Procuring Grid Services from Distributed Energy Resources (DER)

DER Scenarios and Modelling Study Conducted for the Independent Electricity System Operator and Alectra Utilities Corporation

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ACKNOWLEDGMENTS

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ABSTRACT

Distributed energy resources (DER) –such as battery energy storage, solar photovoltaics, small diesel or combined heat and power generators, demand response, and their associated controls and technologies connected to the distribution network– are increasingly being considered for their capabilities to provide energy and grid services. Such services may be provided to the electric utility operating the distribution system as well as to the wholesale market operator operating the bulk transmission system. In particular, DERs may commit to provide multiple grid services across these domains, a strategy known as "value stacking".

This report evaluates the opportunities and challenges related to DER-provided grid services in the context of the electric systems operated in Ontario, Canada, by distribution utility Alectra and wholesale market operator IESO. A set of grid services and scenarios involving one or several of these services are defined, along with two ISO-DSO coordination models. Coordination diagrams are presented, detailing *when* coordination is needed and *what* specific actions are executed to effectively coordinate. Finally, modeling and simulation results evaluating the services and scenarios considered are discussed, in the context of a set of Alectra feeders, as well as other feeders considered to be representative of feeder types that may exist across Ontario.

Keywords

Distributed energy resources (DER)

Grid services

Flexibility services

Non-wires alternatives (NWA)

Wholesale electricity markets

Product Type: Technical Report

Product Title: Procuring Grid Services from Distributed Energy Resources (DER): DER Scenarios and Modelling Study Conducted for the Independent Electricity System Operator and Alectra Utilities Corporation

PRIMARY AUDIENCE: Independent system operators (ISO), distribution utilities.

SECONDARY AUDIENCE: DER aggregators, utility and wholesale regulators

KEY RESEARCH QUESTION

Distributed energy resources (DER) - such as battery energy storage, solar photovoltaics, small diesel or combined heat and power generators, demand response, and other technologies connected to the distribution network - are increasingly being considered for their capabilities to provide energy and grid services. Such services may be provided to the electric utility operating the distribution system as well as the wholesale market operator operating the bulk transmission system. In particular, DERs may commit to provide multiple grid services across these domains, a strategy known as “value stacking”. The overarching goals of this research are to 1) better understand the technical potential and reliability implications of DERs providing a range of grid services, and 2) evaluate the market coordination, operational coordination, and data exchanges required between DERs, Alectra and IESO to enable these services.

RESEARCH OVERVIEW

First, a set of scenarios involving one or several of these grid services are defined, along with two framework models allowing the independent system operator (ISO), distribution system operator (DSO) and participating DERs (individual or aggregated DER) to coordinate their operations. Coordination diagrams are presented, detailing *when* coordination is needed, and on *what* specific actions are executed to effectively coordinate. Finally, modeling and simulation results evaluating the services and scenarios considered are discussed, in the context of a set of Alectra feeders, as well as other feeders considered to be representative of feeder types that may exist across Ontario.

KEY FINDINGS

- DERs can provide one or several grid services (“value stacking” strategy). Two coordination models are considered in this report: DERs provide 1) all grid services through the DSO (Total DSO coordination model) and the DSO aggregates wholesale services with the ISO, and 2) distribution services to the DSO and wholesale market services to the ISO (Dual Participation coordination model).
- The procurement and delivery of grid services from DERs can be decomposed into a series of successive stages, and the coordination needs between ISO, DSO and DERs at each stage can be described using coordination diagrams.
- For the Alectra service territory, robust feeder design tends to address and prevent the most common distribution feeder constraints, allowing for DERs to provide bulk system services to the IESO without causing adverse distribution impacts. However, common thermal and voltage constraints on less robust feeder design will prompt more scrutiny for appropriate location and sizing of DER to provide grid services. Larger DER (commercial- and utility-scale) will be more likely to reliably address distribution constraints and still leave operational headroom for participation in the wholesale energy market.
- Wholesale market offers coming from DERs should consider the cost and physical characteristics of all DERs that make up a wholesale offer, including the aggregation of different technologies and their aggregate characteristics. The way those are aggregated and the information available may depend on the coordination framework in place.

- Distribution system losses, and how DERs may reduce (or in some cases increase) those losses, is the main characteristic that differentiates a DER from a similar technology on the transmission system for market participation purposes. Review of losses impacts from the feeders in this project shows that DERs providing bulk system services would have a minor impact on distribution losses, and in turn a minor impact on dispatch and market solutions; several DER locations were considered across the feeders modeled as part of this analysis.

WHY THIS MATTERS

DER-provided grid services are an emerging approach explored at early adopter utilities and wholesale markets, with limited practical experience to date. This research explores some of the opportunities and challenges related to DER-provided grid services in the context of the Ontario power system, with the goal of informing stakeholders in Ontario and beyond.

HOW TO APPLY RESULTS

This research provides a starting point to industry stakeholders tasked with evaluating approaches enabling DERs to provide grid services to the DSO and/or ISO. Topics covered in this report include service product definitions, structure of market offers, and ISO-DSO coordination models and processes. Further, illustrative simulation results are provided for representative feeder models. The framework for how to conduct these coordination diagrams or modeling efforts can be replicated for similar utility/ISO pairs and similar study applications.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- EPRI Distribution Services Working Group (DSWG)
- EPRI DER Bulk Service Power Working Group (DERBSP WG)

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PROGRAM: DER Integration (P174)

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1 INTRODUCTION

Background

Distributed energy resources (DER), those technologies connected to the distribution network, are increasingly being considered for their capabilities to provide energy and grid services. These services may be provided to the electric utility operating the distribution system, and/or to the wholesale market operator operating the bulk transmission system.

Grid services provided by DERs have the potential to cost-efficiently replace (or enhance) conventional resources, network reinforcements, or solutions otherwise required to maintain reliable operations. For this reason, electric regulators in several jurisdictions are now encouraging (and sometimes requiring) distribution utilities to fully consider DER-provided distribution services as part of their standard planning practices, along with traditional capital investments. In addition, several recent regulatory initiatives, including the Federal Energy Regulatory Commission's (FERC) Order No. 2222 in the U.S., require that wholesale market operators allow and enable DERs to provide energy, capacity, and ancillary services in the wholesale electricity markets if they are technically capable of providing those services.

Objectives and Research Questions

This project researches the opportunities and challenges related to DER-provided grid services in the context of the electric systems operated in Ontario, Canada, by distribution utility Alectra and wholesale market operator IESO.

The overarching goals of this effort are to 1) better understand the technical potential of DERs to provide a range of grid services, and 2) evaluate the market coordination, operational coordination, and data exchanges required between DERs, Alectra and IESO to enable these services, considering two different coordination frameworks.

Key research questions addressed in this work include:

1. What is the technical viability of DER-provided services to defer traditional distribution upgrades?
2. What is the technical impact of DER-provided distribution services at the Transmission-Distribution (T-D) interface?
3. Can DERs provide wholesale market services to the IESO, and if so, how would their offers to the wholesale market be structured?
4. What kind of coordination is needed between Alectra and IESO to enable DERs to provide grid services?
5. How will the coordination process differ based on different frameworks, such as the "Total DSO" and "Dual Participation" Frameworks?

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Approach

This project first clarifies several key concepts, which can be seen as fundamental building blocks. This includes defining the various *grid services* considered, the *scenarios* analyzed (each scenario combining multiple services), and the *coordination models* to be evaluated (Chapters 2 and 3).

Second, coordination needs between Alectra, IESO, and the DERs (or DER aggregators) are analyzed across the scenarios considered (Chapter 4). The goal is to identify in a systematic manner *when* coordination is needed, and on *what*. The analysis structures the coordination needs identified into multiple logical stages, with multiple steps defined for each stage. The end result is a series of coordination diagrams which are detailed enough to convey the coordination needs at a functional level, but flexible enough to serve as a starting point to a range of implementations.

Third, modeling and simulation analysis is conducted at the distribution feeder level for a set of Alectra feeders, as well as other feeders considered to be representative of feeder types that may exist across Ontario (Chapter 5). The goal is to assess quantitatively how DER-provided grid service may impact distribution system operations. The structure of market offers and the potential for adjustments based on DER impacts to the distribution system on losses are also described (Chapter 6).

2
DEFINING GRID SERVICES

The term *grid services*[1] refers broadly to the range of services DERs can potentially provide to distribution system operators[2] (DSO) and/or wholesale market operators[3] (ISO). At a high level, DERs providing grid services are typically required to adjust their power output (active and/or reactive) in response to activation and/or dispatch signals sent by the grid entity to which the services are being rendered (e.g., DSO, ISO). They may require mandatory response or could be voluntary. DERs can provide services as standalone entities, or via DER aggregators[4] (DERA).

The industry has different levels of experience with distribution and bulk system grid services. In areas where wholesale markets exist, wholesale electricity markets have had well-defined services focused on the bulk system grid needs and market products in place associated with these clearly defined system needs including definitions, performance requirements, participation models, bidding procedures, metering and telemetry requirements, and settlement mechanisms. In contrast, distribution services are less clearly defined, with a limited number of early-adopter utilities already procuring these services from DERs as part of their standard planning and operational practices. This chapter provides an overview of these grid services and when applicable, how they are specifically defined in Ontario.

Bulk System Service Products

Bulk system services are provided by resources to the ISO, which acts as the bulk system balancing area authority, through a range of market products, arrangements, and/or standards. Some examples of these grid services are shown in Figure 2-1 (energy is not shown here since the figure focuses on services ancillary to energy). In areas where organized markets exist, there are a number of services that are purchased by the ISO and sold by different market participants. Historically, most of these bulk system services[5] have been provided by larger, transmission-connected resources. In this effort, we focus on three bulk system services with each having corresponding auctions in which they are procured. For each of these services, DERs may

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[1] In Europe, the term "flexibility services" is also used to refer to grid services. This report uses the two terms interchangeably.

[2] While the term *distribution system operator* (DSO) is often used in ongoing discussions related to grid modernization, the utility industry has not yet converged to a universally accepted definition. This report does not intend to set such definition: the term DSO is used broadly to refer to a traditional distribution utility (called, in the Ontario context, a local distribution company or LDC) that has implemented new functional capabilities to manage high levels of DER penetration and enable DERs to provide grid services.

[3] This report developed in a North America context uses the terms *independent system operator* (ISO) and *wholesale market operator* interchangeably. In Europe, the term *transmission system operator* (TSO) is also used.

[4] For simplicity, throughout this report, whenever the term "DER" is used, it is always assumed that this could either refer to an individual DER, or a portfolio of DERs managed as a group by a DERA.

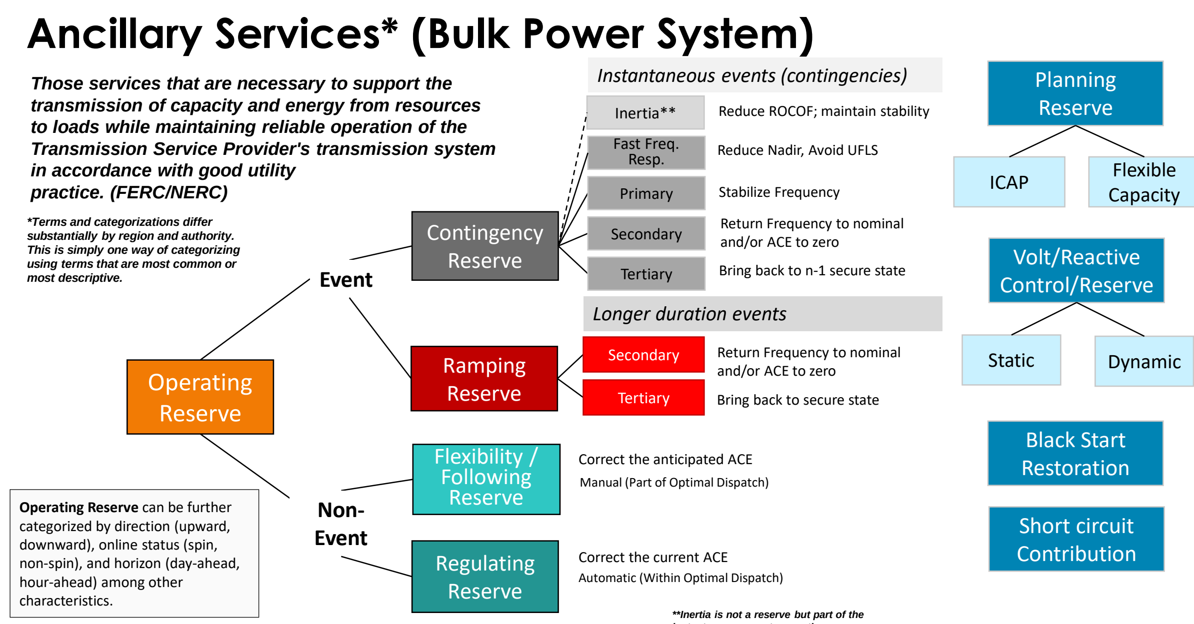
[5] This report uses interchangeably the terms *bulk system services* and *wholesale services* to refer to the services described in this subsection, since organized markets exist in Ontario. We acknowledge that in general, these two terms are not necessarily synonyms.

increasingly participate and compete with traditional resources to provide these services. The three bulk system services we focus on in this project are listed below:

- Energy, including locational and temporal provision
- Operating Reserves
- Capacity

In Ontario, IESO is the ISO operating the bulk system and administering the wholesale electricity markets associated with each of these services.

The rest of this section further describes in the specific context of Ontario the various bulk system services as well as the wholesale market auctions that are used to procure those services, when applicable. It is important to note that the ISO is currently going through a large-scale change to its electricity market design, called the Market Renewal Program[6] (MRP). The MRP has been designed and is currently being implemented with an anticipated go-live date of 2026. In particular, the MRP will include a change to energy pricing with the use of locational marginal prices (i.e., single schedule prices), a day-ahead market, and an enhanced real-time unit commitment, among other features. This may have an impact on how these services are procured, but not a significant impact on the services themselves. In general, we will emphasize the features following MRP, but may call out existing features when it is useful for the reader.



Adapted from Ela et al., *An Enhanced Dynamic Reserve Method for Balancing Areas,* EPRI, Palo Alto, CA: 2017. 3002010941.

Figure 2-1. Examples of bulk system services.

Under current market rules, wholesale market participants in Ontario are classified into two main categories: *dispatchable* and *non-dispatchable.*

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[6] The Market Renewal Program (MRP) is an initiative conducted by IESO to modernize Ontario's electricity markets. Additional information can be found at: https://www.ieso.ca/en/Market-Renewal.

- *Dispatchable* market participants (e.g., generators, storage, large industrial loads, etc.) bid into the wholesale market and receive dispatch instructions every 5 min to reach a specified level of generation or consumption.
- *Non-dispatchable* market participants[7] (e.g., a local distribution company[8] [LDC], self-scheduling generator or load etc.), produce or consume power in real-time and get paid or are charged at the hourly energy price.

Today, most of the loads in Ontario are non-dispatchable, and most of the generators are dispatchable. Finally, the resources from the five interconnected neighboring zones can also import or export power as market participants.

Energy (at time and location)

Energy is obviously the core service provided to consumers and is provided as a product from suppliers that is delivered across the transmission to distribution system to end-use consumers. Following MRP implementation, the ISO will operate both a *day-ahead* energy market (DAM) and real-time energy market (RTM) for buyers and sellers to transact energy across the grid. Based on the supply and demand bids received from the market participants, the IESO will determine the least-cost solution of all suppliers to deliver energy to where it is consumed subject to the constraints of the transmission system and other physical constraints.

The DAM will be cleared for every hour of the following day whereas the RTM is cleared every five minutes. In addition, energy prices for both RTM and DAM will be calculated for different locations across the grid including individual generator locations and substations. By pricing energy for each time point and location, it is said to be converting energy into a commodity that is fungible (a consumer is indifferent to where it came from and who has provided it). The service of providing energy is also thus the service of providing it at the most valuable locations and times. Energy providers can help manage transmission congestion by providing more energy in locations on the receiving end of congested transmission paths and providing less energy at the sending end of these paths. Providers can also support the balancing of energy by providing more or less energy during the times when there is greater or lesser need, respectively. This ability to adjust energy up and down based on the needs at location and times enables these resources to also provide flexibility that can allow for the system to better accommodate changes in conditions from time to time and location to location.

Operating Reserve

In Ontario, operating reserves are procured to balance supply and demand in the event of a contingency, such as a generator or transmission line outage. Three types of operating reserves are procured through the operating reserve market:

- 10-minute synchronized reserve (also called: 10-minute spinning reserve)

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[7] These market participants are not *currently* dispatchable (i.e., their demand is forecasted by the ISO). However, they *could* become dispatchable in the future through some of the service products examined in this report.

[8] This report uses interchangeably the terms *distribution utility*, *distribution system operator* (DSO), and *local distribution company* (LDC). The term LDC is specific to Ontario.

- 10-minute non-synchronized reserve (also called: 10-minute non-spinning reserve)
- 30- minute non-synchronized reserve

Reserve allows for the system to reduce the balancing error of the IESO system and the potential resulting frequency error of the Eastern Interconnection. When the contingency occurs, either all or a subset of the reserve providers are asked to respond by increasing power (or decreasing consumption if a demand-side technology). Synchronized reserve service must be provided by resources that are online and operating and can provide the allocated quantity of reserve within the timeframe specified by the product definition (e.g., 10 minutes). Non-synchronized reserve can be provided by either online resources or offline resources that can be switched online within the timeframe specified by the product (e.g., 10 or 30 minutes).

While most of the reserve products were introduced through NERC or Northeast Power Coordinating Council (NPCC) rules to respond directly following contingency events, IESO also uses the 30-minute non-synchronized reserve for load and renewable ramps and forecast errors. In general, providers of these services can be located anywhere on the IESO system, but they may be discounted when they are significantly constrained by transmission limits. Other balancing areas have introduced zonal reserve products when there is more prevalent transmission congestion and certain reserve have to be located in particular parts of the grid.

The reserve markets are cleared simultaneously with energy in the RTM. The resources are paid per MW-h for the capacity that they allocate to that reserve. They may also be paid for the energy they deliver if and only if they are called to deploy. Under current market rules, each offer to provide operating reserve shall be accompanied by a corresponding energy offer that covers the same MW range. Further, participants cleared for providing reserve are expected to respond if called. A lack of response, or a partial response, may lead to penalties.

Capacity

Capacity is the total capability of a resource to deliver and make itself available to the ISO for critical time periods. Sufficient amount of capacity is necessary to meet resource adequacy criteria, such as less than one day of involuntary load shedding over a 10-year time span. Resources with greater power capability provide greater capacity even if they are not used often. More recently, the accreditation of capacity has been used to determine a comparative amount of capacity between resources and technology that have different reliability performance. A resource that never fails to deliver energy can be said to have perfect capacity and is accredited the full nameplate capacity. A resource that is older and less reliable with a higher forced outage rate will have lower capacity credit than a higher reliable resource with lower forced outage rate of the same size.

Wind, solar, and battery storage have new techniques to determine the capacity accreditation they provide. These methods include effective load carrying capability, which sets the amount of additional load that can be increased with the addition of the resource at the same reliability level as without it. When these resources have greater probability of being available during more critical time periods where there may be greater likelihood of load shedding, they will have greater capacity credit. More recently, capacity has also included energy – it is not just the amount of capacity, but the ability to provide energy during critical time periods. This has been emphasized due to fuel and fuel delivery limitations that have been observed in certain parts of the world.

In Ontario, a capacity auction is run annually in December (of Year X) for a commitment period of one year starting May 1st (of Year X+1) to April 30th (of Year X+2). This one-year commitment period is further divided into two six-month obligation periods: Summer (May to October) and Winter (November to April). Capacity accreditation and capacity needs may be different for those two periods.

All participants cleared in the capacity market are expected to meet their capacity obligations by participating in the energy market. To that end, participants cleared in the capacity market are required to submit dispatch data for all hours of the "availability window" in the day-ahead commitment process (DACP), and in the real-time market. The availability window[9] is defined as follows:

- 12:00 to 21:00 EST, for the Summer period.
- 16:00 to 21:00 EST, for the Winter period.

Market Operation Timelines

Day-Ahead Commitment Process (DACP)

Currently, in Ontario, the IESO uses a day-ahead commitment process (DACP), which provides a dependable view of the next day's available supply and anticipated Ontario demand. The DACP is very similar to DAM in other jurisdictions, except that DACP schedules and prices are not financially binding.

As part of DACP, the dispatchable generators or loads that wish to participate in the day-ahead market must submit their operational data to the ISO by 10:00 AM on the prior day of clearing. These resources also submit an Availability Declaration Envelope (ADE), in which their hours of availability, amount of energy, and capacity limits are specified. These dispatchable resources are allowed to change offered prices, but their bid quantities have to remain within limits specified in the ADE. Importers bringing energy from outside the ISO area do not have to submit import data into the DACP.

The day-ahead calculation engine (DACE) is used to determine DACP schedules. On the pre-dispatch day after the data are submitted by the participants, four DACE runs are executed to generate DACP schedules. In the first three runs, initial schedules are determined, and reliability concerns are also monitored. In the fourth run, which starts at hour 14:00, the final schedules are obtained, and the incentives are calculated. The selected participants can withdraw by hour 15:15.

In future ISO market operations (i.e., post-MRP reform), the DAM will be used to optimally manage resources by committing them on or off over the 24-hour period of the next-day available energy resources and reducing potential real-time failures in power imports. Post-MRP implementation, the day-ahead market (DAM) will replace the DACP.

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[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca/ca-Introduction-to-the-Capacity-Auction.ashx

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Pre-dispatch

In the *pre-dispatch* timeframe, the ISO computes pre-dispatch energy schedules and projected market prices over a forward-looking time horizon, at an hourly resolution. This information allows participants to anticipate market conditions for the coming hours and next day; the goal is to enable efficient and reliable market operations.

During the pre-dispatch timeframe[10] (i.e., the day before the dispatch day), the ISO receives hourly energy bids (supply and demand[11]) and operating reserve bids between hour 6:00 and 10:00. The timing of the pre-dispatch scheduling process for each dispatch day starts after the DACP completes at 15:00 Eastern Standard Time (EST) of the pre-dispatch day and encompasses all hours up to and including the last hour of the next dispatch day. As such, the pre-dispatch optimization process produces rolling hourly advisory schedules for a time horizon of 9 to 32 hours in advance of a dispatch hour.

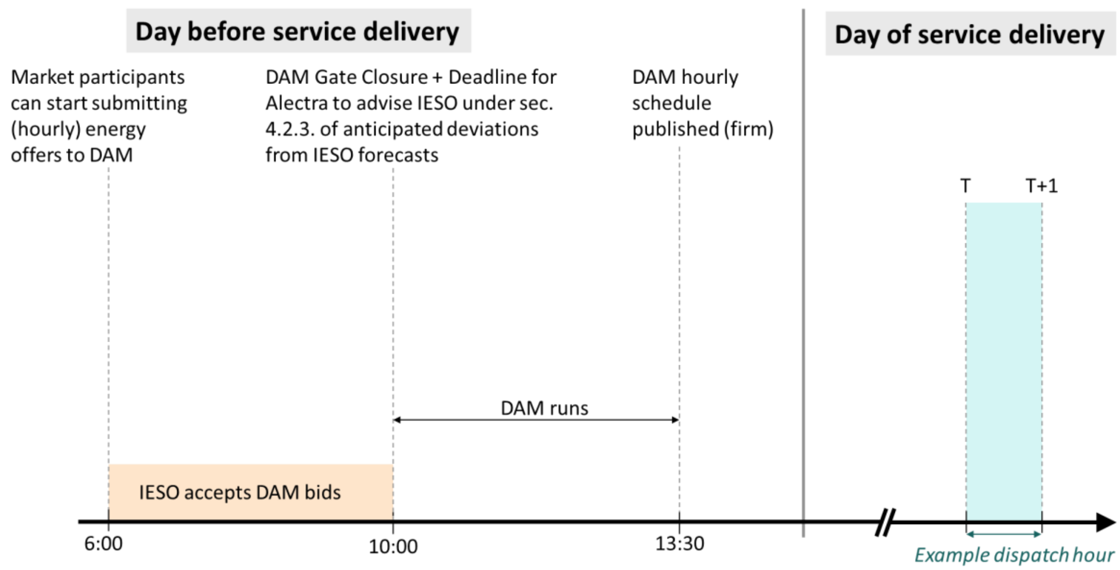

Figure 2-2. Timeline for day-ahead market (applicable to DACP and DAM)

Real time

In the *real-time* timeframe, schedules reflect the optimization of actual generation, reserve allocation and physical demand within the RTM. The ISO issues dispatch instructions to the participants according to the real-time schedules. The ISO runs market clearing software every 5 minutes to determine prices and schedules for each five-minute interval. The RTM Gate closure T-2hrs in the figure refers to the "Mandatory Window", which is the timeframe of 2 hours before, up until 10 minutes before the dispatch hour.

