TECHNICAL BRIEF

Procuring Services from Distributed Energy Resources

Part 2 – Structuring the Coordination between ISO, DSO and DER to Enable DER-Provided Grid Services

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REVISITING COORDINATION AMONG GRID STAKEHOLDERS WHEN DER PROVIDE SERVICES

Distributed energy resources [1] (DER) connected to the distribution system are increasingly being considered for their capabilities to provide grid services, including *distribution services* to the electric utility operating the distribution system, and/or *bulk system services* to the wholesale market operator operating the bulk transmission system.[2] In practice, DER voluntarily providing grid services are financially compensated to adjust their power output (active and/or reactive) in response to system needs. DER can provide grid services as standalone assets or via DER aggregators[3] (DERA); they may also consider providing multiple services across the distribution and/or bulk system domains, a strategy known as *value stacking*.

EPRI recently explored some of the opportunities and challenges related to DER-provided grid services in the context of the Ontario power system. In particular, potential cross-domain impacts require careful consideration: on one hand, distribution services provided by DER can affect the power exchanged at the distribution-transmission (T-D) interface; on the other hand, wholesale market services provided by DER can impact distribution system operations. Further, maintenance and contingency events in the distribution domain can affect power deliverability, and potentially constrain DER participation in wholesale markets. For this reason, the development of robust coordination processes between the various grid stakeholders involved is key to enable DER-provided grid services.

1 This paper series intentionally adopts a broad definition of DER, which includes solar PV, other form of distributed generation, battery storage, demand response, electric vehicles and their supply equipment, and other types of distribution-connected technologies. This approach is consistent with the recent Framework for Energy Innovation (FEI) developed by the Ontario Energy Board (OEB), which states that the definition of DER "is context specific and different definitions may be warranted in different regulatory instruments serving different purposes."

2 While DER can also provide economic or reliability services to the customer, the scope of this paper series is limited to services DE-provide to the *grid*.

3 For brevity, throughout this paper series, the acronym "DER" can either refer to an individual DER, or a portfolio of DER managed as a group by a DERA.

This technical brief, the second of a series of three papers, explores the coordination required between the distribution utility, the wholesale market operator, and the DER providing grid services.[4] 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 paper, 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* coordination frameworks previously introduced in the first of this series of three papers. This document does not intend to make policy or market design recommendations, but simply identifies and discusses potential coordination options to enable DER to provide grid services.

PREREQUISITE: NOTIFICATION OF ABNORMALITIES

Motivations

Processes allowing grid actors to inform each other when abnormalities occur across the grid are a prerequisite to any robust coordination scheme supporting DER to provide grid services. In Ontario, certain coordination processes already exist between the ISO and DSOs, independently of DER operations. In particular, DSOs are required to notify the ISO of any material deviations (planned or unplanned) from IESO's forecasts at the T-D interface.

In addition, certain contingencies affecting the distribution grid may constrain DER imports and/or exports. For normal distribution conditions, the maximum import and/or export limits applicable are generally specified in the interconnection agreement;[5] these limits may be fixed (i.e., traditional interconnection agreement), or may change dynamically with pre-defined factors (i.e., flexible interconnection agreement[6]). Regardless of the type of interconnection agreement, DSOs typically reserve the right to modify these limits when abnormal conditions occur to help maintain grid safety, when necessary.

Finally, on the DER side, several factors may constrain the availability of DER to provide grid services at any given time. This includes whether DER provide customer services,[7] and maintenance and other technical contingencies that may prevent DER from operating at full nameplate capacity.

Five Processes to Notify of Abnormalities

This paper recognizes five coordination processes, labeled 1, 2-a, 2-b, 3 and 4, to formalize the coordination required between the various grid actors when the abnormalities described above occur. For each process, the goal is to identify the parties involved, and the nature of the information exchanged, as illustrated in Figure 1 and further described in Table 1.[8]

All five processes may be activated at *any time* based on needs, and operate completely independently from the coordination stages later discussed in this paper. Further, in addition to these five coordination processes, other processes (not discussed in this paper) may be required to manage other types of abnormalities not necessarily DER-related. For example, the ISO may need to notify DSOs of transmission-level abnormalities affecting the T-D interface.

4 In this paper, the distribution utility is referred to as the *distribution system operator* (DSO), and the wholesale market operator as the *independent system operator* (ISO). The first technical brief in this paper series discusses this terminology in greater details.

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

6 *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.

7 *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 DER 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.

8 The five high-level processes presented in this section may be implemented in various ways; the level of detailed specification required to implement these processes is out of scope for this paper.

Table 1. *Processes to notify of abnormalities*

PROCESS #	PURPOSE	APPLICABILITY: SERVICE TYPE	APPLICABILITY: ISO-DSO COORDINATION MODEL	PARTIES INVOLVED	SOURCE OF ABNORMALITY
Process 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.)
Process 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.
Process 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.
Process 3	Notify DSO of service provider unavailability	Distribution	*(Not dependent on coordination model)*	DER → DSO	Internal to DER
Process 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.)

