-zonal aggregation boundaries could provide the IESO with greater visibility of, and confidence in, the modelled impacts of resource operation relative to the zonal aggregation approach used for HDR today. However, sub-zonal electrical boundaries have several drawbacks. First, the boundaries may still be too large to provide the IESO with high confidence in the dynamics of power flows occurring as a result of the operation of an aggregated resource, making it difficult to rely on these resources to resolve more localized system needs, such as transmission circuit or transformer station constraints. Since determining the impact of power flows may remain problematic, the dispatch of such resources may also compromise bulk system reliability. Given the limited system value and the risk to reliability, the use of sub-zonal aggregation boundaries would likely fail to deliver material benefits relative to zonal aggregation, and could also result in issues with respect to zonal limits and operational flexibility (similar to those found in the zonal aggregation of HDR). Second, the determination of appropriate sub-zonal aggregation boundaries would necessitate substantial coordination with LDCs. For these reasons, further consideration of sub-zonal aggregation boundaries is not recommended at this time.

Conclusion ⟶ Does not merit further consideration at this time

3.3.5.2 Modifying Aggregation Boundaries: Multi-Nodal Aggregations

Multi-nodal aggregation boundaries are more electrically narrow than zonal or sub-zonal boundaries, and can be determined based on T-D nodes with similar electrical conditions. Through planned upgrades to the IESO's resource modelling capabilities, the IESO has the potential to include capabilities to perform the network modelling and dispatching necessary to allow multi-nodal DER aggregations in planned upgrades to its resource modelling capabilities. This option is expected to give the IESO greater accuracy regarding a DER aggregation's impact on local and bulk system conditions. It can also enable DER aggregations to meet more local needs, and could allow the IESO to increase or remove caps on aggregated DERs secured through demand-response or capacity auctions. While the determination of these boundaries requires effort and coordination by the IESO, transmitters, and LDCs, the IESO could establish and refine them incrementally by incorporating such analysis within its regional planning process. For these reasons, multi-nodal aggregation merits further consideration. Planned upgrades to the IESO's IT system should identify opportunities to include the capabilities to perform multi-nodal aggregations.

Conclusion ⟶ Merits further consideration

3.4 Modifying Aggregation Compositions

3.4.1 Background

Aggregation composition describes the makeup of contributor resources within an aggregation. Compositions are generally categorized into two groups: homogenous, where all contributor resources are of the same type, and heterogeneous, where contributor resources are of more than one type.[36]

Heterogeneous or mixed aggregations can provide flexibility for aggregators in determining how to use contributor resources to meet system operator dispatch instructions. For example, an aggregation with wholesale market obligations throughout the day could use solar PV when sunlight is available, but rely on another form of generation later in the day.

As discussed in section 3.2 of this paper, the IESO currently allows for homogenous aggregations of dispatchable generation and dispatchable load and, in the case of HDR, either homogenous aggregated revenue-metered loads (physical HDR) or homogenous aggregated non-revenue metered loads (virtual HDR).[37] All of these aggregations require that contributor resources be of the same type to simplify the modelling of a resource's impact on the bulk system. For example, when modelling the dispatch of a resource and its effect on system conditions, the IESO considers all of the operating characteristics of the resource. The same holds true when modelling an aggregation of multiple contributor resource types. Without knowing the location and type of individual contributor resources, the IESO would have difficulty predicting the aggregation's impacts on system conditions (e.g., voltage or power quality), and risk undermining the reliability and stability of the system.

In addition to the static aggregation composition types discussed above, aggregation composition can change over time. This may occur, for example, when contributor resources switch aggregations in response to a better economic opportunity, i.e., become part of another aggregation or one with a different aggregator. While the resource and the aggregator would be responsible for managing any changes between aggregations, operators must actively track these dynamics to ensure the total capability assigned to an aggregation remains accurate and to prevent a contributor resource from being assigned to more than one aggregation. Monitoring the composition of an aggregation also enables the relevant distribution utility to review aggregations and their contributor resources to determine if the aggregation's operation presents any reliability risks to the distribution system.

These dynamics are applicable to most aggregations, but become even more important when aggregations are composed of different types of resources with different operating characteristics. In a mixed aggregation, the impact on the system of individual contributors responding to the dispatch signal will vary by resource type and location.

[36] As discussed in Part 1 of this white paper series, heterogeneous aggregations are combinations of resources that are separately metered; two resource types behind the same meter are considered a hybrid resource and will not be explored in this paper. Hybrid resources are being explored through the IESO's upcoming work on enabling resources.

[37] An exception occurs where a physically metered DR is able to be part of a virtual portfolio, though these combinations fall short of the heterogeneous combinations described in this option.

3.4.2 Overview of Option

This option looks at the use of mixed aggregations of generation types and mixed aggregations of load types. Mixed aggregations of generation and load together would need to be explored in the future using the learnings from these options as a starting point.

3.4.2.1 Mixed Generation Aggregations

Mixed aggregations give participants the flexibility to help meet system needs by enabling aggregators to offer capabilities beyond what a single resource type could provide. As mentioned earlier, pairing solar PV and other generator types within an aggregation could provide value during the day from the sun and at night based on the generation profiles of both types of resources.

The NYISO and the CAISO both allow heterogeneous aggregations, though the NYISO has yet to implement these rules for DER aggregations (i.e., heterogeneous aggregations are only permitted at the transmission level). Under the NYISO's planned rules, aggregations will only be allowed to provide services that each contributor resource is eligible to provide. For example, while energy storage on its own is technically capable of providing spinning reserve and 30-minute reserve, an aggregation of solar PV and storage would be ineligible to provide either service, since solar PV on its own could not provide either service. As part of its registration process, the NYISO requires aggregators to submit individual DER parameters and unique operating characteristics to inform its modelling and ensure the total capability of an aggregation is equivalent to the sum of its parts.

Both the CAISO and the NYISO evaluate and dispatch heterogeneous aggregations in the day-ahead and real-time markets at the aggregation level rather than the individual DER contributor level. The NYISO requires DER aggregations to submit four separate telemetry signals at the aggregation level: total aggregate response, total aggregate injection, total aggregate negative generation (withdrawals for energy storage), and total aggregate load reduction. This requirement is designed to ensure those resources are economic compared to the rest of the supply mix so that the overall cost of serving load does not increase.[38]

As discussed in section 2, there is little potential to aggregate existing contracted DER resources below a single T-D node under the IESO's existing rules for aggregation. There is, however, potential to use an enhanced aggregation model to pair existing resources with new resources of different types to enhance the value they can provide. Much of the existing DER fleet in Ontario is solar PV, which, by itself, is non-dispatchable. Aggregating solar PV and storage could enable these resources to be more flexible and potentially dispatchable at the aggregate level. Aggregating these resources ahead of the meter instead of putting storage behind the meter of the existing resource has the benefit of enabling the storage device to provide other products and services directly, while working in tandem with the solar PV resource to respond to a dispatch signal. This could give both the participant and the system operator additional flexibility when compared to behind-the-meter storage.

[38] The NYISO requires the individual signals to pair with the different revenue-grade meter files that will be submitted one day after dispatch. Each of these categories has slightly different treatment when being evaluated for settlements, such as the application of the monthly net benefits threshold to the demand reduction portion of response; see [67].

When dealing with mixed aggregations, the different operating characteristics of each contributor – which can vary substantially by resource type – pose a challenge for system operators. With differing startup/shutdown times, ramp rates, operational cost/efficiency measures, charging/discharge rates, and response rates, predicting the effect of these aggregations on the grid will depend on which contributor resources respond and where they are located on the system. This complicates modelling the impact of dispatching an aggregation to meet a need and could exacerbate power quality issues, especially at the distribution level.

To address this barrier, the IESO could:

- Enable mixed aggregations of generation resources, starting with resources with similar output characteristics (e.g., inverter-based technologies)
  - Each resource would not have to be dispatchable, provided the aggregation is dispatchable
  - The effects of different aggregated generation types on power quality and distribution operations would need to be demonstrated through incremental deployment
  - The ability of these aggregations to participate in a capacity auction would require the development of methods to qualify capacity and determine resource adequacy contribution

3.4.2.2 Mixed Demand-Response Aggregations

Mixed aggregations of demand-response resources (combined customer load types, such as residential mixed with commercial and industrial loads) have their own set of challenges. These relate to visibility of the resources' response to dispatch instructions, the granularity of metering to settle the aggregation, and the measurement and verification (M&V) of the aggregation's response to being dispatched.

Mixed demand-response aggregations provide the benefit of flexibility to curtail different types of loads when those loads are actively consuming electricity based on different consumption patterns, end uses, costs or weather sensitivities. Residential loads, for example, tend to be lower during the day and higher in the evenings, while industrial or commercial loads tend to be higher during the day. There are also differences in the seasonal availability of residential versus industrial demand-response capability – with residential space conditioning loads (and DR potential) peaking in the summer and winter seasons. Pairing different load types enables the aggregator to respond to system needs throughout the day, tailoring its aggregation to when system needs are greatest, or to respond to a dispatch instruction based on the lowest shut-down costs or other criteria associated with the various loads within the aggregation.

A central challenge with mixed demand-response aggregations in Ontario is that different loads/customer types often have different types of meters. Residential and small business customers, as well as many large load customers, such as commercial and industrial (C&I) users, are metered and settled by LDCs. Some larger load customers, have more sophisticated IESO-revenue grade metering. To ensure a mixed demand-response aggregation could be dispatched and provide products like dispatchable energy or OR, the IESO would need to have confidence that the aggregate metering data was on the same time interval. Residential smart meters are recorded less often – typically hourly or every 15 minutes – than the five-minute interval required for dispatch.

Another concern is assessing demand reduction performance for settlement purposes when a resource is dispatched. The IESO currently has different M&V methodologies for C&I and residential resource aggregations reflecting the different characteristics of these types of resources. To enable mixed C&I and residential aggregations, the IESO would need to establish a process to apply the appropriate M&V methodology for each contributor within the resource. Additionally, in offering services beyond capacity, mixed resources may be constrained by the granularity of the least granular contributor's metering in the aggregation (i.e., the residential 15-minute interval meters). To address this barrier, the IESO could:

- Enable mixed aggregations of different load types
- Require contributor resources within the aggregated resource to provide telemetry at intervals aligned with the product or service being provided
  - Assist in modelling contributors in an aggregation by aligning their telemetry and, ideally, speed of response
- For residential and C&I customers, permit the transference of telemetry from alternative sources (e.g., smart thermostats, Wi-Fi-enabled water heaters)
- Ensure alternative forms of telemetry encompass a sufficient portion of the customer's load or at least the most responsive component to reasonably reflect the total response to a dispatch signal
- Enable participation in a capacity auction by developing methods to qualify capacity and determine resource adequacy contribution
- Further develop measurement and verification methodologies to capture mixed types of loads participating within an aggregation

3.4.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

This option does not enhance visibility of resources beyond enabling market participation. Existing resources would be incented to maintain or enhance their visibility to the IESO, while aggregate telemetry would help new market participant resources provide at least some level of visibility to the IESO.

Enabling more flexibility for market participants to develop and operate aggregations enhances the services and products they can provide to the wholesale market. This expands both the pool of resources, and the capabilities of existing resources. Aggregations of mixed-resource types can be designed to respond similarly to existing flexible resources, like natural gas or hydro, enabling more competition and potentially lowering the price for wholesale market products and services in the future. Allowing self-scheduled and variable resources to operate in tandem with other types of resources could make them dispatchable in aggregate, enabling the IESO to leverage them to meet system needs instead of having to "plan around" them. Having more flexible resources at more points on the system could allow operators to manage supply and demand and maintain grid stability more efficiently and potentially more reliably.

In determining the impacts on system conditions, the IESO would need to assess the confidence that can be placed in mixed aggregations and the effect of mixed operating characteristics. Based on the outcome of such studies, restrictions may need to be placed on the ways aggregators can respond to dispatch instructions to ensure these resources provide a net benefit to system reliability.

