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Enabling DER Service in Distribution Operations

Current State of the Industry

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EPRI Project Manager
J. Smith

EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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EPRI prepared this report.

Principal Investigator
M. Couto
N. Heine
L. Rogers

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ABSTRACT

The continued evolution of distribution operations has largely been driven by the deployment of new technology on distribution systems. In fact, grid modernization advancements, including the implementation of systems/tools, digitization, and high-speed telecommunications, are largely responsible for shaping the distribution grids' environment. The ability of an operator to operate multiple areas and control assets remotely has made computer model-based management systems a key resource to enhance worker safety and productivity. Today, an operator can orchestrate the operation of complex, highly automated distribution systems that could be hundreds of miles away. But, as the distribution system continues to evolve with the addition of distributed energy resources (DER), new tools and challenges will be thrust upon the distribution system operator (DSO). The transition toward a DSO model will come with requirements for new technologies to be deployed and updated processes to effectively transition to this future state.

This report updates the state of the utility industry regarding the changes underway in the DSO transition. It gives a perspective on how the distribution grid is changing because of decarbonization and addresses the future roles of distribution utilities that are derived from DER integration. It contains a comprehensive state of affairs in procuring services from DER and presents grid architectures for enabling DER services. The final section of the report provides an overview of the key operational capabilities that will be needed in the future of distribution utilities and presents information on the industry's current state based on results of a survey conducted by EPRI.

Keywords

DER services
Distribution services
Distribution system operator
DSO

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1 INTRODUCTION

The continued evolution of distribution operations has largely been driven by the deployment of new technology on distribution systems. In fact, grid modernization advancements, including the implementation of systems/tools, digitization, and high-speed telecommunications, are largely responsible for shaping the distribution grids environment. For example, current distribution operators are moving away from relying on institutional knowledge and moving towards leveraging computer model-based management systems. The ability of an operator to operate multiple areas and control assets remotely has made them a key resource to enhance worker safety and productivity. Today, an operator can orchestrate the operation of complex, highly automated distribution systems that may be hundreds of miles away. But, as the distribution system continues to evolve with the addition of distributed energy resources (DER), new tools and challenges will be thrust upon the DSO.

Naturally, the driving forces behind changes in the energy sector revolve around broader shifts in how electricity is produced, consumed, and procured. It's evident that embracing these transformations is likely to bring long-term benefits to the distribution utilities. The transition towards a Distribution System Operator (DSO) model can be viewed as a positive aspect of modernizing the industry, but it's also a necessary change. In various jurisdictions, the concept of DER flexibility is the main driver for this shift as part of a broader goal to establish an energy network ecosystem that is efficient, adaptable, responsive to demand, and capable of harnessing technological innovations as they emerge. However, adapting to and complying with this new energy landscape is a complex undertaking, entailing technical, legal, and regulatory intricacies. There is a need for new technologies to be deployed and updated processes in order to effectively transition to this future state. Additionally, there exists uncertainty within energy companies regarding the specific role and scope of responsibilities of the DSO in this evolving scenario.

This report provides a state of the Utility Industry regarding the changes underway in the distribution sector. The report is organized as follows:

- **Section 1** gives a perspective on how the distribution grid is changing due to decarbonization and addresses the future roles of distribution utilities derived from DER integration. This section also includes a description of how some jurisdictions are discussing the definition of a DSO.
- **Section 2** addresses the services that DER can provide either for bulk power systems or distribution grids. In particular, this section contains a comprehensive state of affairs in procuring services from DER.
- **Section 3** aims to identify operational challenges in procuring and dispatching grid services from DER and how this impacts the operational tools and processes needed to deal with increased DER integration.
- **Section 4** presents grid architectures for enabling DER services, highlighting the discussion on TSO-DSO coordination models, and providing examples of those models' current state in some jurisdictions.

- **Section 5** provides an initial overview of the key operational capabilities that will be needed in the future of distribution utilities. This section provides the industry's current state based on a survey conducted by EPRI.

How is the Distribution Grid Landscape Changing?

The distribution landscape is changing rapidly – creating new opportunities while increasing system complexity and uncertainty. Today, distribution utilities own and operate medium and low voltage distribution systems and have interconnected varying amounts of DER ranging in size from small rooftop PV to multi-megawatt standalone energy storage plants. New opportunities are emerging for distribution connected DER to become a more actively managed component of the power system, through wholesale market participation, non-wires-alternatives (NWA), or to maximize DER owner benefits. Distribution services, while still at an early stage of development, have the potential to cost-effectively defer conventional capital investments and/or operational expenses otherwise required to maintain normal distribution operations. For this reason, electric regulators are encouraging (and sometimes requiring) utilities to incorporate DER-provided distribution services into their standard planning and operating practices.

Distribution services are one of several service categories that DERs can provide. Other categories[1] include customer services and wholesale market services. Customer services intend to help meet the end-user's energy needs while pursuing local economic and/or reliability objectives. Examples of customer services include increased PV self-consumption, demand charge management, or backup power during grid outages. Wholesale market services are another service category, and include energy, capacity, and ancillary services provided to the market operator.

While DER-provided services (for example, DER flexibility, capacity, and demand response) are receiving continued attention for their potential benefits, utilities are working to better understand whether such services may affect the type, severity, and/or frequency of the risks they routinely manage to ensure compliance with obligation standards set by regulators, including quality-of service metrics. As penetration levels of DERs increase, active management of DERs may be required. This will result in changes within the distribution control center (DCC) across the people, process, and tools being utilized. For example, enabling the monitoring and management of DER as well as confident control center operators and field crews knowing that safety and reliability will not be compromised in the face of increasing automation and rising DER utilization. Where once a rules-based approach to DER management was permissible, increasing reliance on distribution connected assets is requiring DSO to maximize DER availability over a wider range of operating conditions, a job that has not been required in the past.

[1] *ER-Provided Distribution Services: Field Experiences*. EPRI, Palo Alto, CA: 2021. 3002021411; and *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2021. 3002022405.

In the past, the distribution-planning process was designed to address typical load and incremental DER growth several years into the future. However, today, society is relying more and more upon the electric distribution system to integrate new resources and power more of our daily lives. The result is a changing distribution system and system planning that are growing in scale and complexity. Of course, the challenges are not limited to the planning function, but readily spill into operational responsibilities as well.

Distribution system operations are evolving to meet future needs and realize new opportunities. A primary example is the emerging prospect for DER to participate in wholesale markets. This is driving a desire to allow DER to operate beyond static minimum hosting capacity levels and in abnormal conditions. The application of hosting capacity analysis using short term load and generation forecasts with the as switched model– or even wholesale market dispatch schedules – will become a foundational component of distribution operations. Driven by a need for increased reliability and safety, today's DSOs are more well-informed, efficient, and equipped with powerful tools than ever before. Yet, as the distribution system transforms into more dynamic, automated, and resilient future state, new roles, capabilities, and analytics will be needed in the control center. Whether it's leveraging new data streams, making use of advanced applications in DMS systems, or managing dispatchable resources, distribution operators will be at the center of this transformation. With these challenges, broader conversations about the roles and objectives of the Distribution System Operator are being initiated.

What is a DSO (Distribution System Operator)?