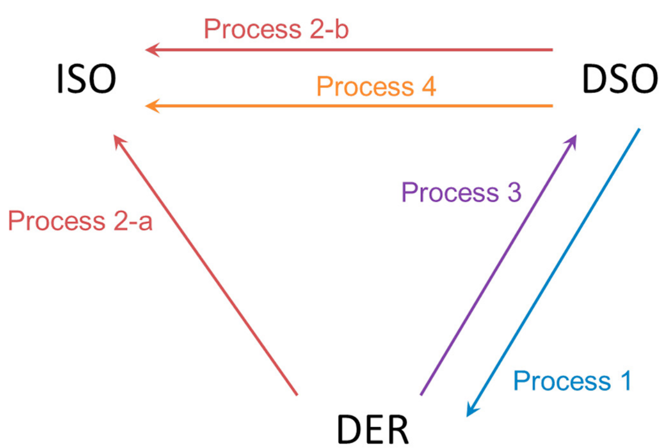

Figure 1. *Notification of abnormalities: processes and grid actors*

Process 1: DSO Notifies DER of Abnormal Distribution Conditions

Process 1 is used by the DSO to notify DER 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 generally 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, at all times, DER 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 DER are settled for energy by the ISO (Dual Participation model) or DSO (Total DSO model), and regardless of whether DER provide grid services.

Process 2-a: DER Notifies ISO of Service Provider Unavailability

Process 2-a is used by DER settled for energy by the ISO (Dual Participation framework) 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, and in particular: 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 DER participating in the wholesale markets via the Dual Participation model.

Process 2-b: DSO Notifies ISO of Service Provider Unavailability

Process 2-b is an extension of Process 2-a, when DER settled for energy by the DSO (Total DSO framework) provide wholesale market services through the DSO.[9]

Process 2-b allows the DSO, acting as wholesale market participant on behalf of the DER it aggregates,[10] 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 DER themselves, or to abnormal distribution conditions preventing DER from participating in the wholesale markets.

9 Refer to the first paper in this series for additional details on the working assumptions related to energy settlement for each of the two coordination models considered.

10 As discussed in the first paper of this series, the DSO could take a range of roles and responsibilities; the two examples of coordination models considered in this series should not be construed as a policy or market design recommendation.

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: DER Notifies DSO of Service Provider Unavailability

Process 3 is used by DER providing distribution services to notify the DSO of a temporary reduction (partial or full) 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, and whether the DER is settled for energy by the ISO (Dual Participation framework) or DSO (Total DSO framework); it can be activated before and/or after the DER is dispatched to perform that service. After a Process 3 notification is received, the DSO may activate contingency plans as needed, including the possible activation of other DER contracted to provide local reserves.

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 4: DSO Notifies ISO of Forecast Deviations Due to Distribution Conditions

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.[11]

11 See IESO Market Manuel 7, Part 7.3, sec. 4.2.3.

COORDINATION STRUCTURE

Hierarchical Approach: Stages—Steps—Functions

This paper series adopts a hierarchical structure composed of three levels –stages, steps, and functions– to describe the coordination needs and activities taking place between the ISO, DSO and DER providing grid services.

- **Level 1 – Stages:** From a functional standpoint, each stage corresponds to a high-level topical area where coordination is necessary between the ISO, DSO and/or DER. Stages are agnostic of any coordination framework.
- **Level 2 – Steps:** Each of the higher-level stages is further decomposed into one or several steps. The number of steps required varies depending on the stage considered, and the steps constituting a given stage follow a logical progression. Further, and contrary to the stages defined in Level 1, steps are not agnostic of coordination framework. For this reason, two sets of coordination diagrams are presented below, one for each of the two coordination frameworks considered, *Dual Participation* and *Total DSO*. 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 lower-level coordination functions (e.g., real power dispatch, reactive power dispatch, etc.), similar to the coordination functions defined as part of EPRI's TSO/DSO Working Group.[12] The mapping from steps to functions is out of scope for this paper series and may vary across implementations.

Logical Breakdown of Coordination Stages

This effort recognizes eight different stages, labeled 0, 1, 2, 3, 4, 5-a, 5-b and 6, and defined in Table 2. Stages are structured following a logical progression, with the outputs of one stage often serving as inputs to another stage, as depicted in Figure 2. Yet, these stages typically run in parallel continuously and follow their own execution timelines. The eight-stage logical breakdown presented is not unique, and other breakdowns are possible. Further, depending on the combination of grid services considered,[13] certain stages may not be required, as indicated in Table 2 and Figure 2. The rest of this paper focuses on stages 1, 2, 4 and 5.[14]

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

13 The coordination diagrams presented in this technical brief are applicable to all value stacking scenarios introduced in the first paper of this three-part series.

14 While not explicitly referenced in the set of stages described in Table 2, asset registration with the ISO (when applicable) and any other ISO-related processes *preceding* offer submission are out of scope for this paper.

Table 2. *Coordination stages*

STAGE	DESCRIPTION	APPLICABILITY: DISTRIBUTION SERVICES	APPLICABILITY: BULK SYSTEM SERVICES	CONSIDERATION IN THIS EFFORT
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.	•		Out of scope.
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.	•		In scope.
Stage 2: Formation and submission of wholesale offers.	DER intending to participate in the wholesale markets submit offers to the ISO either directly (Dual Participation model), or via the DSO (Total DSO model).		•	In scope
Stage 3: Wholesale market clearing mechanisms.	Based on offers collected from wholesale market participants, ISO clearing mechanisms schedule resources including DER participants.		•	Out of scope.