As with all DER aggregations, the type and location of contributors responding to wholesale dispatch instructions will have impacts on the distribution system. Coordination with LDCs will need to take place at the registration and operational stages to ensure the aggregation does not exacerbate distribution-level issues at the expense of bulk system needs. In addition to these general aggregation impacts, mixed resources provide another challenge. The potentially different operating characteristics of contributor resources makes the determination of potential impacts in the future more difficult, adding another layer of complexity to the co-ordination required to ensure reliability at both levels of the system.

3.4.4 Implementation Considerations

Prior to implementation, this option would involve modifications to tools and modelling software, and require completion of certain initiatives associated with the Market Renewal Program, including the determination of LMP and the refresh of the dispatch scheduling and optimization (DSO) tool.

Since power system models will likely need to be updated to properly account for operating characteristics of mixed aggregations, this option could result in considerable capital costs. IESO staff time and effort would also be required to model characteristics, review market rules and manuals, interface with distributors, develop new or modified M&V methodologies, as well as study the impacts of new resource types on system dynamics to determine which types of aggregations would be permitted and appropriate operating constraints.

The results of the IESO real-time visibility project (2021) would also be needed to determine the level of visibility required of DERs and the value of real-time visibility over static data or distributor reporting. The mixed demand-response aggregation component of this option should also leverage the progress of the Demand Response Working Group (DRWG) in alternative M&V methodologies.

3.4.5 Conclusion

3.4.5.1 Modifying Aggregation Compositions: Mixed Aggregations of Dispatchable Generation

Allowing multiple types of generation to participate in a single aggregated resource has a number of advantages relative to permitting only one type of generation. These include lowering the difficulty of finding enough contributor resources to form an aggregation, and giving aggregators the flexibility to respond to system operator dispatch signals. There are, however, potential uncertainties regarding how to electrically model mixed aggregations to ensure reliability for both the bulk system and the distribution system. In Ontario, providing a pathway for existing contracted DERs (which are largely intermittent) to be combined with energy storage within a mixed aggregation would enable the IESO to continue to extract value from these resources when they come off contract without necessarily having to lower the minimum-size threshold or install energy storage behind the meter. Due to the complexities of modelling and the 10-year timeline for most existing contracted DERs to come off contract, this option should be tested through a pilot to better understand potential impacts and implementation considerations.

Conclusion ⟶ Pilot

3.4.5.2 Modifying Aggregation Compositions: Mixed DR Contributors

Existing and prospective DR participants have referenced challenges in building portfolios of DR with sufficient contributing capacity to achieve the IESO's minimum-size threshold, even with the current allowance of zonal aggregation. Additionally, the IESO has experienced performance deficiencies from DR aggregators that could potentially be addressed by expanding the diversity of contributors within an aggregation. Permitting a diverse mix of contributor types (e.g., residential with commercial) within a DR aggregation will not only make it easier to form aggregations, but enhance the ability of an aggregated resource to meet dispatch instructions. This is expected to increase both the capabilities of DR aggregators and interest in future capacity auction participation, enabling more competition in the market. However, because different load customers have different metering types, measurement intervals, and M&V considerations, this option requires further investigation. It is also important to note that the potential of this option may hinge on enabling device-level telemetry as referenced in 6(a) Permitting Alternative Telemetry Sources: Device Level Data. This option should be tested through a pilot to better understand potential impacts and implementation considerations.

Conclusion ⟶ Pilot

3.5 Creating a Participation Model for Aggregated Non-Dispatchable Generation

3.5.1 Background

Part 1 of this series explored participation models – or established pathways for a resource to provide a service or product to the wholesale market – for existing resource types and IESO markets. While participation models have been developed for certain types of DERs in Ontario, none exist for aggregations of non-dispatchable generation. As discussed in section 2 of this paper, much of the existing fleet of DERs in Ontario are solar PV (~74%, 2,786 MW). Currently, the ability of many of these resources (the ~800 MW that are less than 1 MW) to participate in the IAMs is limited because they are too small to participate directly, and are not able to aggregate under the current market design because they are non-dispatchable.

Absent a pathway to market participation, many of these resources may cease to operate, continue to operate as retail-embedded generators, or move behind the meter to provide customer services after their contracts expire. In the first scenario, the IESO loses the capacity and energy contributions from these resources, and, in the latter two scenarios, the IESO loses visibility into these resources and their operation. If a participation model for aggregated non-dispatchable generation was created in the IAMs, these resources could potentially participate as intermittent generators in the energy market, and, provided market design changes are implemented in future, eventually participate in capacity auctions. In providing the IESO with visibility into an aggregation's contributor resources, participation of this nature would inform planning and operational decisions. Creating a participation model for these resources would also allow the IESO to continue to benefit from the capacity contributions of the existing DER fleet, and to provide an appropriate price signal for non-dispatchable aggregations through the capacity auction.

3.5.2 Overview of Option

As outlined in other IESO initiatives on enabling resources, creating a participation model, or enabling an existing resource type to provide a new service, requires a review of technical capabilities, applicable regulations, requirements for participation (entry, operational and settlement), as well as incentives and obligations (i.e., contracts).

While creating a new participation model is a significant undertaking, some of the work required may be simplified by virtue of the nature of the resources involved and by taking advantage of initiatives that are already underway (e.g., market renewal, capacity auction and upcoming initiatives on enabling resources). For example, assessing the operability of intermittent resources is typically less onerous given their operability requirements. At the same time, enabling them to participate in aggregations may also be more straightforward as many of the existing market participation requirements are related to how a resource responds to dispatch signals and makes bids and offers – which are less relevant for non-dispatchable resources. Existing constructs for self-scheduled and directly participating intermittent resources, as well as aggregated resources in general, could be extended to enable this type of participation in the energy market (and potentially the capacity auction, in the future).

Developing the requirements and assessment methodology for self-schedulers[39] in the capacity auction could form the basis of models for other non-dispatchable capacity resources by examining how schedules (or forecasts, in this case) align with identified periods of system need. Qualifying the capacity of a non-dispatchable resource or aggregation would involve comparing the expected output during times of high demand. The basis of this qualification process has yet to be determined though potential qualification methodologies were described in the high-level design for the incremental capacity auction [17, p. 84].

The current capacity auction design also contemplates enabling participation through the consolidation of resources – as explored in Part 1 of this white paper series, consolidated resources are a form of aggregation. While the current market design limits this participation model to resources at the same facility, this design could be amended to enable resources at different locations to participate. Enabling aggregations of non-dispatchable resources could build upon the existing rules for aggregation with the removal of the dispatchability requirement.

It should be noted that participation in the energy market is a requirement for participation in the capacity auction. That said, it is unlikely that existing contracted DERs (especially intermittent generators) would attempt to navigate the complexities of participation in the energy market without the ability to also participate in the capacity auction. This is because energy market participation on its own would yield essentially the same revenue opportunities as being a retail-embedded generator (i.e., HOEP or any successor).

To create a participation model for aggregated non-dispatchable resources, the IESO could:

- Enable non-dispatchable resources to aggregate and participate in the energy market and capacity auction
  - Adapt rules for self-scheduler resources for variable generation for capacity
  - Adapt rules for consolidated resources for aggregated resources for capacity
  - Modify dispatchability requirements for aggregation rules
- Start with aggregations of generation of a single type (i.e., solar) at a single connection point to simplify modelling and evaluation
  - Pilot the capacity qualification of aggregated non-dispatchable resources based on alignment with system needs and evaluate their contribution
  - Collect individual and aggregated telemetry and compare the value with existing forecasting methods for these resources

[39] Self-scheduling generators submit schedules to the IESO indicating the amount of energy they will be providing and when they will provide it, and then follow their submitted schedules – the IESO does not send these generators dispatch instructions; see [77].

3.5.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

Currently the visibility of the majority of DERs that are under contract to the IESO is limited to static information, such as capacity, location, and connection configuration. This information is used in conjunction with operational data from larger facilities to forecast their expected output to inform real-time and long-term operational and planning decisions. After these contracts expire, information about what these resources chose to do – whether to cease operation or move behind the meter to provide benefits directly to customers – may be limited.

Creating a participation model for aggregated non-dispatchable generation would provide a pathway for these resources to access market revenues. By adhering to the IESO's telemetry requirements for market participation, these resources would become visible to the IESO – a factor that will become critical as DER penetration increases. To determine the value of this enhanced visibility, however, the IESO should compare the outcomes of real-time visibility to existing and enhanced forecasting methodologies.

Enabling the existing fleet of variable DER (solar and wind) – ~800 MW of less than 1 MW – to participate in the capacity auction may have a number of benefits. These resources are expected to have recovered their capital costs during the life of their contract, so their marginal costs should be low, which could reduce the price of capacity in the future. Though these resources would be expected to be price-takers in both the energy and capacity markets, more accurate accounting of their contribution to the system may lower forecasting error and potentially improve market efficiency.

The impact to reliability would likely be low for this option, as the operational behaviour of non-dispatchable resources would remain unchanged. However, more accurately forecasting and tracking resource operations could potentially improve confidence and decrease forecasting error, resulting in improved reliability outcomes. This option also has the potential to preserve existing capacity by helping to encourage existing resources to continue to operate after their contracts expire.

As this option is unlikely to change the operational behaviour of the resources operating on the distribution system, it is not expected to impact the distribution system.

3.5.4 Implementation Considerations

Creating a new participation model is a significant undertaking. As discussed above, several initiatives currently in process could help inform the creation of a new participation model for aggregated non-dispatchable generation, including the incorporation of self-schedulers into the capacity auction in the future.

While the IESO would be unlikely to incur capital costs, as existing or planned constructs could likely be extended to accommodate this type of participation, implementation of this option would result in operating and maintenance costs (e.g., costs associated with the use of external vendors).

This option is unlikely to involve modifications to tools, and so could potentially be considered and scoped out in tandem with the market rule and manual changes being initiated and implemented as part of the MRP. However, because the expansion of existing and planned participation models to accommodate aggregations of non-dispatchable generation relies on the specifics of those participation models, this option would need to be delayed pending conclusion of the MRP. The results of the IESO Operations Real-Time Visibility project (2021) would be required to determine the level of visibility required of DERs and the value of real-time visibility over static data or LDC reporting.

3.5.5 Conclusion

At present, there is no market participation model for aggregated non-dispatchable generation resources in the IAMs. Absent a participation model for this category of resources, the IESO risks losing the capacity and energy contributions from a large portion of existing DERs once their contracts expire. If permitted to aggregate, these resources could become eligible for future participation in the capacity auction (if market design changes were made), and access the associated revenues should they compete successfully. It is important to note, however, that alternative opportunities currently exist and may materialize for many current non-dispatchable generators, which may detract from the value of this option. These alternative opportunities include net metering, behind-the-meter load displacement and retail-embedded generation. Consequently, this option should be further explored to assess the capacity value of these resources and the likelihood they will participate.

Conclusion ⟶ Merits further consideration

3.6 Permitting Alternative Sources of Telemetry

3.6.1 Background

The growing penetration of DERs is motivating many ISO/RTOs to re-evaluate the data requirements for market participant resources. This would help ensure they can continue planning and operating the system in a safe and reliable manner, while using these resources to meet system needs. Given historically limited levels of visibility into the distribution system, ISO/RTOs are exploring options to enhance the collection of three primary forms of data from DERs: (1) static data, such as DER type, location and technical capability; (2) operational data, or telemetry that provides visibility into DER real-time operations; and (3) revenue-grade data to help facilitate financial settlement. While each of these data types is important for planning and operating the bulk system, this section focuses on telemetry/operational data for DERs participating in the wholesale market.

During Ontario's early experience with DERs, the IESO could manage low penetration levels despite having limited, and often no, visibility into the real-time operations of these resources. Early DER adoption was driven by generation procurement programs (e.g., feed-in tariff), with most contracted resources not needing to respond to market signals or follow dispatch instructions.[40] The IESO monitors the operations of only a subset of these DERs. For DERs that lack telemetry (e.g., small solar and wind facilities), the IESO predicts aggregate behaviour using telemetry from larger monitored facilities, in combination with meteorological forecasts.