[10] This pre-dispatch timeframe applies to both DACP and DAM.

[11] Demand bids are submitted by dispatchable loads.

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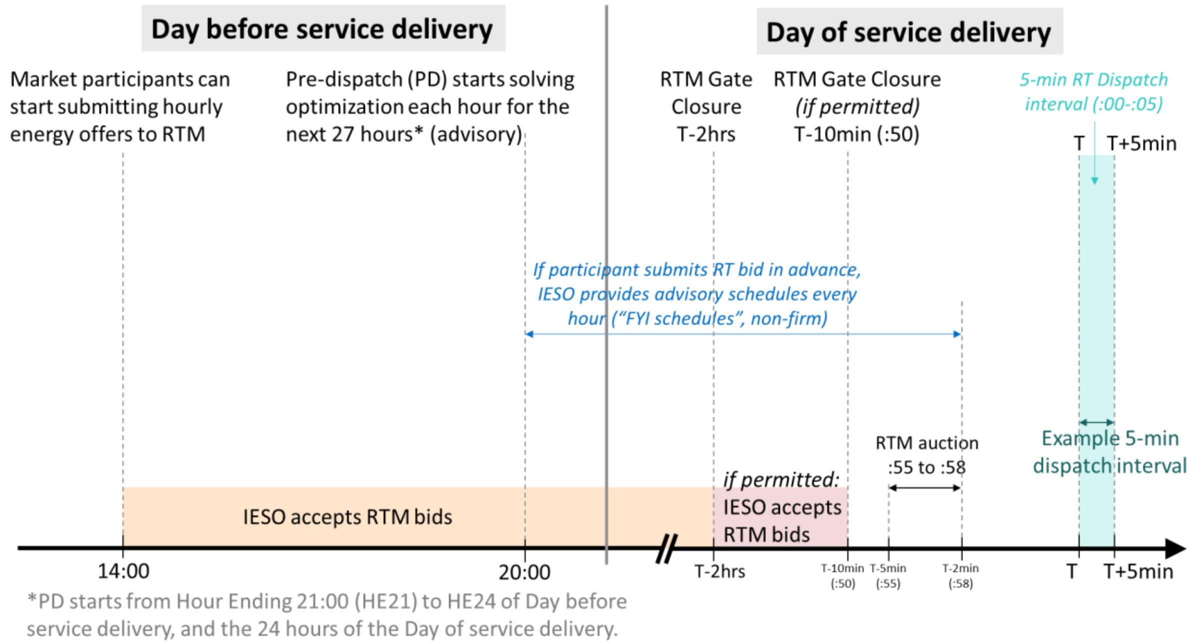

Figure 2-3. Timeline for real-time market

Distribution Service Products

Distribution service products are provided by DERs to distribution utilities, such as Alectra in Ontario. Distribution services are less clearly defined than bulk system services, with a limited number of early-adopter utilities already procuring these services from DERs as part of their standard planning and operational practices. In particular, product definitions for distribution services are not yet standardized across utility service areas.

The concepts of *distribution services* and *Non-Wires Alternatives* (NWA) are closely related. NWAs are utility-driven solutions that defer or eliminate the need for conventional system upgrades to address network constraints. Such need may arise from a range of factors, including load growth and increased DER penetration. The technical requirements for DER-based NWAs can be decomposed and packaged into one or several distribution services, such as the ones introduced in this section, based on the specific system needs identified by the distribution utility.

In contrast to IESO's well established service products, Alectra, like most distribution utilities today, has yet to formally develop service products enabling DERs to provide distribution services as part of its standard planning and operational practices.

Distribution service products may be designed to help address system needs occurring in normal (or "ordinary") system conditions or may be called less frequently to address needs in abnormal ("alternate" or "emergency") system conditions.

This report distinguishes between two types of distribution system conditions, which may trigger the activation of specific distribution service products:

- *Planned conditions* comprise of normal conditions (including nominal and peaking conditions) and planned alternate conditions (e.g., resulting from construction work). In this report, the term *planned* refers to a system need, condition, or state which is known (or forecasted) in advance of its occurrence. For example, a planned DER outage, or a planned alternate network configuration.

- *Unplanned conditions* are triggered by a contingency event and require real-time corrective response (as opposed to pro-active or preventative changes). In this report, the term *unplanned* refers to a system need, condition, or state which is not expected, emerges in real time, and typically triggers a corrective response by one or multiple stakeholders.

DSOs experimenting with DER-provided distribution services typically develop a suite of distribution service products. Each product is typically designed to address distribution constraints occurring in specific system conditions. The effective utilization of any given service product therefore varies based on pre-defined triggering factors leading to service activation.

This project defines two distribution service products, termed *capacity deferral* and *local reserve*[12], as follows:

- *Capacity deferral* is a distribution service intended to be called to address distribution constraints arising in planned system conditions.

- *Local reserve* is a distribution service intended to be called to address distribution constraints arising in unplanned system conditions. Such conditions may result from a range of contingency events, including distribution equipment failures, or from service providers contracted to provide capacity deferral that fail to meet their obligations.

Most of the early-adopter distribution utilities have been experimenting with at least one service product similar to the *capacity deferral* product defined above. These early adopters typically combine capacity (MW) and energy (MWh) requirements into the same service product. Further, DERs providing this service are paid to "reserve" the appropriate capacity and energy required, regardless of whether the service ends up being activated. For this reason, this family of distribution service products, to be used in planned conditions, is sometimes said to be "with capacity reservation".

In contrast, many early adopters who have also been experimenting with distribution service products like the *local reserve* product defined above do not require DERs to reserve any capacity or energy: when a contingency occurs, DERs may *choose* to respond to a service activation request. For this reason, this second family of service products, to be used in unplanned conditions, is sometimes said to be "without capacity reservation". Naturally, a distribution utility could also choose to offer a local reserve product with capacity reservation.

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[12] While the terms *capacity deferral* and *local reserve* are used throughout this report to refer to the two distribution service products described in this section, this naming convention can be changed without affecting the validity of the content presented in this report.

The notion of capacity (and energy) reservation described above is an important consideration when specifying distribution service products. However, the content presented in this report is largely agnostic of that design feature.

Applications of DER-Provided Distribution Services

Two broad categories of distribution service applications can be considered.

First, distribution services can help optimize grid operating costs. Examples of such “economic” services include DERs participating in Volt-Var Optimization (VVO), loss minimization, or asset degradation management schemes. The commonality between these examples is that a given feeder may be physically capable of sustaining a certain operating point, but DER-provided economic services may provide flexibility to help modify that operating point in order to lower the operating costs. While the *capacity deferral* and *local reserve* service products introduced above may support these use cases, this first family of applications is not the primary focus of this report.

A second category of distribution service applications aims to address physical constraints occurring in planned or unplanned conditions. The goal is to maintain (or restore) normal distribution system operations. This may include thermal and/or voltage constraints. Distribution utilities, through their existing planning and operations practices, have a full suite of conventional solutions already available to address such constraints, each associated with specific capital and/or operational expenditures. DER-provided distribution services may complement existing solutions (for example, when providing new capabilities to help increase grid resiliency beyond what conventional solutions can achieve) or, in certain cases, serve as cost-effective alternatives.

3
SCENARIOS: COMBINING MULTIPLE GRID SERVICES

Several combinations of distribution and/or bulk system services, called *scenarios* throughout this report, are defined in this chapter. In addition, two coordination models, termed *Total DSO* and *Dual Participation*, are described.

Scenarios Considered

Throughout this report, the term *scenario* is used to refer to a combination of one or several services which the same DER (or DERA) intends to provide to the DSO and/or ISO. When a scenario combines more than one service, DERs are said to be pursuing *value stacking* strategies, "stacking" revenues from these multiple grid services.

Seven different scenarios are considered in this report, numbered 1, 2, 3a, 3b, 4a, 4b, and 5:

- *Scenario 1*, titled "Transmission Energy Dispatch", investigates the participation of distribution-connected DERs in the wholesale energy market. Distribution congestion is not considered for this first scenario.
- *Scenario 2*, titled "Distribution Override", also investigates the participation of DERs in the wholesale energy market, this time identifying possible distribution congestion.
- *Scenario 3a* focuses on DERs providing distribution capacity to defer conventional distribution upgrades, while *Scenario 3b* investigates a value stacking case where DERs also pursue participation in the wholesale energy market. These two scenarios are jointly referred to as "Distribution Import-Congestion".
- *Scenarios 4a* and *4b* investigate DER-provided operating reserves during contingencies. Scenario 4a focuses on distribution applications like unplanned distribution outages. Scenario 4b considers a combined service offering of DER providing both distribution and traditional operating reserve[13] for bulk system applications, such as the loss of a large generator. *Scenario 4b assumes that a resource providing wholesale operating reserve may be called to dispatch that reserve, effectively providing a wholesale energy service.* Scenarios 4a and 4b are jointly referred to as "Distribution Operating Reserves".
- *Scenario 5*, titled "Capacity Service", is an extension of Scenario 3a, where DERs providing distribution capacity also pursue capacity products in the wholesale market as part of a value stacking strategy. *Scenario 5 assumes that a resource providing wholesale capacity will submit wholesale energy offers, as required by the terms of the wholesale capacity product*[14].

[13]The rest of this report references "the" wholesale reserve product for Scenario 4-b. However, ISOs have multiple operating reserve products. Scenario 4-b assumes DER participates in one or several of these reserve products.

[14] This assumption reflects the way the ISO's capacity market operates today (with the associated capacity auction timelines).

The seven scenarios considered in this project are summarized in Table 3-1.

Table 3-1. Scenarios Considered

		DER-Provided Services					
		Wholesale Domain			***Distribution Domain***		
Scenarios		Energy	Capacity	Reserve	Capacity deferral	Local reserve	**Value Stacking**
"Transmission Energy Dispatch"	1	●					
"Distribution Override"	2	●					
"Distribution Import-Congestion"	3a				●		
	3b	●			●		♦
"Distribution Operating Reserves"	4a					●	
	4b	○		●		●	♦
"Capacity Service"	5	○	●		●		♦

- Notes: ● indicates the primary service(s) considered; ○ indicates a service implicitly required by participation in a primary service; ♦ indicates scenarios considering value stacking strategies.

Priority Order When Delivering Multiple Services

Across all seven scenarios defined in Table 3-1, this project assumes that DERs only commit to deliver services they can *actually* provide. In practice, participation rules should deter service providers from pursuing participation strategies leading them to *willingly* default on their service commitments with one system operator to provide services to another operator as part of profit maximization strategies.

Said differently, system operators expect DERs to deliver on their service commitments. This is particularly true for DSOs, considering that the pool of alternative service providers which can be called when a provider fails to deliver on their distribution service obligations is structurally smaller than what ISOs may have access to at the wholesale market level.

When a given DER commits to provide multiple grid services, the "priority order" for delivering these services is assumed to reflect the commitment sequence followed by that particular DER. For example, when a DER commits to provide two distinct services, the service that was committed *first* takes priority over the second service. Therefore, the notion of "priority" as used in this chapter refers to service providers keeping a sequential ordered list of the services they have already committed to provide, then they make sure *before* committing to an additional service N+1 that this new service is compatible with the requirements of services 1 through N already committed[15].

Conversely, the term "priority order" as used in this chapter does not intend to position the importance of one service domain (i.e., distribution, wholesale) over the other. Further, the term "priority order" does not mean that there should be situations where DERs should find

[15] This verification process could be left to the service providers themselves, assuming that the loss in revenues and/or financial penalties in case of underperformance are significant enough to deter providers from over-committing. External parties (for example, the service requesting entities themselves) could also be involved in this verification process.

themselves unable to meet the demands of both service requesting entities, and one entity would somehow get “priority” over the other in terms of using the resource.

Table 3-2. Priority orders when delivering multiple services

		DER-Provided Services					
		Wholesale Domain			***Distribution Domain***		
Scenarios		Energy	Capacity	Reserve	Capacity deferral	Local reserve	**Value Stacking**
“Transmission Energy Dispatch”	1	1					
“Distribution Override”	2	1					
“Distribution Import-Congestion”	3a				1		
	3b	2			1		♦
“Distribution Operating Reserves”	4a					1	
	4b	(2)		2		1	♦
“Capacity Service”	5	(1)	1		2		♦

- Notes: “1” indicates the service commitment agreed to first, “2” indicates the service commitment agreed to second, “(x)” indicates a service implicitly required by participation in another service, which takes the same priority order as that other service; ♦ indicates scenarios considering value stacking strategies.

Scenarios 1 and 2 only involve bulk system services, therefore avoiding any conflicts potentially leading a service provider to fail to deliver on their obligations with one system operator to provide services to another instead. Similarly, Scenarios 3a and 4a only involve distribution services, avoiding that same issue by design[16].

However, Scenarios 3b and 4b involve distribution and bulk system services. These scenarios implicitly assume a commitment sequence where DERs *first* commit to providing a distribution service, and *then* may commit to a wholesale service in a way that is compatible with their prior distribution service commitments, as indicated in Table 3-2.

Scenario 5 presents similarities with Scenario 3b, but effectively *reverses* the priority order. In Scenario 5, the commitment to provide wholesale capacity comes first; participation in this wholesale product creates a requirement to participate in wholesale electricity markets, as described earlier in this chapter. Therefore, DERs in Scenario 5 effectively commit *first* to reserve capacity to submit energy offers, and *then* may commit to provide a distribution service (specifically, *capacity deferral* is considered in Scenario 5) in a way in that is compatible with their prior wholesale market commitments.

Coordination Frameworks

Grid services provided by DERs require new forms of coordination between the DSO, ISO and the DERs. In particular, one coordination aspect relates to whether DERs intending to provide

[16] It is understood that DER power production can still have some indirect impact on wholesale energy market conditions, even if DER is not actively participating in the market.

wholesale market services can submit service offers directly to the ISO or must submit their offers through the DSO. In the latter case, the DSO could gather the *individual DER offers* received and pass them “as is” to the ISO; alternatively, the DSO could first aggregate all the DER offers received into a *single offer*, before passing that aggregated offer to the ISO. The DSO also has the possibility to check feasibility of all offers prior to submittal to ISO.

This project considers two coordination framework models, referred to as *Total DSO* and *Dual Participation*:

Under the *Total DSO* coordination framework[17], DERs seeking to participate in the wholesale electricity markets cannot submit their offers directly to the ISO. Instead, DERs must submit wholesale offers to the DSO, which aggregates all offers received and submits a single aggregated offer to the ISO. Additionally, DERs seeking to provide distribution services submit these offers to the DSO.

Under the *Dual Participation* coordination framework, DERs seeking to participate in the wholesale electricity markets may submit their offers directly to the ISO, while staying within the limits established by the DSO as part of the DER interconnection agreement or otherwise. Separately, DERs seeking to provide distribution services submit these offers to the DSO, and they may be required to further notify the ISO.

[17] L. Kristov, P. De Martini and J. D. Taft, "A Tale of Two Visions: Designing a Decentralized Transactive Electric System," in *IEEE Power and Energy Magazine*, vol. 14, no. 3, pp. 63-69, May-June 2016, doi: 10.1109/MPE.2016.2524964.

4

STRUCTURING THE DER-DSO-ISO COORDINATION: PRINCIPLES AND APPLICATIONS

This chapter focuses on the coordination needs between DSO, ISO, and DERs across the Scenarios considered in this project[18]. The goal is to 1) identify in a systematic manner *when* coordination is needed, and on *what*, and 2) represent this information in a structured way.

The end-result is a series of coordination diagrams presented in this chapter, which are detailed enough to convey coordination needs at the functional level, but flexible enough to serve as a starting point to a range of implementation approaches. Coordination diagrams are developed for both the *Total DSO* and *Dual Participation* models[19].

Preliminaries: Processes to Notify of Abnormalities

First, and independently of whether DERs are connected to the distribution grid, the ISO and DSO already have coordination processes to mutually inform each other of possible abnormalities. In particular, the DSO is required to notify the ISO of any deviations (planned or unplanned) from the T-D forecasts.

Further, when DERs are connected to the distribution grid, “abnormalities” can occur either on the DER side, or on the grid side. Coordination processes are necessary for the DERs and grid entities (DSO, ISO) to inform each other when such abnormalities occur. Some of these processes are needed regardless of whether DERs intend to provide grid services.

The interactions needed between all three parties are identified in Figure 4-1. The processes referred to in the figure will be described in the following sections of this chapter.

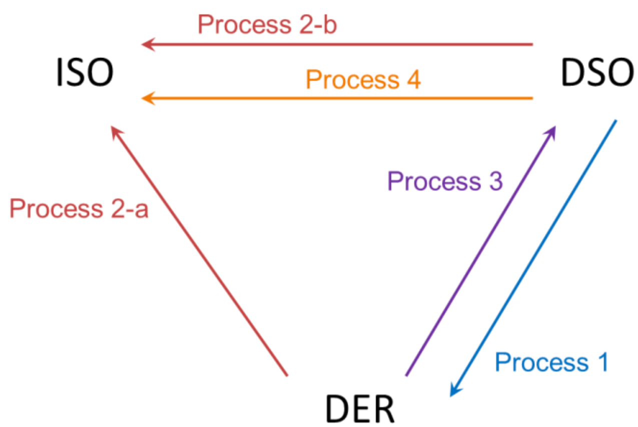

Figure 4-1. Grid actors involved in notification of abnormalities

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[18] The Scenarios considered in this project are defined in Chapter 3.

[19] The Total DSO and Dual Participation models are defined in Chapter 3.

Specifically, the ability of DERs to provide grid services depends in part on the amount of power they can exchange with the grid (imports and/or exports) which may vary over time. Factors to consider include:

- DER *nominal nameplate*, and DER *availability* to provide services at any given time. Availability to provide grid services may depend on a range of factors including 1) whether DERs provide customer/end user services[20], as 2) maintenance and other technical contingencies preventing DERs from operating at full nameplate capacity.
- *Maximum import and/or export limits* applicable at any given time. For normal distribution conditions, these limits are explicitly defined in the interconnection agreement[21]; these limits may be fixed (traditional interconnection agreement), or variable and depending on pre-defined factors (flexible interconnection agreement[22]). Regardless of interconnection agreement type, DSOs typically reserve the right to modify these limits when abnormal conditions occur to help maintain grid safety, if necessary.

This report defines five coordination processes, listed in Table 4-1, to formalize the coordination needs described above. While the coordination diagrams presented later in this chapter occasionally reference these processes explicitly, all five processes operate independently from the stages described in the diagrams and can be activated at any time based on needs.

[20] *Customer services* intend to help meet the end-user's energy needs while pursuing local economic and/or reliability objectives. Most DER-provided customer services intend to minimize the end-user's retail electricity costs. Examples include increased PV self-consumption and time-of-use (or demand charge) management. These services are often the main reason why BTM DERs get installed in the first place. Typically, customer services also generate associated grid benefits (e.g., peak reduction). In addition, backup power is a different type of customer service, where the primary goal is not retail bill minimization, but power availability during grid outages.

[21] All DERs intending to connect to the distribution grid must first secure an interconnection agreement with the DSO. This requirement applies regardless of whether DERs intend to provide grid services.

[22] *Flexible interconnection* is a DER control strategy used to defer or avoid system upgrades and/or increase distribution system utilization. In general, this may involve defining operating constraints on the DER active and/or reactive power at key times when transmission and/or distribution system constraints are binding. In practice, most early-adopter utilities have focused on using flexible interconnection to limit (i.e., curtail) active power exports from DER units in order to avoid grid congestions. This arrangement should consider both the improvement in interconnection approvals as well as future coordination (type and frequency) required to maintain acceptable grid operations.

Table 4-1. Processes to notify of abnormalities

Process #	Purpose	*Service type*	*ISO-DSO coordination model*	Parties involved	Source of abnormality
1	Notify DER of abnormal distribution conditions	*(Not dependent on service type)*	*(Not dependent on coordination model)*	DSO → DER	Distribution grid *(e.g., maintenance, equipment failure, default of other service providers, etc.)*
2-a	Notify ISO of service provider unavailability	Wholesale	Dual Participation	DER → ISO	Internal to DER, or restrictions notified to DER through Process 1 and resulting from distribution grid conditions.
2-b	Notify ISO of service provider unavailability	Wholesale	Total DSO	DSO → ISO	Internal to DER, or restrictions notified to DER through Process 1 and resulting from distribution grid conditions.
3	Notify DSO of service provider unavailability	Distribution	*(Not dependent on coordination model)*	DER → DSO	Internal to DER
4	Notify ISO of forecast deviations due to distribution conditions	*(Not dependent on service type)*	*(Not dependent on coordination model)*	DSO → ISO	Distribution grid *(e.g., maintenance, equipment failure, default of service providers, etc.)*

In addition to the five coordination processes described in Table 4-1, other processes (not described in this report) may be needed to manage abnormalities. For example, the ISO may need to notify the DSO of transmission-level abnormalities affecting the T-D interface.

Process 1

Process 1 is used by the DSO to notify DERs of modified export and/or import limits resulting from *abnormal* distribution system conditions. These temporary changes (planned or unplanned) may be more restrictive than the limits otherwise applicable in normal conditions (and defined in the interconnection agreement); temporary restrictions may even require a temporary disconnection of the DER from the distribution grid.

When abnormal conditions (planned or unplanned) require a DER de-rate (partial or total), the temporary restrictions are notified to the DER(s) concerned immediately upon discovery by the DSO of the underlying system condition(s). Therefore, DERs are informed of the active and/or planned restrictions they are (or will be) subject to due to abnormal distribution conditions.

Process 1 is applicable whether DERs are settled for energy by the ISO (Dual Participation model) or DSO (Total DSO model), and regardless of whether DERs provide grid services.

Process 2-a

Process 2-a is used by DERs settled for energy by the ISO (Dual Participation model) to notify the ISO of a temporary reduction in the capacity they can (or intend) to commit to wholesale market participation. The term "outage slip" is used, whether the reduction is partial or total. A total reduction corresponds to DER withdrawing completely from wholesale market participation.

Outage slips can reflect technical issues (planned or unplanned) internal to the DER (including unavailability due to maintenance), and/or planned or unplanned contingencies in the distribution domain (and unrelated to the DER itself) creating abnormal distribution conditions, and subsequently restrictions notified by the DSO to the DER through Process 1. Process 2-a can be activated at any time. For example: before a wholesale offer is submitted; after an offer is submitted but before market clearing time; after offers are awarded; or even after service delivery has actually started.

Process 2-a is already implemented in IESO's jurisdiction. The process was originally developed in the context of large, individual, transmission-connected wholesale market participants. The same process can be considered for smaller DERs participating in the wholesale markets via the Dual Participation model.

Process 2-b

Process 2-b is an extension of Process 2-a, when DERs settled for energy by the DSO (Total DSO model) provide wholesale market services through the DSO.

Process 2-b allows the DSO, acting as wholesale market participant on behalf of the DERs it aggregates, to notify the ISO of a temporary reduction (partial or total) in the DER capacity available to provide wholesale services. Similar to Process 2-a, outage slips submitted through Process 2-b can reflect planned or unplanned contingencies related to the DERs themselves, or to abnormal distribution conditions preventing DERs from participating in the wholesale markets.

In practice, Process 2-b is largely identical to Process 2-a. The main difference is that while in Process 2-a, the DER itself notifies the ISO, in Process 2-b, it is the DSO that notifies the ISO.

Process 3

Process 3 is used by DERs providing distribution services to notify the DSO of a temporary reduction in the DER capacity available to effectively deliver on their service commitments.

Process 3 is applicable only after a DER is formally contracted by the DSO to perform a distribution service, but before or after it is scheduled/called to perform that service.

Process 3 is equivalent to Processes 2-a and 2-b, but for distribution services. Outage slips submitted through Process 3 may reflect planned or unplanned contingencies (partial or total) resulting from conditions internal to the DER submitting the outage slip.