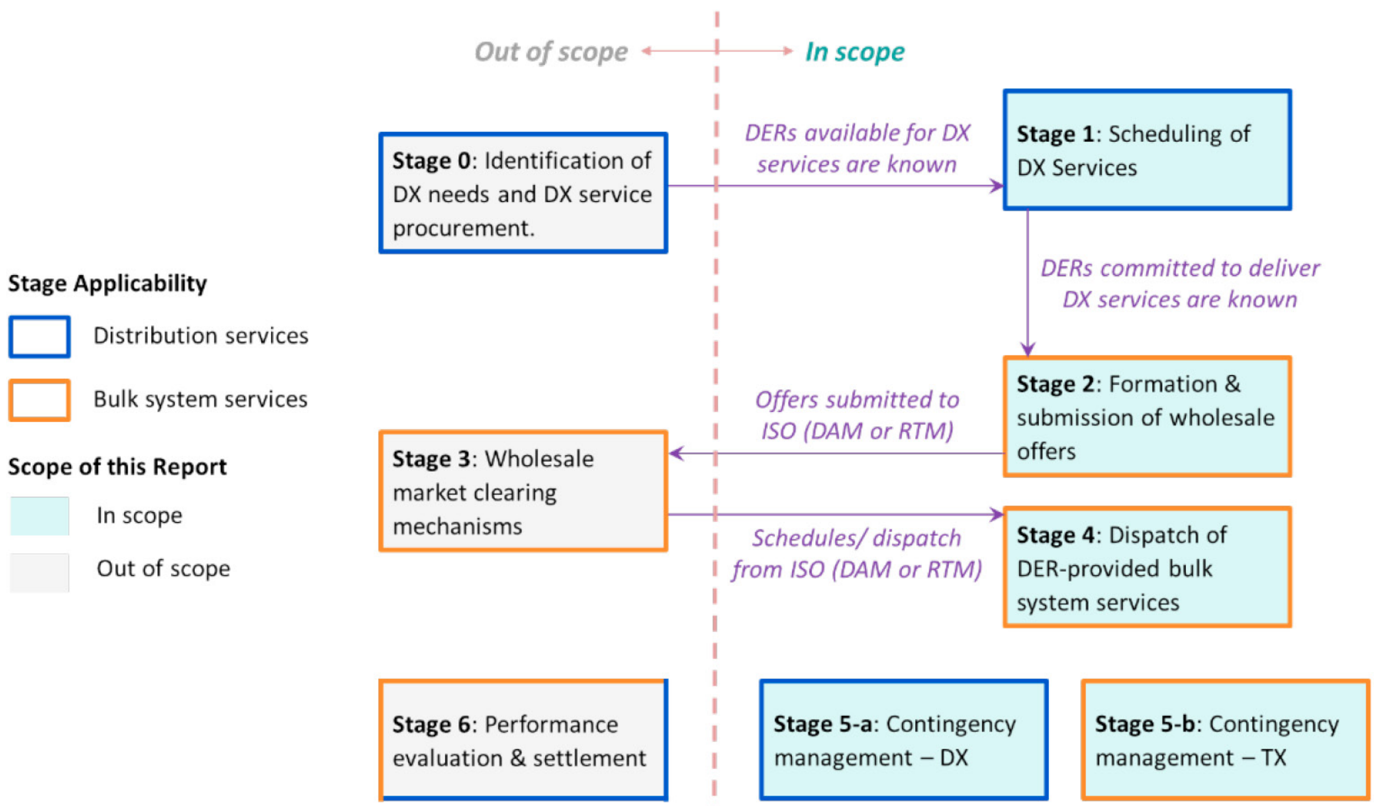

Figure 2. *Coordination stages*

CASE 1: TOTAL DSO COORDINATION FRAMEWORK

Functional diagrams presented in this section assume the Total DSO coordination framework, where DER seeking to participate in the wholesale electricity markets must submit their wholesale offers to the DSO. This paper series assumes that the DSO aggregates all wholesale offers received and submits a single aggregated offer to the ISO. Additionally, DER seeking to provide distribution services submit their offers to the DSO. The functional diagrams below decompose each stage into multiple steps.

Stage 1: Scheduling of Distribution Services

In Stage 1, represented in Figure 3, 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).[15] 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 always dispatched at the initiative of the DSO.