Under the challenges faced by distribution utilities the responsibilities of distribution system operators will likely change to transform how they plan and operate their distribution grids. Traditionally, utilities operate and maintain the network to deliver high reliability and power quality to the grid users while ensuring the efficient use of the grid assets and the system security in cooperation with the transmission system operator/independent system operator (TSO/ISO).

Utilities have historically designed and operated distribution grids by planning network investments and using automation to change the reconfiguration to accommodate power flows, meet peak demands, and manage faults. Nevertheless, the remarkable penetration of distributed generation, the introduction of demand response programs, rising EV demand, and the growing number of new players (for example, aggregators and prosumers) significantly increases the complexity of managing the distribution grid.

Historically, distribution companies were part of the vertically integrated utilities. Nevertheless, in some jurisdictions like in Europe, the Electricity Directive 2009/72/EC[2] defined requirements for unbundling of distribution utilities aimed to ensure their independence in a vertically integrated undertaking (VIU) from the supply branch and to prevent market distortion through cross–subsidization and discrimination of other supply companies. In the distribution, this new

[2] Electricity Market Directive (EU-2019/944), Available on: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:en:PDF

entity does not sell energy; it is just responsible for managing the distribution grid—so-called DSO or DNO. Nowadays, DSO is a more common term that involves active management of DERs and distribution flexibility. As such, in many jurisdictions, the definition of DSOs[3] has been proposed, stating that distribution utilities will be a central player in promoting the energy transition by having enhanced roles beyond traditional ones.

Table 1 provides an overview of the DSO definitions under discussion or adopted in some jurisdictions. For example, in the European Union framework, in addition to the DSO definition, the Electricity Market Directive (EU-2019/944) also defines the role of the DSO in the market and sets the requirements for its independence. Article 32 (Incentives for the use of flexibility in distribution networks) establishes requirements for flexibility's use in distribution networks. For that purpose, the DSOs are incentivized to procure flexibility services DER provides in the areas under their supervision. Also, the same directive addresses the role of the DSO in integrating electromobility (Article 33) and its tasks in data management (Article 34). This legislation has highlighted the roles of the European DSOs in paving the way for decarbonization.

Table 1: DSO Definitions in several jurisdictions

DSO Definition	Jurisdiction
"Distribution System Operator means a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity."	Electricity Market Directive (EU-2019/944)[4]
"A Distribution System Operator (DSO) securely operates and develops an active distribution system comprising networks, demand, generation, and other flexible DER. As a neutral facilitator of an open and accessible market, it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability, and affordability in support of whole system optimization. A DSO enables customers to be both producers and consumers, enabling customer access to networks and accessible markets, customer choice and great customer service."	UK – Open Energy Network initiative[5]

[3] In North America, the term DSO often corresponds to the person in the control center acting as the distribution system's main operator, focusing on "keeping the lights on" and maintaining safety, reliability, and power quality.

[4] (EU-2019/944) - Electricity Market Directive, Available on: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:en:PDF

[5] UK Energy Networks Association, Open Networks: Future Worlds, 2018.

Table 1 (continued): DSO Definitions in several jurisdictions

DSO Definition	Jurisdiction
"In this report, we use the term distribution system operator (DSO) broadly, to refer to the entity that is responsible for operating the distribution system. This entity could be a distribution utility or, as on the transmission system, a separate organization."	ESIG – Energy System Integration Group[6]
"DSO refers to the entity that is responsible for planning and operational functions associated with coordinating DER services for distribution networks and/or DER participation in wholesale markets in coordination with the TSO, aggregators, and other relevant parties."	Australia – Report for AEMO (Australian Energy Market Operator)[7]

The DSO definition usually does not imply an entity different from the existing DU. However, in some contexts, like in Australia, in the scope of Australia's Open Energy,[8] it is considered the splitting out of the market operation from the role of a DSO. For such, there are two different definitions:

- **DMO (Distribution Market Operator)**. This term refers to the function of the distribution level market operator, as distinct from the wholesale market operator.
- **DSO (Distribution System Operator)**. This term refers to the expanded technical capability of a current distribution network services provider to identify and communicate network constraints.

However, it should be noted that the DSO's role in the markets is an ongoing discussion with very few real-life implementations but several pilots already under development (see Section 8). Based on the DSO definitions in different jurisdictions, the following roles are envisioned for the DSOs:

- **System Operator**. Using new and existing tools and operational procedures to maintain the safe, reliable, secure, and efficient operation of a distribution system with large amount of distributed energy resources (DER).
- **Neutral Market Facilitator**. Enabling distribution connected DERs to participate in the wholesale markets while respecting the distribution network integrity.

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[6] EISG, DER Integration into Wholesale Markets and Operations, A Report of the Energy Systems Integration Group's Distributed Energy Resources, January 2022, Available on: https://www.esig.energy/wp-content/uploads/2022/01/ESIG-DER-Integration-Wholesale-Markets-2022.pdf

[7] Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design, 31 May 2018, prepared by Newport Consortium for AEMO, Available on: https://aemo.com.au/-/media/files/electricity/nem/der/2019/oen/newport-intl-review-of-der-coordination-for-aemo-final-report.pdf?la=en

[8] AEMO and Energy Networks Australia, Interim Report: Required Capabilities and Recommended Actions, 2019. Available on: https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

- **Grid Integrator**. Providing customers with interconnections options for integrating customers and resources into a network that is heavily congested in some areas.
- **Distribution Service Procurer**. Identifying effective alternative solutions to be deployed as alternatives to conventional reinforcement to a constrained grid.
- **Service Provider**. Utilizing network assets and DER connected to the distribution system in innovative ways to support and balance the whole system managed by Transmission System Operator (TSO) or Wholesale Market Operator (WMO).
- **Load Serving Entity**. Delivering electricity to end users and using retail rate structures to recover costs and incentivize behavior from consumers.

Critical Role of the DSO Derived from DER Integration

In a modern energy landscape where bi-directional power flow is becoming the norm, the role of the DSO becomes even more critical in operating a safe and reliable distribution system. As DERs like solar panels, wind turbines, and energy storage systems (ESS) become more prevalent, the DSO must adapt to effectively manage these resources and maintain grid stability. Reasons why the DSO's role is crucial in this context include:

- **Grid Reliability and Stability**. With the increasing penetration of DERs, the DSO plays a vital role in ensuring grid reliability and voltage stability. Bi-directional power flow introduces new challenges such as voltage fluctuations, power quality issues, and protection coordination. The DSO must effectively manage these challenges by implementing advanced monitoring and control systems, grid automation, and real-time analytics to maintain proper voltage levels, frequency control, and system stability.
- **System Planning and Grid Integration**. The DSO is responsible for system planning and integrating DERs into the distribution grid. This includes assessing the hosting capacity and impact of DERs on the grid to ensure the safe and efficient integration of DERs. By carefully planning and coordinating DER installations, the DSO can mitigate potential grid congestion, voltage issues, and other operational challenges associated with bi-directional power flow.
- **Grid Resilience and Outage Management**. Bi-directional power flow can enhance grid resilience and outage management capabilities. The DSO can leverage DERs to support critical infrastructure during outages, integrate microgrids for localized power supply, and utilize distributed energy storage to enhance grid resiliency.
- **Monitoring and Control of DERs**. As bi-directional power flow becomes the norm, the DSO needs to monitor and control the behavior of DERs connected to the distribution system. This includes managing DER output, curtailment when necessary, and ensuring compliance with grid regulations and safety standards. The DSO should have effective communication and control systems in place to monitor and respond to changes in DER output, grid conditions, and demand fluctuations to maintain system stability and protect the integrity of the distribution system.