Process 3 is applicable to DERs providing distribution services, regardless of whether they are settled for energy by the ISO (Dual Participation model) or the DSO (Total DSO model).

After a Process 3 notification is received, the DSO may activate contingency plans as needed, including the possible activation of DERs contracted to provide local reserves.

Process 4

Process 4 is used by the DSO to notify the ISO of material deviations (planned or unplanned) from the ISO forecasts at the T-D interface.

Process 4 is already implemented in IESO's jurisdiction[23].

Developing a Coordination Structure

This report adopts a hierarchical structure composed of three levels to describe the coordination needs between the ISO, DSO and DERs providing grid services: *stages*, *steps*, and *functions*.

Level 1: Stages

From a functional standpoint, *stages* define high-level topical areas where coordination is necessary between the ISO, DSO and/or DERs across the Scenarios considered in this report.

Logical Breakdown of Coordination Stages

Eight stages, depicted in Figure 4-2, are defined in this project[24].

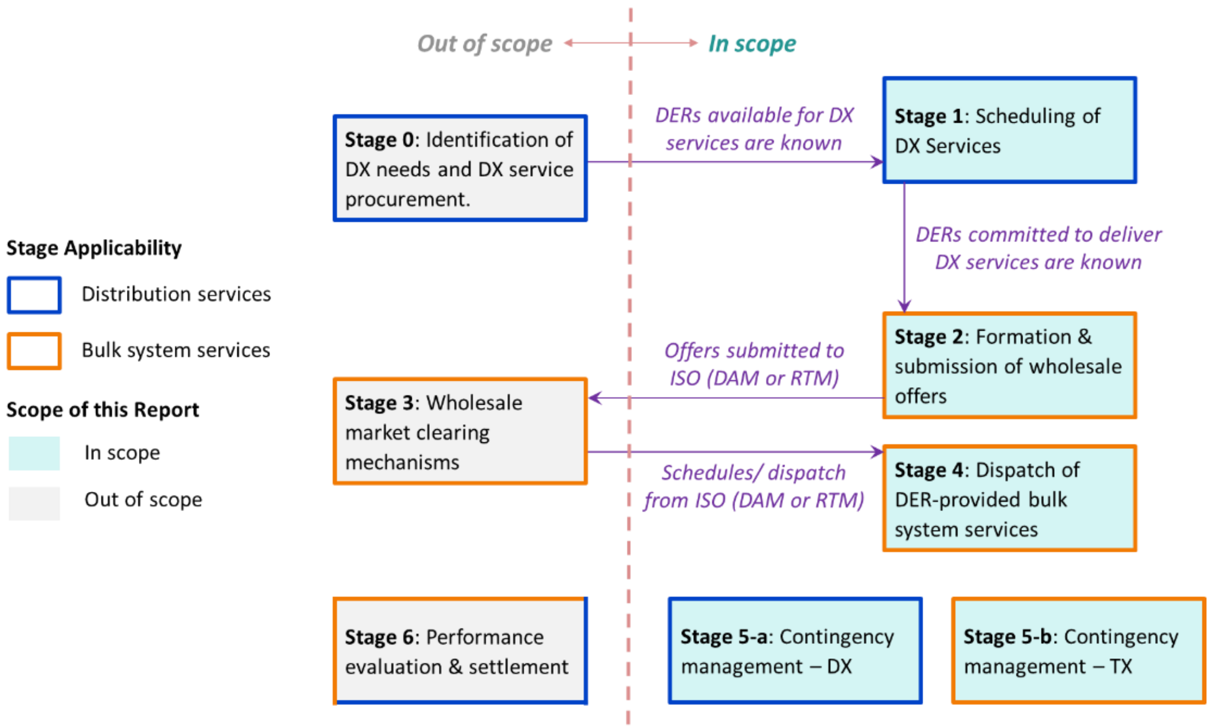

Figure 4-2. Coordination stages considered

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[23] See IESO Market Manuel 7, Part 7.3, sec. 4.2.3.

[24] While this project adopted the 8-stage logical breakdown presented, other breakdowns are possible.

The stages represented in Figure 4-2 are defined as follows:

- *Stage 0: Identification of distribution needs, and distribution service procurement* – DSO identifies distribution service opportunities based on distribution needs, procures services, and finalizes contractual arrangements with services providers. (This stage is out of scope for this report).
- *Stage 1: Scheduling of distribution services* – DSO schedules distribution services to be used in normal or planned abnormal conditions. Distribution services to be used in unplanned abnormal conditions are dispatched in Stage 5.
- *Stage 2: Formation and submission of wholesale offers* – DERs intending to participate in the wholesale markets submit offers to the ISO either directly (Dual Participation model), or via the DSO (Total DSO model).
- *Stage 3: Wholesale market clearing mechanisms* – Based on offers collected from wholesale market participants, ISO clearing mechanisms schedule resources including DER participants. (This stage is out of scope for this report).
- *Stage 4: Dispatch of DER-provided wholesale services* – Based on market clearing results, participating DERs are dispatched to deliver wholesale services.
- *Stage 5-a: Contingency management for distribution-level incidents* – When distribution contingencies occur, DSO dispatches DERs providing local reserves as needed.
- *Stage 5-b: Contingency management for transmission-level incidents* – When generation or transmission contingencies occur, ISO dispatches DERs providing wholesale reserves as needed.
- *Stage 6: Performance evaluation and settlement* – Performance assessment of service providers and financial settlement following service delivery. (This stage is out of scope for this report).

Stages 0 through 6 are structured following a logical progression, with the outputs of one stage often serving as inputs to another stage. Yet, these stages typically run in parallel continuously and follow their own execution timelines.

All stages introduced above are agnostic of the participation model considered. However, the practical implementation of each stage may depend on the coordination model considered, as shown in the coordination diagrams presented below.

Further, depending on the combination of grid services considered for each Scenario, certain stages may not be required. Specifically:

- Stages 0, 1, and 5-a are only applicable when distribution services are considered.
- Stages 2, 3, 4, and 5-b are only applicable when wholesale market services are considered.

Temporal Considerations for Coordination Stages Applicable to Bulk system services

The ISO's timelines for the Day Ahead Market (DAM) and Real Time Market (RTM) were previously introduced in Chapter 2.

Figure 4-3 and Figure 4-4 below depict stages 2, 3 and 4 all applicable to wholesale market services in the context of the ISO's DAM and RTM timelines.

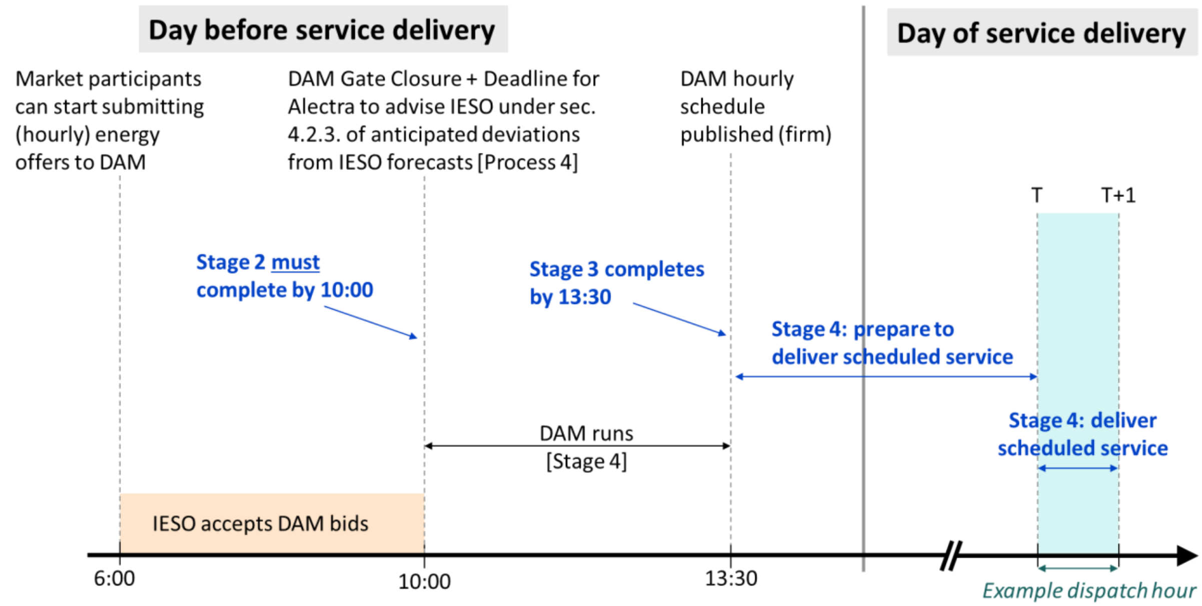

Figure 4-3. Timeline for participation in Day Ahead Market (DAM)

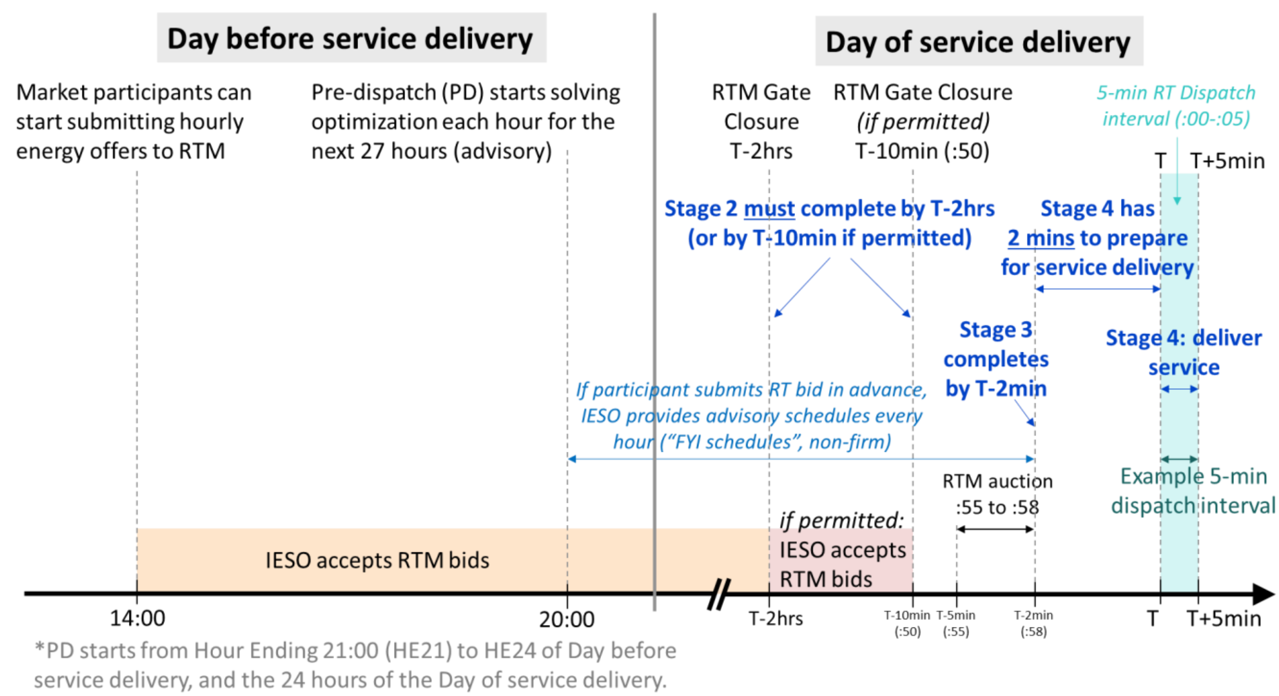

Figure 4-4. Timeline for participation in Real Time Market (RTM)

Level 2: Steps

Each of the eight higher-level stages from Level 1 are further decomposed into multiple *steps*. The number of steps required varies depending on the stage considered.

For each stage, steps follow a logical progression. Further, and contrary to the stages defined in Level 1, steps are <u>not</u> agnostic of the participation model considered. For this reason, two sets of coordination diagrams are presented below, one for each of the two coordination models considered in this report.

Finally, certain steps are considered optional and identified as such.

Level 3: Functions

The practical implementation of each step may require calling one or multiple coordination *functions*, similar to the coordination functions defined in EPRI's TSO/DSO working group[25]. The mapping from steps to functions is out of scope for this report and may vary from one implementation approach to the other.

Application to the "Total DSO" Coordination Model

This section presents functional and sequence diagrams defining *steps* for each of the stages represented in Figure 4-2, assuming the <u>Total DSO</u> coordination model. All DERs providing grid services are assumed to be connected under a retail tariff.

The coordination diagrams presented are applicable to all Scenarios summarized in Table 3-1.

Stage 0: Identification of Distribution Needs, and Distribution Service Procurement

This section is left intentionally blank. Stage 0 is out of scope for this effort.

Stage 1: Scheduling of Distribution Services

In Stage 1, the DSO schedules distribution services to be used in normal or planned abnormal conditions (step 1.1). In normal conditions, no further notifications to the ISO are needed (step 1.2.a). However, in planned abnormal conditions, a notification to the ISO may be required via Process 4 if leading to material deviations from the nodal forecasts (step 1.2.b)[26]. Distribution services to be used in unplanned abnormal conditions are not dispatched in Stage 1 (step 1.2.c), but in Stage 5-a. Regardless of the distribution conditions or type of distribution service considered, distribution services are <u>always</u> dispatched at the initiative of the DSO.

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[25] *TSO-DSO Coordination Functions for DER.* EPRI, Palo Alto, CA:2022. 3002021985.

[26] The EPRI team conducted a case analysis, not included in this report, to evaluate the potential deviations from IESO forecasts which distribution services could introduce at the T-D interface. Findings suggest that when DERs are settled for energy by the DSO (Total DSO model), existing and future ISO nodal models provide proper visibility on the effect that distribution services addressing distribution constraints arising in *normal* system conditions will have at the T-D interface. However, distribution services addressing constraints arising in *alternate* or *emergency* system conditions may lead to unexpected deviations at the T-D interface. Yet, the analysis finds that existing coordination processes between the ISO and DSO (i.e., Process 4 described in this chapter) could be used to route notifications from the DSO to the ISO if the change is considered material.

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The functional and sequence diagrams for this stage are represented in Figure 4-5 and Figure 4-6.

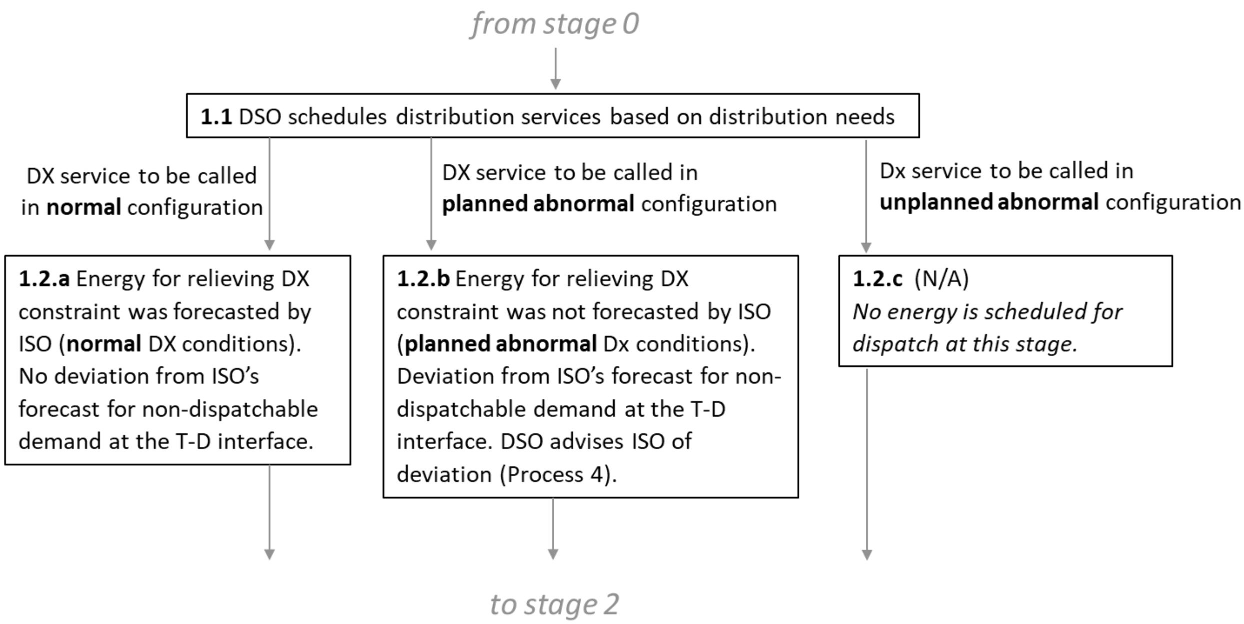

Figure 4-5. Functional diagram, Stage 1 with Total DSO model

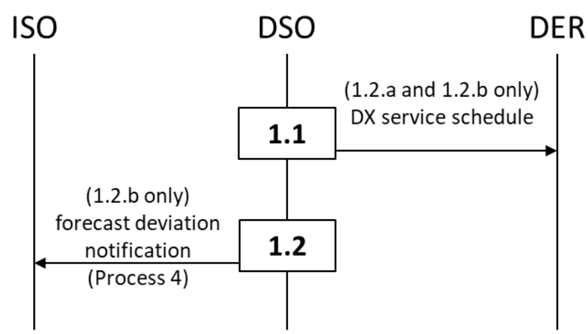

Figure 4-6. Sequence diagram, Stage 1 with Total DSO model

Stage 2: Formation and Submission of Wholesale Offers

In Stage 2, DERs intending to participate in the wholesale markets submit their offers to the DSO acting as aggregator under the Total DSO coordination model (step 2.1.a). The DSO may define a gate closure by which DERs must submit their offers. Alternatively, DERs may agree to be automatically considered for wholesale participation (step 2.2.b).

These offers submitted by the DERs to the DSO take into account the import and/or export limits applicable to each DERs in normal system conditions (as defined in the DER interconnection agreement), along with any temporary restrictions already notified to the DER by the DSO via Process 1.

Once offers are collected from DERs, the DSO may run further analysis to ensure that all offers can be dispatched while maintaining normal system conditions (step 2.2), before submitting an aggregated offer to the ISO before gate closure time (step 2.3). The aggregated offer is directly based on the individual DER offers collated and vetted by the DSO.

The functional and sequence diagrams for this stage are represented in Figure 4-7 and Figure 4-8.

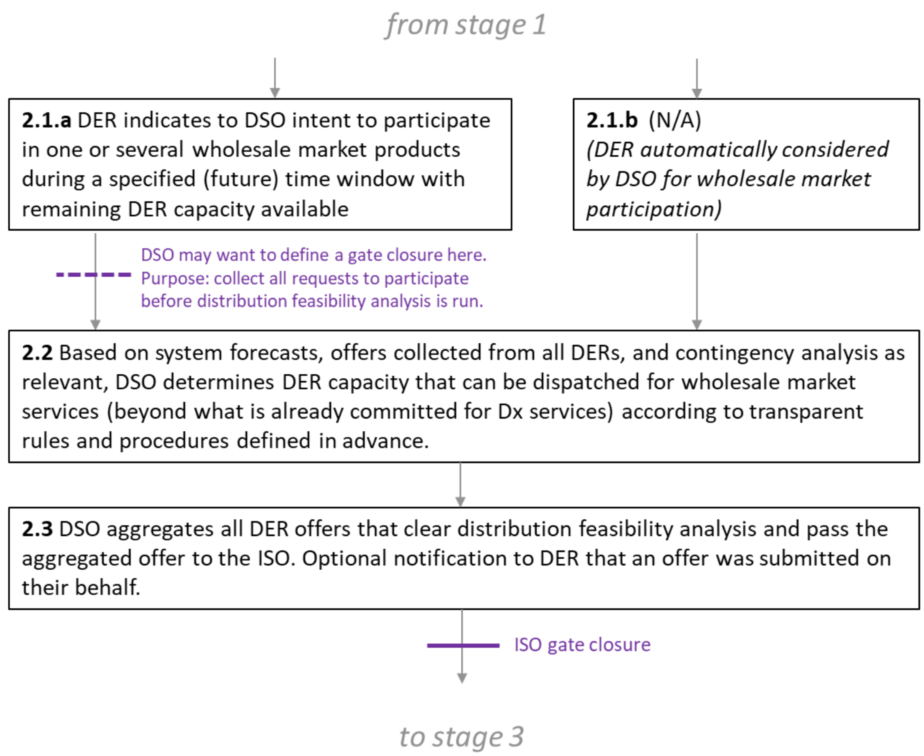

Figure 4-7. Functional diagram, Stage 2 with Total DSO model

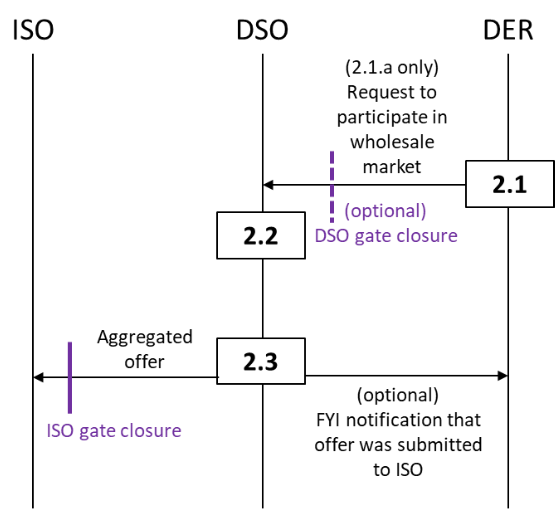

Figure 4-8. Sequence diagram, Stage 2 with Total DSO model

Stage 3: Wholesale Market Clearing Mechanisms

This section is left intentionally blank. Stage 3 is out of scope for this effort. A high-level description of the clearing mechanisms used in the ISO is provided in Chapter 2.

Stage 4: Dispatch of DER-Provided Bulk System Services

In Stage 4, DERs are dispatched to deliver bulk system services based on market clearing results. As described in Figure 4-4, if participation in RTM is considered, the ISO sends advisory schedule(s) to the DSO acting as DER aggregator until the dispatch interval is reached (step 4.1). Multiple advisory schedules may be sent over time, as represented in Figure 4-10. Since advisory schedules are not sent out in the DAM, step 4.1. is only applicable to RTM participation. A firm dispatch schedule is eventually sent out by the ISO in both cases (step 4.2). The DSO disaggregates the schedules across the participating DERs (step 4.3) and sends out individual DER schedules (step 4.4).

The functional and sequence diagrams for this stage are represented in Figure 4-9 and Figure 4-10.