In the future, the IESO expects there will be increasing numbers of DERs that can change their output and consumption, and whose operating characteristics are not dictated solely by meteorological conditions. Once their contracts expire, existing intermittent and variable contracted DERs also have the potential to achieve some measure of dispatchability, through the addition of new equipment (e.g., energy storage) or as part of an aggregation. Increasing numbers of these types of DERs present both risks, if they operate in ways the IESO cannot predict, monitor or influence, and benefits, if they can contribute to meeting system needs.

To help predict, monitor and influence the operations of DERs, system operators are increasingly interested in capturing the operational data of DERs in real-time. However,when assessing what data requirements should be imposed on DERs, the trade-off between the enhanced planning and operational capabilities enabled by the additional data, and the added costs for DERs to adhere to such requirements needs to be considered [18]. This concern is particularly relevant for small DERs,[41] which may face challenges meeting the costs associated with the IESO's existing telemetry requirements for IAM participation. Permitting alternative sources of telemetry could offer a pathway for DERs to provide adequate operational data with reduced cost and complexity.[42] In deciding whether or how to impose operational data requirements on DERs, ISO/RTOs must also factor in their ability to capture and use the resulting data to produce net benefits. When DER penetration is low, ISO/RTOs may see DER impacts as "noise" that has little material impact on the system. However, as DER penetration levels grow, so too does their cumulative material impact and the need and benefit of capturing real-time information.

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[40] Some renewable generation facilities are required to provide operational data to the IESO and curtail output in certain situations.

[41] This issue was also raised by FERC in developing Order 2222 [39, p. 167].

[42] FERC Order 2222 requires ISO/RTOs to develop their own tariff provisions that address metering and telemetry requirements [3, p. 9]. Such tariffs "must not impose unnecessarily burdensome costs on the distributed energy resource aggregators or individual resources in a distributed energy resource aggregation that may create a barrier to their participation in the RTO/ISO markets" [3, p. 187].

Before moving on to an exploration of alternative sources of telemetry, it will be helpful to provide a brief overview of the current telemetry requirements for DERs in the IAMs. The IESO's telemetry requirements can be characterized in terms of the types of resources from which operational data is collected, the operational data, and how it is collected.

3.6.1.1 Types of DERs from which the IESO Collects Operational Data

The IESO currently collects real-time operational data from a limited subset of all distribution-connected resources, focusing on DERs that are larger (and more materially impactful), and those that are dispatchable and must comply with dispatch instructions. The IESO collects this information to maintain the degree of visibility required to help ensure both system reliability and the efficient scheduling and dispatch of resources.

3.6.1.1.1 Loads

The IESO collects operational data from distribution-connected load customers that qualify for and choose to become dispatchable loads,[43] as well as from large non-dispatchable loads 20 MVA or greater. If these customers have DERs behind their meter, the IESO only captures operational data relating to customer consumption and does not have direct visibility into behind-the-meter resources that may impact customer load profiles.

All other distribution-connected loads are LDC-metered and the IESO does not capture real-time operational data from these customers.

3.6.1.1.2 Generators

There are two overarching classes of distributed generators: dispatchable generators and non-dispatchable generators.

Dispatchable generators[44] are required to submit real-time operational data to the IESO and must have a dispatch workstation set up to receive dispatch instructions.[45] Variable generation facilities[46] are technically classified as dispatchable, but they are limited to dispatching down (curtailing).

Non-dispatchable generators include self-scheduling generation facilities (that submit their own production schedules to the IESO), and intermittent facilities (that generate according to factors outside the operator's control).[47]

43 These loads must be at least 1 MW in size.

44 Dispatchable generators include energy storage resources.

45 A dispatch workstation is a dedicated computer network linked to the IESO.

46 These are wind and solar facilities 5 MW or larger.

47 Intermittent facilities include run-of-river hydro facilities, as well as wind and solar facilities less than 5 MW.

3.6.1.1.3 Operational Data the IESO Collects

Where operational data requirements are applicable, the data the IESO requires from DERs, and the standards applied to the data and its transmission, may vary depending on the type and size of the resource. More stringent requirements apply to large resources (because their activities are more material to bulk system reliability), and to dispatchable resources (because they are relied upon for grid balancing).

When describing telemetry requirements for data acquisition and transfer, system operators commonly use the following terms:

Scan rates refer to the periodicity with which an entity (like an ISO/RTO) queries data from a source. For example, an ISO/RTO might want to know the output of a DER every four seconds.

Latency refers to the time delay as measured from when the data is transmitted from the source (e.g., a DER) to when it is received (e.g., by an ISO/RTO).

Accuracy or maximum tolerable error refers to the per cent difference between the measured value of the data relative to the true value of the data. Sometimes references are made to "total" or "full-scale" error, which can be used to describe the net error from aggregations and/or any intermediary measurements that lead up to the final value.

Generally speaking, data requirements include active power, reactive power and status and, for larger resources, other equipment statuses and phase-to-phase voltages. Participants with larger facilities must have latency requirements of two seconds, while participants with small facilities have latency requirements of 1 minute or faster.[48] Wind and solar facilities above 5 MW must submit operational data (consisting of both actual and available output) with a scan rate of 30 seconds at a precision of 0.1 MW [19]. These variable generation facilities are also required to submit meteorological data, which helps the IESO predict the behaviour of the province's entire fleet of smaller wind/solar facilities. All other resources with operational data requirements have scan rates of four seconds and total maximum tolerable error requirements of 2% [20, p. 47]. The monitoring data the IESO collects is summarized in Table 9.

[48] The full details of these requirements are available in Appendix 4 of the IESO Market Rules; see [78].

TABLE 9: IESO OPERATIONAL/MONITORING DATA REQUIREMENTS FOR EMBEDDED RESOURCES

	Embedded Resource Type	**Data Required (not all requirements are listed)**	**Latency**	**Scan Rate**	**Accuracy**
Generation	< 1 MVA	Not Applicable			
	Self-scheduler < 10 MVA				
	Self-scheduler ≥ 10 and < 20 MVA	Active power* Reactive power* Voltage* Resource/ equipment statuses*	≤ 1 minute (IESO may mandate ≤ 10 seconds if required for reliability)	4 seconds	2 %
	Intermittent ≥ 1 and < 20 MVA and variable [wind / solar ≥ 5 MW < 20 MVA]	Operational monitoring Active power (actual and available) Voltage* Resource status*	≤ 1 minute (IESO may mandate ≤ 10 seconds if required for reliability)	4 seconds	2 %
		Meteorological monitoring (additional requirement for variable only) Various data		30 seconds	Precision of 0.1 MW
	Dispatchable ≥ 1 and < 20 MVA	Active power Reactive power* Voltage Various other data Resource/ equipment statuses	≤ 1 minute (IESO may mandate ≤ 10 seconds if required for reliability)	4 seconds	2 %
	All ≥ 20 MVA		≤ 2 seconds	4 seconds	2 %
Loads	Dispatchable ≥ 20 MVA		≤ 2 seconds	4 seconds	2 %
	Non-dispatchable ≥ 20 MVA		≤ 1 minute (IESO may mandate ≤ 10 seconds if required for reliability)	4 seconds	2 %
	Dispatchable ≥ 1 and < 20 MVA		≤ 1 minute (IESO may mandate ≤ 10 seconds if required for reliability)	4 seconds	2 %

* Upon IESO request

Although the IESO's market rules permit latency up to one minute for small dispatchable resources, practically speaking, such a lag may impact the resource's ability to contribute effectively to the operations of a five-minute market. As such, the IESO prefers latency of 10 seconds or less when relying upon dispatchable resources in order to effectively meet scheduling requirements.

3.6.1.2 How the IESO Collects Operational Data – The Real-Time Network

To operate Ontario's high-voltage electricity system, the IESO uses its real-time network to acquire operational information from market participants and transmit dispatch instructions to dispatchable resources.

Real-time network connections with the IESO are established via either a multiprotocol label switching (MPLS) network or a site-to-site virtual private network (VPN) connection over the internet. Although MPLS is the preferred connection, the VPN option can be used in cases where the facility has been deemed medium performance.[49] MPLS connections are provided by the IESO and, in cases where the size and the location of the facility warrant, a secondary connection may also be supplied. VPN-connected facilities require the market participant to supply a reliable connection to the internet. Both installations also require the market participant to provide a clean physical space to house the IESO's remote equipment and allow access for maintenance personnel. Further requirements include an uninterruptable power supply (UPS) to sustain operational data transfer during a power outage.

Market participants provide real-time operational data to the IESO using two standard data transfer protocols:

- Distributed Network Protocol (DNP)
  - DNP is an open, standards-based protocol used in the electric utility industry to address interoperability between substation computers, remote terminal units (RTUs), intelligent electronic devices (IEDs) and master stations.
- Inter-Control Centre Protocol (ICCP)
  - ICCP is used for real-time data transfer to the IESO; participants either provide their own ICCP server and software or use a third party's ICCP server and software. Co-ordination with the IESO is necessary to establish the communication link between the participant and the IESO control centre. This protocol is normally used for market participants that provide large volumes of data for a fleet of facilities and is typically SCADA to SCADA.

[49] The IESO has performance requirements ranging from low, to medium and high. These requirements are stated in the Chapter 4 Appendices of the IESO Market Rules; see [78].

3.6.2 Overview of the Option

To gain real-time visibility into currently contracted DERs, and create a pathway to obtain visibility into DERs that could participate in the IAMs in the future, this white paper explores several alternative sources of operational data. These could reduce the cost and complexity of aggregations – of small DERs or larger DERs participating in the IAMs – providing the IESO with the operational data required for dispatch and monitoring purposes.

3.6.2.1 Device-Level Telemetry

The emergence of smart home or internet-of-things (IoT)-enabled devices enables the IESO to collect, either directly or indirectly, real-time operational data from these devices. Data can take a variety of forms, including:

- Change of status (e.g., on/off) from devices like smart thermostats and Wi-Fi-connected water heaters
- Device-level energy metering (e.g., from electric vehicles (EVs) and/or charge points, smart plugs) or circuit-level energy metering from equipment, such as smart electrical panels

Currently, most IoT devices communicate using a site-host's wireless network or through the public internet. This means they would not likely transmit securely through a dedicated connection, such as a VPN and a DNP3 modem – both of which are normally required by the IESO for dispatchable resources to communicate with the IESO's SCADA/EMS for dispatch and monitoring purposes.

However, imposing such requirements for individual DERs is likely problematic for two reasons:

- The required dedicated links may be cost-prohibitive for residential and small commercial customers (the most likely direct hosts of these devices)
- The volumes of data produced by many small devices communicating directly with the IESO could be unmanageable without substantial upgrades to the IESO's SCADA/EMS

To resolve this issue, an aggregator could be leveraged to collect real-time device-level operational data from the contributor resources within an aggregation, and subsequently provide this data in the format and level of security acceptable by the IESO's SCADA/EMS system (e.g., DNP3 through a VPN). Many companies have already established persistent communications to their end devices (e.g., for monitoring, software/firmware upgrades), which can be used for both telemetry and control, allowing the companies or distribution utilities to act as aggregators for the population of their devices [21].