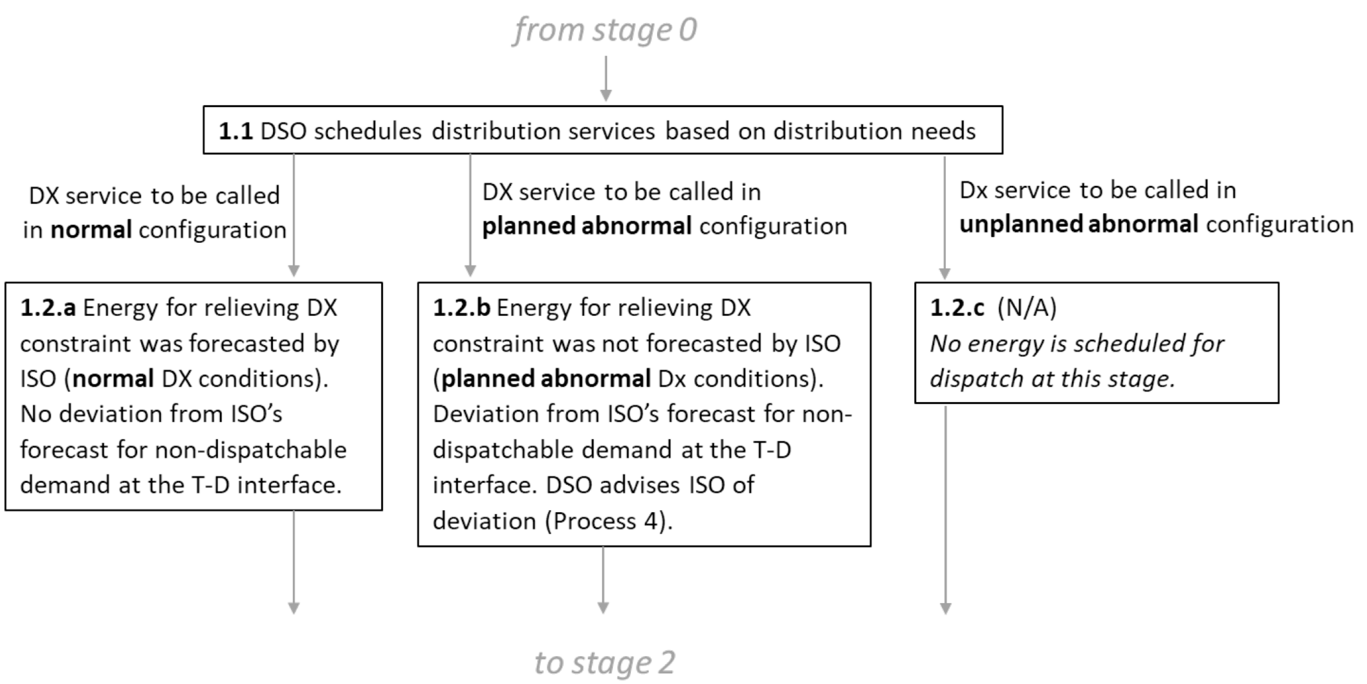

Figure 3. Functional diagram, Stage 1 with Total DSO model

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15 As part of this research effort, EPRI conducted a case analysis (not included in this paper) to evaluate the potential deviations from IESO forecasts which distribution services could introduce at the T-D interface. When DER are settled for energy by the DSO (which is assumed under the Total DSO model), findings suggest that IESO's nodal forecasts provide proper visibility on the effect that distribution services may have at the T-D interface when addressing distribution constraints arising in *normal* system conditions. 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 IESO and the DSOs (and in particular, Process 4 described above) could be used to route notifications from the DSO to IESO if the change is considered material.

Stage 2: Formation and Submission of Wholesale Offers

In Stage 2, represented in Figure 4, DER intending to participate in the wholesale markets submit their offers to the DSO, which then aggregates all offers into a single aggregated offer (step 2.1.a). The DSO may define a gate closure time by which DER must submit their wholesale offers. Alternatively, DER may agree to be automatically considered for wholesale participation (step 2.2.b). The wholesale offers submitted by the DER to the DSO take into account the import and/or export limits applicable to each DER 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 DER, 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 the ISO gate closure time[16] (step 2.3). The aggregated offer is directly based on the individual DER offers collated and vetted by the DSO.

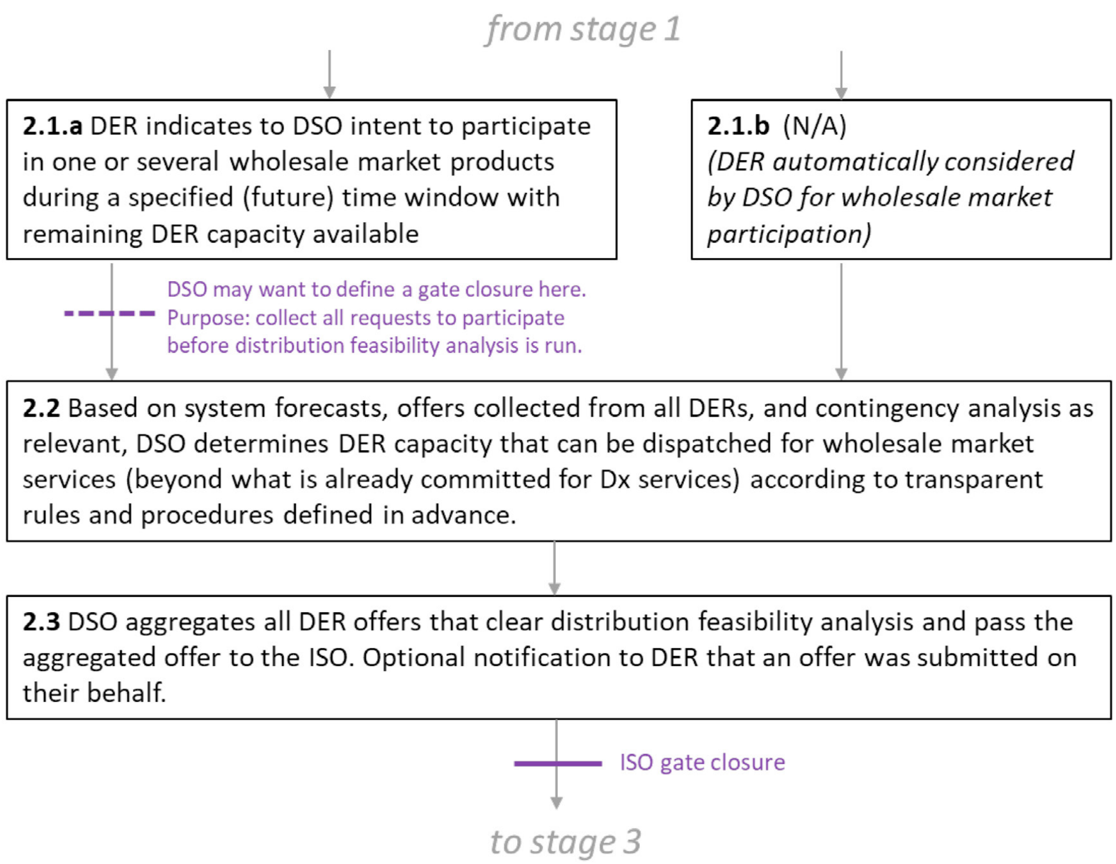

Figure 4. *Functional diagram, Stage 2 with Total DSO model*

16 Gate closure refers to the end of the bid submission window as defined by the ISO

Stage 4: Dispatch of DER-Provided Bulk System Services

In Stage 4, DER are dispatched to deliver bulk system services based on market clearing results. As described in Figure 5, if participation in real-time markets (RTM) is considered, the ISO sends advisory schedule(s) to the DSO acting as intermediary until the dispatch interval is reached (step 4.1). Since advisory schedules are not sent out in the day-ahead market (DAM), step 4.1. is only applicable to RTM participation. A firm dispatch schedule is eventually sent out by the ISO (step 4.2). The DSO disaggregates the schedules across the participating DER (step 4.3) and sends out individual DER schedules (step 4.4).