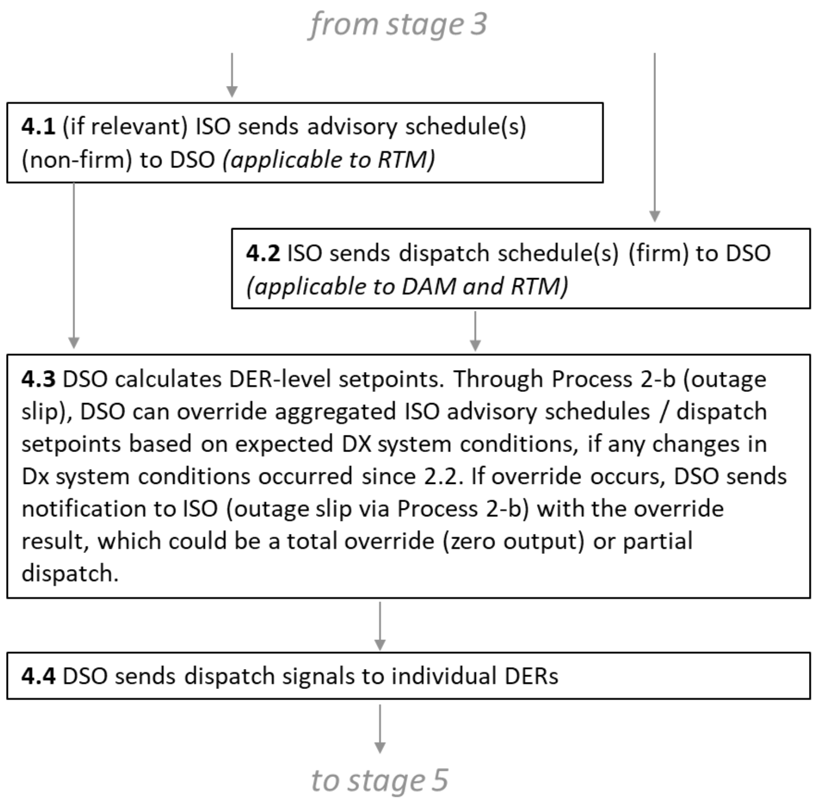

Figure 4-9. Functional diagram, Stage 4 with Total DSO model

Note on Figure 4-10*: Process 2-b can be called at any time, not necessarily in reaction to an advisory or dispatch schedule. Because Process 2-b can be called at any time, it can be called, for example, after receiving an advisory or dispatch schedule, which Figure 4-10 illustrates. Figure 4-10 should* **not** *be interpreted as "Process 2-b can only be called after receiving an advisory or dispatch scheduled".*

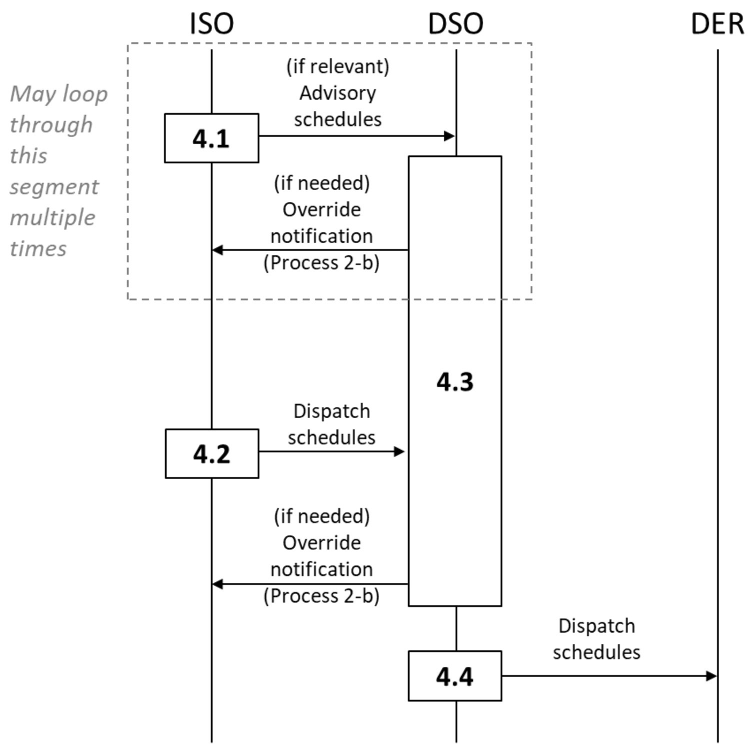

Figure 4-10. Sequence diagram, Stage 4 with Total DSO model.

Stage 5-a: Contingency Management for Distribution-Level Incidents

In Stage 5-a, the DSO responds reactively to an unplanned distribution incident. Step 5.1 focuses on reporting consequences of the incident to the ISO and DERs. Step 5.2 dispatches DERs providing local reserve, if available and helpful to address the distribution constraints created by the incident. (As previously stated in Stage 1, regardless of the distribution conditions or type of distribution service considered, distribution services are always dispatched at the initiative of the DSO). Step 5.3 updates the DER capacity available for local reserve and possibly seeks to procure additional reserve, if practicable. The functional and sequence diagrams for this stage are represented in Figure 4-11 and Figure 4-12.

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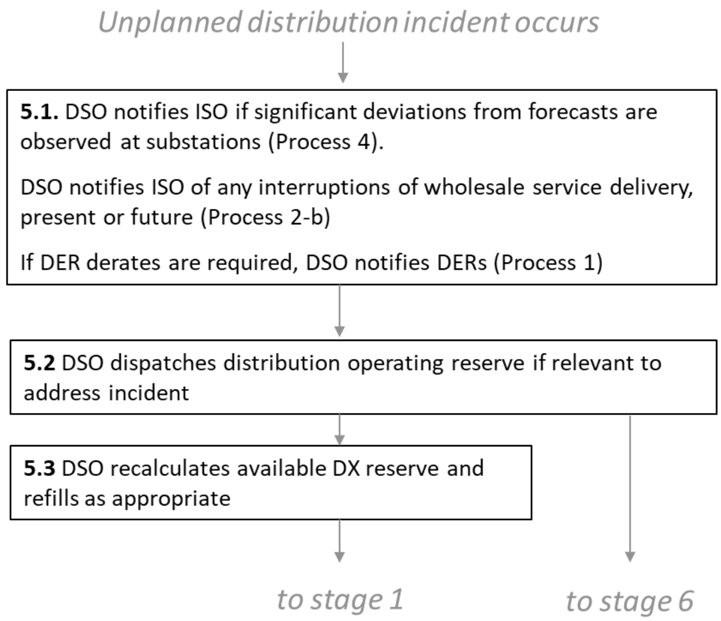

Figure 4-11. Functional diagram, Stage 5-a with Total DSO model

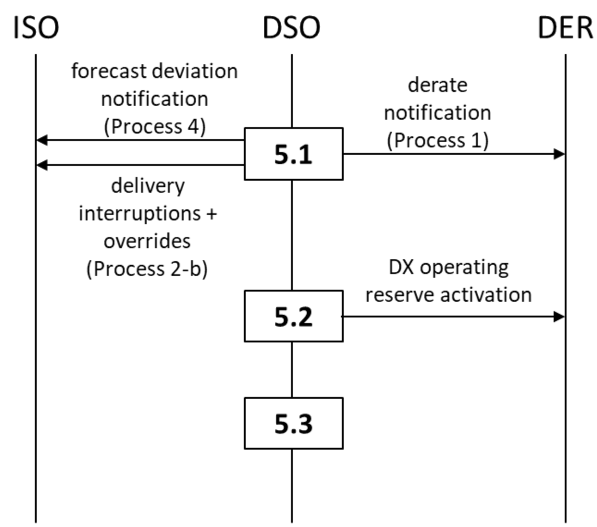

Figure 4-12. Sequence diagram, Stage 5-a with Total DSO model

Stage 5-b: Contingency Management for Transmission-Level Incidents

In Stage 5-b, the ISO responds reactively to an unplanned generation or transmission incident. ISO sends a reserve dispatch order to the DSO (step 5.1), which itself dispatches DERs (step 5.2). Step 5.3 updates the capacity available for wholesale reserve and possibly seeks to procure additional reserve, if practicable.

The functional and sequence diagrams for this stage are represented in Figure 4-13 and Figure 4-14.

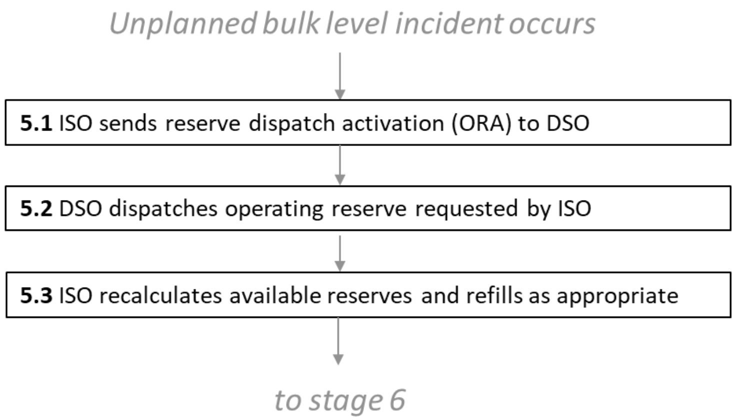

Figure 4-13. Functional diagram, Stage 5-b with Total DSO model

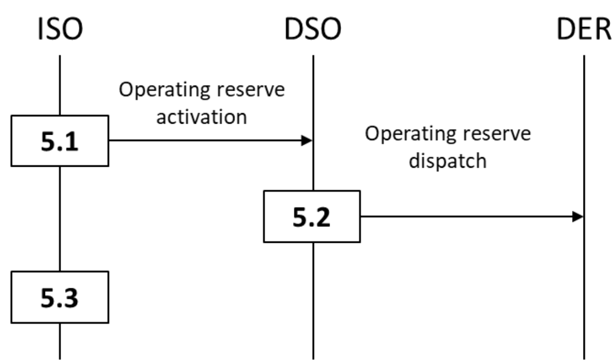

Figure 4-14. Sequence diagram, Stage 5-b with Total DSO model

Stage 6: Performance Evaluation and Settlement

This section is left intentionally blank. Stage 6 is out of scope for this effort.

Application to the "Dual Participation" Coordination Model

This section presents functional and sequence diagrams defining *steps* for each of the stages represented in Figure 4-2, assuming the Dual Participation coordination model. All DERs providing grid services are assumed to be connected under a wholesale distribution tariff. The coordination diagrams presented are applicable to all Scenarios summarized in Table 3-1.

The step numbering in this section is the same as in the previous section to facilitate comparisons between the Total DSO and Dual Participation models. For this reason, certain steps necessary when assuming the Total DSO model but not needed when considering the Dual Participation mode are intentionally marked "N/A".

Stage 0: Identification of Distribution Needs, and Distribution Service Procurement

This section is left intentionally blank. Stage 0 is out of scope for this effort.

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Stage 1: Scheduling of Distribution Services

In Stage 1, the DSO schedules distribution services to be used in normal or planned abnormal conditions (step 1.1). In normal conditions (step 1.2.a) and planned abnormal conditions (step 1.2.b), the DER submits a floor price bid[27] to the ISO, corresponding to the amount of energy required to provide the distributions service[28]. Distribution services to be used in unplanned abnormal conditions are not dispatched in Stage 1 (step 1.2.c), but in Stage 5-a.

The functional and sequence diagrams for this stage are represented in Figure 4-15 and Figure 4-16.

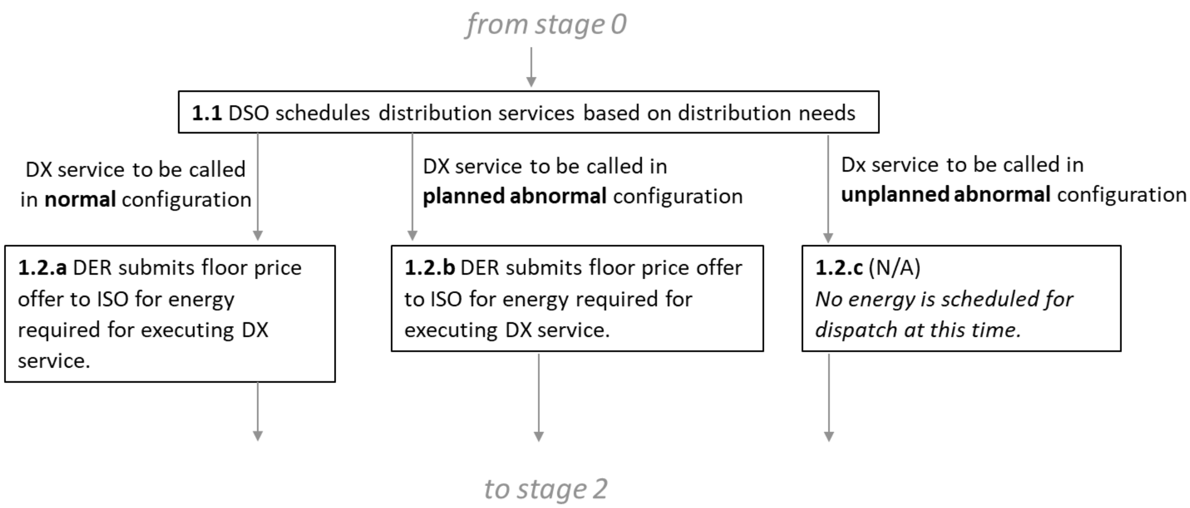

Figure 4-15. Functional diagram, Stage 1 with Dual Participation model

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[27] DERs settled for energy by the ISO (Dual Participation model) *must notify the ISO* that they are being dispatched by the DSO to deliver a distribution service. This project assumes that once dispatched by the DSO to deliver a distribution service, such DERs immediately submit an energy offer to the ISO at the floor price (the lowest price at which the IESO will settle injections or withdrawals from the market at the DER location). This offer corresponds to the energy amount required to execute the distribution service request. The purpose of submitting the offer at floor price is to guarantee that the DER bid gets accepted by the ISO's clearing algorithms while staying consistent with the existing bidding process. The offer includes a code, tag, or indicates in some other manner that the energy offer was submitted to fulfill a distribution service activation request from the DSO. The amount of energy required to fulfill the distribution service requirements is settled by the ISO based on the wholesale market price for energy observed during the time intervals when the DER delivered the distribution service. While this project assumes the process described in this footnote, other approaches are possible. Therefore, this process should not be construed as a policy or market design recommendation.

[28] The EPRI team conducted a case analysis, not included in this report, to evaluate the potential deviations from IESO forecasts which distribution services could introduce at the T-D interface. Findings suggest that when DERs are settled for energy by the ISO (Dual Participation model), existing bidding interfaces appear sufficient to provide the ISO with proper visibility on the anticipated load demand at the T-D interface, and potential variations resulting from DER-provided grid services.

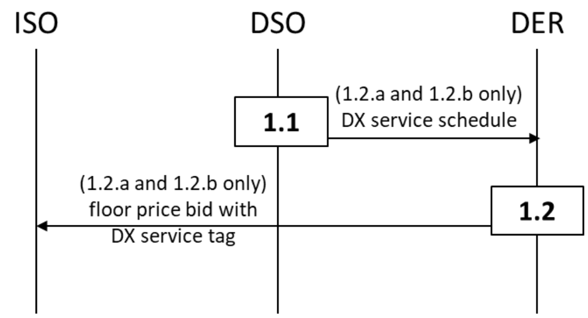

Figure 4-16. Sequence diagram, Stage 1 with Dual Participation model

Stage 2: Formation and Submission of Wholesale Offers

In Stage 2, DERs intending to participate in the wholesale markets submit their offers directly to the ISO, before gate closure time (step 2.3). Optionally, this may be preceded by a courtesy notification to the DSO (step 2.1). These offers take into account the import and/or export limits applicable to each DER in normal system condition (as defined in the DER interconnection agreement), along with any temporary restrictions already notified to the DER by the DSO via Process 1.

The functional and sequence diagrams for this stage are represented in Figure 4-17 and Figure 4-18.

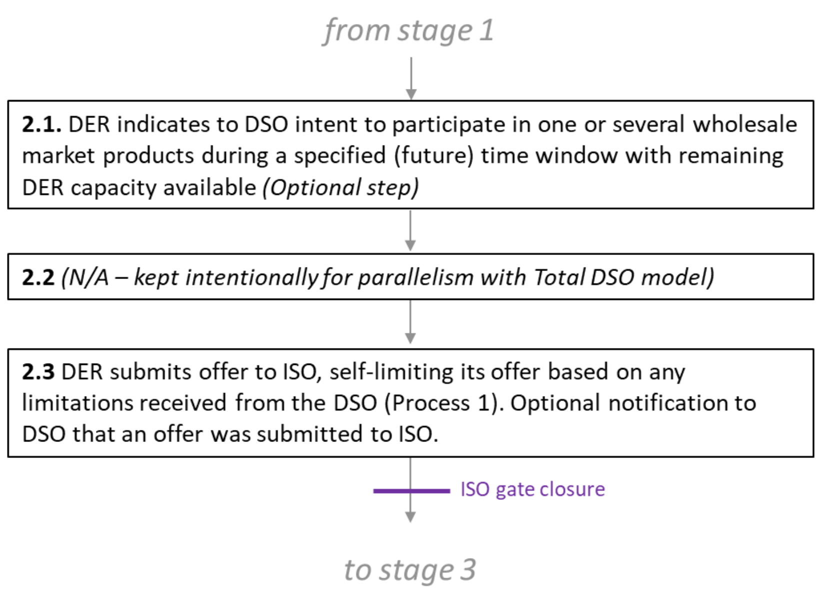

Figure 4-17. Functional diagram, Stage 2 with Dual Participation model

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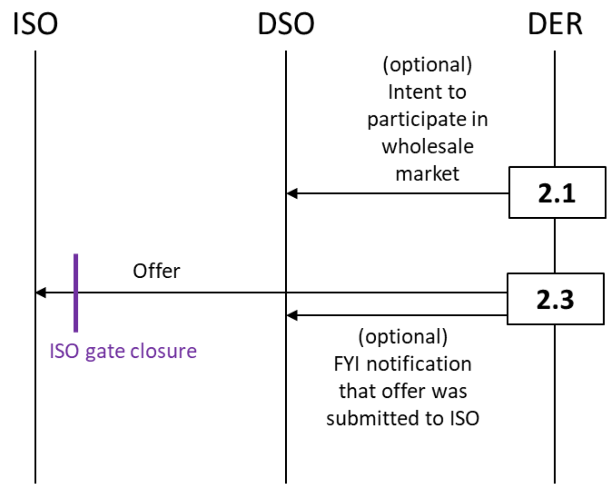

Figure 4-18. Sequence diagram, Stage 2 with Dual Participation model

Stage 3: Wholesale Market Clearing Mechanisms

This section is left intentionally blank. Stage 3 is out of scope for this effort. A high-level description of the clearing mechanisms used in the ISO is provided in Chapter 2.

Stage 4: Dispatch of DER-Provided Bulk System Services

In Stage 4, DERs are dispatched to deliver wholesale services based on market clearing results. As described in Figure 4-4, if participation in RTM is considered, the ISO sends advisory schedule(s) to the DER until the dispatch interval is reached (step 4.1). Multiple advisory schedules may be sent over time, as represented in Figure 4-20. Since advisory schedules are not sent out in the DAM, step 4.1. is only applicable to RTM participation. A firm dispatch schedule is eventually sent out by the ISO in both cases (step 4.2). The DSO may be kept informed by the ISO and/or the DER. If system conditions require to do, the DSO can place import and/or export restrictions on the DER via Process 1, which would trigger the submission of an outage slip by the DER to the ISO (Process 2-a).

The functional and sequence diagrams for this stage are represented in Figure 4-19 and Figure 4-20.

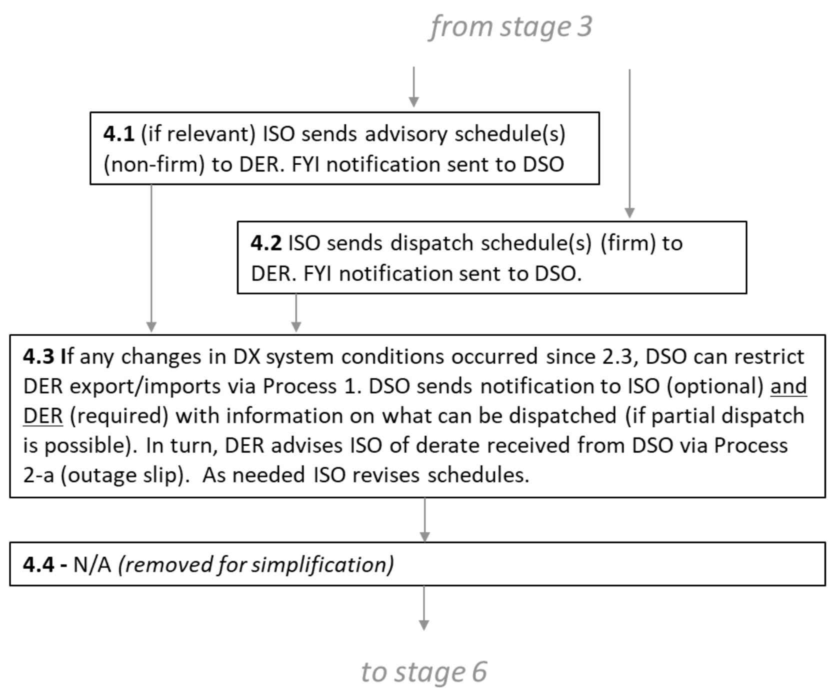

Figure 4-19. Functional diagram, Stage 4 with Dual Participation model

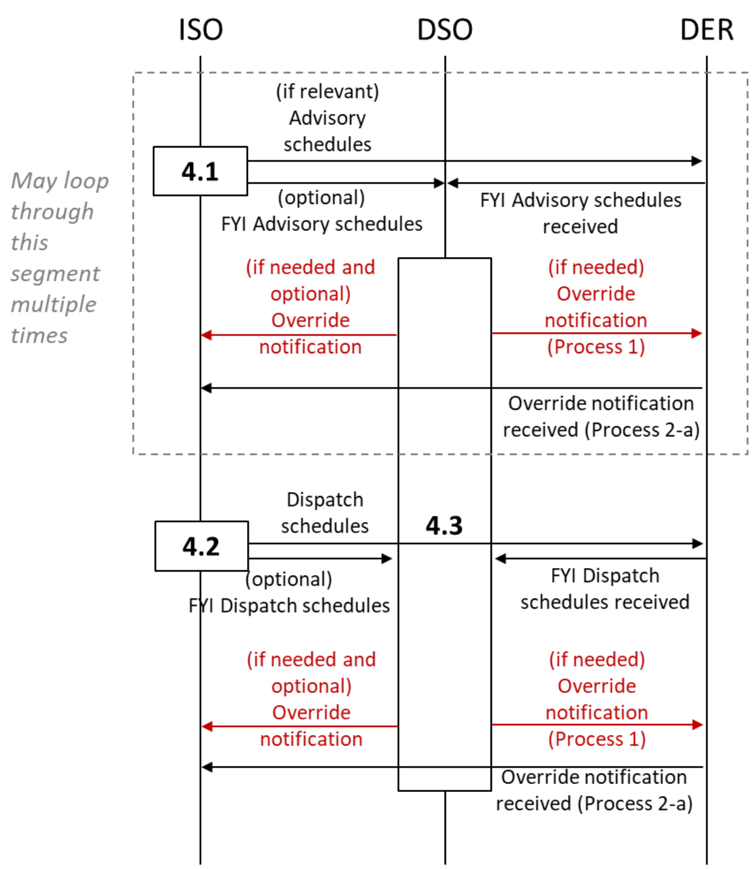

Figure 4-20. Sequence diagram, Stage 4 with Dual Participation model

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Stage 5-a: Contingency Management for Distribution-Level Incidents

In Stage 5-a, the DSO responds reactively to an unplanned distribution incident. Step 5.1 focuses on reporting consequences of the incident to the ISO (forecast deviations) and DERs. In Step 5.1.a, the DERs themselves submit outage slips via Process 2-a if they are unable to perform as expected due to the distribution incident. In Step 5.2, the DSO dispatches DERs providing local reserve, if available and helpful to address the distribution constraints created by the incident, and the DER submits a floor price offer to the ISO. Step 5.3 updates the DER capacity available for local reserve and possibly seeks to procure additional reserve, if practicable.

The functional and sequence diagrams for this stage are represented in Figure 4-21 and Figure 4-22.

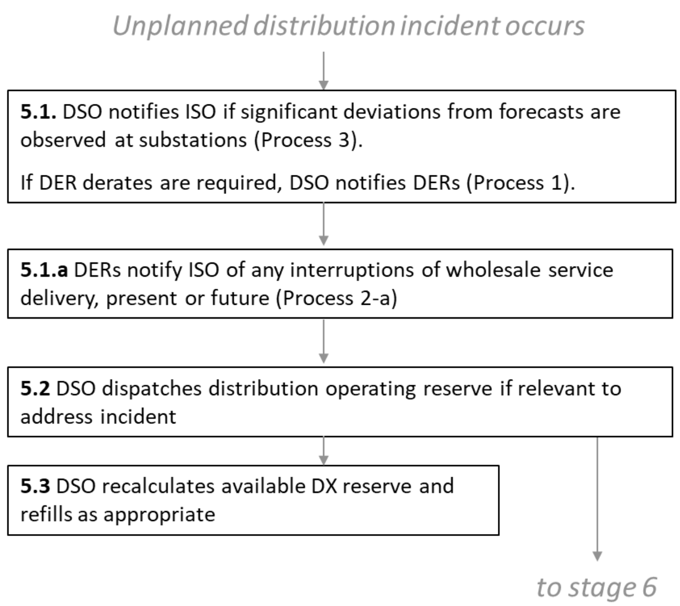

Figure 4-21. Functional diagram, Stage 5-a with Dual Participation model

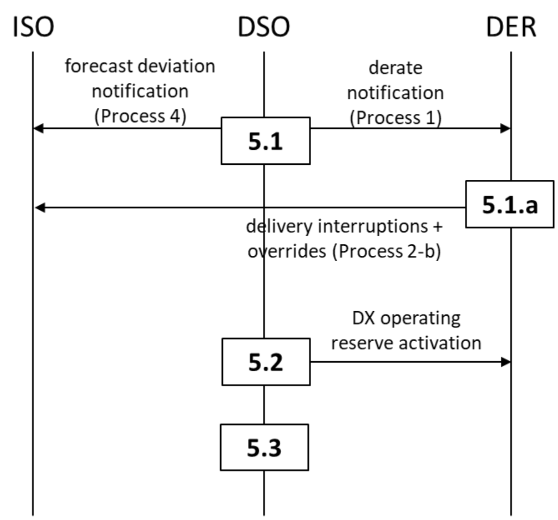

Figure 4-22. Sequence diagram, Stage 5-a with Dual Participation model

Stage 5-b: Contingency Management for Transmission-Level Incidents

In Stage 5-b, the ISO responds reactively to an unplanned generation or transmission incident. ISO sends a reserve dispatch order to the DER (step 5.1), which dispatches accordingly (step 5.2). Step 5.3 updates the capacity available for wholesale reserve and possibly seeks to procure additional reserve, if practicable.