ISO/RTOs may have concerns about whether small DERs of this nature can communicate their performance and respond in a timely manner to dispatch instructions from the SCADA/EMS. Based on the experience in other jurisdictions, the proposed IoT pathway is more than capable of updating field measurements or statuses and responding to dispatch instructions within a 1-minute time frame – which would meet the IESO's minimum requirement for energy and OR (for embedded resources below 20 MVA).[50] In fact, in other jurisdictions, the current transfer capabilities and measurement accuracies of DER aggregations meet the practical requirements for the provision of regulation services (which are far more demanding than energy and OR market performance requirements).[51] This is possible because a large number of contributor devices within an aggregation allows the variation of responses from each device to cancel each other out. Further, as noted by Sandia National Labs, DERs can achieve extremely fast response times to grid disturbances – in aggregate – by combining slower response-time DERs (smaller DERs with less sophisticated and cheaper bandwidth connections) with larger and faster response-time DERs (with more sophisticated and more expensive bandwidth connections) [21, p. 49]. These response times can currently be achieved with the underlying network infrastructure, and do not rely upon network advancements such as 5G. Whether such an arrangement can meet the IESO's existing requirement for 2% accuracy is yet to be determined; however, the inaccuracies of individual DER devices have been shown to cancel each other out, resulting in adequate accuracy for the aggregation as a whole.[52]

While these limitations do not preclude DERs from operating in the real-time energy and OR markets, it is important to note that the sophistication of small IoT-enabled energy devices is growing rapidly, as is the sophistication and reach of the underlying communications infrastructure [3, p. 23]. Further, there has recently been an emergence of products that have built-in revenue-grade metering (e.g., solar inverter systems [22] or EV charge points) – these devices not only deliver telemetry, but can collect and transmit measurement data that can be legally used for settlement. There are also devices that can adhere to the strict standards for the financial settlement of electricity required by Measurement Canada [23, 24].

3.6.2.2 Inverters

Modern inverter technology can transmit operational data wirelessly over the internet in real-time. Such features are now standard in most inverters and allow access to this information for site hosts (e.g., homeowners with a rooftop solar system), equipment manufacturers, and potentially third parties, which could include aggregators. These capabilities also provide an avenue for the IESO to capture this data. Modern inverter technology can be assumed to be used in new installations of inverter-based technologies (e.g., solar PV), but also upon inverter replacement of existing renewable facilities. Similar to IoT devices, these inverters can connect to a site host's wireless router and transmit operational data over the public internet or cellular networks. An easily connectable RTU[53] may also allow the inverter to communicate directly with the IESO SCADA/EMS. However, for reasons described earlier, it is problematic for small DERs to transmit operational data to the IESO SCADA/EMS directly, likely making an aggregated approach preferable for most smaller resources.[54]

[50] The Bonneville Power Administration has demonstrated smart water heater response times of 5 seconds; see [84, p. 62].

[51] For example, PJM obtains regulation from water heaters [79, p. 11]. This is being demonstrated in Honolulu [69] and expanding elsewhere [68, 70].

[52] Of note, is the NYISO's decision to reduce the accuracy requirement for DER telemetry to 5%, which the NYISO argues would allow DER aggregators to leverage "cost-effective approaches for telemetry" [83].

[53] A common open-source RTU connection is described in section 3 of [72].

[54] FERC Order 2222 requires the aggregator to be the single point of contact with the ISO/RTO – not the individual DERs that comprise the aggregation. However, flexibility is afforded to the ISO/RTO where individual telemetry may be justifiable [3, p. 205].

3.6.2.3 LDC-Collected Operational Data

Distributed generators with a capacity of 250 kW or more are required by the Ontario Energy Board to provide basic operational data to the LDC, if the LDC requires it [25, p. 37]. For the purposes of standardizing such requirements, Hydro One has developed technical interconnection requirements (TIR) that apply to distributed generators both within its service territory and connected within the service territories of LDCs embedded within its service territory [26]. Some LDCs also have Hydro One collect this data on their behalf to avoid the costs of developing the required infrastructure. Large LDCs that have their own SCADA systems also generally collect this operational data from distributed generators within their service territories, though some have also adapted Hydro One's TIR for their own use.

Under the TIR, data on the following would be sent:
- Active and reactive power
- Phase-to-phase voltages (for three-phase generators) or phase-to-neutral voltages (for single-phased generators)
- Three-phase currents (where applicable)
- Device statuses

Any change in monitored status or quantity must be communicated – using either DNP3 or ICCP – to Hydro One SCADA systems in under 10 seconds and is scanned every four seconds. While the TIR provides the ability to require operational data from distributed generators less than 250 kW, Hydro One does not currently do so. Table 10 shows the similarities between the operational data the IESO requires from market participants, and the operational data Hydro One requires from distributed generators greater than 250 kW.

TABLE 10: HYDRO ONE TIR DATA REQUIREMENTS VS IESO DATA REQUIREMENTS

<table>
<tr><th>Collector and Resource Type</th><th>Operational Data Required</th><th>Requirements for Communicating Changes</th><th>Permissible Error</th></tr>
<tr><td>Hydro One
Generation ≥ 250 kW</td><td rowspan="2">Active power
Reactive power
Phase-to-phase voltages
Resource/ equipment status</td><td>10 seconds</td><td>2 %</td></tr>
<tr><td>IESO
Dispatchable generation < 20 MVA</td><td>1-minute</td><td>2 %</td></tr>
</table>

The operational data for these distributed generators could be supplied to the IESO for those that opted to become market participants, essentially having an LDC or aggregator act as the intermediary for data that is already being collected for monitoring purposes at the distribution level of the system.[55] This option highlights the fact that the operational data required by the IESO for market participation is already being collected for a sub-set of potential market participant DERs, and could be used to meet the IESO's requirements at a lower cost and complexity for DERs and for the IESO.[56] It is important to note that the persistent data quality issues associated with DERs below 10 MW render much of this operational data unusable by the IESO's control room; these issues would need to be remedied before the IESO could effectively use the data.

3.6.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

The options described above could provide additional sources of operational data for DERs whose behaviour and impacts could otherwise only be estimated by the IESO (e.g., hourly demand response, small intermittent generators). If these resources were to participate in the IAMs, the IESO would benefit from a greater degree of visibility, as enabling device-level telemetry can confer visibility into the operations of smaller DERs operating behind the meter of retail customers.

These options can also help improve competition in the IAMs in two ways. First, reducing the costs of providing operational data to the IESO could reduce the overall cost of market participation for DERs and encourage greater participation in the IAMs. As highlighted by numerous stakeholders throughout the engagement on this initiative, the high cost of complying with the IESO's requirements for the installation of equipment to collect and transmit operational data is one of the main barriers to market participation. Second, by creating pathways for telemetry where none existed previously (such as through device-level telemetry), new types of DERs and DER hosts can begin to compete to deliver market products. This is particularly beneficial for enhancing competition in the real-time energy and OR markets, where real-time performance must be monitored to ensure compliance with dispatch signals.

Increased visibility through added streams of operational data will help the IESO's operators manage reliability in real-time by getting a more accurate understanding of supply-side and, increasingly, demand-side DERs. With these resources participating in the real-time energy and OR markets, the IESO would have access to more resources to balance supply and demand and rectify outages. However, very large-scale operational data aggregation – depending on how the data is aggregated – could introduce uncertainty as to the location of power flows at the interfaces with the bulk system, which, in turn, could negatively impact reliability.

The operational data made available through these options also has the potential to be leveraged by LDCs for monitoring, planning and operating purposes. However, the options in and of themselves have no direct positive or negative impact on the distribution system.

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55 Regardless of whether these distributed generators opt to become IESO market participants, capturing this data could be used to improve system reliability and forecasting.

56 In its Order 2222, FERC proposed that ISO/RTOs should rely on data available through the distribution utility (if sufficient), rather than impose new and duplicative requirements on DERs. FERC further indicated that ISO/RTOs "coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing metering and telemetry data, and that such protocols minimize the costs and other burdens and address concerns raised with respect to privacy and cybersecurity" [3, pp. 207-208].

3.6.4 Implementation Considerations

There are several important issues that must be studied and addressed in order to successfully implement these options. The main issues relate to the management of data volumes, reassessment of market rules, and risks to cybersecurity.

These telemetry options, if implemented, would result in substantial volumes of data that must be interpreted. DER aggregators can consolidate contributor telemetry to reduce the data volumes impacting the IESO. For data not already aggregated, the IESO can consolidate the data internally to ease the computational burden on the SCADA/EMS. The methods and ability to successfully incorporate this new data hinge on the capabilities of the IESO's SCADA/EMS, which is currently in the process of being upgraded. If the SCADA/EMS cannot incorporate this new telemetry, it may be necessary to perform costly upgrades or leverage another platform, such as a Distributed Energy Resource Management System (DERMS), which will also have significant development costs.

Under current market rules, a 1-minute latency for dispatchable DERs is acceptable. This requirement is well within the technical capabilities of the telemetry options outlined in this section. However, since a 1-minute latency may not serve the practical needs of a 5-minute market, more consideration should be given as to whether this rule should be strengthened to maintain the efficacy of the 5-minute market.

Device-level and, to a lesser extent, inverter-based telemetry for smaller DERs may only be economic if data can be transmitted by affordable means between the device and the aggregator, given the smaller scale of those DERs. This implies leveraging the public internet and avoiding the use of a secure connection, such as a dedicated VPN for the device-to-aggregator communication pathway. Before moving ahead, the IESO would need to assess the cybersecurity risks associated with this approach, and determine acceptable risk tolerances relative to participation volumes.

3.6.5 Conclusion

3.6.5.1 Permitting Alternative Telemetry Sources – Device-Level Data

Permitting device-level telemetry could enable a diverse assortment of smaller-scale DERs – for which the current methods of providing telemetry to the IESO may be too expensive and complex – to participate in the wholesale markets. Through device-level telemetry, large household loads, such as water heaters, air conditioners and EV chargers, could be leveraged through an aggregator to respond to the IESO's dispatch instructions in real-time, while giving the IESO the ability to monitor their performance. It is expected that the technical level of performance of such an arrangement would be compatible with the IESO's standards for dispatchable resources as set out in the market rules. However, more study is needed to test the real-world performance of device-level telemetry, determine M&V requirements, and assess the associated cybersecurity risks. Due to the potential benefits, this option should be tested through a pilot to better understand possible impacts and implementation considerations.

Conclusion ⟶ Pilot

3.6.5.2 Permitting Alternative Telemetry Sources – Inverters

As modern inverters are becoming more broadly deployed, both in new projects and as replacements on existing projects, it makes sense for market participants and the IESO to begin to leverage their advanced features, including their ability to supply telemetry. As is the case with device-level telemetry, the ability to leverage inverter telemetry, in aggregated form, will need to be studied in more detail to assess compliance with IESO data transfer, accuracy, and security requirements. This option should be tested through a pilot to better understand potential impacts and implementation considerations.

Conclusion ⟶ Pilot

3.6.5.3 Permitting Alternative Telemetry Sources – LDC-Collected Operational Data

LDC-collected operational data represents an existing source of telemetry that is likely compatible with the IESO's minimum standards for accuracy, scan rate, latency, and security for market participation. Using this data to meet IESO telemetry requirements could lower the costs of market participation for DERs and address a central barrier identified by stakeholders. However, the IESO would have to coordinate with distributors (or other data aggregators) to obtain access to the data stream, and ensure both that its systems have capacity to accommodate the number of additional connections and that the large data streams provided can be accommodated by the IESO's SCADA/EMS, which may face bandwidth and computational constraints. This option merits further consideration both in regard to the IESO's ability to incorporate additional connections and data streams and the extent to which these existing data streams could meet IESO telemetry requirements.

Conclusion ⟶ Merits further consideration

3.7 Enhancing Transmission-Distribution Interoperability

3.7.1 Background

As DER participation in the IAMs increases, consideration of transmission- and distribution-level system conditions and constraints will be critical to ensure IESO dispatch schedules are accurate and feasible, and that operation of these resources does not negatively impact distribution system reliability. This is especially true for DER aggregations comprising multiple contributor resources due to the potential for large numbers of these resources to operate in a coordinated fashion.

While enhanced communication and coordination would be beneficial across all operational interfaces: (1) IESO-LDC; (2) IESO-DER/DER aggregators; (3) LDC-DER/DER aggregators; and (4) DER-DER aggregators,[57] this section focuses on addressing coordination points between the IESO and LDCs across the T-D interface[58] in order to preserve system safety and reliability. This enhanced communication and coordination is referred to as T-D interoperability.