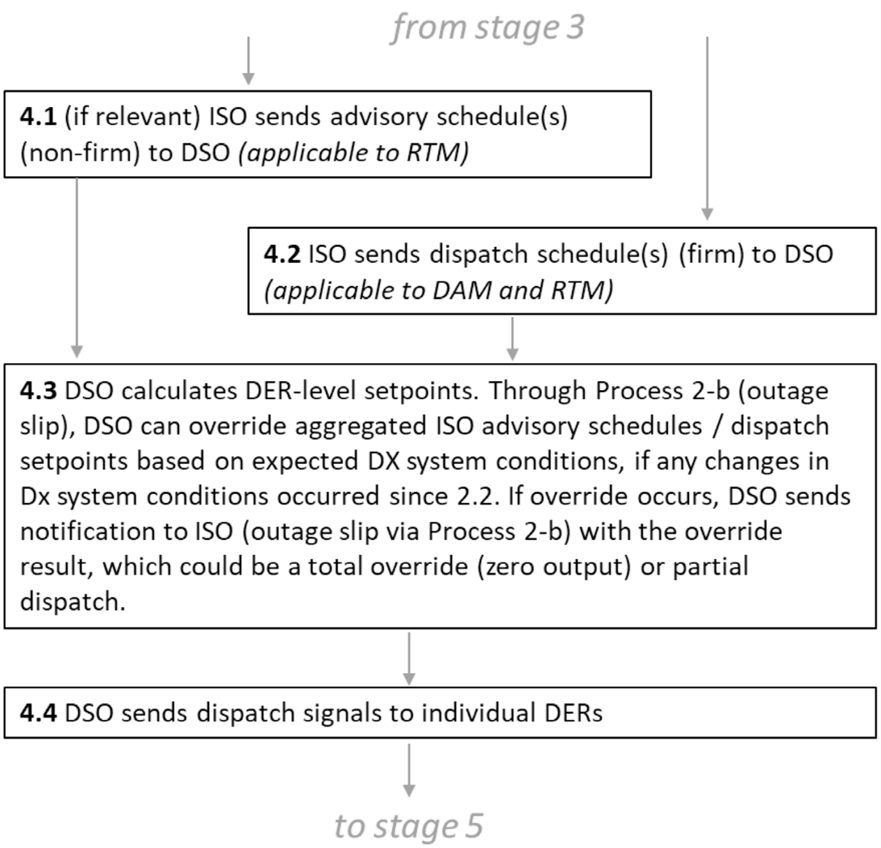

Figure 5. *Functional diagram, Stage 4 with Total DSO model*

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

In Stage 5-a, represented in Figure 6, the DSO responds reactively to an unplanned distribution incident. Step 5.1 focuses on reporting the incident to the ISO and DER. Step 5.2 dispatches DER providing local reserve, if available and helpful to address the distribution constraints created by the incident. Step 5.3 updates the DER capacity available for local reserve and possibly seeks to procure additional reserve, if practicable.

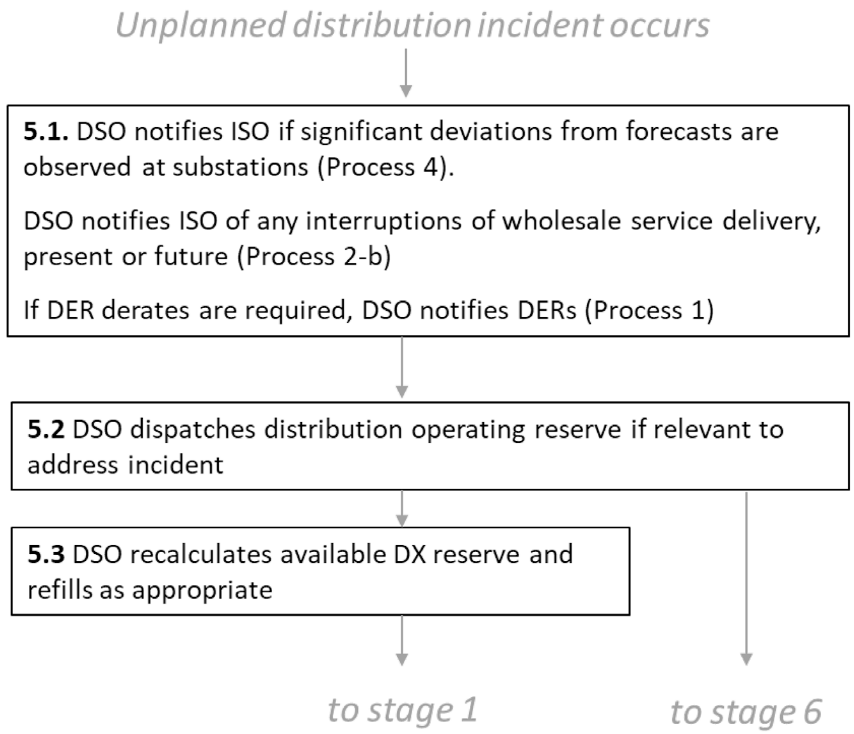

Figure 6. *Functional diagram, Stage 5-a with Total DSO model*

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

In Stage 5-b, represented in Figure 7, 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 DER (step 5.2). Step 5.3 updates the capacity available for wholesale reserve and possibly seeks to procure additional reserve, if practicable.