Enabling grid services from DERs will require specific capabilities from distribution utilities, along with overcoming several technical challenges. Distribution operations organizations must have the ability to identify and quantify the grid services that can be provided by DERs, such as frequency regulation, voltage support, and active power control. This requires expertise in assessing the technical capabilities of DERs and their potential to contribute to grid stability and reliability. However, there are also non-trivial challenges in procuring grid services from DERs due to their decentralized and intermittent nature. Coordinating and dispatching these services in real-time requires sophisticated algorithms and control systems to optimize DER operation and ensure timely response to grid needs. This can be performed by a DERMS (Distributed Energy Resources Management System). Furthermore, utilities need to develop and implement grid architectures in coordination with bulk system operators, that can accommodate the integration of DERs and enable their services. This involves incorporating advanced monitoring and communication technologies and establishing interoperability standards for seamless integration. Many of these things rely on foundational grid modernization advancements as well (for example, DMS, distribution automation, advanced metering infrastructure, and so on).

This report is structured to describe the current state of distribution operations and the industry preparedness for enabling DER to provide grid services. First, existing and emerging examples of grid services from DERs are presented, followed by a discussion of the operational challenges in procuring and dispatching these services. Later, the report describes several grid architectures for enabling DER services, including relevant examples from domestic and international utilities that have investigated or piloted DER services programs. Finally, the report proposes a set of core capabilities that distribution operations organizations will require for effective DER integration. These topics delve deeper into the practical aspects of harnessing the potential of DERs and developing robust systems and processes to optimize their contributions to the grid.

2 GRID SERVICES FROM DER

Distribution network planners are tasked with identifying, evaluating, and recommending solutions to ensure that sufficient capacity and flexibility exists on an ongoing basis to enable the safe and reliable operation of distribution grids. Traditionally, capital investments (for example, transformer upgrades, reconductoring, new voltage regulation equipment) have been the core set of solutions available to distribution planners. Alternatively, the distribution planners can consider “non-wire” solutions, or distribution services, and other novel grid software and control products such as DMS and DER management system (DERMS). Distribution services[9] refer to the imports and/or exports of active and/ or reactive power that DERs can voluntarily provide for a fee and in close coordination with the DSO, to address specific distribution system constraints.

However, DER-provided distribution services are still nascent, mainly when compared to other more established ancillary services in the wholesale market. While wholesale electricity markets have had well-defined market products for several decades, the distribution services are in their early days. Wholesale markets have clearly defined participation models, bidding procedures, metering and telemetry requirements and settlement mechanisms. Regulators in a growing number of jurisdictions are beginning to encourage (and sometimes require) that DUs fully consider DER-provided distribution services as part of their standard planning and/or operational practices. This shifting mindset seeks to realize the potential cost-efficiency that DERs can offer to ratepayers.

In general, distribution services can be provided by DERs connected either behind the meter (BTM) or in front of the meter (FTM), as standalone or aggregated resources. Depending on the distribution system needs, a given distribution service may seek to increase power exports to the grid, or equivalently decrease imports from the grid (“more energy on the grid”). Alternatively, the service opportunity may seek to decrease power exports to the grid, or equivalently increase imports from the grid (“less energy on the grid”).

Previous experience with demand response (DR) can be considered as distribution services, especially when it comes to interfacing with third party aggregators managing a resource portfolio. Nevertheless, DR has been traditionally used for system balancing purposes, not for solving distribution grid restrictions. Contrary to the DERs such as solar PV or ESS, DR resources are usually not power exporters and are not able to change reactive power and provide Volt/Var control. Although this enables DERs to provide a wider range of grid services compared to DR resources, DERs exporting power to the grid can also make the service delivery process much more complex to manage for the DSO. Accordingly, the provision of distribution services by DERs at scale will demand the definition of several requirements such as prequalification evaluation to provide the services, sourcing processes, contractual agreements, and performance and settlement plans.

[9] *DER-Provided Distribution Services: Field Experiences*. EPRI, Palo Alto, CA: 2021. 3002021411.

Distribution service opportunities are characterized by planners through the use of technical parameters, or service attributes. These attributes aim to describe a service opportunity while being agnostic of several factors, including:

- The point of connection (DERs connected behind the retail meter vs. front of the retail meter)
- The size of the resource portfolio (standalone vs. aggregated DERs)
- The portfolio readiness (existing vs. new resources)
- The commitment term to perform the service (for example, next hour vs. up to multi-year commitments)
- The compensation structure (price formation and payment mechanisms)
- Whether the providers pursue value stacking strategies (single vs. multi-use applications)

Examples of Distribution Services Provided by DER

DSOs are responsible for identifying distribution needs that may potentially be addressed by DERs, and packaging the opportunities deemed viable into one or several service products. Distribution needs can be packaged into service products in multiple ways. Further, once service products are defined, there exists a range of mechanisms by which they can be awarded to service providers, as well as a variety of financial compensation schemes. Many early-adopter utilities experimenting with distribution services (see Table 2) are defining service products that combine capacity and energy requirements. For example, the service provider could be required to provide up to 500 kW for up to 5 hours every day between 12pm and 5pm.

Differently, another approach envisions building upon the segmentation commonly adopted in the wholesale domain, and distinguishing between capacity, energy, and ancillary services. Specifically, for a given distribution grid need, the capacity and duration requirements would be separated into two different service products: capacity and energy. Once a grid need is characterized, interested service providers would first bid to provide the capacity component, and a separate bidding process would address the energy component. When several grid needs are localized in the same area, their respective capacity and energy requirements could be consolidated into a single capacity product and a single energy product.

This section describes four examples of distribution services.

Table 2. Example of commercial and demonstration projects on grid services topics

Case Study	Location	Utilities Involved	Status	Key Features
Distribution Investment Deferral Framework (DIDF)[10]	California, USA	PG&E, SCE, SDG&E	Commercial Program	Recent development of a distribution deferral tariff to facilitate participation of residential DERs
York Region NWA project[11]	Ontario, Canada	Alectra, IESO	Demonstration Project	Local service products can be used to address distribution and bulk needs
Flexible Power Initiative[12]	United Kingdom	WPD, NPG, SSEN, SPEN, ENW, UKPN	Commercial Program	Multi-phase approach to service pricing on evolving market maturity

Distribution Capacity

Distribution capacity is a supply and/or a load modifying service that DERs provide via reduction (or increase) of power injection (or absorption) to reduce the net loading of one or several network components (for example, transformer, line). This service can be provided by one or several DERs, typically located downstream of the network elements subject to congestion and is intended to be activated by the DU in normal operating conditions.

The service provider responds to a control signal indicating the delivery schedule and associated setpoints, which then serves as input to the DER controls. The delivery schedule may be sent to the provider ahead of time; alternatively, activation can be triggered based on forecasts, or even based on present operating conditions. The response time required from providers delivering this service may range from day-ahead to 5-15 minutes and may even be faster depending on the provider's capabilities.