Focusing on options to enhance T-D interoperability is important for a number of reasons. DERs participating in the wholesale market would, by necessity, have a market relationship with the ISO/RTO that bypasses the electrical relationship with the distribution utility, a phenomenon commonly known as "tier bypassing" [27, p. 13]. More generally, since a distribution utility must prioritize both electric service to its customers and the safety and reliability of its system, there may be instances where it must constrain the ability of the DER to respond to a dispatch instruction from the ISO/RTO. For example, a distribution circuit that is out of service or abnormally configured could render DERs unavailable to meet the ISO/RTO instruction, requiring the DER aggregator to make up for that potential shortfall with other contributor DERs, submit an outage/de-rate notice to the ISO/RTO or, if time allows, revise its market offer and receive a new instruction based on its updated capability. Having some knowledge of these distribution system conditions is critical in determining the feasibility of the dispatch and operation of DERs in wholesale markets.

In Ontario, the IESO is aware of these issues and is already collaborating with LDCs on T-D interoperability through the IESO-led Grid-LDC Interoperability Standing Committee [28]. This committee is a forum for sharing information and engaging with LDCs and other stakeholders on matters relating to the coordination of IESO- and LDC-controlled grid resources. Work to date has included identifying potential DER evolution scenarios, exploring various coordination arrangements, and assessing the operational risks associated with each. The latter assessment has made clear that both the operational risks and their potential impacts differ between the transmission system and distribution system [29]. Operational risks that are high for the IESO under a specific DER evolution scenario may not necessarily translate in the same way for the LDC at the distribution level. This reinforces the need for the IESO to better mitigate potential future risks by considering distribution-level impacts and constraints in its operation and dispatch of DERs in the IAMs.

[57] The concept of operational interfaces is described in [27, p. 61].

[58] The T-D interface is the physical point where the transmission and distribution systems interconnect, typically at a major sub-station that reduces the voltage level as the electric topology transitions from networked to radial. The Ontario system has many T-D interfaces, with each local distribution area (LDA) corresponding to a single T-D interface that must operate reliably and safely as an electrical unit.

Before moving to a discussion of potential options to enhance T-D interoperability, it is important to understand a fundamental caveat. In a high-DER future, the safety and reliability of the transmission and distribution systems cannot be guaranteed in the absence of transmission and distribution tools (e.g., rather than manual coordination processes) that can model DER dispatch in real-time and communicate to avoid the violation of T-D level constraints. As such, establishing communication and operational coordination processes among the IESO, LDC, and DERs can only alleviate safety and reliability issues on the distribution system to a certain extent; they cannot be entirely avoided if the tools to model the impact of DER dispatch are not developed and implemented. However, as recognized by FERC in Order 2222, increased development and deployment of communication technologies, such as improvements in metering and telemetry, will enable the wider use of DERs [3, p. 23].

This problem has been described by other ISO/RTOs, including ISO New England (ISO-NE), which addressed the issue in its response to FERC's *Participation of DER Aggregations in Markets Operated by RTOs and ISOs* NOPR [30, p. 4]. For example, when the ISO/RTO issues dispatch instructions to a DER aggregation in real-time, there is not sufficient time for:

- A distribution utility to assess the feasibility of that dispatch and communicate any required dispatch modifications to the affected DER aggregator
- The DER aggregator to modify its real-time energy market offer (to reflect the resulting impact of distribution constraints on its dispatch)
- The ISO/RTO to rerun the real time dispatch based on the modified DER offers

Similarly, in Ontario, an LDC that determines a wholesale participating DER must be taken offline due to a distribution constraint needs a mechanism to communicate this to the IESO, so that change can be accounted for in the final wholesale-level dispatch. Currently, this capability does not exist in Ontario. In the absence of this capability, analyzing distribution system constraints on the feasibility of DER dispatch to the best extent possible before dispatch instructions are issued by the IESO (i.e., in the connection phase or the day-ahead time frame) becomes more important.

3.7.2 Overview of Option

3.7.2.1 Modify Resource Registration and Connection Processes to include LDC Input

The first option under consideration to enhance T-D interoperability is for the IESO to re-visit and modify its resource registration and connection assessment processes. The modified version would include LDC assessments of impacts to the distribution system and, ultimately, LDC approval for registration of DER resources as market participants. While not a real-time interoperability strategy, this measure serves to reduce (but not eliminate) the likelihood of interoperability issues once projects are built and participating in the IAMs. For clarity, the connection assessment process refers to the physical connection of the resource to the electric transmission or distribution system, while registration refers to the establishment of contractual and regulatory relationships between the resource and the IESO for the purposes of wholesale market participation. For the former, the IESO assesses new interconnecting resources participating in its market for potential system safety and reliability concerns, which typically results in limitations on resource operations (e.g., maximum rate of injection of real power into the grid) and requirements to complete grid upgrades before the resource begins commercial operation. These elements are then captured in an interconnection agreement between the resource owner/operator and the IESO. Separately, as part of the registration process and before it can allow the resource to participate in its markets, the IESO needs to collect certain legal, financial, technical and operational information.

In the case of DERs whose point of interconnection is on the distribution system, the LDC should also play a role in both the IESO's connection and registration processes. Such an approach was previously demonstrated as part of the Feed-In Tariff (FIT) and microFIT standard-offer programs, which required applicants to undergo a screening process known as the distribution availability test to assess project impacts on the relevant distribution system.[59] These supporting LDC processes were implemented because the IESO did not have visibility into the distribution system conditions required to conduct a detailed impact analysis.

Currently, IESO-LDC coordination is required as part of the IESO's Connection Assessment and Approval (CAA) process for DERs (embedded generation facilities and embedded load facilities) greater than 10 MW at the IESO-controlled grid connection point. While the IESO is responsible for the overall administration and coordination of the CAA process, distributors have responsibilities under the Distribution System Code. These include initiating the request for connection assessment by submitting the appropriate system impact assessment (SIA) application for embedded generation projects greater than 10 MW, plus a copy of the distribution SIA and review and commentary [31, p. 14]. As DER participation in the IAMs increases, this type of IESO-LDC coordination could be extended to DERs and DER aggregations below 10 MW to help ensure the safe and reliable operation of both the bulk and distribution systems. If implemented, these types of changes would need to be reflected in the IESO's market manuals [31], market rules (e.g., Chapter 11 Definitions [32]), procurement or auction rules, and the Distribution System Code [33] that sets out distributor requirements for coordination with the IESO.

In registering for the IESO's capacity auction, participants must identify each individual energy market resource they intend on using to satisfy a capacity obligation and indicate the associated auction capacity for each resource. When facilities register their participation in the energy market, they are required to identify both the facility and the resources that make up the facility. These resources can comprise one or more units, and are used for submitting bids or offers in the energy market [34, p. 19]. The IESO could make this resource enrollment information available to LDCs for them to assess potential negative impacts to the distribution system and report to the IESO on any distribution system constraints that could impact the ability of DERs to operate in accordance with IESO dispatch. Ultimately, the IESO would incorporate the LDC's assessment prior to proceeding with registration of potential DER market participants.

[59] Details are available in the IESO's FIT Version 5 program document archive; see [73].

Similar processes have been implemented in other jurisdictions. For example, in California, a DER provider must follow a sequential approach that starts with the distribution utility's interconnection process before progressing to the CAISO's new resource implementation process (essentially its registration process). This requires DERs to undergo review by the respective distribution utility first in order to assess potential adverse distribution system impacts and identify whether any individual DERs are participating in more than one DER aggregation. This review also requires the DER or DER aggregator to obtain a "concurrence letter" from the applicable distribution utility to attest that there are no concerns with its wholesale market participation [35, p. 7]. Any concerns and/or constraints identified must be addressed via a joint resolution process, prior to proceeding with the CAISO's New Resource Implementation (NRI) process [36]. Similarly, PJM's wholesale-DER ruleset proposal recognizes the importance of operational coordination with distribution utilities and the distributor's central role in the interconnection process. As part of this process, the distributor performs an assessment to determine whether DER aggregations include contributor resources that are located on the same or adjacent feeders and must confirm that there are no reliability impacts expected from the coordinated operation of the DERs [37, pp. 20, 22]. PJM is further advocating for the creation of a wholesale DER model interconnection process that is integrated across transmission and distribution systems [38, p. 20]. PJM has also integrated distributors into the registration process for demand-response resources. Highlighting the importance of distribution utility reviews in providing resource visibility in wholesale markets [38], the registration process for PJM's demand-response program is automated in a PJM tool that sends each registration to the distribution utility to confirm the information for each site is accurate. Similarly, as part of its registration process, the NYISO requires aggregators to register each individual DER facility comprising its DER aggregation, reinforcing the need for greater coordination with distributors in the future [39]. In fact, the operator has explicitly stated the need for distributors to review all DERs in an aggregation for reliability risks to the distribution system that would have impacts on wholesale feasibility of dispatch [40, p. 8]. Furthermore, FERC has recognized the importance of ISO/RTO-distribution utility coordination in the interconnections of DER aggregations in order to properly assess the impacts of these resources on both the distribution and transmission systems [3, pp. 82-84].[60]

[60] For example, FERC has recognized that a utility should have the opportunity to review the list of resources that are part of a DER aggregation and that are located on its distribution system prior to their participation in wholesale level markets, so that the utility may assess if the resource will be able to respond to wholesale-level dispatch without adversely impacting the distribution system [3, pp. 251-253].

3.7.2.2 Share Day-Ahead Schedule of DERs

Under the second option for enhancing T-D interoperability, the IESO would share day-ahead DER schedules with LDCs. This would help determine the feasibility of the IESO's dispatch and identify any reliability impacts that consider distribution system constraints that have arisen since the resource was originally connected and registered. Other system operators, such as the NYISO, have developed draft operational coordination requirements between the ISO, distribution utility, and DER/DER aggregator. These include the NYISO sharing the day-ahead dispatch schedule at each T-D interface (i.e., node) with the distribution utility, which would evaluate any distribution system conditions impacting the ability of DER/DER aggregations to operate in accordance with the ISO's planned operation of these resources, and ensure the proposed operation is compatible with the dispatch schedule and within any distribution system limitations. If any issues are identified, the distribution utility will communicate them to the NYISO via email or phone, and any re-dispatch will continue to be reviewed until a feasible dispatch can be agreed upon [41, p. 4]. Similarly, in California, the CAISO will coordinate with the applicable distribution utility to avoid conflicting operational dispatch, which may include sharing dispatch instructions [42, p. 110]. While not yet implemented, PJM proposes sharing day-ahead schedules with respective distribution utilities to facilitate the safe and reliable operation of DERs in its wholesale markets. In fact, recognizing the importance to distribution system reliability of sharing dynamic information about individual DER/DER aggregations [38, p. 26], PJM has also proposed to develop a web tool for retail interactions, similar to its DR Hub for demand-response resources in the PJM markets [37, pp. 4,23]. Importantly, in FERC Order 2222, the Commission's determination requires that each ISO incorporate a distribution utility review process for DER aggregations participating in its wholesale-level markets, which includes the ISO sharing with the utility any necessary information and data for it to then review and assess any risks that wholesale operation and dispatch of these resources may have on the reliable and safe operation of the distribution system [3, p. 225]. Further, a distribution utility that finds risks to its distribution system[61] upon completion of its review and assessment process should have an opportunity to notify the ISO and recommend removal of the resource from the DER aggregation or the placement of operational limitations on that aggregation [3, p. 228].

To enhance T-D interoperability and as part of this option the IESO could:

- Share with the applicable LDC: day-ahead schedules, dispatch instructions, and telemetry, as well as up-to-date resource lists of DERs participating in IAMs
- Create a web tool for interactions with the LDC

While the IESO proceeds with it efforts to implement a day-ahead market [43], the current day-ahead commitment process (DACP) commits certain dispatchable resources and the economic scheduling of imports in the day-ahead time frame, in return for a financial guarantee. The DACP uses a day-ahead calculation engine (DACE) to optimize energy and OR for the 24 hours of the next day and determines the least-cost security-constrained solution for a dispatch day based on the bids and offers submitted by resources [44].