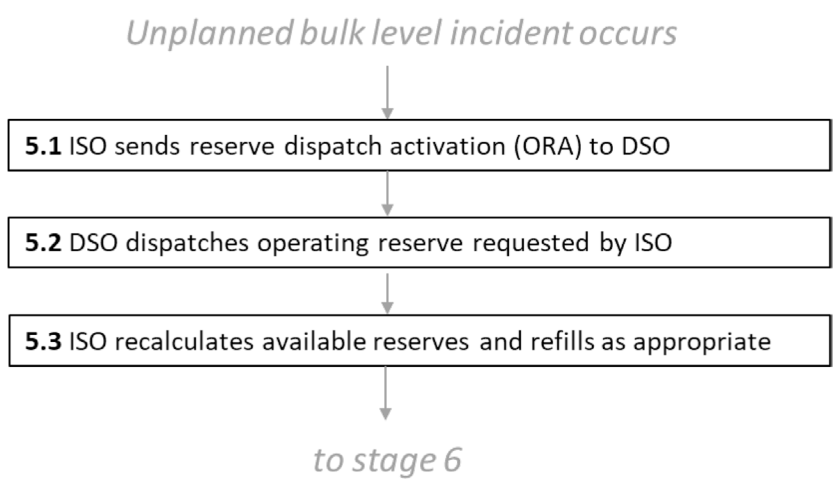

Figure 7. *Functional diagram, Stage 5-b with Total DSO model*

CASE 2: DUAL PARTICIPATION COORDINATION FRAMEWORK

Functional diagrams presented in this section assume the Dual Participation coordination framework, where DER seeking to participate in the wholesale electricity markets may submit their offers directly to the ISO. Separately, DER seeking to provide distribution services submit these offers to the DSO; in addition, they may be required to further notify the ISO.[17]

Stage 1: Scheduling of Distribution Services

In Stage 1, represented in Figure 8, 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 to the ISO, corresponding to the amount of energy required to provide the distributions service.[18] Distribution services to be used in unplanned abnormal conditions are not dispatched in Stage 1 (step 1.2.c), but in Stage 5-a.

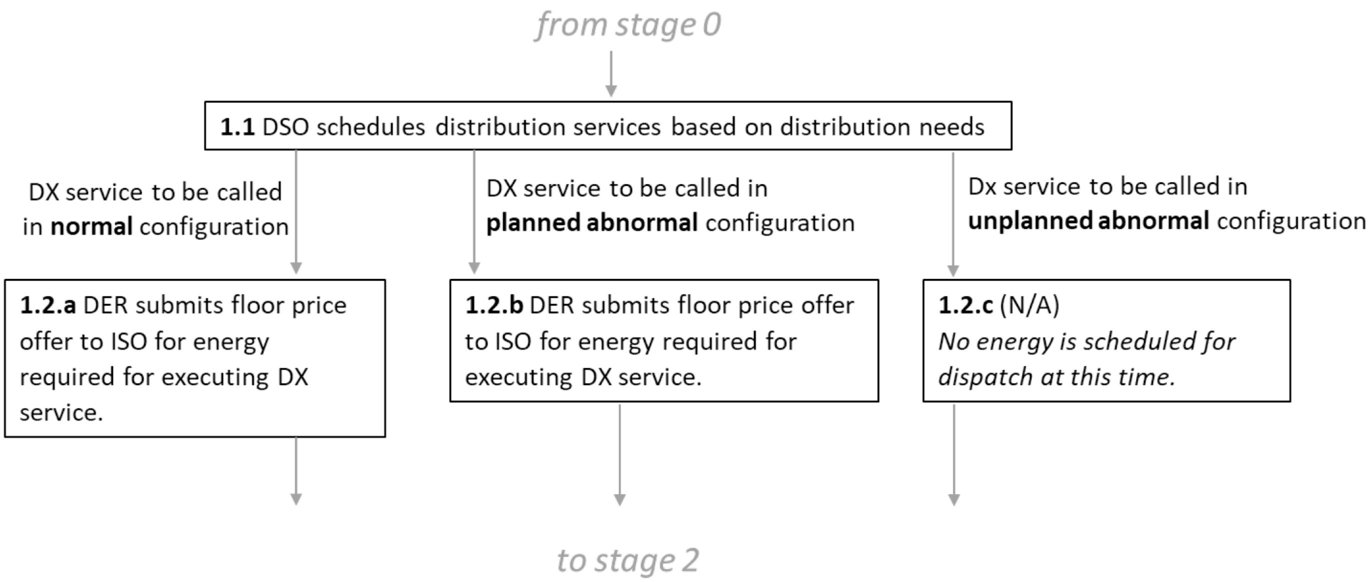

Figure 8. *Functional diagram, Stage 1 with Dual Participation model*

17 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 model are intentionally marked "N/A."

18 EPRI conducted a case analysis, not included in this paper, to evaluate the potential deviations from IESO's T-D forecasts which distribution services could introduce. Findings suggest that when DER 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.

WHOLESALE MARKET AWARENESS OF THE ENERGY REQUIRED FOR DISTRIBUTION SERVICES

DER settled for energy by the ISO under the Dual Participation model must notify the ISO that they are being dispatched by the DSO to deliver a distribution service. In practice, once dispatched by the DSO to deliver a distribution service, this paper assumes that the DER 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 paper assumes the process described above, other approaches are possible. Therefore, this process should not be construed as a policy or market design recommendation.

Stage 2: Formation and Submission of Wholesale Offers

In Stage 2, represented in Figure 9, DER 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.