The functional and sequence diagrams for this stage are represented in Figure 4-23 and Figure 4-24.

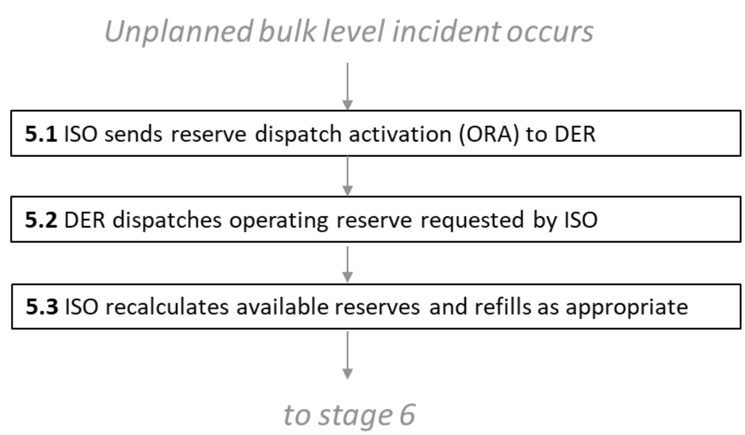

Figure 4-23. Functional diagram, Stage 5-b with Dual Participation model

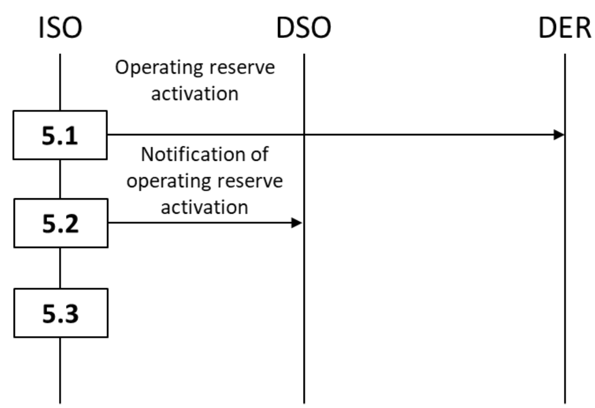

Figure 4-24. Sequence diagram, Stage 5-b with Dual Participation model

Stage 6: Performance Evaluation and Settlement

This section is left intentionally blank. Stage 6 is out of scope for this effort.

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5

DISTRIBUTION IMPACTS OF DER-PROVIDED GRID SERVICES FOR SELECTED ALECTRA FEEDERS

This chapter describes feeder simulations performed to assess the system impacts of grid services at the T-D interface provided by DER, or in other words, at the distribution feeder head or source. A summary of some of the notable results of those studies are reviewed in this chapter.

Feeders Modeled

Alectra selected eight (8) feeder models from the York region, where a companion project demonstrating the delivery of DER-provided distribution system and wholesale market services is being conducted.[29] These feeder models represent a variety of total feeder demand, presence of existing small DER, and even a few large DERs that already participate in the wholesale electricity markets. In addition, the IEEE 34-bus test feeder and the IEEE 342-Node secondary network feeder models[30] are included in simulations to represent different feeder compositions and to use standardized and available models.

A summary of key information on each feeder is provided in Table 5-1. Each of the Alectra feeders are operated at the 27.6 kV voltage class. The IEEE 34-bus feeder is operated at 24.9 kV, and the IEEE 342-Node model (which consists of eight (8) feeders) is run at 13.8 kV, with a 115kV source. Asterisks indicate feeders that currently host DER that participate in the wholesale electricity markets.

Table 5-1. DER Scenario Modeling Feeder Model Characteristics

Feeder	Peak Amps	Average Amps	Min Amps	Peak MW	Average MW	Min MW	Connected DER MW
1	397	235	156	18.9	11.2	7.4	0.5
2	445	204	93	21.3	9.7	4.4	2.8
3*	158	86	16	7.6	4.1	0.8	9.1*
4	375	163	57	17.9	7.8	2.7	1.1
5	299	123	69	14.3	5.9	3.3	0.25
6*	379	168	91	18.1	8.0	4.3	4.7*
7	389	170	76	18.6	8.1	3.6	0.2
8	428	168	91	20.4	8.0	4.3	0.7
9 (IEEE 34)	47	28	19	2.1	1.2	0.8	0.0
10 (IEEE 342)	125	75	50	42.8	25.8	17.2	0.0

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[29] IESO York Region Non-Wires Alternatives Demonstration Project. https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/IESO-York-Region-Non-Wires-Alternatives-Demonstration-Project. 2021.

[30] IEEE PES Test Feeder Library. https://cmte.ieee.org/pes-testfeeders/resources/ (Source is a 2017 article from IEEE Transactions on Power Systems, vol. PP, no.99, pp. 1-1. 2017, with full reference on the website)

Peak loads as shown were provided within time-series metering data from Alectra for a calendar year at hourly intervals. The same data informed average and minimum ("overnight") load levels used in simulations. These are net load demand levels including non-dispatchable generation (uncontrolled by the utility) from existing small DER. IEEE test feeder loading was determined by the as-is models provided publicly from IEEE.

Description of Modeling Method

The study method simulates three load levels (peak, average and minimum) as separate snapshot power flow studies per feeder. These illustrate the power flow exchanged at the T-D interface in the as-is, baseline condition, prior to adding DER to explore their impact on the grid when used for both distribution and bulk system services.

Model Conversion

The simulation studies performed in this project use two of the more common tools in the industry, CYME and OpenDSS. These tools geographically represent the feeder and incorporate all electrical characteristics like impedance, operating voltage, ampacity, and control parameters.

Alectra provided eight (8) feeders to EPRI in the CYME file format. The total load measured at the feeder sources was allocated down to the load elements in the model, splitting the demand by ratios of per-site transformer kVA to total connected kVA. Note, for future use and business decisions, the simulations should be compared to actual field conditions for full context. Some modifications to loading and existing DER elements were made on a case-by-case need, as described later.

EPRI used an in-house Python script that can capture critical elements from CYME to produce a model version in the OpenDSS format. Conversion to OpenDSS can support review on a common, open-source format, and it can also support simple means of anonymizing the model to preserve system information security. Figure 5-1 shows a feeder sample in both formats. (Note, the substation/feeder source is indicated with the red dot icon.)

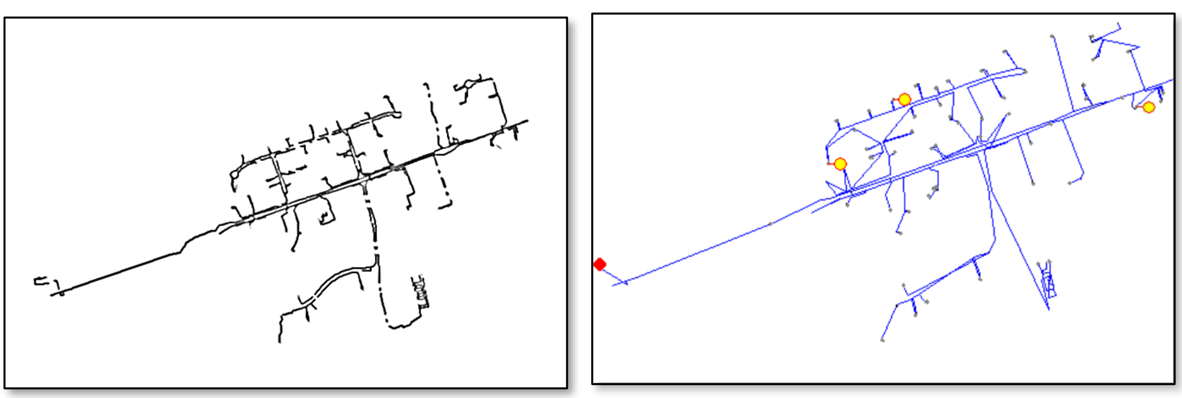

Figure 5-1. Example of Model Conversion from CYME to OpenDSS (Feeder 1)

Power flow and voltage performance was compared between OpenDSS and CYME models to determine the quality of match. A few important overall assumptions are listed below:

- All 27.6 kV feeders operated at ~28.5 kV (1.033 per unit).
- Overall feeder power factor is assumed to be 0.92.

- Note, all feeders have substation load tap changers (LTC) to regulate source voltage, but none have voltage regulators or shunt capacitors. These are normal to include in distribution feeders, but not always required.
- Existing DER on any of the models is assumed to be solar and will not participate in distribution services or the wholesale energy market, as it is not considered dispatchable.
  - Feeders 3 and 6 are exceptions to these assumptions, as they have a few large, dispatchable generators (combined heat and power (CHP) between 4 to 8 MW). These are modeled as if they are the "future" market-participatory DER, as well as possible non-wires alternatives.
- No customer classes are identified, so demand magnitudes are the distinguishing factor.

The IEEE feeders are publicly available in spreadsheet form, then converted to OpenDSS. EPRI created OpenDSS versions of these feeders, as well, to enable the same study methods as used on the feeders.

Modifying the "Baseline" Models

In existing conditions, most of the Alectra feeder models lack true distribution constraints (thermal overloads, voltages over or under industry standard operating limits) – in other words, these feeders have a robust design. Simply scaling up the feeder load would have to be significant to simulate true overloads. To create a theoretical reference point representing a distribution constraint, the study method used a smaller increase of feeder loading meant to purposefully but only slightly exceed the normal planning, which is 400 Amps total load on the feeder mainline. This is important for identifying the required amount of DER to address constraints for scenarios 2 through 5.

Also, for those feeders with large DER present, the studies here adjusted the feeder loading and total DER to discount those sites to obtain a baseline feeder operation, since they are already participating in the electricity markets. Then, the study cases used those sites as the simulated locations for DER in the scenario simulations.

The combination of approaches above created per feeder adjustments to load as shown in Table 5-2. These values produce feeder power flow that exceeds the planning threshold for each scenario to consider impacts and mitigations with DER.

Table 5-2. Adjusted DER Scenario Modeling Feeder Model Characteristics

Feeder	Peak Amps	Average Amps	Min Amps	Peak MW	Average MW	Min MW	Connected DER MW
1	434	235	156	19.7	11.2	7.2	0.5
2	451	141	32	20.7	6.8	1.5	2.8
3*	431	228	35	20.8	10.9	1.7	0.4
4	438	157	40	19.9	7.5	1.9	1.1
5	424	157	85	19.0	7.5	4.1	0.25
6*	432	165	82	19.6	7.9	3.9	0.7
7	439	174	76	19.8	8.3	3.6	0.2
8	466	155	77	21.1	7.4	3.7	0.7
9 (IEEE 34)	47	28	19	2.1	1.2	0.8	0.0
10 (IEEE 342)	125	75	50	42.8	25.8	17.2	0.0

Comparison of this table to Table 5-1 highlights all feeders now have loading over 400 amps, and the feeders with large existing market-participatory DER (feeders 3 and 6) show significantly smaller existing DER. E DER is all assumed to be solar. The full nameplate capacity is assumed to be produced for both the average and min load conditions, where only 20% of nameplate is produced at the peak condition, to mimic typical production of solar facilities relative to their nameplate rating and time of day.[31]

Addition of DER for Scenario Studies

Each feeder will be simulated with hypothetical DER distributions, to observe the changes in power and other metrics at the T-D interface, and to evaluate what they must be able to do for various services. Below is the list of requested DER technologies to evaluate:

- Utility-scale energy storage
- Commercial-scale energy storage
- Residential-scale energy storage
- Utility-scale natural gas generator
- Commercial-scale natural gas generator
- Smart thermostats
- Commercial & Industrial Demand Response

The project assumes a few very important things about DER model additions and their capabilities for simulations.

- All DER sites are modeled downstream of feeder constraints (aka congestion). Varying scales of DER unit size and fleet count are added to compare impacts of equivalent amounts of DER per scenario.
- DER added for these studies are all controllable to provide desired output as needed.
- All DER will be connected under a "flexible interconnection agreement" (see Chapter 4). This means DER may be larger than would be allowed under typical screening methods.
    - This assumes there are different reasons (specific feeder operating conditions) where DER will be curtailed to avoid creating constraints.
    - But this will maximize DER capability to provide services.
- Any utility-scale or commercial-scale DER will be placed on feeders using a manual selection of locations relative to feeder constraint locations.
    - Utility-scale sites are added on mainline locations, to avoid overloading existing transformer equipment.
    - Commercial scale sites are connected on the secondary side of large transformers with loads and transformers greater than 500 kW.

[31] Feeders that have true minimum load conditions overnight would not have any contribution to power flows from solar DER, but this assumption was made to capture the most conservative potential feeder conditions that could happen in a temperate season during the daytime.

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- An automated allocation method is used for locating residential-scale DER in each feeder model. This targets a percentage of all feeder load elements with small load demand, evenly spreading the aggregate MW size needed for DER services across all those sites. A check is performed of total load and DER net power flow against 90% of the transformer rating to prevent reverse power flow overload.

Figure 5-2 highlights the way each DER can be allocated. In this case, all DER types and classes are energy storage (ES).

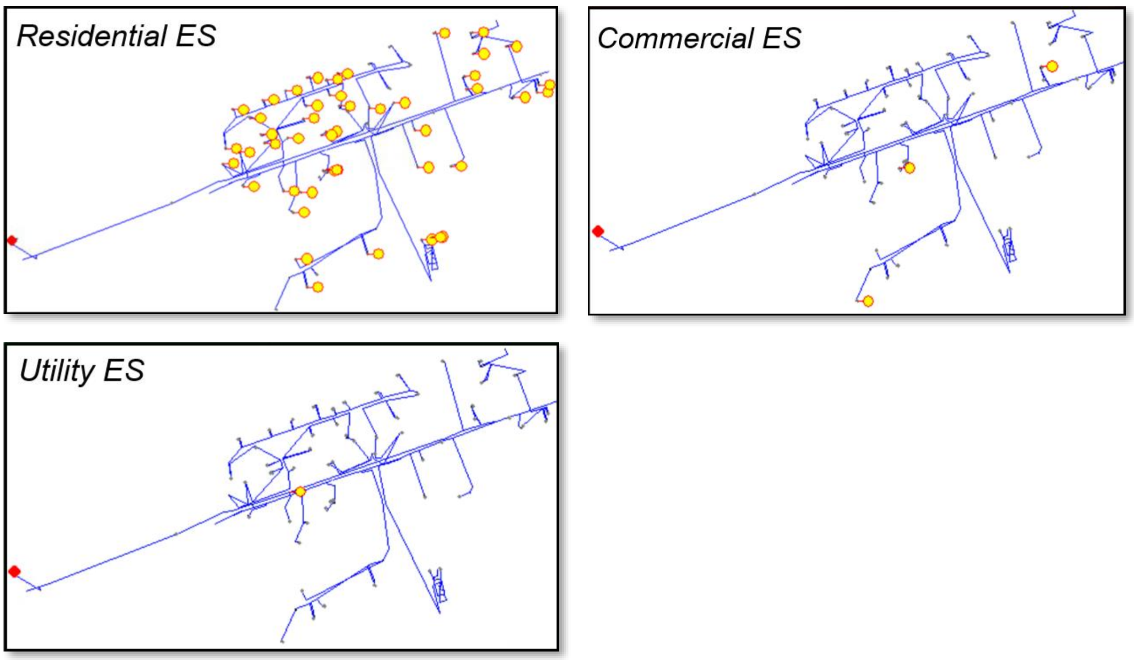

Figure 5-2. Sample Method of Allocating Energy Storage (ES) on Feeder 1

Automating the Study Process

A variety of grid operations conditions can be highlighted by the power flow simulations planned in this study:

- A baseline condition is run "as-is" at three load levels (peak, average, minimum).
- "DER Loss Impact" studies simulate a sweep of aggregate DER sizes using the locations of DER found in the previous section to identify possible impacts to total feeder losses.
- "Congestion Relief" studies find the necessary DER size (using 0.5 MW increments) that would be large enough to relieve thermal distribution constraints.
- "Value Stacking" studies build on the Congestion Relief results by adding another single or aggregate 3 MW, which makes total connected DER large enough to concurrently participate in both distribution services and the wholesale electricity markets.

Each of these sensitivities, shown in Table 5-3, are simulated and analyzed with an automated power flow script per scenario.

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Table 5-3. Sensitivity Factors of Simulations Run per Feeder

Operating Case	Load Level	Existing DER Output	DER Technology
•Baseline •DER Loss Impact •Congestion Relief •Value Stacking	•Peak •Average •Minimum	•Full (at min and average load) •Partial (at peak load)	•Utility-scale storage •Commercial-scale storage •Residential-scale storage •Utility-scale gas •Commercial-scale gas •Smart Thermostats •Commercial Demand Response

Simulating All Requested DER Technologies

Every feeder was evaluated with the three scales of energy storage DER. This made simulations efficient, but other DER technologies are also evaluated.

Energy Storage

Energy storage requires power from the grid or other co-located DER to charge the equipment to full capacity, but it can then be discharged on a schedule or using other signals and measurements when needed.

Natural Gas Generators

Natural gas generators are modeled both at a utility scale and commercial scale. In this project, the output of these devices is similar to energy storage, with the capability to produce power at or nearly at full nameplate rating. The time element of the behavior of these technologies can make a difference, but this will not be simulated in this scope of work.

Demand Response – Smart Thermostats and Commercial DR

Two DER technologies capable of providing "demand response" (DR) – smart thermostats and commercial demand response.

Smart thermostats are capable of making small changes in kW demand per residential customer. This prompts a higher volume of thermostats to meet the feeder power reduction needed.

Commercial-scale demand response programs are an arrangement with large customers to reduce their site and process demands. The use of commercial DR usually applies at the macro scale, to help with supply-demand balancing, but in this study, it is purposefully identified to provide services to the feeder it is connected to, as well as serving the bulk grid.

In general, these DR technologies produce a percentage of load reduction. Smart thermostats are allocated in two volumes for two separate case studies, placing DER at either 50% of feeder load locations or at 80% of load locations.

- At 50% allocation, they produce a 25% per-site load reduction for distribution services, and an expanded per-site 45% reduction is assumed for the "value stacking" use case, meaning to participate in the wholesale energy market.
- At 80% allocation, they produce a 10% load reduction for distribution services and a 20% reduction for value stacking.

Commercial DR sites are assumed to reduce site load by 25% for congestion relief and 50% for additional market participation. The locations of commercial DR are selected manually by focusing on larger load demand sites.

Per-feeder characteristics for DR allocation are shown in Table 5-4. Each residential load site is assumed to serve 6-10 homes, and each smart thermostat can reduce around 1 kW of load for a balance between power reduction and customer comfort. Commercial DR can have significant impact, and realistic energy change assumptions attempt to meet both distribution service needs and practical customer operations limits. (Feeder 10, or the IEEE 342-Node feeder with secondary networks, is not included in this table as network complexity would have been burdensome to simulate so many demand response locations.)

Table 5-4. Feeder 4 Customer Load Characteristics for Demand Response Studies

Feeder	Residential Load Sites	Residential Reduction Potential (MW)	Commercial Sites (> 0.5 MW)	Commercial Demand (total MW)	Commercial Reduction (MW)
1	159	0.95 – 1.59	13	12.9	3.2
2	435	2.6 – 4.4	4	3.6	0.9
3	60	0.36 – 0.6	11	14.2	3.6
4	240	1.4 – 2.4	9	9.4	2.35
5	81	0.49 – 0.8	0	0.0	0.0
6	78	0.47 – 0.78	2	2.7	0.68
7	120	0.72 – 1.2	4	3.7	0.93
8	87	0.5 – 0.87	0	0.0	0.0
9 (IEEE 34-bus)	38	0.2 – 0.38	0 (2 close to 500)	0.85	0.2

The results of average size and amount of load reduction per DR site is be evaluated for practicality and feasibility. Feeder 4 was the only circuit fully evaluated, but after applying the DR technology allocation to all feeders, it can be seen in the table that some feeders have relatively few residential or commercial sites, with their respective potential size of aggregate load reduction. The resulting DER capacity prevents some feeders from using one or both of these technologies, as they would not be sufficient to address distribution constraints.

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Technical Impact(s) to be Assessed

The impact of DER at the T-D interface is evaluated on the following metrics and conditions.

- Overall feeder losses
- Change in total net load with added DER (amps and watts)
- Maximum and minimum operating voltage
- Success or failure to provide distribution and bulk services
- Challenges with using the DER (feeder operating conditions)
- Changes in power flow under contingencies

Some studies are performed as “sweeps” of a range of DER sizes, usually up to 10 MW. This highlights situations where the size of the DER begins to make material impacts on the grid, both for desired load reductions and potentially undesirable voltage or reverse flow conditions. This also helps identify if the “congestion relief” magnitude of DER falls within allowable operating conditions.

As an example, the sweep of DER sizes (per class) versus the maximum feeder element loading is given in Figure 5-3. It shows each type of DER has the effect of reducing load on Feeder 1, but eventually it begins to increase “loading” again (reverse flow). For reference, the magnitudes of DER needed for congestion relief and market participation are given in the purple and red dashed lines, respectively.

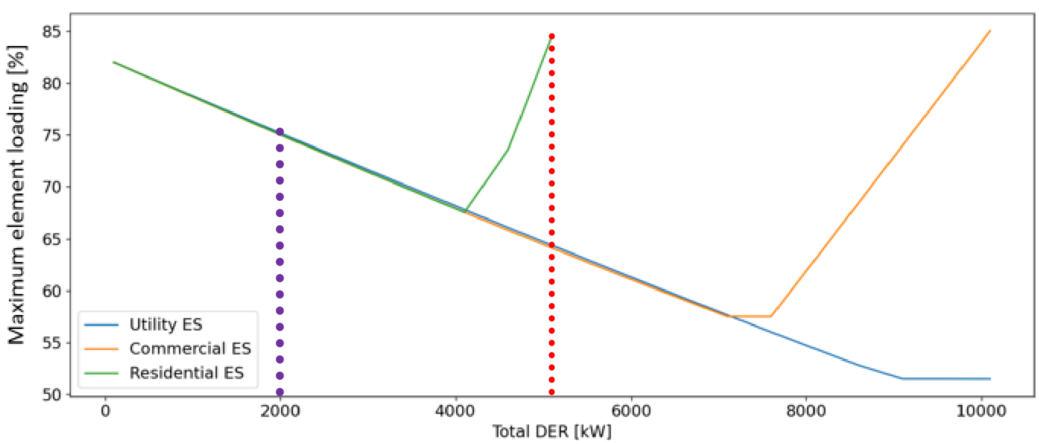

Figure 5-3. Feeder 1: Maximum Feeder Element Loading vs Total DER at Peak Load

Another reason for sweep studies is to highlight the range of impacts on feeder losses at various locations and sizes of DER. Figure 5-4 and Figure 5-5 show four locations on the feeder to identify what varying sizes of DER will do to the feeder losses. The graph shows that the location of the DER affects the change in relative losses impact, with gradually higher magnitude of losses change as the DER size grows. Location IV illustrates that when DER output begins to match nearby demand, it can eventually stop creating a losses reduction and begin to reintroduce losses. The highest magnitude in change of losses is only about 80 kW, which is very small compared to total loads around 20 MW. This is a robust feeder with low impedance and stiff operating voltages.