[61] A DER operating as part of an aggregation that increases voltage above acceptable limits or creates overloads is an example of such a risk.

As part of the DACP, the IESO collects information from market participants to determine the next day's supply and demand situation and to make its scheduling and commitment decisions in the form of dispatch data. This dispatch data includes the offers, bids, self-schedules, and estimates of intermittent generation (e.g., a schedule or forecast that represents the best estimate of what these resources plan to produce the next day) required by the IESO and used to determine physical operations for the next day [45].

In determining the day-ahead schedule, the IESO uses this dispatch data, in conjunction with its demand forecast and other generation facility technical information, to create schedules and commitments for the next day, with the final results published by 15:00 [46, p. 4]. Prior to publication, these schedules could be shared with LDCs to help them assess any distribution constraints that would impact the proposed schedule and feasibility of operation. For clarity, only the day-ahead schedule for DERs within a particular LDC's service territory would be shared with an LDC.

3.7.2.3 Coordinate on Boundaries of Aggregation Zones

The IESO could also adopt a coordination framework with LDCs that takes a joint approach to identifying existing T-D interfaces (i.e., nodes) that would be allowable points for aggregation, followed by the creation of "new" or additional nodes based on distribution-level constraints.[62] As part of this approach, the IESO and LDCs would work together to continually update these nodes or aggregation boundaries as distribution network conditions evolve resulting from the increasing penetration of DERs.

For example, the NYISO is working with distribution utilities to identify the set of transmission nodes that balance DER aggregation participation and electrical system differences. All DER resources within an aggregation will need to be behind the same NYISO-modelled transmission node. The NYISO has proposed coordinating with local distribution utilities to manage any distribution-level constraints in the process of identifying the electrical bounds of each transmission node, and jointly reviewing the transmission nodes annually if needed. As part of this process, the utilities will be required to identify distribution facilities that could potentially be negatively impacted if DER aggregations are dispatched across them. Such facilities will be classified as distribution system constraints and could comprise normally open circuits, line overload potentials, and franchise demarcations. After they are identified, these distribution constraints will delineate the circuits that can be considered electrically alike, forming the electrical bounds of an expanded or contracted transmission node [47].

In a similar way, California allows sub-zonal aggregation, which is a form of multi-nodal aggregation already described in section 3.3. The CAISO models each multi-node DER aggregation as a single resource located at a "weighted-average" pricing node location, using distribution factors that represent the impact of the distribution system on the resource's ability to deliver services to the grid. In California, DER aggregators have a default set of distribution factors; however, they may also choose to submit updated factors with their day-ahead and real-time market bids and offers to reflect short-term changes in the availability of their contributor resources. Larger changes, such as the overall size, location or composition of the aggregation, can prompt the need for a joint CAISO-distribution utility re-assessment of system impacts before dispatch and operation of the resource aggregation. If the IESO were to implement this option, it would also need to coordinate with LDCs in defining aggregation boundaries.

[62] If the IESO were to allow a multi-node DERA, it would model the DERA at multiple T-D interfaces by reflecting the share of DERA capacity at each T-D interface.

Despite efforts to coordinate with distribution utilities on boundaries of aggregation zones, increasing DER penetration has the potential to disrupt existing models for power flow[63] on the distribution system, causing new operational distribution constraints to arise that may then be aggravated by wholesale dispatch. In this sense, transmission nodes are dynamic and continually changing, which is the rationale behind the NYISO's proposal to work with utilities to review transmission node boundaries on an annual basis, as needed. Should the IESO pursue implementation of this option in the future, these considerations would need to inform design choices.

3.7.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

Implementation of any of the options for enhancing T-D interoperability would increase the IESO's visibility into distribution-connected resources by taking into account information provided by LDCs in IESO processes, such as at the connection and registration stages or in the day-ahead scheduling of resources. In addition, exposing resources operating within the distribution system to economic signals that reflect the needs and conditions of the bulk system, and enhancing T-D interoperability via joint IESO-LDC coordination efforts, would support a larger number of DERs participating in the IAMs. This, in turn, would increase confidence in their ability to contribute to the safe and reliable operation of the electricity system, and enhance competition in the IAMs.

In terms of bulk system reliability, the IESO's primary reliability concern is the feasibility of DER operation and dispatch given dynamic distribution system conditions. A key problem to avoid is hidden coupling, which occurs when a resource receives conflicting operating instructions based on differing system needs [27, p. 13].[64] While enhancing T-D interoperability would mitigate risks to reliability on both sides of the system, resulting in a net positive impact on reliability, a certain degree of reliability risk nonetheless remains. The inherent variable operating characteristics of DERs can result in scheduling risk, requiring more manual intervention in real-time, which may adversely impact reliability. Further, no connection assessment process, whether at the IESO or distributor level, can guarantee full deliverability to the bulk power system under all possible conditions. This is a greater concern for DERs than for transmission-connected resources because current LDC interconnection processes determine if the DER can inject its full capacity onto the distribution system under normal distribution system conditions. However, abnormal conditions on the distribution system are frequent (e.g., if a reconfigured distribution circuit creates a situation where there is not enough capacity on the distribution system to support a DER injection dispatched by the IESO while that distribution circuit is in a reconfigured state). The dynamic nature of the distribution system means there will be situations in which distribution system constraints prevent DERs from being fully deliverable to the bulk power system.

[63] Power flow moves electric power from where it is produced to where it is consumed.

[64] In practice, if a particular DER receives control signals from the DER aggregator, it would not receive control signals from the bulk system balancing authority or LDC operations (and vice versa). However, these resources could receive control signals from both the bulk system balancing authority and LDC operations if they are providing both bulk system and distribution services.

At the distribution level, implementing options to enhance T-D interoperability – for example, by the IESO sharing registration data and day-ahead schedules with LDCs – will increase LDC visibility of distribution-connected resources providing wholesale-level services. The LDC may then leverage such enhanced visibility for future distribution system planning and optimization of its operations. However, as described in section 3.7.2.3, increasing DER participation in wholesale markets will also increase the complexities of managing the distribution system and require LDCs to effectively integrate new DERs and manage increased two-way power flows across the T-D interface. Implementing these options to enhance T-D interoperability would likely necessitate expansion of the LDC role. To support better coordination, for example, LDCs would need to enhance their own capabilities to forecast DER behaviour and corresponding system impacts at the T-D interfaces [48]. If LDCs become accountable for these new functions, the OEB will need to determine whether, how, and when it would be appropriate for the incremental costs they incur to fulfill these responsibilities to be recovered from customers and potentially implement and reflect such new functions via new and/or modified code requirements.

By definition, this option would necessitate joint coordination across the IESO and LDCs, likely requiring significant LDC effort. The extent of this involvement would need to be assessed, depending on the needs of each individual T-D interface, and would vary according to an LDC's existing capabilities/resources, size, and the levels of DER penetration within its service territory.

3.74 Implementation Considerations

In the short term, manual coordination processes associated with this option would likely be complex to administer. Similar to the options relating to modifying aggregation boundaries explored in section 3.3, this option would require IESO staff time and effort to review market rules and manuals, interface with distributors, communicate more detailed information to/from prospective market participants, model nodes, and process and manage data. Beyond implementation of tools and processes to enable tighter coordination with LDCs, additional staff would be required to manage ongoing communication and information-sharing functions between the IESO and LDC.

Implementation of the largely manual processes, such as the modification of registration and connection assessment processes to include enhanced LDC involvement, sharing of day-ahead schedules and joint coordination to identify and define aggregation boundaries, would not be expected to incur capital costs. Since manual coordination processes are not transformative in nature (e.g., do not require an overhaul of existing tools and systems), the cost to implement enhanced T-D interoperability in the near term would likely be low, from a capital perspective. That said, these processes would need to become more automated as the penetration and participation of DERs in wholesale markets increases. If new tools or shared IESO-LDC interoperability platforms need to be developed and embedded into existing IESO processes and systems, capital expenditures may be substantial. For example, longer-term solutions, such as a shared DER lifecycle management platform, may require an investment of more than $10 million [27, p. 63]. However, as noted by FERC in its Order 2222, it would be beneficial for ISOs to develop coordination frameworks with a focus on interoperability of information technology and communication systems early on, for early attention to these interoperability requirements and challenges could help prevent duplication of efforts and unnecessary costs in the future [3, p. 250].

In considering implementation time frames, in the near term the manual processes required to implement the first sub-option could occur alongside current IESO initiatives, provided sufficient staff resources could be made available. Implementation of the second and third sub-options involving sharing day-ahead schedules and jointly defining aggregation boundaries with LDCs would, however, need to be delayed, pending completion of the market renewal initiatives (e.g., changes to scheduling and unit commitment) that will directly impact this work [49]. With the completion of the IESO's MRP, proceeding with implementation of these sub-options could be feasible, provided the growing level of DER penetration in the IAMs over the next few years justifies a higher level of coordination with LDCs, and the consideration of options to enhance interoperability.

Further, in implementing this option the IESO may leverage existing forums and projects. These could include building on the work of the Grid-LDC Interoperability Standing Committee, as well as existing relationships with LDCs, potential DER market participants, and other key stakeholders, to begin scoping, planning and testing prior to assuming full responsibility for project implementation. Another key initiative informing the integration of DERs in wholesale markets is the IESO-led York Region Non-Wires Alternatives Demonstration project, which is expected to result in significant learnings for the options in this paper. In particular, the project will test whether the adoption of an independent total distribution system operator model will simultaneously enhance T-D interoperability and demonstrate the ability of non-wires alternatives to defer investments in traditional distribution and transmission infrastructure.[65]

3.7.5 Conclusion

3.7.5.1 Enhancing T-D Interoperability – Modifying Connection Process for Aggregations

To avoid expected areas of conflict between the operational needs of the bulk system and of the distribution system, it is important to involve LDCs in the connection assessment and registration process for aggregated DERs. This would give them a measured ability to approve or reject DER aggregations that threaten to compromise the reliability of their systems or degrade the life of their assets. This is a prudent first step toward further coordination that may be required in the future given the current limitations on the real-time modelling of the distribution system, and the absence of real-time communication and coordination protocols for DER aggregation dispatch. Initially, such efforts could focus on particular T-D interfaces that may present concerns for LDCs. As the volume of DER aggregations increases, more T-D interfaces of concern could be incorporated into this vetting process. This option merits further consideration in order to better understand the components of and process for a coordinated connection and registration process for DERs and aggregations that incorporates distribution-level considerations.

Conclusion ⟶ Merits further consideration

[65] See Concept Design for IESO York Region NWA Demonstration slides in [80].

3.7.5.2 Enhancing T-D Interoperability – Sharing Day-Ahead Schedule with LDCs

Sharing day-ahead schedules for DER aggregations with the relevant LDCs (i.e., those within whose service territory the DER aggregation is electrically connected) would enable them to prepare for potential adverse circumstances or reject scheduling that can cause reliability issues. However, this option has the potential to create an ongoing administrative burden for both the IESO and LDCs, unless sophisticated automated processes are developed. An additional issue with this option relates to the confidentiality of market participants' intentions, particularly if the role of LDCs is expanded to include resource ownership in the future. Due to these issues, and the fact that the IESO's day-ahead market is still under development as a component of the MRP, this white paper recommends that this option be paused, and reconsidered as DER aggregation volumes achieve sufficient scale.

Conclusion ⟶ Does not merit further consideration at this time

3.7.5.3 Enhancing T-D Interoperability – Coordination of Aggregation Boundaries

To further mitigate potential conflicts between the needs of the bulk system and the conditions expected within the distribution system, LDCs can participate in the development and regular reevaluation of aggregation boundaries affecting their service territory, by having input into which T-D interfaces can be used as part of the same aggregation. Since LDC input into this process may not be warranted in the short term, given the lack of DER aggregations participating in the IAMs (other than HDR), this option should be paused, and reconsidered when DER aggregation volumes achieve sufficient scale.