[10] https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/didf-partnership-pilot.page?WT.mc_id=Vanity_didf-partnership-pilot

[11] https://www.google.com/search?q=York+Region+NWA+project&rlz=1C1GCEU_enIE1061IE1061&oq=York+Region+NWA+project&gs_lcrp=EgZjaHJvbWUyBggAEEUYOTIHCAEQIRigAdIBBzgwOWowajSoAgCwAgA&sourceid=chrome&ie=UTF-8

[12] https://www.flexiblepower.co.uk/

Voltage Support

Voltage support is a voltage management service that DERs provide by injecting (or absorbing) active and/or reactive power to dynamically correct excursions outside of voltage limits, and/or support conservation voltage reduction (CVR) strategies. DERs providing this service must have voltage regulation capabilities that go beyond mitigating the voltage rise caused by the DER itself (a requirement already included in most interconnection agreements). The DU coordinates the activation of the voltage support service with its own voltage regulation equipment.

This service is intended to be activated in normal operating conditions. The service provider may receive from the DU a list of predefined power setpoints (which serve as input to the DER controls). Alternatively, the provider may be required to lock its DER controls on a stream of voltage measurements provided by the DU and adjust in real time its power injection/absorption accordingly. The response time required from service providers may range from 15 minutes to 1 second and may even go sub-cycle depending on the system needs and service provider capabilities. To qualify for this service, DERs must have the capability to support voltage beyond simply mitigating voltage rise caused by the DER itself, as specified in interconnection requirements (that is, IEEE 1547).

Back-Tie

Back-tie is a supply and/or load modifying service that DERs provide via reduction of load demand and/or increase of power injection to reduce post-contingent loading of grid infrastructure. In abnormal conditions, this service enables the fast reconnection of a feeder (or feeder section) with an identified operational need to one or more backup feeders that have excess capacity reserves (including reserves from DERs providing this back-tie service) to restore customers.[13] To qualify for this service, DERs must have excess capacity reserves (generation, electric storage) and/or the ability to reduce load demand (demand response). This service is activated in response to a control signal from the utility and can be provided by a single DER and/or an aggregated set of DERs.

This provides operational flexibility to (1) reconfigure distribution circuits when restoring customers after an unplanned outage (abnormal conditions), or (2) maintain service during a planned outage for maintenance and/or upgrade (normal conditions). To qualify for this service, DERs must have excess capacity reserves (generation, electric storage) and/or the ability to reduce load demand (demand response). The required activation response time may range from a few hours to 5-15 minutes, and possibly faster depending on the service provider's capabilities.

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[13] *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2021. 3002022405.

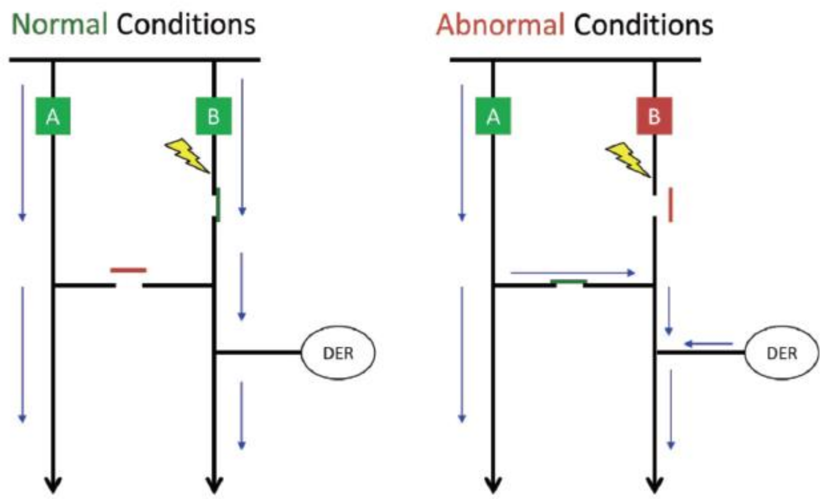


Figure 1: Back-tie: Example use in abnormal conditions

Figure 1 presents an illustrative scenario where the back-tie service is used as a contingency measure following an unplanned outage. In normal conditions, the tie breaker between feeders A and B is kept open. In abnormal conditions, the breaker is closed for feeder A to pick up some of the demand from feeder B, but the breaker rating is not sufficient for feeder A to pick up all the demand from feeder B. In this example, a DER connected to feeder B is contracted to provide capacity support and help restore customers on feeder B while maintaining the breaker loading below an acceptable level.

Resilience

Resilience is a supply and/or load modifying service that DERs provide during abnormal conditions via reduction of load demand and/ or power injection to enable the operation of an ad-hoc microgrid formed to supply power to intentionally islanded end-use customers. Service requirements may differ for DERs able to act as microgrid master (voltage source), and DERs only able to act as grid follower (current source or load modifier). In particular, DERs contracted to perform this service as microgrid master require grid forming capabilities and may perform autonomously with minimal to no control signals received from the distribution utility.

This service is activated in response to a control signal from the DU, or when pre-specified system conditions arise. Service requirements may differ for DERs able to act as a microgrid master (voltage source), and DERs only able to act as a grid follower (current source or load modifier). In particular, DERs contracted to perform this service as a microgrid master require grid forming capabilities and may perform autonomously with minimal to no control signals received from the distribution utility. DERs contracted to provide this service as a grid follower adhere to instructions from the grid master(s). The required response time to activation may range from a few hours to 5-15 minutes and may be even faster depending on the service provider’s capabilities.

Examples of Bulk Services provided by DER

Distribution-connected DERs can provide traditional and emerging ancillary services to the bulk power system as an opportunity for aggregated BTM and FTM resources.

Energy

DERs may play a crucial role in balancing supply and demand in the energy markets, both in day-ahead and real-time scenarios. DER services in day-ahead markets may involve aggregators, which bundle multiple DERs to provide a consolidated energy offering. DER aggregators can leverage battery storage systems to shift energy consumption from high-demand periods to low-demand periods. By charging batteries when electricity is abundant and cheap, and discharging them when demand is high, load shifting helps to balance supply and demand and reduce strain on the grid during peak times. With the increasing penetration of renewable energy sources like solar and wind, DER services can help optimize the integration of these intermittent resources into the grid. Aggregators can forecast and schedule the output of distributed renewable generators to align with the anticipated demand, ensuring a reliable power supply. In addition, DER enables demand response programs, where energy consumers voluntarily adjust their electricity usage in response to price signals or grid conditions. By participating in demand response, consumers can curtail or shift their energy consumption during periods of high demand, reducing stress on the grid and potentially earning financial incentives Real-time energy markets cater to unexpected fluctuations in electricity demand or supply that occur within a shorter timeframe. In real-time markets, DER offers fast-response capabilities to help balance the grid.

Inertia

A service that is typically provided instantaneously by conventional synchronous generators, which uses the stored kinetic energy in rotating machines to slow the rate of change of frequency in the event of a rapid fluctuation in demand or generation. Some emerging technologies such as solar photovoltaic (PV) and ESS do not have rotating mass and cannot provide inertia in the traditional sense since they are non-synchronous. In this regard, the term "synthetic inertia" that was first introduced in the research community has developed over the years and refers to mimicking rotating mass inertia using inverter-based resources such as solar and storage. New technologies such as solar and energy storage must be equipped with appropriate power-electronics based controls to be able to respond instantaneously to frequency deviations.