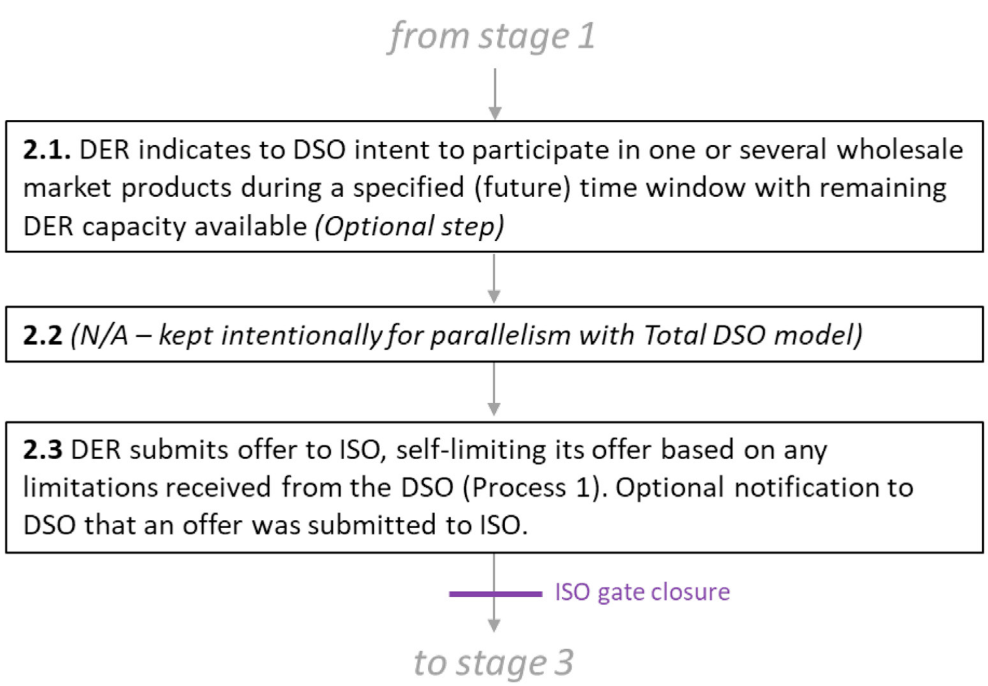

Figure 9. *Functional diagram, Stage 2 with Dual Participation model*

Stage 4: Dispatch of DER-Provided Bulk System Services

In Stage 4, DER are dispatched to deliver wholesale services based on market clearing results. As described in Figure 10, if participation in RTM is considered, the ISO sends advisory schedule(s) to the DER until the dispatch interval is reached (step 4.1). 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, 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).

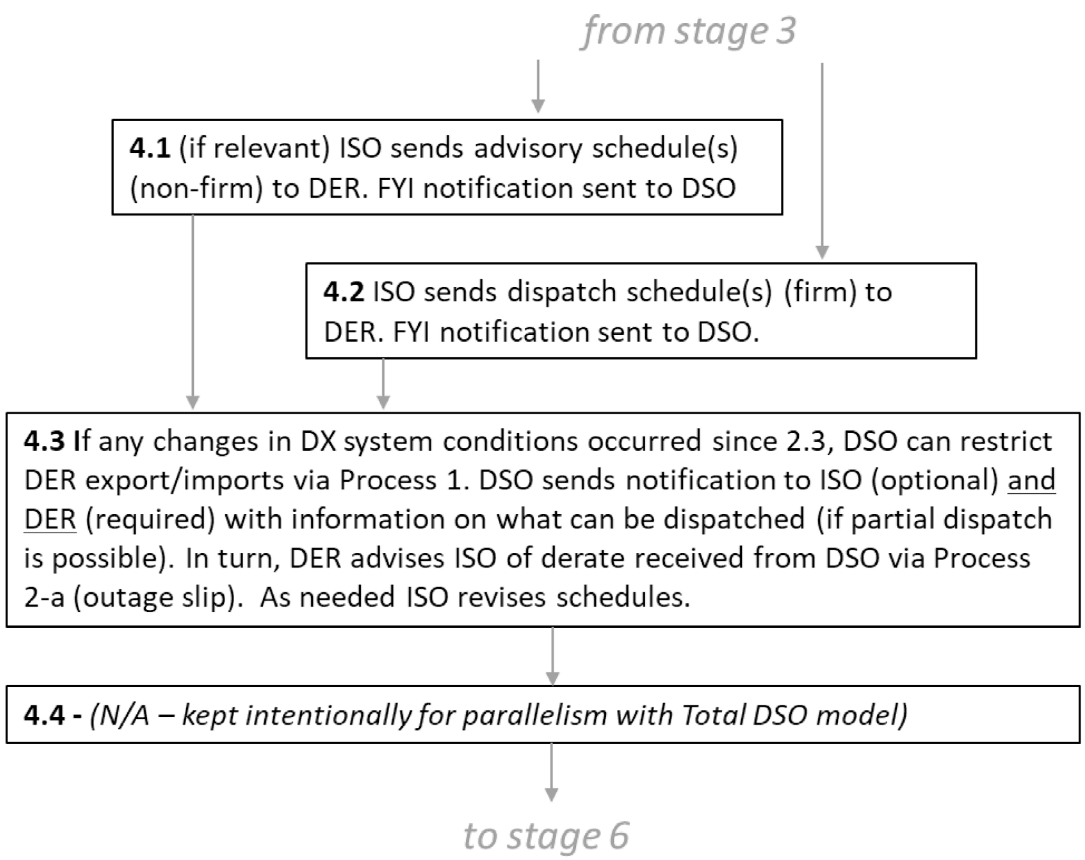

Figure 10. *Functional diagram, Stage 4 with Dual Participation model*

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

In Stage 5-a, represented in Figure 11, 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 DER. In Step 5.1.a, the DER themselves submit outage slips via Process 2-a to the ISO if they are unable to perform as expected due to the distribution incident. In Step 5.2, the DSO dispatches DER 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.