Conclusion ⟶ Does not merit further consideration at this time

3.8 Identifying and Communicating System Capabilities and Needs

3.8.1 Background

A central consideration for prospective DER developers is whether they will be approved to connect their resources to the electricity grid,[66] and, if so, whether they will be likely to operate them in an economic manner for the useful life of the facility.

In deciding whether and how to accommodate requests to connect DERs, system operators at all levels (used here to refer to any operator of electricity systems, including bulk system operators, transmitters, and distributors) strive to balance the capabilities and needs of their electrical systems. High-level considerations for both parties are outlined in Table 11.

TABLE 11: DEVELOPER AND SYSTEM OPERATOR CONSIDERATIONS

Developer Considerations	System Operator Considerations
Can the system operators connect my resource? Once connected, can I operate my resource in an economic manner? Or will system conditions constrain my resource's operation?	**Can the resource be accommodated without electrical system upgrades?** Does the resource (and its operational characteristics) satisfy an electrical system need? Will the resource continue to serve this need throughout its expected lifespan?

This section of the paper discusses how the IESO and Ontario's LDCs may communicate the capabilities and the needs of their electrical systems in ways that:

- Provide prospective DER developers with more actionable information and guidance on where resources can be connected; and
- Help meet the needs of the electricity system with greater efficiency and precision

Prior to describing options to accomplish these objectives, this paper outlines considerations that pertain to identifying system capabilities and needs.

66 This is particularly applicable for resources that plan to inject power (e.g., generators) and not typically applicable to demand-side DERs.

3.8.1.1 Approving DER Connections based on System Capabilities

Because DERs are embedded within the distribution system, connection requires approvals at the bulk system level (by ISO/RTOs and transmission operators)[67] and almost always at the distribution system level (by distribution utilities). These approvals depend on existing and forecast power system conditions – knowledge held by system operators and planners at both levels. Before deciding to approve a connection, system operators must ensure the electrical system is capable of incorporating the resource without compromising safety or reliability, or the longevity of system components.[68] It is important to note that a system's *ability* to connect a resource does not necessarily mean the resource is *needed* at that connection point.

DER connections can be assessed on case-by-case basis, where the project proponent has limited or no knowledge of system conditions that might influence approval prospects. However, with more streamlined processes, system operators can generate and provide freely accessible information to developers about where the system can – and cannot – accommodate new resources. This first-level screen can help a resource determine whether it can or should proceed with the connection request, saving time and effort for both the developer and system operator.

Historically, system capability assessments for DERs have been performed specifically to assess the capacity available to host distributed generation (i.e., resources that plan to inject power into the grid).[69] In power system terminology, this has colloquially been referred to as "hosting capacity." While definitions vary, hosting capacity can be defined as "the quantity of distributed generation that can be integrated into the electrical system without requiring changes/upgrades to the existing electricity infrastructure, and without prematurely wearing out existing equipment."[70] Methodologies for determining hosting capacity vary from simplistic to highly complex, [71] and involve differing levels of detail, from electrical zone down to a circuit or feeder level. Capacity analysis can estimate available capacity numerically, or simply indicate the likelihood that resources will be permitted to connect [50]. Since electrical systems and conditions can shift, hosting capacity analysis must be updated and published regularly to reflect material changes.

If a resource passes the first layer of screening identified by the hosting capacity analysis, a project-level assessment may be necessary at the distribution utility level. However, conducting a power system impact analysis for each resource can be cumbersome, so the review at the distribution level might be simplistic for smaller distributed-generation projects and more involved for larger ones. When determining whether to connect a project (or projects in general) in a particular electrical area, the distribution utility generally errs on the side of caution by assuming coincident adverse conditions (even if these occur infrequently).[72]

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[67] Bulk system operators are generally concerned with the impact of larger projects, the cumulative impact of smaller projects, and with other macro-level issues, such as congestion on the transmission system.

[68] The transmitter or distribution utility may also indicate whether system upgrades are necessary to permit connections, and offer the project proponent the opportunity to bear the costs of those upgrades in order to connect. Due to the costs associated with both studying project impacts and upgrading the grid, this is generally reserved for larger projects.

[69] Such assessments are also used to determine whether large loads can connect.

[70] This and several definitions of hosting capacity are described in [50].

[71] A highly simplistic method of determining hosting capacity is the "15% rule", which caps penetration levels at 15% of a feeder's peak load; see Table 1 in [50]. In Ontario, Hydro One uses the "7% rule", which specifies that total generation must not exceed 7% of the annual line section peak load on F-class feeders or 10% for M-class feeders; see [53].

[72] For example, periods where minimum loads coincide with maximum generator output.

Such legacy modelling assumptions and practices (applied at both the bulk system level and the distribution level), which are used to define hosting capacity and/or authorize connections, do not exploit the advanced technical capabilities DERs may have in responding (either individually or collectively) to the very adverse system conditions the system operators are trying to prevent. For example, while solar PV systems produce electricity regardless of system conditions, modern inverter technology makes it possible to curtail solar output.[73] Alternatively, leveraging a complementary DER to mitigate adverse impacts – for example, a flexible load (such as an electric hot water heater or battery storage device) – can increase consumption to resolve issues relating to excess PV generation.[74] The Regulatory Assistance Project, which developed guidelines for integrating DERs into electricity grids, recommends that ISO/RTOs and distribution utilities account for such capabilities to alleviate constraints to distributed generation integration [51]. While the operational and market mechanisms to exploit these features are not currently broadly deployed by ISO/RTOs, such control strategies are increasingly being put into practice.[75,76] As such control strategies become more common and reliable, hosting capacity restrictions can evolve to take account of these changes.

3.8.1.2 Identifying Needs and/or Providing Market Signals

In addition to providing hosting capacity information, system operators and planners can identify specific needs in areas of their service territory where DERs may be able to provide an alternative to wires solutions.[77] This can be performed at a fraction of the effort, and provide greater benefits to system operators than attempting to communicate hosting capacity for all service areas.

Historically, if and when needs are published, they typically address local supply requirements. Though seldom done in the past, needs can also be specified to mitigate congestion or other power system issues caused by too much local supply.[78] However, ISO/RTOs and distribution facilities have not always clearly articulated system needs, capabilities, and opportunities with the granularity needed by DER developers, making it difficult for developers and customers to determine how to site DER projects to achieve maximum grid benefits.

Even if system needs are known and communicated, disparities may remain between the locational-temporal system need and the electricity price available to the DER at that location. For example, if the market applied a zonal price, but the system need related to a specific transmission circuit and distribution circuit, the available zonal pricing structure would fail to guide investment and real-time operations to meet that need. As applying a geographically specific dynamic electricity price would be a complex undertaking, some utilities have adopted a programmatic approach – for example, by offering monthly payments, rebates, or equipment in exchange for the ability to control the customer's DER to manage these more locational-temporal specific system constraints.[79]

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73 However, it may not make financial sense to install a PV system if this type of curtailment occurs too frequently.

74 For hosting capacity enhancement techniques, see section 5 in [50].

75 Hawaiian Electric Company (HECO) has used grid-interactive water heaters to "load build" in conditions of solar oversupply.

76 See [75], and for a description of the theoretical application of such a strategy, see [74].

77 These are known as "non-wires alternatives" or "non-wires solutions."

78 Using responsive loads to meet supply congestion is a new approach, but may increase with the growth of distributed generation. Responsive loads can effectively increase or enhance the hosting capacity for distributed generation.

79 These alternative approaches are described in [81, pp. slide 25, 31-32].

In addition to establishing needs, considering and communicating their expected longevity can impact the utilization of resources over their expected life. For example, if needs do not persist and constraints on operations materialize, the resource owners face reduced market revenue and potentially curtailment (if reliability becomes an issue). Resource owners may, therefore, benefit from a forecast of system conditions to help guide their investment decisions. However, each level of geographic specificity may result in more dynamic system conditions and less certain forecasting ability. While historic information on system conditions can often be made available with considerable effort, ISO/RTOs and distribution utilities will face major challenges in producing meaningful projections of conditions that influence DER operations. Even if these forecasts are produced, conditions can change dramatically based on other changes to load, supply and infrastructure. As a result, ISO/RTOs and distributors may only be able to communicate areas where future trends in system conditions are obvious and those where they are uncertain. Areas where future conditions are uncertain may not be favourable to deployment of distributed generation, but may instead favour the development of DERs with more flexibility and control as a hedge against uncertainty (e.g., flexible load).

3.8.2 Overview of Option

A number of dynamic factors can determine bulk and distribution system capabilities and needs. While it is impossible to produce entirely accurate granular indicators of current and future system conditions, this section describes some reasonable steps that could be taken to provide better information to potential DER market participants.

3.8.2.1 Identify Hosting Capacity and System Needs on the Transmission and Distribution System

3.8.2.1.1 Providing Guidance on Hosting Capacity/System Value

At the Transmission Level

To provide guidance on where the bulk system can accommodate DERs, the IESO could identify areas of bulk system congestion and work with transmitters to determine hosting capacity and/or system value that reflects transmission asset constraints.[80]

[80] At foreseeable uptake levels, DERs in Ontario result in the reduction of net load on the IESO-controlled grid, and will rarely negatively affect the TS. DERs do, however, influence congestion on the bulk system in ways that may be detrimental to its efficient operation. Prior TS "hosting capacity" limits were set to mitigate congestion, and were indicative of the bulk system value of DERs at that TS.

Previously, under the FIT and LRP programs, the IESO released a transmission availability table.[81] This table provided developers with general guidance to facilitate the planning of projects, and discussions with transmitters and LDCs. For the transmission system, the granularity of the information provided was at the transformer station (TS) bus level.[82] Providing this level of information gave proponents a sense of the capacity available beneath that TS bus. Information was also provided on "area limits," which were developed to mitigate transmission congestion caused by excessive generation – congestion that would otherwise impede the flow of electricity between regions of the bulk system. These area limits, portrayed visually in the form of a transmission area map, were important, because even if generation capacity was available at the underlying distribution level, transmission congestion could still be aggravated by the resulting net load reductions on the TS. These transmission availability tables were developed for a specific purpose – the batch processing of non-dispatchable distributed generation that operated independently of market signals. As such, there is limited benefit in recycling this process for DERs participating in wholesale markets.

Going forward, in a paradigm where market forces are intended to drive DER behaviour, the communication of hosting capacity is therefore most relevant:

- For DERs that are not dispatchable (e.g., self-scheduling, intermittent)
- When market signals are not reflective of system conditions (e.g., if a nodal price is unavailable to market participants, identifying hosting capacity at that node becomes important)

For the above, future efforts to portray bulk system hosting capacity could involve the regular deployment of a transmission area map to identify area limits and the portrayal of TS bus capacity. If the effort required prevents detailed capacity assessments, the level of availability could be broadly classified – as available, limited, or unavailable – rather than as a specific numerical amount (see Table 12). This information could be updated with regular planning cycles.

TABLE 12: SIMPLIFIED DISPLAY OF HOSTING CAPACITY

Hosting Capacity	Available	Limited	Unavailable
Zonal Transfer	Available	Limited	Unavailable
TS Bus	Available	Limited	Unavailable

As mentioned earlier, distributed generation may still be able to connect within zones and downstream of TS buses that have limited or unavailable transmission capacity. However, a "limited" or "unavailable" status can be viewed as a reasonable proxy for bulk system value, future market price outlook, and/or potential for curtailment due to bulk system conditions. And while an "available" status could suggest curtailment is unlikely due to bulk system conditions, it is not indicative of system need.

[81] For an example and further description of transmission availability tables, see [83].

[82] Although less relevant to distribution-connected resources, circuit capacity tables were also provided.