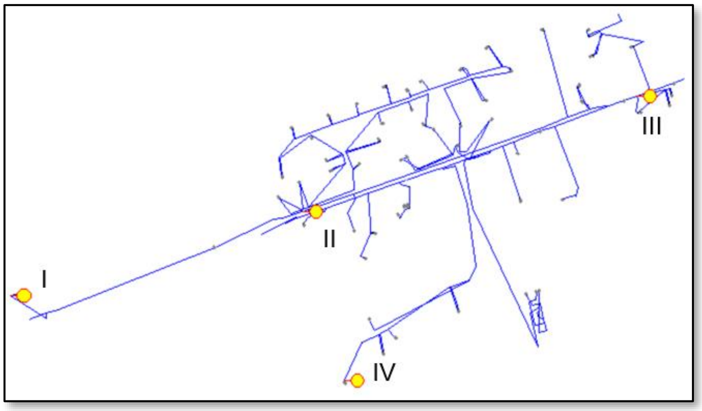

Figure 5-4. DER Losses Impact Study Locations on Feeder 1

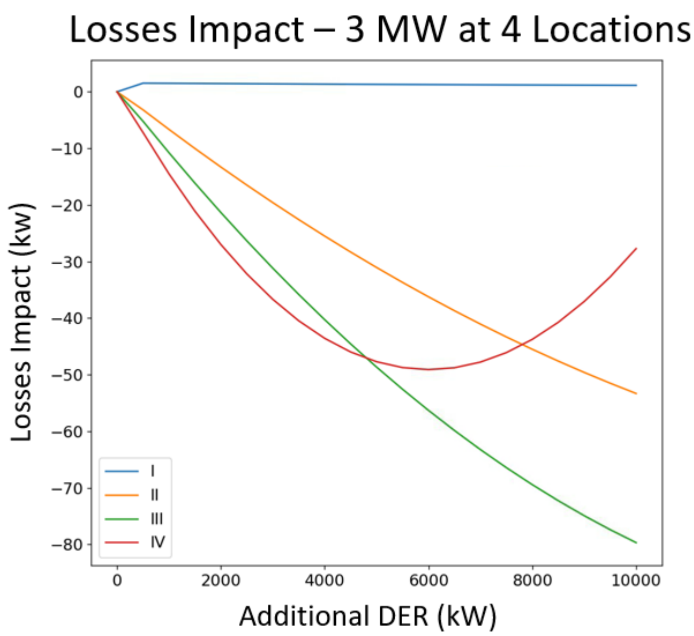

Figure 5-5. Range of Losses Impacts Across Feeder 1

Figure 5-6 shows the potential for voltage to increase with DER, per allocation of energy storage class and total size. This example illustrates a change in voltage of only 0.003 per unit, which is about 0.36 volts on a 120 Volt scale.

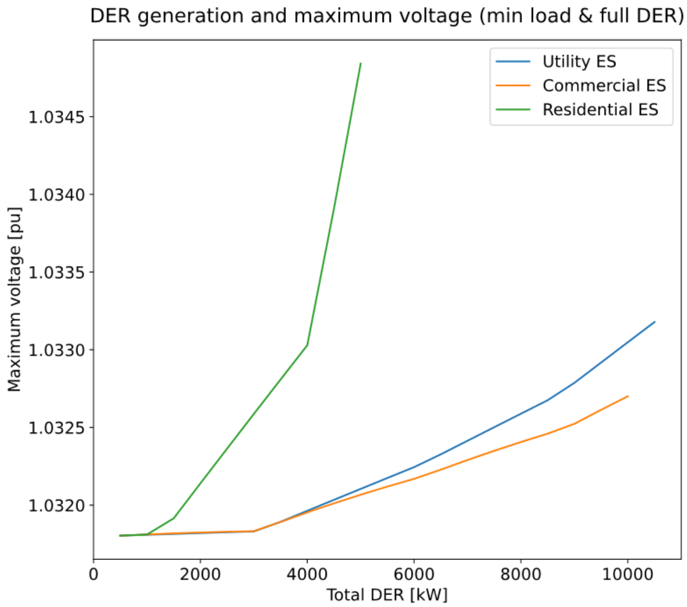

Figure 5-6. Maximum Voltage on Feeder 1 at Min Load per DER Location and Size

This collection of metrics and visuals is used to analyze all feeders simulated. Each metric provides a sense of how simple or difficult it may be to serve feeder distribution constraints, which then evaluates whether additional DER can be installed beyond what is needed at the distribution level to be able to participate in the energy markets.

Modeling Samples to Illustrate Technical Findings per Scenario

This section includes notable results from all feeder simulations to show the effects of DER for different scenarios and relevant data and metrics that go with each scenario. Note that these simulations do not make direct reference to either of the coordination frameworks evaluated in the other chapters of this report. These simulations highlight the technical effects seen on the feeder whenever the agreed upon DER magnitudes have been settled and reach the dispatch stage of operations.

Scenario 1 – Transmission Energy Dispatch

In the first scenario, a very simple interaction between DER and the wholesale market is investigated. The DER (in this case, energy storage) is dispatched without regard to any distribution constraint, to simply review what the effect of the added DER providing wholesale energy services is on the power exchanged at the T-D interface.

In peak conditions, there are very low losses on the feeder, even without any DER added. The change in losses once DER is added is not substantial, compared to the total load, so the T-D interface sees nearly a like-for-like change in total MW, with only about 20 kW or so reduced losses, at most. The summary of power exchanges is given below in

Table **5-5**.

Table 5-5. Feeder 1 Metrics at Peak Load with Varied DER Sizes

Added DER Technology	Added DER Generation [kW]	Feeder Current [A]	Feeder [kW]	Feeder [kvar]	Total Losses [kW]
N/A (Baseline)	0	434.3	19737	8229	189.4
Utility ES	500	424.7	19233	8216	185.4
Utility ES	2000	396.4	17722	8179	174.2
Utility ES	5000	341.0	14702	8115	154.7
Commercial ES	500	424.5	19229	8194	181.5
Commercial ES	2000	395.5	17709	8108	161.1
Commercial ES	5000	339.8	14681	8034	134.0
Residential ES	500	424.5	19229	8200	181.7
Residential ES	2000	395.6	17708	8119	160.6
Residential ES	5000	339.3	14675	7987	127.4

Most feeders provided have similar performance, in terms of the impact on losses. Relative to load, Feeder 1 has just under 1% losses, which is the lowest magnitude of losses at baseline. However, the IEEE 34-bus feeder has a unique construction compared to Alectra's feeders. It only serves 2 MW of demand, but the losses reach up to 0.28 MW, which is about 13.6%. This feeder is longer with some smaller wires and other equipment. Table 5-6 below shows the DER sizes considered for the IEEE 34-bus feeder are much smaller, to remain relevant to total feeder load. Losses can be reduced as much as 250 kW.

Table 5-6. IEEE 34-bus Metrics at Peak Load with Varied DER Sizes

Added DER Technology	Added DER Generation [kW]	Feeder Current [A]	Feeder [kW]	Feeder [kvar]	Total Losses [kW]
N/A (Baseline)	0	46.9	2055	313	281.1
Utility ES	300	38.4	1680.25	258	199.0
Utility ES	500	32.7	1430	230	154.7
Utility ES	1300	12.9	541.20	165	62.7
Commercial ES	300	38.0	1666.08	243	177.8
Commercial ES	500	32.6	1427	209	127.3
Commercial ES	1300	13.2	553.92	159	33.4
Residential ES	300	38.4	1682.28	264	207.8
Residential ES	500	33.1	1446	238	169.0
Residential ES	1300	13.1	548.66	171	72.1

These results show that DER added for wholesale services can have a measurable impact on power exchanged at the T-D interface, but it is dependent on the makeup of the feeder, including load demand, impedance, and DER location. For most Alectra feeders, the losses are not substantial, and they are even less pronounced at average and min load cases. However, the IEEE 34-bus model results illustrate that feeders built without a robust design may witness more variable changes in total load and losses.

Scenario 2 – Distribution Override

The difference between Scenarios 1 and 2 is the consideration of distribution level constraints, both in baseline conditions and as could be seen with the addition of DER. Simulations for

Scenario 2 illustrate three cases where the feeder in baseline conditions (prior to additional DER) may already have overloads, over- or under-voltage, or where DER additions may create or exacerbate these issues. Note that these simulations only reflect a sample of *conditions* that could potentially drive the need for overrides and not the *frequency* of such conditions.

Two conditions are evaluated in this section: 1) picking up additional load from a neighboring feeder, and 2) feeder voltage challenges (low voltage without DER, high voltage with DER).

Load Pickup

The first example given here is a case where a feeder is being evaluated to pick up load from a neighboring feeder after an interruption. This is shown on Feeder 1, with the load "pick up" location at the star icon (see Figure 5-7), at a magnitude of 4 MW. The same allocations of DER class (commercial and utility) and sizes as were simulated in Scenario 1 are used here.

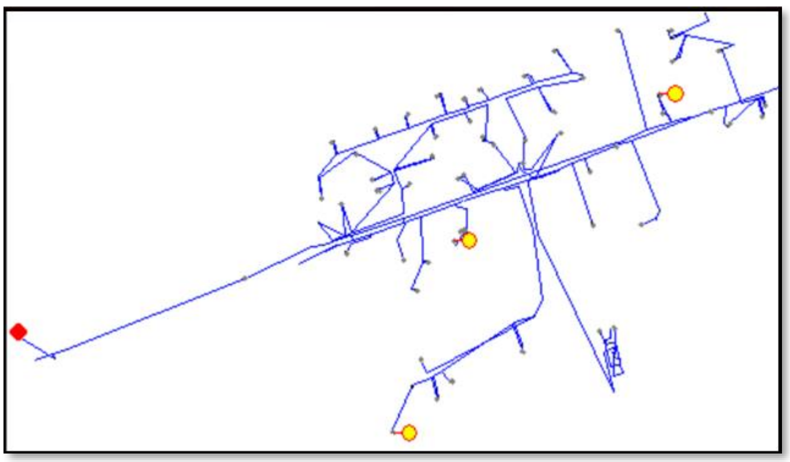

Figure 5-7. Feeder 1 with Pickup Location Identified

Table 5-7 below illustrates the changes seen in total load and current. The feeder loading at baseline exceeds the 400 Amp limit when no DER is added to the feeder. Feeder load is significantly increased (about 90 amps) with the added section of the neighboring feeder. When DER has been added to the feeder (matching the allocation shown in Figure 5-2) at varying sizes and at peak load, the fleet and aggregate size of DER is not enough to offset both the added load and bring the feeder loading below the limit.

Table 5-7. Feeder 1 Peak Power Flow Results with Added Load from Neighboring Feeder

Added DER Technology	Added DER Generation [kW]	Feeder Current [A]	Feeder [kW]	Feeder [kvar]
N/A (Baseline)	0	434.3	19737	8229
N/A (Added Load)	0	523.4	23771	9923
Utility ES	2000	485.3	21753	9865
Utility ES	5000	429.3	18727	9786
Commercial ES	2000	484.5	21740	9793
Commercial ES	5000	428.2	18708	9705

In this abnormal feeder configuration, the DSO would have to override any amount of DER previously offered to the wholesale energy market (reminder, this scenario does not yet consider DER for providing distribution services), and the DSO would have to notify the ISO of a temporary and slight overload for the feeder until the contingency is resolved.

Feeder Voltage Constraints

Other feeders may witness high voltage when DER is added, especially at minimum load conditions. The IEEE 34-bus feeder is already experiencing voltage challenges. It contains two sets of voltage regulators to keep operating conditions within limits, even at a much smaller scale of load. The feeder topography is displayed in Figure 5-8, along with the voltage profile that occurs at minimum load.

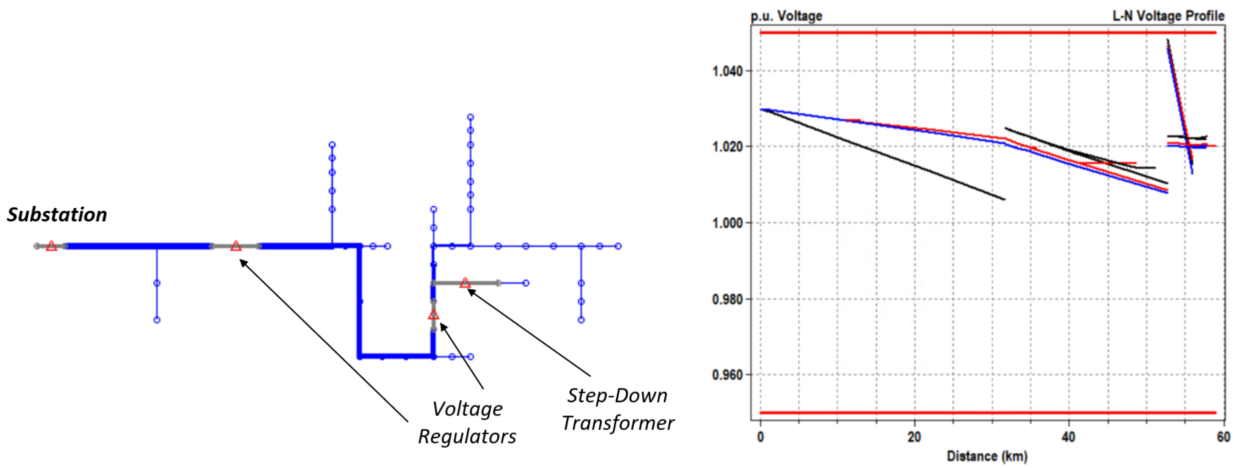

Figure 5-8. IEEE 34-bus Topography and Minimum Load Voltage Profile

When DER is added to this feeder (1.3 MW) for market participation, at minimum load conditions, the voltage profile seen in Figure 5-9 is the result. Each regulated “zone” of the feeder between regulators or far end of the feeder experiences an overvoltage, if the regulators do not have any adjustment given to their settings.

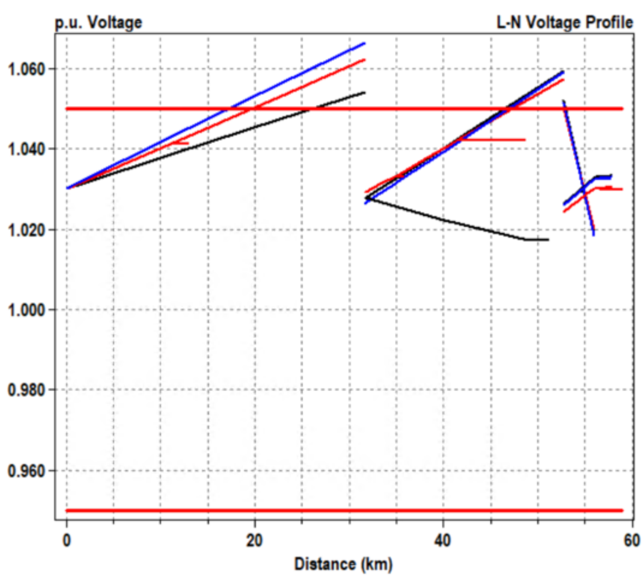

Figure 5-9. IEEE 34-bus Voltage Profile at Minimum Load with DER (Full Output)

In this use case, DER output can be overridden to a fraction of total output to bring voltages back within acceptable operating ranges. If the DER is reduced to 0.7 MW at minimum load conditions, almost all of the feeder returns to voltage values less than 1.05 per unit (see Figure 5-10). This total DER at minimum load could be used for any grid service, but it highlights the need for is likely not a situation that calls for grid support other than to avoid creating abnormalities.

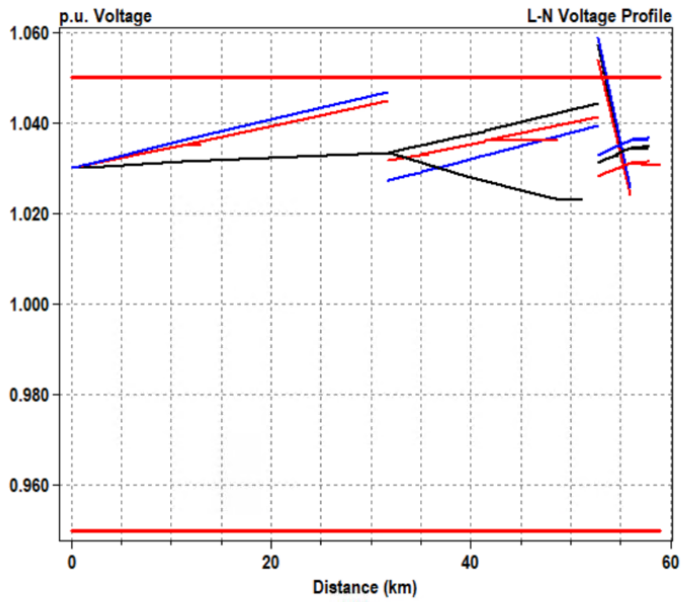

Figure 5-10. IEEE 34-bus Voltage Profile at Minimum Load with DER (Reduced Output)

Scenario 3 – Distribution Import-Congestion

Feeders with existing thermal distribution constraints (i.e. overload or congestion) can be relieved by DER acting as a non-wires alternative (NWA).[32] Two important conditions are highlighted in this project: (3a) DER sized to serve that overload strictly for distribution needs, and (3b) DER that can be operated to both serve the distribution congestion and still participate in the wholesale energy market, in a "value stacking" arrangement. Simulations in this scenario explore how much DER is needed to serve the feeder constraint, and then additional capacity is included to export for the electricity market (3 MW larger).

Scenario 3a – Distribution Congestion Relief Only

Energy Storage

Feeder 8 is used for the first demonstration of distribution congestion relief. Figure 5-11 shows its topography with 2 notable load areas or "pockets". This feeder has a total load of 21.1 MW, which is about 466 Amps.

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[32] Feeders also experience voltage constraints at times, but historical approaches to using NWA are typically reserved only for thermal loading constraints, for practical and economic reasons.

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Figure 5-11. Feeder 8 Topography with Existing DER Locations Identified

For the congestion relief studies, the DER must be able to reduce element loading to the planning threshold of 400 Amps. DER increments of 0.5 MW are considered, and the study finds that 3.5 MW of DER is needed. This magnitude is evaluated for all three scales of energy storage. The allocation of each of those DER is shown in Figure 5-12.

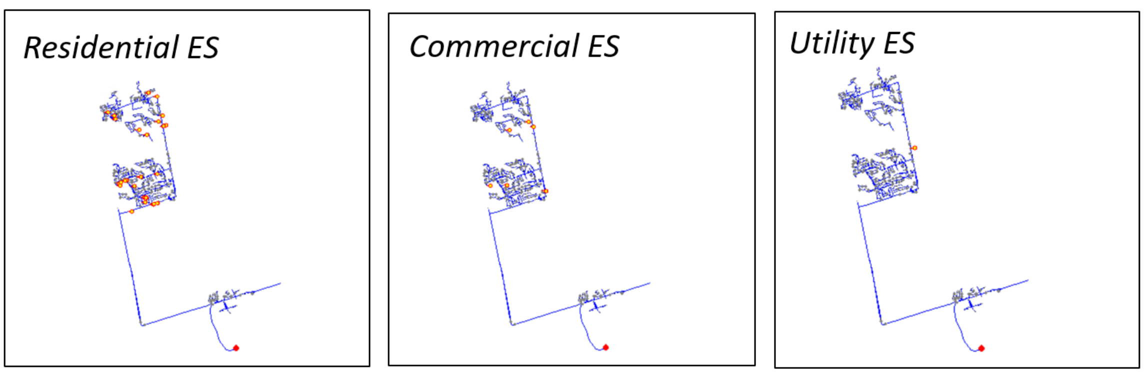

Figure 5-12. Energy Storage Allocations for Feeder 8 (DER scales left to right: residential, commercial, utility)

The Feeder 8 element loading is displayed as a heat map in Figure 5-13 (substation located at the star). On the left is the baseline condition, and on the right is the result after addition of energy storage (same value change for either residential or utility-scale storage). Loading percentages listed are relative to element ratings, not the planning threshold. In baseline conditions, the jumper location is loaded to 67% (467 Amps of 700 Amps). After the addition of DER, the line rating drops to 56% (392 Amps). This shows the DER is able to effectively relieve the total load on the feeder, below the planning threshold.

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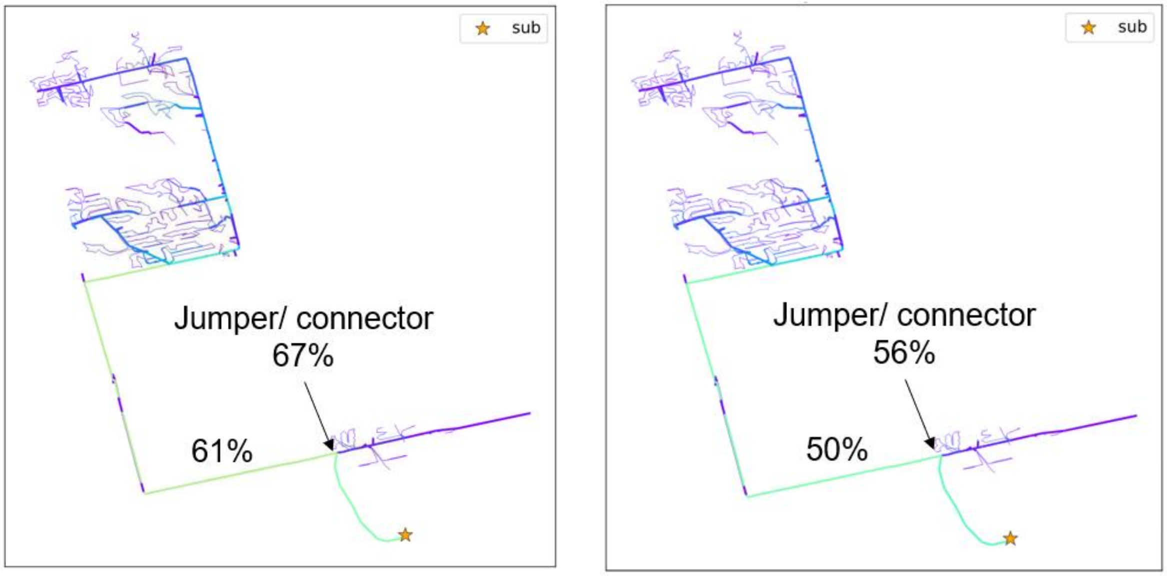

Figure 5-13. Heat Maps of Feeder 8 Displaying Changes in Feeder Element Loading with DER as NWA (left: baseline, right: storage added - residential or utility-scale)

Smart Thermostats and Demand Response

To illustrate other DER technologies, Feeder 4 is simulated to use smart thermostats and commercial-scale demand response. Figure 5-14 shows the topography of Feeder 4, with a single load pocket. This feeder has a total load of 19.9 MW (438 Amps).

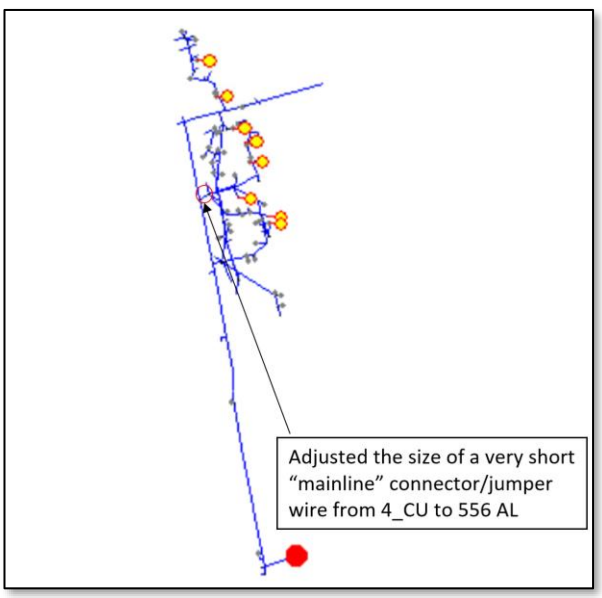

Figure 5-14. Feeder 4 Topography with Existing DER Locations Identified

For the congestion relief studies, to reduce the Feeder 4 load down to 400 Amps, DER increments of 0.1 MW are considered, and the study finds that between 1.7 and 2.4 MW of DER is needed. This is evaluated for both scales of smart thermostat deployment and for commercial demand response (allocation shown in Figure 5-15).