Fast Frequency Response (FFR)

An immediate active power dispatch service, triggered by a system frequency deviation, which, like inertia, assists in slowing the rate of change of frequency. Several emerging (or inverter-based resource) technologies such as demand response, ESS, and variable energy resources (VERs) such as wind and solar PV can technically provide FFR due to their dependance on power electronics controls that enables such technologies to respond immediately after their controls detect a frequency deviation. Typically, PV may only be used to provide FFR for over-frequency events by reducing the plant output since PV is generally operated at its maximum available power capacity (while considering inverter ratings). However, PV also has the technical ability to provide FFR for under-frequency events given that it can rapidly inject power when it is not already providing its maximum available power capacity (this requires the plant to be curtailed). Therefore, PV plants have the ability to provide FFR on an active power-frequency droop curve, that is, it is possible to implement droop control in the individual inverters or in the plant-level controller. An ESS also has the technical capability to provide FFR and PFR when it has available energy (to discharge) or available storage (to charge). In the discharging mode, an ESR can reduce its power output in response to over frequency events and increase its power output in response to under-frequency events. In the charging mode, vice versa is applicable. In this regard, the duration of response is limited by the state of charge of the ESR.

Primary Frequency Response (PFR)

This service is provided autonomously by generator governors and loads and can even be provided by demand response in some areas. Primary Frequency Response (PFR) is also commonly referred to as primary contingency reserve, frequency responsive reserve, governor response, primary control reserve, or frequency governor response. PFR is an essential service that helps maintain the reliability and stability of interconnections by acting as the first line of defense against frequency deviations when a contingency occurs. The physical and operational characteristics that ascertain the ability of a specific resource to provide this service typically include a specific droop setting that dictates the amount of response the resource can potentially provide per frequency deviation, a specific dead band that indicates the minimum required frequency deviation before a response can be obtained from the resource, the available range of response that is described by the headroom between the resource's operating point and its maximum operating (capacity) limit, and adequate available capability such that the resource can provide a sustained response until the system frequency is brought back to nominal levels of 60 Hz.

Contingency Reserve

It refers to the upward response capability that is utilized to address unexpected contingency events such as generator or transmission outages. Contingency reserve can be provided by both online (spinning) resources and offline (non-spinning) resources. (Secondary) contingency reserve is more commonly referred to as spinning reserve, non-spinning reserve, synchronized reserve, ten-minute reserve, ten-minute operating reserve, ten-minute synchronized reserve, or ten-minute non-spinning reserve. Secondary contingency reserve is an upward active power service intended to respond to significant events, including unplanned generation or transmission outages (or contingencies).

Regulating Reserve

This service is procured on a continuous basis, this service is used to manage small deviations in net load in both the upward and downward direction in a 2-6 second timeframe. Regulation reserve is more commonly referred to as regulation, automatic generation control (AGC) reserve, regulation up and regulation down, or load frequency control. Regulation is procured in both the upward and downward direction to address instances of under- and over generation respectively.

Flexibility Reserve

Similar to regulating reserve but for future forecasted net load deviations rather than current deviations. This reserve helps to address the variability in net load due to larger penetrations of intermittent resources and potential forecast errors. Flexibility Reserve is also referred to as ramp capability, load following, flexible ramp, following reserve. However, unlike regulation that is employed to address the current ACE, flexibility reserve is used to correct the forecasted ACE in a future interval.

Voltage Support

It corresponds to a localized service that is provided through the production/absorption of reactive power to maintain voltage levels within given limits, generally within 5-10% of nominal voltage. DERs can also help regulate voltage levels within the grid; as they are often located closer to the end consumers, they can adjust their output to support voltage control, ensuring efficient power delivery and reducing losses. DERs, such as inverters in solar PV systems can provide reactive power support to maintain grid voltage levels. By injecting or absorbing reactive power, DER resources assist in improving power factor and voltage control.

State of Affairs in Procuring Services from DER

The roles and objectives of a DSO are in transition at utilities across the globe. In the U.S., the Federal Energy Regulatory Commission's (FERC) Order 2222 requires independent system operators (ISOs) and regional transmission organizations (RTOs) to allow and enable aggregations of distributed energy resources (DER[14]) to provide market services. The European Commission is pursuing similar objectives with the development of a European Network Code on Demand Side Flexibility. In Canada and the United Kingdom, distribution utilities are partnering with wholesale market operators to create new, local distribution markets to balance the changing needs of the grid with the increasing desire to buy and sell locally produced energy.

[14] In FERC Order 2222, DERs including any resource on the distribution system or behind a customer meter, including generation, storage, and load resources.

These examples and others are catapulting distribution operations organizations into the spotlight to determine and demonstrate the potential benefits of procuring grid services from DER. The following subsections provide concrete examples from North America, Europe, and Australia.

North America

While North American utilities have displayed a wide range of interest in DER services, there is no question that recent regulations have created more impetus for change. In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222 (O2222), which set a path forward for independent system operators (ISOs) and regional transmission organizations (RTOs) to work with distribution utilities, distributed energy resource (DER) aggregators, and relevant electric retail regulatory authorities to enable participation of DERs in the wholesale electricity markets that ISO/RTOs manage. Each ISO/RTO has drafted a plan, with input from constituent transmission and distribution utilities, to address the requirements set forth by the Order. While compliance filings for O2222 are not yet fully approved, the Electric Reliability Commission of Texas (ERCOT) instituted a pilot program for aggregate DER (ADER) resources to participate in ERCOT's energy market.

FERC Order 2222

FERC Order 2222 aimed to enable participation of distributed energy resource(s) aggregations in energy, ancillary services, and capacity markets operated by ISOs/RTOs. The order directed these entities to ensure existence of adequate participation models for heterogeneous DER aggregations through potential tariff changes, while establishing any needed rules for coordination to ensure bulk system and distribution system reliability. While compliance filings from the ISO/RTOs have been developed and submitted, implementation of Order 2222 is not anticipated to occur in many regions for several years. Implementing the new tools and practices to ensure reliable and practical DER participation in wholesale markets will require additional steps for most utilities and ISOs/RTOs.

Notably, two ISO/RTOs had already filed with FERC designs regarding DER aggregation (DERA) participation, and FERC accepted those designs before the order was issued:

- The California Independent System Operator (CAISO) filed tariff revisions in March 2016 and received FERC acceptance in June 2016.[15]
- The New York Independent System Operator (NYISO) filed tariff modifications in June 2019, followed by FERC approval of those changes in January 2020.[16]

[15] CAISO, Order Accepting Proposed Tariff Revisions Subject to Conditions, FERC, 155 FERC ¶ 61,229, 2016.

[16] NYISO, NYISO Aggregation Order, FERC, 170 FERC ¶ 61,033, 2020.

These two ISO/RTOs proposed tariff changes to comply with Order No. 2222, both of which have been approved. In addition, ISO New England (ISO-NE) currently allows DERAs to participate in wholesale markets as demand response (DR) resources or settlement only resources.[17]

FERC required each ISO/RTO to modify its tariff to include a comprehensive and non-discriminatory process for timely review by distribution utilities (DUs) of individual DERs in a DERA, triggered by registration of DERA in the ISO/RTO market or incremental change (addition or removal of DERs) to the DERA already in the market. To comply with the order, ISO/RTOs are required to coordinate with DUs to establish criteria that DUs would use to determine whether each DER is eligible to participate in the DERA, and if the participation of a DER in a DERA would pose significant risks to the reliable and safe operation of the distribution system. The combination of a short timeframe for conducting this review and the possibility that a single DER aggregation may contain numerous individual DERs implies that distribution utilities will benefit from developing efficient processes or tools for completing the review within the defined timeline.