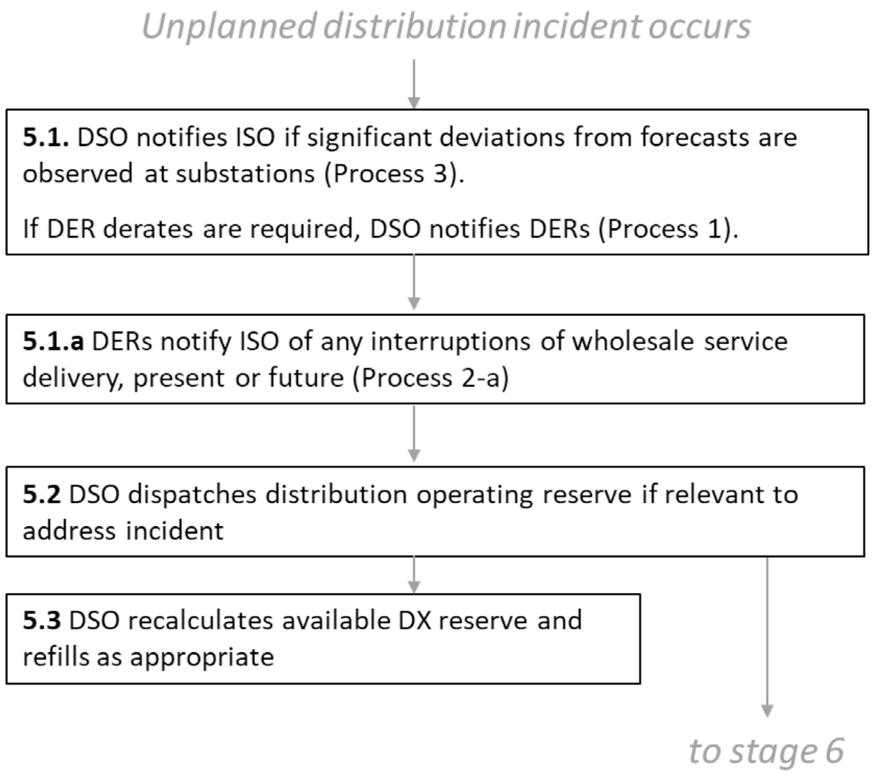

Figure 11. *Functional diagram, Stage 5-a with Dual Participation model*

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

In Stage 5-b, represented in Figure 12, 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.

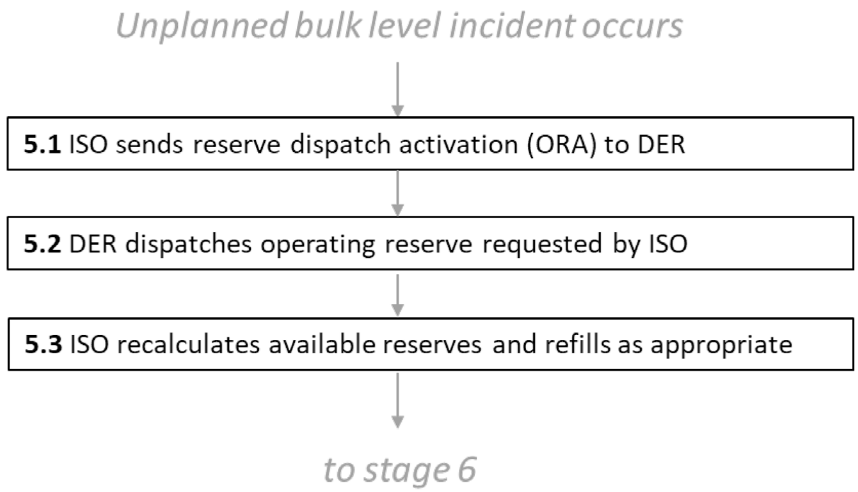

Figure 12. *Functional diagram, Stage 5-b with Dual Participation model*

KEY TAKEAWAYS

This technical brief, the second of a series of three companion papers, explores the coordination required between the distribution utility, the wholesale market operator, and the DER providing grid services. This document does not intend to make policy or market design recommendations; rather, the goal is to inform grid stakeholders in Ontario (and beyond) tasked with assessing the potential development of DER-provided grid services.

First, ***five high-level coordination processes*** are defined to formalize the coordination required between the various grid actors ***when the abnormalities occur*** (e.g., distribution constraints, technical contingencies internal to DER, etc.). These processes may be activated at any time based on needs and operate independently from the coordination otherwise required to enable DER-provided grid services.

Second, ***eight coordination stages*** are defined, each stage describing a ***topical area where coordination is necessary between the ISO, DSO and/or DER***. Stages are agnostic of any coordination framework.

Third, this paper further ***breaks down four of these stages into more detailed steps***. Steps are not agnostic of coordination framework. Therefore, steps are defined for each of the two coordination frameworks introduced in the first paper of this series, *Total DSO* and *Dual Participation*. The steps constituting a given stage follow a logical progression, which can be summarized in the form of a ***coordination diagram***.

The third brief in this three-part series further evaluates the concepts introduced in the first two papers in the context of a selection of distribution feeders, including several Ontario feeders.

EPRI PREPARED THIS REPORT FOR THE INDEPENDENT SYSTEM OPERATOR (IESO) AND ALECTRA UTILITIES.

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