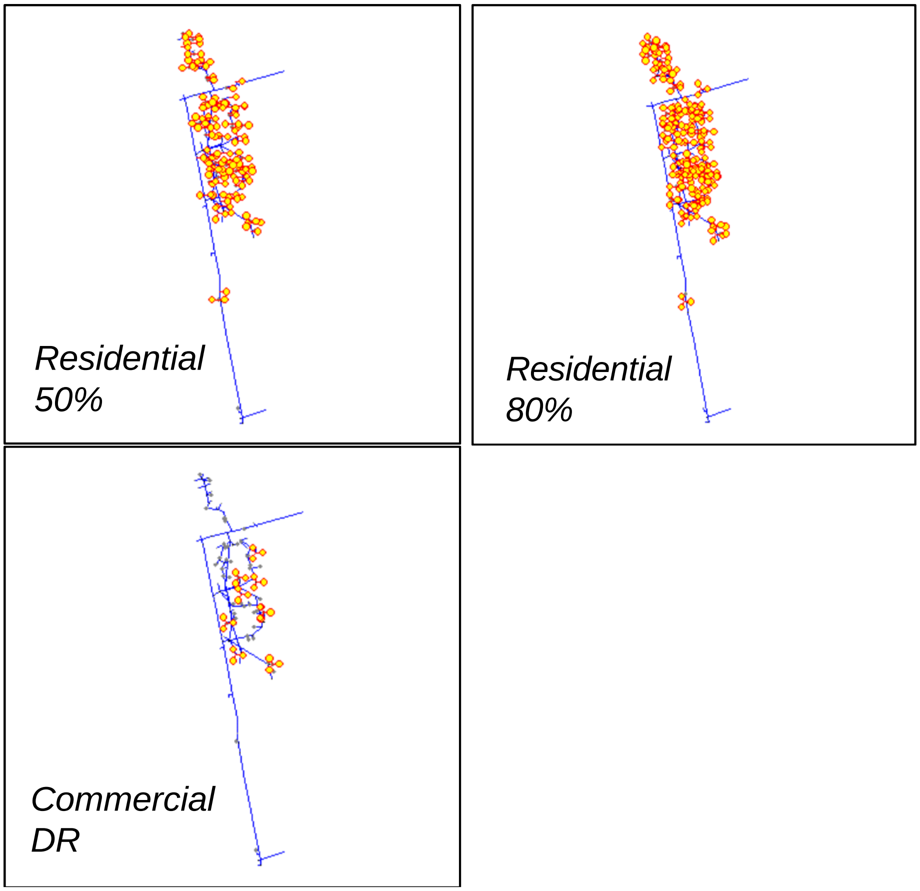

Figure 5-15. Demand Response Allocations for Feeder 4 (DER scales left to right: commercial, thermostats at 50% saturation, thermostats at 80% saturation)

Commercial demand response is able to reduce the feeder below 400 Amps with an aggregate of 2.3 MW of reduction, which is a 25% drop in per-site load. Smart thermostats, when distributed to 50% of feeder loads, require 2.4 MW in aggregate. Across 120 sites and 10 homes per site, at 25% reduction, this would require each thermostat to reduce 2 kW of load. This is likely a too much to be practical. If the thermostats are located at 80% of load sites, this requires only 1.9 MW across 200 load sites, which is about 0.8 kW per thermostat, which is more reasonable. However, this saturation on the feeder may not be plausible, considering the true number of residential customers, size of home, willing grid event participants, and other factors.

Table 5-8 describes whether the allocation of thermostats and demand response is reasonable or feasible for all feeders. Only one feeder comes close to relieving the load with residential thermostats, and only two feeders have enough large sites to provide enough reduction for full feeder relief. (Note, feeder 10, or the IEEE 342-bus feeder with secondary networks, was not simulated with demand response due to the model's complexity, so this table does not include results for feeder 10.)

Table 5-8. Feeder 4 Customer Load Characteristics for Demand Response Studies – Feasibility

#	Load Sites	Residential Reduction Potential (MW)	Commercial Sites (> 0.5 MW)	Commercial Demand (total MW)	Commercial Reduction (MW)	Relief Needed (MW)	Feasibility Notes
1	159	0.95 – 1.59	13	12.9	3.2	2.0	Res: No Comm: Yes
2	435	2.6 – 4.4	4	3.6	0.9	2.5	Res: Yes Comm: No
3	60	0.36 – 0.6	11	14.2	3.6	1.5	Res: No Comm: Yes
4	240	1.4 – 2.4	9	9.4	2.35	2.4	Res and Comm close, but improbable
5	81	0.49 – 0.8	0	0.0	0.0	1.5	Res: No Comm: No
6	78	0.47 – 0.78	2	2.7	0.68	2.0	Res: No Comm: No
7	120	0.72 – 1.2	4	3.7	0.93	2.0	Res: No Comm: No
8	87	0.5 – 0.87	0	0.0	0.0	3.5	Res: No Comm: No
9	38	0.2 – 0.38	0 (2 close to 500)	0.85	0.2	0.3	Res: Possible Comm: No

Scenario 3b – Distribution Congestion Relief + Wholesale Energy Market Participation

Energy Storage

For Feeder 8 storage DER to serve the distribution constraint and participate in the wholesale energy market, the total added DER becomes 6.5 MW. The results of these increases differ between DER scales (see Table 5-9). Increasing DER output has the same effect on total feeder load regardless of DER type, but the table shows an overload has occurred when applying commercial-scale storage. One or more of the storage locations is sized large enough for this market participation use case to exceed the rating of nearby grid equipment, likely the interconnection transformer. The other two scales of storage do not pose the same concern. This may determine which future scale of DER to pursue, how to appropriately size and locate DER, which DER will need to be overridden, or which cases are more valuable.

Note that there are no issues on this feeder with high or low operating voltage. Also, this feeder has the potential to reduce losses with DER by as much as 330 kW, or 1.5% relative to baseline peak load.

Table 5-9. Feeder 8 Peak Measurements for Scenario 3 Conditions with Energy Storage

Feeder Conditions	DER Type	Feeder MW	Total DER MW	Feeder Losses MW	Heaviest Load vs Rating %	Vmax (pu)	Vmin (pu)
Baseline	(none)	21.1	0.1	0.693	67	1.029	0.93
Congestion Relief (3a)	Residential	17.4	3.6	0.495	56	1.031	0.94
	Commercial	17.4	3.6	0.496	59	1.031	0.94
	Utility-scale	17.4	3.6	0.497	56	1.031	0.94
Market Participation (3b)	Residential	14.3	6.6	0.364	62	1.032	0.95
	Commercial	14.3	6.6	0.402	133	1.032	0.95
	Utility-scale	14.3	6.6	0.368	47	1.032	0.95

Smart Thermostats and Demand Response

The scale of smart thermostats and commercial load demand response on Feeder 4 are increased for participating in the wholesale energy market. However, the assumed changes in energy provided are likely not realistic in any of these cases. The range of total demand reduction is now between 3.5 to 4.8 MW. Translating these to per-thermostat reduction would be between 1.7 to 3.7 kW. This also does not take into account the success of all sites to participate, customer choice (opt-out), or other practical reasons that could reduce the total impact of power exchanged at the T-D interface/feeder source.

When increasing the commercial demand response to 4.6 MW total, this represents all commercial loads reducing their demand by 50%. This, again, is likely not practical for every commercial electricity customer to maintain critical operations as well as processes needed to make their operations economical and gainful. Table 5-10 summarizes the findings of both congestion relief and market participation conditions for the smart thermostat and demand response allocations on Feeder 4.

Table 5-10. Feeder 4 Peak Measurements for Scenario 3 Conditions with Demand Response (with Utility-scale Energy Storage for Reference)

Feeder Conditions	DER Type	Feeder MW	Total DER MW	Feeder Losses MW	Heaviest Load vs Rating %	Vmax (pu)	Vmin (pu)
Baseline	(none)	19.9	0.2	0.239	82	1.02	0.99
Congestion Relief (3a)	Utility-scale ES	17.8	2.2	0.208	57	1.03	0.99
	Commercial DR	17.5	2.5	0.184	55	1.03	0.99
	Residential DR (50%)	17.4	2.6	0.182	56	1.03	0.99
	Residential DR (80%)	18.1	1.9	0.198	57	1.03	0.99
Market Participation (3b)	Utility-scale ES	14.8	5.2	0.169	49	1.03	0.99
	Commercial DR	15.2	4.8	0.140	47	1.03	0.99
	Residential DR (50%)	15.4	4.6	0.145	51	1.03	0.99
	Residential DR (80%)	16.5	3.5	0.162	52	1.03	0.99

Scenario 4 – Distribution Operating Reserves

This unique scenario accounts for grid interruptions. Backup DER service providers are contracted and ready to serve feeder load, but specific and likely contingencies have to be identified to plan for appropriate location and size of DER to serve the altered grid. The simulations performed for this scenario include picking up a section of a neighboring feeder (with and without DER), as well as the loss of part of the feeder, evaluating for successful distribution services to avoid overload as well as concurrent participation in the wholesale market.

Scenario 4a – Distribution Reserves Only

Feeder 2 is used to illustrate how multiple technologies could be used to address heavy loading, and that they could act as reserve for each other. The general topography of the feeder is shown in Figure 5-16.

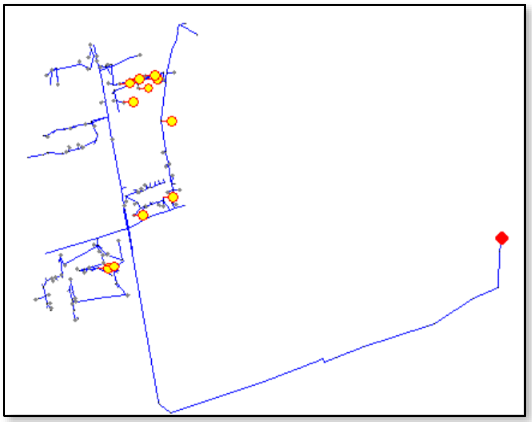

Figure 5-16. Feeder 2 Topography with Existing DER Locations Identified

The heavily loaded branch is in the middle left of the feeder, where it branches off of the mainline. This influenced the selection of the commercial and utility-scale DER locations to be sure both that branch and the overall feeder can benefit from the supplied power. The allocation of each DER scale is shown below in Figure 5-17.

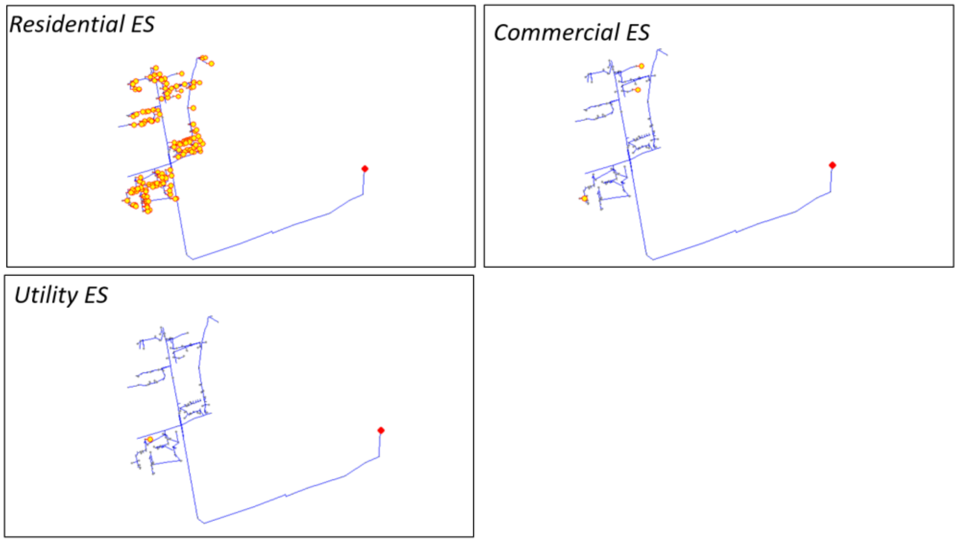

Figure 5-17. Energy Storage Allocations for Feeder 2 (DER scales: residential (top left), commercial (top right), utility (bottom))

The Feeder 2 topography is also displayed in the form of a heat map in Figure 5-18. The left image is the baseline condition, and the right image is the result after addition of utility-scale energy storage. The heavy branch is loaded to about 89% of its rating. The mainline is loaded to about 65% of rating at peak. After the addition of DER, the branch loading changes to 62%, and the mainline rating drops to 58%. This describes the assumed condition that DER have first been activated to provide congestion relief as a non-wires alternative. Next, the feeder is evaluated to see if other allocations of DER could be installed concurrently for use as reserves and achieve the same or similar congestion relief.

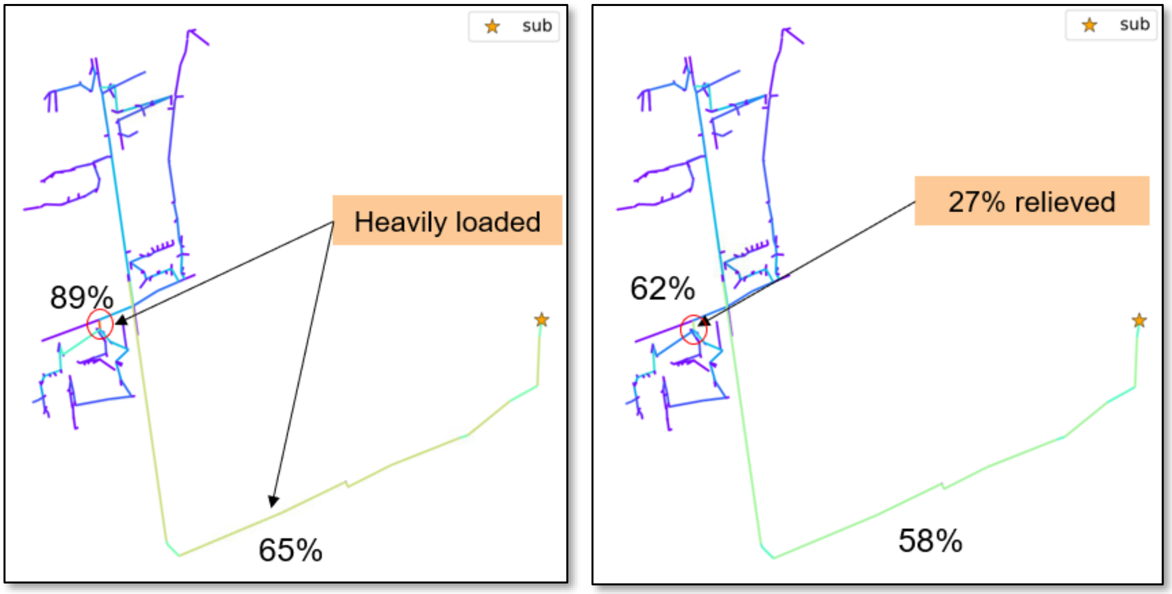

Figure 5-18. Heat Maps of Feeder 2 Displaying Changes in Feeder Element Loading with DER as NWA (left: baseline, right: utility-scale storage added)

If the utility-scale storage unit is the primary DER intended to provide congestion relief, and it were to have some failure, either the commercial or residential storage fleet could provide backup. Both the commercial and residential storage allocations could reduce the branch and mainline sections to 78% and 58%, respectively. They also have reduction impacts on other portions of the feeder. An allocation that creates a more "like for like" condition is possible with more targeted customer outreach efforts and installation of commercial and residential locations.

Scenario 4b – Distribution Reserves + Bulk Grid Reserves

When considering the bulk grid market for reserve energy, the same technologies illustrated here can increase their output if a contingency arises on the Transmission system. The general loading and losses conditions of Feeder 2 for both congestion relief and market participation are given in

Table 5-11 This table assumes the DER allocation that is active for congestion relief is signaled to provide more power if and when called upon for bulk system reserves, through the market bidding process. Generally, all metrics conditions appear to have positive impacts as DER output increases, and it does not begin to produce any undesirable overloads, as other feeders could experience.

Table 5-11. Feeder 2 Peak Measurements for Scenario 4 Conditions with Energy Storage

Feeder Conditions	DER Type	Feeder MW	Total DER MW	Feeder Losses MW	Heaviest Load vs Rating %	Vmax (pu)	Vmin (pu)
Baseline	(none)	20.7	0.6	0.508	89	1.03	0.947
Distribution Reserves (4a)	Residential	18.1	3.1	0.400	78	1.03	0.953
	Commercial	18.1	3.1	0.398	78	1.03	0.953
	Utility-scale	18.1	3.1	0.400	62	1.03	0.953
Add Bulk Grid Reserves (4b)	Residential	15.0	6.1	0.292	65	1.03	0.958
	Commercial	15.0	6.1	0.300	66	1.03	0.957
	Utility-scale	15.0	6.1	0.310	60	1.03	0.957

Scenario 5 – Capacity Service

This scenario is an extension of Scenario 3 – Distribution Congestion-Import. The primary difference is that the DER participate in a capacity auction at the bulk grid level, where they bid for and commit capacity to be available at heavy load times of year. This is usually done months in advance of the season of need. This also commits the DER to provide energy offers to wholesale electricity markets in the normal day-ahead and real-time market processes for those periods where the capacity is required.

From a simulation perspective, the results of these arrangements are highly similar to the results evaluated in Scenario 3. This section will describe how Feeder 3 would potentially adjust operations from today's condition to how the new market coordination. Feeder 3 has three very large DER totaling 8.8 MW that already participate in the wholesale electricity markets. The feeder model has been modified as if that DER is not "existing", but they are re-inserted as the simulated commercial-scale DER allocation.

The topography of Feeder 3 is provided in Figure 5-19, showing where all existing DER are located, but identifying those that will be specifically included in the "baseline" simulation. This will give an estimate of feeder operations prior to the behavior of DER participating in the market.

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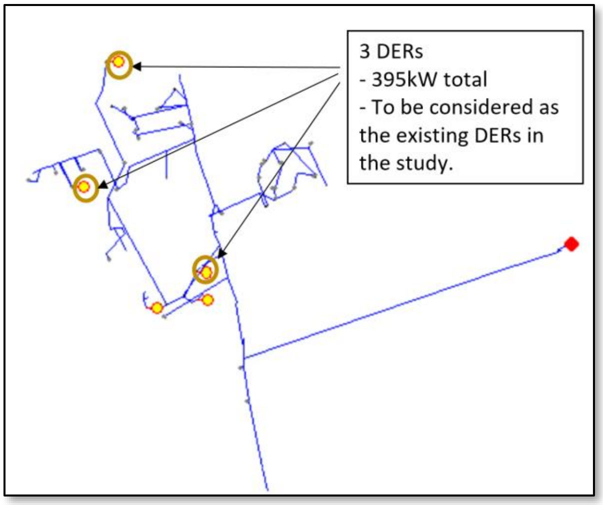

Figure 5-19. Feeder 3 Topography with Existing DER Locations Identified

When DER are installed to provide *capacity* service to the distribution feeder, this goes hand in hand with providing the needed *energy*. This is effectively the same as providing congestion relief.

The heatmaps below in Figure 5-20 show where the feeder is constrained and how well the DER can relieve the loading. The load relief result is true of any scale of DER; however, commercial-scale storge allocation required 0.5 MW more capacity than either residential or utility scale storage.

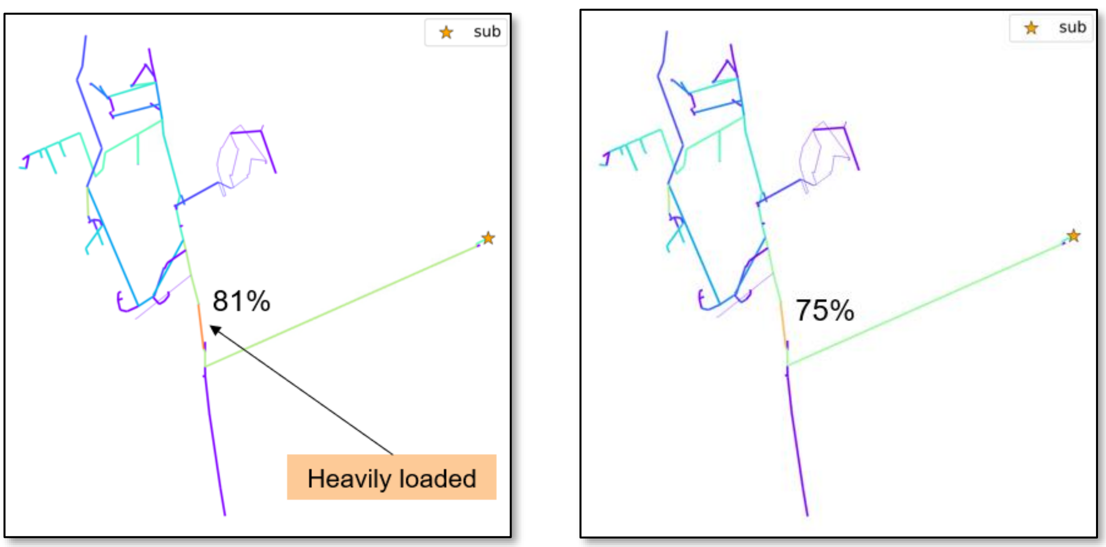

Figure 5-20. Heat Maps of Feeder 3 Displaying Changes in Feeder Element Loading with DER as NWA (left: baseline, right: storage added)

Considering a bulk grid capacity market, Table 5-12 displays the results of increasing the output of each allocation to meet that capacity need. It shows the increased total size of residential storage systems produce an overload on some part of the feeder, likely the transformers or line sections near to their installation. This condition would be more extreme under minimum load conditions, if DER produce at full nameplate. This highlights that even in peak load conditions, a flexible operating agreement with interconnected DER is needed (see Chapter 4 for more details), and the amount of DER installed should be purposefully designed to meet a service capability without creating an operating violation possibility.

In addition to these results, all three allocation types of DER are scaled up to the same magnitude as the existing 8.8 MW commercial sites. Table 5-12 shows that this creates a reasonable impact at peak for large scale DER, but it exacerbates the overload condition for residential storage output. So, this is not a reasonable condition to execute or expect in real feeder design and operations. The existing DER fleet/class can operate at full capacity without negative impact at peak load conditions.

Table 5-12. Feeder 3 Peak Measurements for Scenario 5 Conditions with Energy Storage

Feeder Conditions	DER Type	Feeder MW	Total DER MW	Feeder Losses MW	Heaviest Load vs Rating %	Vmax (pu)	Vmin (pu)
Baseline	(none)	20.8	0.08	0.248	84	1.03	0.99
Distribution Capacity	Residential	19.3	1.6	0.213	83	1.03	0.99
	Commercial	18.8	2.1	**0.227**	84	1.03	0.99
	Utility-scale	19.3	1.6	0.229	84	1.03	0.99
Add Bulk Grid Capacity	Residential	16.3	4.6	0.166	118	1.03	0.99
	Commercial	15.8	5.0	0.210	83	1.03	0.99
	Utility-scale	16.3	4.6	0.195	83	1.03	0.99
Existing Gen at 8.8 MW	Residential	12.0	9.2	0.121	295	1.04	0.99
	Commercial	12.1	9.2	**0.213**	85	1.03	0.99
	Utility-scale	12.1	9.2	0.159	83	1.03	0.99

Summary of Feeder Results

Table 5-13 below shows a table of overall simulation results, including the peak loading, DER size needed for congestion relief, losses impact, potential need for DSO overrides, and highlighted observation notes about general feeder conditions through all simulations.