While the determination and communication of hosting capacity and bulk system value requires effort on the part of the transmitter, Hydro One Networks, Ontario's largest transmitter, regularly publishes both the numerical TS bus hosting capacities, and the hosting capacities for the distribution systems it supplies [52]. This means that a high proportion of the province's electricity system has no-cost access to both transmission- and distribution-level transformer station hosting capacities. Hydro One has also developed a capacity evaluation tool to help prospective generators determine whether sufficient capacity exists for their project [53].

At the Distribution Level

At the distribution level, more detailed information on low-voltage distribution feeder capacity and circuits can become important for parties interested in connecting distributed generation. However, producing this information regularly may be challenging and expensive [54, p. 40]. Instead, similar to the option proposed at the bulk system level, the distributor may identify nodes and circuits according to whether they have availability, limited availability, or no availability, taking into consideration capacity and congestion on their systems. Even this high level of guidance can be useful for distributed generation developers. Currently, developers are typically required to submit a detailed application with project information to the LDC before the latter can determine connection availability.

Areas where capacities overlap between the bulk system and the distribution system provide the most likely locations for the deployment of distributed generation.

3.8.2.1.2 Communicating System Needs

At the Transmission Level

The IESO can communicate transmission-level system needs identified through the provincial and regional planning processes.

Through its Annual Planning Outlook [55], the IESO could specify, at both a bulk system and zonal level, where certain system services, such as capacity, are needed. Going forward, given the expanded capabilities of DERs on the load side, the IESO could further identify areas that would clearly benefit from load flexibility, which can be used to alleviate not only province-wide surplus conditions, but regional surpluses that contribute to transmission congestion.

The IESO, through its regional planning process, could also identify more geographically specific needs, including where DERs could potentially act as non-wires alternatives [56]. The regional planning process is itself needs-based, prioritizing the analysis and review of regions based on the level and urgency of need, with each region being reviewed at least every five years.[83] While the IESO could continue identifying local capacity needs through regional planning, the process could also be leveraged to determine which areas can benefit from load flexibility to alleviate congestion – something that has not been considered in the past.

[83] The IESO has recently started to present needs in a more granular way through its regional plans.

At the Distribution level

Rather than identify the distribution transformer and feeder capacities in their service territory (which may require substantial effort), distributors may contribute to the effective siting of DERs by publicizing key electrical areas where DERs could add value. These could include locations where circuits are either approaching their thermal limits, and would benefit from distributed generation or load curtailment, or where they have excess distributed generation, and could benefit from flexible loads that increase in response to excess generation. These needs can be established through community energy planning activities, which are supported by the province [57].

The points at which the overt needs of the transmission and distribution systems overlap are the most ideal locations for siting DERs.

3.8.3 Potential Impacts to Visibility, Competition, Reliability and Distributors

By steering DER development interest to the most appropriate areas of the electricity grid (in terms of hosting capability and system need), the IESO can enhance interest and competition in these areas and drive better value for ratepayers for the services the system needs most.

Communicating system needs and capabilities prevents DERs from being deployed in areas that can aggravate adverse system conditions, while promoting resource deployment in areas where they contribute to bulk system reliability. The options outlined in the section could also help mitigate existing transmission congestion and avoid contributing to congestion in the future.

When both the IESO and LDCs identify preferred areas for DER deployment based on obvious needs, DER siting can be drawn toward areas that have overlapping benefit. As a result, when DERs are dispatched for bulk system need, there is an increased likelihood that local system needs are met simultaneously, and a decreased likelihood that the DERs will adversely impact the distribution system. Distribution systems can further benefit when DERs act as non-wires solutions at the local level, which can reduce distribution system costs if new distribution assets can be deferred or avoided.

3.8.4 Implementation Considerations

The development of the informational products identified in this option must be informed by several factors:

- The frequency and effort of determining hosting capacity based on existing processes
- The necessity for developing hosting capacity in the presence of market signals
- The existing processes that can be leveraged to determine system need

The frequency with which hosting capacity (in the form of area limits and transmission circuit limits) will be reassessed would likely have to be incorporated into the IESO's existing products and processes to minimize workload and manage stakeholder expectations with respect to the delivery of this information. Such higher-order information could be included in the IESO's Annual Planning Outlook.

The need to impose bulk system hosting capacity constraints on DERs largely depends on whether or not market signals are reflective of transmission system constraints.[84,85] If market signals are perfectly reflective of such constraints, and resources are curtailable, then bulk system hosting capacity constraints on DERs might be unnecessary. If the MRP results in zonal market prices, transmission system hosting capacity information, such as TS limits and transmission circuit congestion, will still be of value.

At the regional level, the IESO can continue to leverage the regional planning framework already established (and in the process of being enhanced) to identify needs for particular transformer stations that serve LDCs. Regional plans take approximately two years to develop and are conducted at least once every five years. Changes to the regional planning process, which aim to increase coordination between bulk, regional, and community energy planning, are currently underway, and may expedite opportunities to identify how and where DERs may be leveraged as non-wires alternatives [58]. In coordination with LDCs, this work could also identify particular distribution system areas that would be most ideal for the siting of DERs. In deviating from past emphasis on local supply needs, the IESO may wish to identify non-wires opportunities that can resolve local oversupply conditions, which exacerbate transmission congestion and could be addressed by load increases from demand-side DERs, such as batteries and flexible loads.

3.8.5 Conclusion

3.8.5.1 Identifying System Capabilities and Needs – Hosting Capacity

Providing public information on available hosting capacity can help guide DER development in areas of the system with the ability to accommodate new resources. The IESO has past experience coordinating with transmitters to provide such information relating to the transmission system. While Hydro One currently provides TS and even DS hosting capacity information for its service territory, this white paper recommends that the IESO further consider processes to regularly determine and communicate higher-tier constraints relating to zonal and transmission circuit congestion for the entire province, while working with transmitters to determine TS bus constraints outside of Hydro One service territory. These activities could be undertaken periodically as needed with a manageable amount of effort.

Conclusion ⟶ Merits further consideration

3.8.5.2 Identifying System Capabilities and Needs – System Needs

The determination and communication of system needs could expediently direct DER development toward areas of high and overlapping bulk and local system benefits. The IESO's regional planning process provides an avenue for coordination between the needs of transmitters, LDCs, and communities. To enable more efficient and valuable DER siting, the IESO could address the extent to which DERs could be used to meet local system needs as part of its regional planning process.

Conclusion ⟶ Merits further consideration

[84] FERC Order 2222 recognizes the benefits of DERs locating in accordance with price signals reflective of system conditions, but does not discuss issues where price signals are not reflective of those system conditions [3, p. 7].

[85] In its DER Roadmap, and as part of its move toward nodal pricing, the NYISO noted that "sub-zones and load pockets may experience real-time conditions that are not fully reflected in the zonal price" [85].

4. Conclusion

As discussed in section 1 of this paper, the IESO has considered the options to enhance DER participation in the IAMs explored in this white paper from the perspective of:

- Increasing the visibility of distribution-connected resources
- Enhancing competition in the IAMs
- Maintaining bulk system reliability
- Impacts to the distribution system and distributors
- IESO resources and costs required to implement
- Implementation time frame
- Ongoing administration requirements
- Interdependencies with other IESO initiatives
- Whether there are viable alternatives that can achieve the desired outcome

Based on an evaluation of the potential impacts of the options, each was placed into one of three categories based on whether the option:

- **Merits further consideration** by the IESO and stakeholders and should be considered in any future market design initiatives or IESO tool changes;
- **Should be tested through a pilot** to assess the technical feasibility before making a decision on whether the option merits further consideration; or
- **Does not merit further consideration at this time** based on high-level net benefits or need.

A summary of the conclusions for each of the options explored in this paper is included in Table 13.

4.1.1 Options that Merit Further Consideration and Pilots

Exploring a phased approach to reducing the minimum-size threshold represents the most direct way to expand eligibility to smaller DERs, while still mitigating potential operational and administrative risks to the IESO. As discussed in section 3.1, even with a reduction in the minimum-size threshold, it is likely that the parameters of permitted DER aggregations would also need to change to accommodate the characteristics of certain types of DERs. Implementing multi-nodal aggregations and aggregations of non-dispatchable generators would require significant changes to the IESO's tools and market rules, but would also remove significant barriers to participation.

Mixed aggregations of dispatchable generation and mixed DR contributors would further reduce barriers to participation. Even so, these options would require piloting before further consideration, given that their technical feasibility with the IESO's existing tools is unknown at this time. As a result, there is merit in clarifying existing rules and processes with respect to identifying the connection point to the ICG for DERs, and revising the connection assessment process to take into account dynamics at the T-D interface or below.

In addressing barriers associated with the high cost and complexity of complying with telemetry requirements, the use of already available data should be prioritized. Investigating whether telemetry data already collected by LDCs for certain types of DERs can be used for market participation purposes represents a way to avoid duplication of efforts and costs for DERs. Further, piloting device-level data or data from inverters could help determine whether these sources could comply with current IESO requirements or whether modifications to those requirements are warranted.

In order to help address potential future coordination issues with LDCs, and respect risks to their distribution systems, consideration should be given to the development of a coordinated connection and registration process for DERs, especially aggregations.

Providing guidance to participants on where the bulk system can accommodate DERs, identifying areas of bulk system congestion, and working with transmitters to determine hosting capacity that reflects transmission asset constraints will also help address informational barriers relevant to DERs. Further, the identification of more geographically specific needs through the regional planning process, including where DERs could potentially act as non-wires alternatives, would assist DERs in locating where they can provide the most value to the system.

For those options identified as meriting further consideration, the IESO will incorporate learnings on the potential impacts and key considerations into any future market design work related to DERs, as well as decision-making related to enhancing the capabilities of IESO software tools. The IESO will also consider opportunities, including the use of targeted calls under the Grid Innovation Fund, to explore the options identified as requiring pilots. These, in turn, will improve understanding of the associated technical capabilities, implementation challenges and potential benefits – to the IESO and ratepayers.

4.1.2 Further Work Required

As the IESO proceeds with further work to enhance the participation of DERs in the IAMs, the insights and considerations from this white paper will help it determine which approaches to integration can provide the most benefits. Before making decisions on whether to proceed with a particular option, it will be critical to understand the scope of future potential market participation (e.g., how many MW, what type of resources, which products they could provide). As discussed in section 2 of this white paper, the potential for existing contracted DERs to participate in the IAMs in the short term is limited due to the types of resources represented (largely intermittent) and the timeline over which contracts expire (2030 - 2040). As such, much of the benefits case for implementing any of the options discussed in this paper would likely stem from their ability to encourage new DERs to participate in the wholesale markets. The IESO will be exploring opportunities to conduct this analysis in 2021.

TABLE 13: SUMMARY OF CONCLUSIONS

Option	Merits Further Consideration	Pilot	Does Not Merit Further Consideration at this Time
Reducing the Minimum-Size Threshold			X
Reducing the Minimum-Size Threshold - Phased Approach	X		
Clarifying Existing Aggregation Rules and Processes	X		
Modifying Aggregation Boundaries: Sub-Zonal Aggregation Boundaries			X
Modifying Aggregation Boundaries: Multi-Nodal Aggregations	X		
Modifying Aggregation Compositions: Mixed Aggregations of Dispatchable Generation		X	
Modifying Aggregation Compositions: Mixed DR Contributors		X	
Creating a Participation Model for Aggregated Non-Dispatchable Generation	X		
Permitting Alternative Telemetry Sources: Device Level Data		X	
Permitting Alternative Telemetry Sources: Inverters		X	
Permitting Alternative Telemetry Sources: LDC Collected Operational Data	X		
Enhancing T-D Interoperability: Modifying Connection Process for Aggregations	X		
Enhancing T-D Interoperability: Sharing Day Ahead Schedule with LDCs			X
Enhancing T-D Interoperability: Intra-day Coordination with LDCs/Boundaries			X
Identifying and Communicating System Needs and Capabilities: Hosting Capacity	X		
Identifying and Communicating System Needs and Capabilities: System Needs	X		

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