One of the challenges posed by Order 2222 will be capturing the potential impacts from DER aggregations providing bulk system services during the interconnection or technical review process. Although there are regional differences, much of the DER connected to the distribution system today is non-dispatchable and largely uncontrolled. As a result, utilities have focused on impacts related to the potential intermittency of DER as opposed to the impact of multiple individual devices being dispatched in concert. To overcome this gap, a practical first step is for distribution utilities to work with RTOs/ISO to document and standardize the performance requirements for various wholesale services. Those performance requirements can then be translated into technical studies to determine if DER providing specific services will cause adverse impacts to safety or reliability. Clearly defined studies pertaining to various market services will not only ensure system reliability but will also aid in expediting the registration and review process.

Recognizing the need for real-time coordination to ensure safe and reliable operation of transmission and distribution (T&D) systems, FERC required each ISO/RTO to create a process for ongoing coordination that addresses data flow and communication among itself, the DER aggregator, and the distribution utility. Each ISO/RTO must also require the DER aggregator to report to the ISO/RTO any changes to offered quantity and the relevant distribution factors that is caused by distribution system outages. Furthermore, each ISO/RTO must include coordination protocols and processes for the operating day that can allow distribution utilities to override the ISO/RTO dispatch of a DERA when such override is necessary to maintain the reliable and safe operation of the distribution system.

[17] Post-Technical Conference Comments of the California Independent System Operator Corporation, FERC, June 2018.

To evaluate the need for override, distribution utilities will need transparent access to planned dispatch schedules during operational timeframes. This involves both the aggregation level dispatch between ISOs/RTOs and DER aggregators, as well as the device level dispatch instructions issued by DER aggregators to individual DERs.

Without visibility into the planned behavior of resources in the day-ahead and day-of timeframes, distribution utilities currently do not have the capability identify potential constraints to safety and reliability and instead must rely on prior studies and more conservative approaches to DER management. Increased monitoring of individual DER devices will enable the operation of more DER in abnormal or constrained situations and could even minimize the override of ISO/RTO dispatch signals.

Currently, distribution utilities have minimal visibility into the operation of most DERs. Table 3 provides a summary comparison of the main market design aspects for DERAs across the six FERC jurisdictional ISO/RTOs. The top gray box in each category includes the general approach with unique aspects for each ISO following in the white columns. Readers are reminded that many of the designs are not approved by FERC as of June 2023.

Table 3: Summary of ISO/RTO distributed energy resource aggregation market design proposals

FERC Order No. 2222 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Eligible Wholesale Market Services	All ISO/RTOs are proposing to allow DERAs provide wholesale energy service.					
	Energy, Ancillary Services (AS), Installed Capacity Market Not eligible for Voltage Support. To be eligible for AS, each DER must be eligible.	**Energy, AS (Regulation, Synchronized Reserve, Black Start)** Not eligible for Non-Synchronized Reserve.	**Energy, AS (Reserves and Regulation)**	**Energy, AS (Reserves and Regulation), Forward Capacity Market (FCM)**	**Energy, AS (Reserves and Regulation)**	**Energy, AS (Reserves and Regulation)** Not eligible for Resource Adequacy (RA) as qualifying capacity counting rules do not exist for DERAs in California.
Locational Requirements	Most ISO/RTOs are proposing single transmission pricing node aggregations.					
	Single Trans. Pricing Node Similar to a hybrid approach. NYISO identifies the nodes in coordination with NYTOs.	**Single Trans. Pricing Node** Must be primarily mapped to the same node.	**Single Trans. Pricing Node**	**Multiple Trans. Pricing Nodes** Intersection of DRR Aggregation Zone and Metering Domain.	**Single Trans. Pricing Node**	**Multiple Trans. Pricing Nodes** Single Sub-Load Aggregation Point (Sub-LAP).
Metering Requirements	All ISO/RTOs except for PJM and MISO require aggregate-level meter data.					
	Aggregated Revenue Quality Meter data Multiple streams (energy injections, energy withdrawals, and demand reductions). Individual DER data could be directly measured or calculated values.		**Aggregated Revenue Quality Meter data** Multiple streams (energy injections, energy withdrawals, and demand reductions). Individual DER data could be directly measured or calculated values.		**Aggregated Revenue Quality Meter data** Multiple streams (energy injections, energy withdrawals, and demand reductions). Individual DER data could be directly measured or calculated values.	

Table 3 (continued): Summary of ISO/RTO distributed energy resource aggregation market design proposals

FERC Order No. 2222 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Maximum Size (Individual DERs)	Most ISO/RTOs require larger DERs to participate as stand-alone resources or be the only resource in the DERA.					
	20 MW	**5 MW**		**SODERA: 5 MW** Other models: If larger than 5 MW, must be its own DERA.		**1 MW**
Maximum Size (DERA)	Only ISO/RTOs allowing multiple pricing node aggregations impose size requirements on aggregations.					
				5 MW on total DER size at each pricing node if aggregated across multiple pricing node.		**20 MW** if aggregated across multiple pricing nodes.

ERCOT Aggregated DER Pilot Project

Following in the footsteps of FERC Order 2222, ERCOT and the Public Utility Commission of Texas (PUCT) authorized a pilot program to investigate the benefits and limitations of enabling the participation of aggregate distributed energy resources (ADER) in ERCOT's wholesale energy market.[18] ERCOT, the PUCT, and participating stakeholders identified six goals of the project:

1. Assess the operational benefits and challenges of heterogeneous Distributed Energy Resource (DER) aggregations which are net generation or net load and address those challenges to allow meaningful use of DER aggregation.
2. Understand the impact of having Ancillary Services and energy delivered by ADERs and assess how ADERs can best be used to support reliability.
3. Assess challenges to incentivizing competition and attract broad DER participation through Load Serving Entities (LSEs), while ensuring adequate customer protections are in place.
4. Allow Distribution Service Providers (DSPs), the Commission, and others to study distribution system impacts of ADERs which inject to the grid.
5. Evaluate the impacts to transmission system congestion management associated with the dispatch and settlement of ADERs at a zonal level.
6. Identify potential Pilot Project enhancements and study the need for and benefit of transitioning distribution-level aggregations to different levels of more granular dispatch and settlement and evaluate more complex use-cases and business models.

The first phase of the project is limited both in terms of capacity limitations and participation opportunities. System wide energy and non-spin reserves are capped at 80MW and 40 MW, respectively, with opportunities to increase those limitations in future stages of the pilot. To expedite the initiation of the project and minimize the additional burden to ERCOT and distribution service providers, ADER will be treated as aggregate load resources (ALR), which aligns with many of the FERC O2222 compliance plans that created heterogeneous DERA participation models based on existing demand response models. As of March 2023, 6.5 MW of energy and 2.2 MW of non-spin provided by seven distinct ADER have been accepted by ERCOT[19] Currently ERCOT is working with qualified scheduling entities (QSEs) to register and model these resources in their operational systems, set-up and validate telemetry, and perform qualification testing.