Table 5-13. Overall Feeder Simulation Results

Feeder	Peak MW	DER MW for Dx Relief	Pre-DER Losses	Losses Impact	Override Needed?	Notes
1	19.7	2.0	189 kW	Up to 62 kW	Yes	Residential DER, sized for both congestion relief and market participation, cause some feeder element/transformer overloads at average and min load.
2	20.7	2.5	508 kW	Up to 216 kW	Possible	Power flows in reverse through the T-D interface in min load conditions if DER produces at full nameplate. No overloads or voltage issues, though.
3	20.8	1.5 to 2.0	248 kW	Up to 127 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also, power flows in reverse through T-D interface.
4	19.9	1.7 to 2.4	239 kW	Up to 99 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also, power flows in reverse through T-D interface.
5	19.0	1.5	584 kW	Up to 201 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also some notable undervoltage to correct.
6	19.6	2.0	434 kW	Up to 140 kW	Yes	Residential and commercial systems could substantially overload feeder elements, nearly 200%, when sized for market participation. Also, power flows in reverse through T-D interface.
7	19.8	2.0	799 kW	Up to 315 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also some notable undervoltage to correct.
8	21.1	3.5	693 kW	Up to 329 kW	Yes	Some notable undervoltage to correct. Potential for commercial DER to overload feeder elements in market participation size.
9 (IEEE 34-bus)	2.1	0.3	281 kW	Up to 248 kW	Yes	Overvoltage in min load, undervoltage at peak. Voltage regulators already handling excessive conditions. DER can exacerbate high voltage.
10 (IEEE 341-Node)	42.8	5.0	562 kW	Up to 108 kW	Yes	Min load, DER can cause reverse flow, must be prevented.

Key Findings from Feeder Scenario Simulations

Simulating feeders with DER providing both distribution and bulk grid services highlights that many of Alectra's feeders have similar behaviors, but it also shows that DER location and size cannot be unlimited, even in a robustly built distribution system. Some key findings, assumptions, and recommendations are provided regarding market offers, general technical impacts, the evolution of operations over time, and review of the unique results of the IEEE test feeders compared to the group of Alectra feeder studies.

Alectra Feeder Observations

The Alectra feeders all behave similarly, due to a few characteristics such as feeder cable and equipment design, operating voltage class, and the moderate feeder loading planning threshold.

- Throughout all simulations of the eight Alectra feeders, after enhancing them to scale up the load for prompting DER to provide distribution services, very few of them exhibited troublesome voltage conditions.
- The thermal congestion constraint was most often on the main or backbone line of the feeder between the substation and the first major loading section(s) of the feeder.
- In many cases, all three scales of energy storage DER could be used at both the congestion relief and market participation scales without issue.
- The most common limitation was an overload when applying a large volume of residential storage relative to the service equipment connecting them to the feeder.
- Most often, the losses witnessed on the feeder were at or below 0.5 MW, or less than 3% relative to peak load. It also shows there is little opportunity for substantial loss reduction from DER on the Alectra feeders.

In comparison to typical distribution feeder operations in the industry, and primarily in North America, these feeders are much more robust and resistant to negative impacts that can be seen with large swings in load and voltage. As stated, voltage issues were minimal in many of the simulations. It is reasonable to assume that the same methods applied to this study would produce more notable changes to other, less robust feeders, such as those that taper down wire sizes toward the farthest ends from the substation, which would accumulate impedance and possibly promote greater voltage changes and losses impacts from DER.

IEEE Test Feeders

The IEEE 34-bus feeder is inherently challenged with maintaining appropriate voltage. It is very lightly loaded, but it is also very long. It has voltage regulators to address voltage drops, but introducing DER only has positive effects if connected in locations where the reduction of load is truly needed. Also, DER of any notable size can produce overvoltages because of the low load demand, even at peak. The scale of losses on this feeder was much higher at 14%, despite only being 0.3 MW. DER had the effect of reducing losses by over 30%, which translates to about 9% total losses.

The IEEE 342-Node secondary network feeder introduced a completely different operating paradigm. Some of the same methods of applying DER allocations were used, but this still posed challenges in power flow conditions. Radial feeders are able to deal with some amount of equal or reverse power flow from DER, but secondary network feeders with complex network protectors trip open if power flows in reverse, as a way to preserve the network in case one of the multiple primary voltage feeders has a fault. This challenges the allowed DER sizes, meaning anything close to or in excess of load demand will pose a risk to the intended design and operation of networks. However, even with DER added, the voltage profiles for primary or secondary portions of this model are almost perfectly flat, meaning all parts of the feeder operate within a much tighter tolerance than most feeders. These findings highlight the need for careful design and evaluation of DER to match the needs and operations of the network. The complexities of time-varying loads and specific equipment capabilities and settings would have to be considered to provide a thorough evaluation and confirmed recommendations on how to operate it with high penetration of DER.

General Analysis Assumptions and Opportunities

The results shown in the chapter focused on peak loading conditions to highlight if the simulated DER allocations can provide peak load relief. Results from simulation of the other two load levels are provided in a more comprehensive version of this report for Alectra and IESO, and they sometimes show that the DER can create thermal or voltage issues if producing energy at the same nameplate rating used at peak load. A flexible interconnection agreement is critical to ensure that the DSO has permission to override whenever either operating framework calls for more energy than would be appropriate for distribution operations.

It is also important to note these studies only employ snapshot power flow analysis and do not consider the evolution of metrics with time-series conditions. The true nature of cumulative losses and the economics of flexible DER operations would be most effectively and accurately portrayed by simulating time-series operations, or at least estimating operations by extrapolation. In many situations, DER may be non-operational or in standby for long periods of time, which may make put their return on investment at risk. Time-series studies would also illustrate some of the nuances of energy storage versus other technologies, such as the need to both charge and discharge at certain intervals, which may mean it is an unreasonable choice for those feeders that have long duration heavy load demand.

6

WHOLESALE MARKET OFFERS FOR DISTRIBUTED ENERGY RESOURCES PROVIDING WHOLESALE SERVICES

The participation of DERs in wholesale electricity markets is an emerging area, with limited experience to date. Drivers such as FERC Order 2222, various European initiatives, and the DER Market Vision and Design Project in Ontario have resulted in increased interest in this area.

Depending on the coordination framework considered (Total DSO or Dual Participation), the ISO would receive submitted offers from either the DSO (Total DSO model), or a DER/DER Aggregator (Dual Participation model). Regardless of the coordination framework considered, it is important to understand what the *structure* of these wholesale offers may be. In particular, this will help future participants to better understand the different elements that should constitute their offer, and how those elements may differ from wholesale offers submitted by resources of similar technologies connected to the transmission system.

Developing an offer and its associated parameters that is accurate, and accounts for the unique characteristics of DER (or aggregated DERs) submitting the offer ensures that DER resources are utilized in a way that maximizes economic efficiency, maintains distribution and bulk power system reliability, and promotes fairness and equity across participants.

In this chapter, the first section briefly describes the generic format of offers DERs should provide to the ISO to participate in wholesale electricity markets. Next, the structure of these offers is described, to properly account for any unique characteristics of the DERs that would affect the values submitted.

The analysis that follows primarily focuses on the impact of distribution system losses on the dispatch of DER for wholesale services and how this may influence how its offers are structured. This effect on distribution losses is the primary characteristic that is unique to DERs, when compared to similar technologies participating in wholesale markets that are connected to the transmission system. In addition, distribution congestions may also be impacted when DERs are dispatched for wholesale services, depending on the topology of the distribution system, along with other aspects.

Wholesale offers are submitted to the ISO in Stage 2, and specifically at Step 2.3, either by the DSO on behalf of the DERs it aggregates (Total DSO model), or by directly by the DERs (Dual Participation model). This section makes explicit the information included in the wholesale offers submitted to the ISO[33].

[33] Recall that this report uses the term DER is used to refer collectively to individual DER, or DERA.

Offer Structure and Parameters

The structure of the offer submitted by DERs participating in the wholesale markets includes the offer data for the products DERs intend to participate in. The information submitted for electricity markets includes the offer type (i.e., market product selected), and a set of monotonically increasing offer price/quantity pairs, expressed in [MW, $/MWh].

In addition to the price-quantity based energy and operating reserve offers, DERs may be asked to submit additional parameters, depending on the desired participation model (e.g., electric storage resource, variable resource, conventional generator, or demand response). These participation models are designed to review characteristics of certain technologies participating in the electricity markets, but in most cases do not require a specific DER technology. In most regions that have responded to FERC Order 2222, DER may select the participation model that best fits their characteristics and strategy when multiple valid options exist.

The registered resource type for each DER determines the offer parameters they must submit, to represent physical and economic parameters. The various resource types available intend to offer flexibility to participating DERs through multiple options available for registration. Examples of offer parameters are presented in Table 6-1.

Table 6-1. Market Offer Parameters

Offer Parameters	Unit	Description
Energy Offer	$/MWh, MW	Price-quantity pairs. Typically, a series of monotonically increasing steps that indicate quantities of Energy (MWh) for a given price ($) the DER is willing to supply.
Operating Reserve Offer	$/MW-h, MW	Price-quantity pairs. Typically, a series of monotonically increasing steps that indicate the quantities of reserve capacity (MW) for a given price ($) that the DER is willing to commit.
Start-up cost	$/start	The cost to start a resource from offline state. May also include different costs depending on how long the resource has been offline
No Load Cost	$/h	Cost to be online, independent of operating point
Other Parameters:		
Maximum Output	MW	Maximum power output of the DER
Ramp Rate	MW/minute	The speed at which the resource can move from one dispatch interval to the next
Maximum/Minimum Discharge Limit	MW	Max/min MW quantity a resource can inject to the grid
Maximum/Minimum Charge Limit*	MW	Maximum/minimum MW quantity that a storage or demand-side technology can withdraw from the grid
Energy Capacity*	MWh	The maximum energy capacity of energy-limited resource
Maximum SOC*	MWh	SOC value that should not be exceeded (gone above) when charging from the grid
Minimum SOC*	MWh	SOC value that should not be exceeded (gone below) when discharging into the grid

*Offer parameters for energy storage systems

Depending on the participation model that is chosen, the participant (DER or DSO) will have to determine the parameters that best reflect the set of DERs that are part of the offer that can best reflect the operating characteristics of each of those resources. This will require aggregation of parameters, in some cases a sum of all parameters, and in other cases something different. In general, these will be dependent on the types of technologies, their operating costs, the way the DERs may be managed following an ISO dispatch award, the offer strategy of the participant, and other criteria. Because this will vary substantially on these factors and because most factors are not necessarily unique to a DER providing wholesale services, we do not discuss further the details of the way in which an aggregation may come up with the parameters and price/quantity offers provided. However, the nature of the distribution system and how it may impact the way in which DERs look to the ISO in its determination of optimal dispatch is unique to the way a DER or DSO may submit its offer to the grid compared to other technologies. Therefore, we focus on these criteria to demonstrate how these may affect the offer shared with the ISO.

Distribution Losses and Potential Impact on DER Offers to the Wholesale Market

In the context of the electricity market, distribution losses refer to the energy that is lost from resistance losses. This section focuses specifically on distribution losses. The effect that DERs may have on distribution losses is the characteristic that is most unique to DERs participating in wholesale markets, when compared to similar technologies connected to the transmission network. This is in regards with how the wholesale market may dispatch the resource in an optimal manner consistent with electricity market clearing practices in Ontario and in other organized electricity markets. Distribution congestions can also affect the market offers, along with distribution losses. However, for the distribution feeders studied as part of this analysis, no congestion issues were observed. For this reason, the effect of distribution congestions on market offers is not considered in the following sections, but they may be relevant for other distribution feeders.

Distribution losses affect the net change at the transmission interface. If injecting power at a distribution node increases distribution losses, more power must be delivered from the transmission system; conversely, if injecting power at a distribution node decreases distribution losses, less power must be delivered from the transmission system. Marginal losses may affect the relative cost of individual DERs (or the aggregate DERA offer curve).

Knowing how the dispatch of DERs impacts distribution losses can help determine the allocation of their dispatch schedules, and how the resources may compete with other resources across the ISO's wholesale market. Previous works have looked at incorporating distribution losses into distribution-level LMPs (DLMPs)[34,35]. The DLMPs would have marginal distribution losses impact the price that is paid across the distribution feeder, and resources at locations that reduced losses greater would end up getting paid more based on their location. A distribution optimal power flow would determine optimal scheduling inherently. It is unlikely that DLMPs will be in place in the near future in any distribution system within the province of Ontario. A different

[34] L. Bai, J. Wang, C. Wang, C. Chen and F. Li, "Distribution Locational Marginal Pricing (DLMP) for Congestion Management and Voltage Support," in IEEE Transactions on Power Systems, vol. 33, no. 4, pp. 4061-4073, July 2018, doi: 10.1109/TPWRS.2017.2767632

[35] A. Papavasiliou, "Analysis of Distribution Locational Marginal Prices," in IEEE Transactions on Smart Grid, vol. 9, no. 5, pp. 4872-4882, Sept. 2018, doi: 10.1109/TSG.2017.2673860.

solution that does not require a detailed distribution market, real-time distribution optimal power flow algorithm, or major jurisdictional changes can be considered.

In markets where DLMPs are not considered, the distribution losses can be captured in the market offers through a variety of mechanisms. One approach is to include an adjustment factor in the offer price to account for the expected distribution losses. This adjustment factor is typically based on historical data and modeling of the distribution system. Another approach is to include the expected distribution losses as a separate component in the market offer. This approach requires accurate measurement and forecasting of the distribution losses, which can be challenging in practice. It is important to note that while these approaches can help to account for distribution losses in market offers, they may not fully reflect the actual costs or impacts of these losses on the electricity system. The use of DLMPs, which reflect the actual costs and constraints of the distribution system, can provide a more accurate and efficient mechanism for capturing distribution losses in the market.

This section shares thoughts on how distribution losses may be considered through an offline analysis; the approach is applied for illustrative purposes to modeling results obtained in the previous chapter. On key aspect of the approach described below is the use of sensitivity factors to capture in the market offers submitted by the DERs the effect on distribution losses. Definitions for several sensitivity factors are first provided, and several illustrative cases are then discussed.

Distribution Delivery Factor (DDF): The distribution delivery factor shows how much power is going to reach the Transmission-Distribution (T-D) interface (reference bus) if additional power is injected at distribution bus i.

$$\mathrm{DDF_i} = \frac{\Delta Energy\ delivered\ to\ T{-}D\ interface}{\Delta Energy\ injected\ at\ dist.location\ i}$$

If the DER creates an energy value at the T-D interface greater than its production, DDF will be greater than 1 to reflect the positive impact to reduce feeder losses. If the DER adds losses to the feeder, DDF will be less than 1.

Distribution Loss Adjustment Factor (DLAF): This is a factor by which the incremental cost of power production of a given DER is multiplied to take into account the distribution losses, defined as the inverse of the distribution delivery factor:

$$\mathrm{DLAF_i} = \frac{1}{DDFi}$$

Adjusted Offer (AO): The adjusted offer is determined by multiplying the original offer (OO_i), which may be based on the DER's incremental energy costs, by the Distribution Loss Adjustment Factor ($DLAF_i$). This assumes that transmission losses will be considered as part of the locational marginal prices of IESO's MRP market clearing platform, such that only the effect from distribution losses need to be factored into the adjusted offer. When the distribution losses can effectively be decreased because of the presence of the DER, then the offer can be lowered so that the resource looks more attractive to the ISO. When the presence of the DER can increase the losses on the distribution system, then the offer is raised since it will cost more to the system to dispatch the resource.

$$\mathrm{AO_i = OO_i * DLAF_i}$$

In both coordination frameworks, DERs most frequently will submit offers as a group versus individually. A DER Aggregator or the DSO will aggregate many resources for the submittal to the ISO. In this case, the different adjusted offers from DERs that take into account distribution losses can be combined into a multi-segment set of monotonically increasing price/quantity pairs. Current rules allow for up to 20 segments per market participant. The aggregator (or DSO, in the Total DSO coordination model) can take the set of relevant adjusted offers, combine them effectively in increasing order, and then submit to the ISO, which would be considered along with offers from other market participants.

The EPRI team carried out detailed analysis with several case studies to illustrate how the approach described above can incorporate distribution losses into DER offers. Details of that analysis are reserved for Alectra and IESO, but for brevity, the key findings of the study are given below:

- When the effect of distribution losses is considered, this approach may lead to modify the market offer as seen by the ISO, to account for the cost change (positive or negative) resulting from the change in distribution losses.
- A power injection from a DER participating in the wholesale markets generally reduces distribution losses in absolute terms. Yet, the relative effect on distribution losses for the feeders evaluated is relatively low. This result is specific to the case studies presented; other distribution feeders may have more notable impacts to loss magnitudes and adjusted offer amounts.
- The effect of distribution losses on the adjusted DER offers is small in this study. However, this small change in losses could be sufficient to change which DERs are cleared in the wholesale market, and/or the order in which they are cleared. Incorporating distribution losses into DER offers may not have a significant effect in the near-term, but this effect may increase at higher DER penetration levels.
- Robust feeder design and operation results in minor changes to losses and DER offer adjustment. Other distribution topologies may see larger impacts on distribution losses, especially longer feeders, depending on how close the DERs are to the major load centers along the feeder. In these other topologies, the effect of DER market participation on distribution losses may be more significant and produce a greater impact on loss-adjusted offers. This would justify considering the impact on distribution losses when comparing the offer from distribution-connected DERs to other transmission-connected market participants.

7 CONCLUSIONS

This project explores the potential implications and coordination needs when distributed energy resources (DER) connected to the distribution grid are used to provide services to both the distribution system and wholesale electricity market. It highlights the need for deliberate coordination between all three parties in the process: distribution system utilities, the bulk system and market operator, and DER owners and aggregators. While these aspects are primarily explored in the context of the electric systems managed by Alectra and IESO, the concepts and structure developed are purposefully defined with a level of generality allowing for their application to other electric systems.

Grid Services and Scenarios

Five families of scenarios are examined, covering a set of illustrative grid conditions and scenarios involving combinations of DER-provided distribution and bulk system services:

- *Scenario 1*, titled “Transmission Energy Dispatch”, investigates the participation of DERs in the wholesale energy market. Distribution congestion is not considered for this first scenario.

- *Scenario 2*, titled “Distribution Override”, also investigates the participation of DERs in the wholesale energy market, this time identifying possible distribution congestion.

- *Scenario 3a* focuses on DERs providing distribution capacity to defer conventional distribution upgrades, while *Scenario 3b* investigates a value stacking case where DERs providing distribution capacity also pursue participation in the wholesale energy market. These two scenarios are jointly referred to as “Distribution Import-Congestion”.

- *Scenarios 4a* and *4b* investigate the use of DER-provided operating reserves for use during system contingencies. Scenario 4a focuses on distribution applications such as unplanned distribution outages. Scenario 4b considers a value stacking scenario combining the use of DER-provided operating reserve for both distribution outages and traditional operating reserve services for bulk system applications, such as the loss of a large generator. Scenarios 4a and 4b are jointly referred to as “Distribution Operating Reserves”.

- *Scenario 5*, titled “Capacity Service”, is an extension of Scenario 3a, where DERs providing distribution capacity also pursue capacity products in the wholesale market as part of a value stacking strategy.

Coordination processes between the ISO, DSO and DERs can be developed for each of the scenarios considered. Some scenarios only require simple interactions to successfully execute an operational coordinated plan; this is a pre-requisite to later address the associated financial aspects and economic impacts (not addressed in this report). Other scenarios are more complex due to timing or sizing aspects, grid constraints, and other commitments that have to be considered for DERs to appropriately interact with the service requesting entities (i.e., DSO and/or ISO). While this report does not explicitly investigate market settlement, the coordination processes identified include communication and information exchange requirements that would support DSO, ISO and DER parties to make appropriate reconciliation.

Coordination Frameworks

Grid services provided by DERs require new forms of coordination between the DSO, ISO and the DERs. DERs can independently provide one grid service or may simultaneously provide several grid services ("value stacking" strategy). Two coordination models are considered in this report: DERs can either provide 1) all grid services through the DSO, and the DSO aggregates wholesale offers with the ISO (Total DSO model), or 2) distribution services to the DSO, and wholesale market services to the ISO (Dual Participation model). Which framework is active is important for identifying appropriate communications and information shared.

Under the Total DSO coordination framework, DERs must submit wholesale offers to the DSO, which aggregates all offers received and submits a single aggregated offer to the ISO. Additionally, DERs seeking to provide distribution services submit these offers to the DSO.

Under the Dual Participation coordination framework, DERs seeking to participate in the wholesale electricity markets may submit their offers directly to the ISO, while staying within the limits established by the DSO as part of the DER interconnection agreement or otherwise. Separately, DERs seeking to provide distribution services submit these offers to the DSO, and they may be required to further notify the ISO.

ISO-DSO-DER Coordination

The procurement and delivery of grid services from DERs can be decomposed into a series of successive stages, and the coordination needs between ISO, DSO and DERs at each stage can be described using coordination diagrams. This report develops a set of block diagrams for either operating framework, illustrating the potential for added complexity or relative simplicity of applying each framework.

This report adopts a hierarchical structure composed of three levels to describe the coordination needs between the ISO, DSO and DERs providing grid services: *stages, steps, and functions*. This hierarchy allows for describing the processes needed in either operating framework to get from identifying grid needs to executing the needed services. Table 7-1 below gives a summary of the stages defined in the body of the report.

One key finding of this report is that coordination processes consistent with existing wholesale market mechanisms can be developed, to enable DERs to provide distribution and/or bulk system services. While the coordination processes defined are specific to each of the two coordination models considered in this report, their overall structure and objectives remain very similar.

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Table 7-1. Stages Proposed for Market Coordination

Stage	Task Description
0	Identification of Distribution Needs, and Distribution Service Procurement
1	Scheduling of Distribution Services
2	Formation and Submission of Wholesale Offers
3	Wholesale Market Clearing Mechanisms
4	Dispatch of DER-Provided Bulk System Services
5a	Contingency Management for Distribution-Level Incidents
5b	Contingency Management for Transmission-Level Incidents
6	Performance Evaluation and Settlement

Simulated Distribution Impacts of DER-Provided Grid Services

Ten distribution feeders are simulated in this project to measure power flow conditions, including expected power, loading relative to feeder element and equipment ratings, operating voltages, and system losses, from the perspective of both the local impacts as well as at the T-D interface. Each feeder has a unique topography and presence of varying amounts of existing DER (solar), which are accounted for in the simulations. The peak load, minimum load, and average demand time periods are studied in snapshot power flows.

For the Alectra service territory, robust feeder design tends to address and prevent the most common distribution feeder constraints in the industry, allowing for DERs to provide bulk system services to the IESO without causing adverse distribution impacts. However, common thermal and voltage constraints on less robust feeder design will prompt more scrutiny for appropriate location and sizing of DER to provide grid services.

Based on observations of the feeders evaluated, larger DER (commercial- and utility-scale) are more likely to reliably address distribution constraints and still leave operational headroom for participation in the wholesale electricity markets. Residential-scale DER can be effective and providing a localized impact, and more directly offsetting power demand, but achieving the next level of grid participation for wholesale electricity market services becomes difficult due to relative sizing of customer load and system equipment.

The snapshot power flow conditions studied are illustrative for anticipated impacts at “corner cases” and the average feeder condition, but time-series analysis is more likely to capture the big picture. This could highlight concepts like frequency of grid constraints, total energy traded in a calendar year, total losses impact of traditional versus market-participatory operations, coincidence factors of distribution and bulk grid services, and other time-sensitive conditions.

Market Offer Structure

An important aspect of allowing DER to participate in wholesale electricity markets is the actual structure of the market offer provided and how it may differ from other participants in the wholesale electricity market. It can be beneficial for DER market offers to consider DER characteristics, the market coordination mechanism, and distribution system characteristics. This ensures that DER resources are utilized in a way that maximizes economic efficiency, maintains distribution and bulk power system reliability, and promotes fairness and equity across participants. The ISO will usually require small DERs to aggregate in the Dual Participation Framework, and DERs will be aggregated typically by transmission node in the Total DSO framework. The offer must combine costs and physical characteristics of all DERs in the aggregated offer within the requirements of the wholesale offer. These requirements may include monotonically increasing price quantity pairs, maximum capacity limit, and ramp rates, with potentially additional features for technology participation models.

The physical characteristics that make a DER unique from a similar technology connected on the transmission system that is participating in the wholesale market are the impacts that distribution system may have on the cost-effective dispatch of that resource. DERs may reduce (or sometimes increase) distribution losses depending on what location of the distribution system they are located. Distribution system congestion can also make it so that more energy from higher cost DERs may be more cost effective to dispatch than energy from lower cost DERs, when the lower cost DERs cause the congestion. In the modeling efforts of this study for the feeders studied, both of these impacts are found to be minor in the optimal dispatch of these resources, such that similar results for the wholesale market may have been observed without their consideration. However, other distribution systems and those in the future with greater levels of DERs may have a much larger impact, and the inclusion of these impacts in offers of the DERs to the wholesale market operator may be beneficial for efficient solutions.

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