[18] ERCOT, Item 8 - Aggregate Distributed Energy Resource Pilot Project - Phase 1 Governing Document. https://www.ercot.com/files/docs/2022/11/01/Item 8-Aggregate Distributed Energy Resource Pilot Project – Phase 1 Governing Document.docx

[19] ERCOT, Phase 1 of ADER Pilot Project Update – March 8, 2023, Task Force Workshop. https://www.ercot.com/files/docs/2023/03/09/Phase-1-of-the-ADER-Pilot-Project-Update—ERCOT—03-08-23-Final.pptx

Alectra-IESO York Distribution Market

In September 2020, the Independent Electric System Operator (IESO) in Ontario, Canada published a report in which it estimated that more than 4,000 MW of DERs have been contracted or installed over the past ten years in Ontario, with solar accounting for more than half of the total DER capacity[20]. As DER deployment is expected to grow even higher in the coming years, IESO has developed a series of white papers and started pilot programs to understand the impacts of DERs on the transmission-distribution interface. In a 2019 white paper, IESO presented existing participation models for DERs and potential options to expand the models in the future[21]. The white paper also identifies several barriers that may hinder the participation of DERs in the wholesale market. In a separate white paper, IESO investigates the coordination necessary for DERs to provide distribution services through non-wires alternatives and participate in transmission-level markets[22]. A transmission-distribution interoperability framework was developed to maximize the potential of DERs in providing services.[23]

The IESO initiated a non-wires alternative demonstration project in York Region to explore market-based approaches in which DERs can provide energy and capacity services. The project is funded by the IESO's Grid Innovation Fund and Natural Resources Canada and will be delivered by Alectra Utilities. IESO ran the first local capacity auction in November 2020 in which 10 MW were cleared from seven customers including aggregated residential customers with controllable smart thermostats, industrial customers, and small-scale generators[24]. In the summer of 2021 Alectra activated the contracted DER on eight occasions coinciding with local and system peak load conditions.

The York Region Distribution Market demonstration project aimed at developing a better understanding of how to competitively secure and operate DER to meet local, regional and province-wide electricity needs. The project investigated whether DERs are capable of providing communities with more options to address their local electricity needs at lower cost than traditional solutions. One of the goals of the project is to explore market-based approaches for securing services from DERs, and it was also an opportunity to explore models of coordination between the TSO and the DSO, assess operational and reliability characteristics of particular DERs, and identify operational barriers to NWAs.

[20] IESO, Progress Report on Contracted Electricity Supply, September 2020, https://www.ieso.ca/-/media/Files/IESO/Document-Library/contracted-electricity-supply/Progress-Report-Contracted-Supply-Q3-2020.ashx

[21] IESO, Distributed Energy Resources: Models for Expanded Participation in Wholesale Markets, 2020. https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.ashx

[22]ESO, Coordinating DERs used as non-wires alternatives (NWAs), 2019. https://www.ieso.ca/Get-Involved/Innovation/Coordinating-DERs-used-as-non-wires-alternatives

[23] IESO, Development of a Transmission-Distribution Interoperability Framework, May 2020. https://ieso.ca/get-involved/innovation/transmission-distribution-interoperability

[24] IESO, IESO York Region NWA Project, November 2020. https://www.ieso.ca/Corporate-IESO/Media/News-Releases/2020/11/IESO-York-Region-NWA-Project

Europe

In recent years, European institutions and policymakers have focused on the untapped potential of flexibility and the need to bring electricity markets closer to end-users. This has generated a growing interest in utilizing the flexibility offered by DERs. Regulations have outlined the responsibility of the TSO for balancing services, while the DSO is responsible for non-frequency ancillary services. However, there is room for agreement between the DSO and TSO regarding the provision of balancing services by distribution-level resources. European entities are advocating for a paradigm shift that allows DSOs to evolve into active managers of their networks, capable of procuring flexibility within their operating areas. DERs are seen as the primary source of flexibility to address local grid issues, offering DSOs an alternative to grid reinforcement or deferral.

The utilization of flexibility from DERs connected to distribution networks was initially defined by Regulation 2017/1485.[25] This regulation establishes guidelines for electricity transmission system operation, including rules and responsibilities for coordination and data exchange between TSOs, TSOs and DSOs, and TSOs or DSOs and significant grid users (SGUs). Article 182 of the regulation provides guidelines for the prequalification and provision of active power reserves by units or groups connected to the distribution system. These guidelines include information on service delivery, timelines, and coordination with the reserve, connecting DSOs, and any intermediary DSOs involved.

In 2019, the European Commission introduced Directive 2019/944,[26] which aims to enhance the electricity markets. This directive promotes the active involvement of consumers in the energy market, encourages competition in the electricity market, and recognizes the important role of aggregators as intermediaries between customers and the wholesale market. Additionally, the directive outlines the responsibilities of the distribution system operator (DSO) within the market framework.

One specific aspect addressed in the directive is the utilization of flexibility in distribution networks. Article 32 of the directive, titled "Incentives for the use of flexibility in distribution networks," introduces new requirements for incorporating flexibility into distribution networks. Although the existing European legislation, such as the Electricity Directive (EU 2019/944), refers to "Flexibility Services," the term itself is not explicitly defined. "Flexibility services" generally refers to the voluntary participation of different assets, including distributed generation, storage devices, demand-side flexibility, renewable self-consumption, energy communities, and power control of renewable sources. These services involve modifying generation injection and/or consumption patterns in response to external signals such as price signals or activation to support the operation of the electric system.

[25] European Commission (EU) 2017/1485 Establishing a guideline on electricity transmission system operation. Available on: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R1485

[26] European Commission. Directive (EU) 2019/944 on Common Rules for the Internal Market for Electricity; European Commission: Brussels, Belgium, 2019.

Table 4 offers a comprehensive overview of the design aspects related to flexibility products within the local flexibility markets that were examined in this report. The detailed information for those jurisdictions is in Appendices A, B, C, D and E.

Table 4. Summary of DER flexibility market initiatives in Europe[27]

Trial/ Commercial Application	Sthlmflex (Sweden)	NorFlex Norway)	GOPACS (Netherlands)	Enera (Germany)	UK Tenders (UK)	ENEDIS Tenders (France)
Targeted Flexibility Services						
Network Deferral	X	X			X	X
Congestion management	X	X	X	X	X	X
Reliability enhancement	X				X	X
Network re-energization					X	
System balancing	X	X				
Bids Specification						
Minimum bid size	0.100 MW	0.0001MW	As per intraday market	As per intraday	0.010-0.050 MW	Product dependent
Long-Term Contracts						
Evaluation Criteria	Availability offer	–	–	–	70 % price/ 30 % technical criteria	On price except for voltage-related tenders
Call-up	Once per year	–	–	–	Twice per year	Ad hoc
Price Caps	Published	–	–	–	Published	Non-published
Short-Term Market						
Start of trading	D-7	D-7	D-1 to T-6h	D-3 to T-1h	–	–
Gate closure time	Nominal 120 minutes, in practice at 09.00 D-1	120 minutes	As per Intraday Market	Nominal 15 minutes, in practice some hours before	–	–

[27] Chondrogiannis, S., Vasiljevska, J., Marinopoulos, A., Papaioannou, I. and Flego, G., Local electricity flexibility markets in Europe, EUR 31194 EN, Publications Office of the European Union, Luxembourg, 2022, ISBN 978-92-76-56156-9, doi:10.2760/9977, JRC130070.

Table 4 (continued): Summary of DER flexibility market initiatives in Europe

Trial/ Commercial Application	Sthlmflex (Sweden)	NorFlex Norway)	GOPACS (Netherlands)	Enera (Germany)	UK Tenders (UK)	ENEDIS Tenders (France)
MTU[28]	60 minutes	60 minutes	15 minutes	15 minutes	–	–
Buying Parties						
DSO	X	X	X	X	X	X
TSO	For balancing and congestion	For balancing and congestion	For congestion	For congestion	–	–
Network Operators' Coordination						
Procurement rule	DSO over TSO	DSO over TSO	Separate procurement	DSO over TSO	N/A	N/A
Security Coordination	Subscription rights	To be developed through the FDR[29]	TSO/DSO analysis	Cascading top-down	None	None

Among the reviewed marketplaces, all primarily emphasize congestion management flexibility services. Following closely behind, the second most prevalent focus is on network deferral, and the third most common aspect is the enhancement of network reliability, such as activating flexibility during planned maintenance or unforeseen outages. The specific service being provided significantly influences the structure of the traded flexibility products. For congestion management, the norm is to engage in short-term trading, typically one week ahead and closer to real-time operations. In contrast, for network deferral and reliability enhancement services, longer-term contracts extending from months to years in advance are typically used. An exception to this pattern is found in the two Nordic markets examined in this study, which aggregate bids into the Transmission System Operator (TSO) balancing market.

All the local flexibility markets under review are geographically organized into local congestion zones, where offers can be grouped into portfolios, mirroring the zonal arrangement of the wholesale market. There are slight variations, such as in the ENEDIS tenders, where specific connection points within the zone might be exempted due to technical considerations. Conversely, GOPACS takes a more flexible approach by combining firm congestion zone configurations with ad hoc formation of IDCONS as needed, based on the location-based information of offers.

[28] MTU – Market time unit. The MTU is the period for which the flexibility product price is established.

[29] FDR – Flexibility Data Register.

Regarding the harmonization of long-term trading of flexibility across these markets, it is notably low. The frequency of calls, evaluation criteria, and product structures vary significantly. This mirrors the situation in long-term contracts for system services like capacity remuneration mechanisms, where national peculiarities play a decisive role. On the other hand, short-term flexibility markets exhibit a higher degree of harmonization, typically following a continuous pay-as-bid trading approach. Nevertheless, there are still observable differences. The initiation of trading depends on whether buying network operators disclose their flexibility demand, which is influenced by factors such as forecast accuracy (better when closer to real-time), expected procurement costs (often higher closer to real-time), and market liquidity (less mature markets necessitate longer trading periods). The gate closure time is heavily influenced by the level of integration with wholesale markets, with GOPACS, utilizing flexibility offers from the intraday market, having the shortest gate closure time. In contrast, Nordic marketplaces have chosen a nominal gate closure time of exactly 2 hours to avoid overlapping with the balancing market.

United Kingdom

The transition from DNO to DSO in the United Kingdom is a significant focus in the ENA Open Network projects. These projects aim to facilitate the evolution of the distribution network towards a more active and flexible role, enabling the integration of (DERs) and the optimization of their operation. The transition involves shifting from a traditional DNO model focused on managing the physical infrastructure to a DSO model that actively manages and coordinates the flow of electricity within the distribution network, ensuring efficient utilization and incorporating advanced technologies and market mechanisms. In addition, the ENA Open Network projects play a crucial role in driving this transition and exploring innovative approaches to enhance the functionality and resilience of the UK's distribution system. Since 2019, the British regulatory body, Ofgem, has been encouraging the establishment of local flexibility markets. This initiative was initiated through the introduction of a new price control framework called RIIO-ED22, which applies to DSOs. As a result, Great Britain has emerged as the most advanced DSO market in Europe, with six DSOs actively procuring flexibility and offering commercial opportunities within the market.

In addition, the UK’s Flexible Power initiative is a collaborative effort among to integrate the procurement of distribution services, known as “flexibility services,” DERs into their standard planning practices. The initiative aims to establish common concepts and practices across participating DUs, enabling streamlined processes. Each DU involved in Flexible Power seeks to offer a standardized program to engage with DER asset owners and other consumers, referred to as flexibility providers, to either reduce peak demand or increase energy supply in Constraint Management Zones (CMZs) defined by the DSOs, which are areas with distribution constraints. The contracted services encompass various activities such as adjusting the demand profile of a factory, providing local network support through on-site generation or reactive power for voltage control, and utilizing energy storage to charge during surplus periods and export during predefined network events.

Participants in the program receive financial compensation for the grid flexibility they offer through four distinct service offerings, tailored to specific grid requirements. The Flexible Power initiative provides participants with a new revenue stream from their power assets while enabling the integration of more DERs, leading to reduced carbon emissions and decreased grid management costs. The structure of Flexible Power emphasizes participant autonomy and aims to establish markets that align DER flexibility with real-time grid needs. DUs issue flexibility tenders on an ongoing basis based on network loading analysis and demand forecasts. Potential flexibility providers can access information such as flexibility locations, procurement notices, and requirement data to determine their interest in bidding on specific opportunities.

Prior to providing flexibility services, distributed resources undergo a comprehensive onboarding process. Upon successful completion, a contract is established between the DU and the resource owner. Once contracted, providers gain access to the Flexible Power Portal through an application programming interface (API). The portal allows them to declare the availability of their assets, receive dispatch signals from the DU for flexibility services, and access performance and settlement reports. The API is also used to record provider meter readings, facilitating the tracking of asset availability and performance. Table 5 Depicts the four distribution service products available through the Flexible Power program, all of which provide active power capacity to address thermal constraints.

Table 5*:* Flexible Power product offerings[30]

Product/Service	Sustain	Secure	Dynamic	Restore
Description	DERs pre-emptively reduce peak demand at point of contract by flexing supply up-down per a schedule.	DERs provide a scheduled response to manage peak loads and prevent system violations.	DERs provide immediate response following a fault (often during summer maintenance work) or during unplanned network event.	DERs provide immediate response to restore electricity following an unplanned network event.
Case	Scheduled Constraint Management	Pre-Fault Constraint Management	Post-Fault Constraint Management	Post-fault Network Restoration
Availability Payment	Yes, for scheduled availability pre-agreed within contract	Yes, arming payment for availability at week-ahead	Yes, arming payment for availability at week-ahead	No
Utilization Payment	Yes	Yes	Yes	Yes
Availability Declarations	Week-ahead. By midnight every Wednesday for the following week (Mon-Sun)			

[30] https://www.flexiblepower.co.uk/

Table 5 (continued): Flexible Power product offerings[31]

Product/Service	Sustain	Secure	Dynamic	Restore
Availability Acceptance	Week ahead. By midday every Thurs for the following week (Mon-Sun)			
Availability Acceptance	Fixed within contract; notice sent 15 min. ahead of requirements	Fixed week-ahead on acceptance of availability; notice sent 15 min. ahead of requirements	Notice sent 15 min. ahead of requirements	

The Sustain and Secure products are designed to be activated in normal or planned abnormal conditions.[32] The goal is to defer traditional network reinforcements, or the cost of a planned outage. These products typically pay service providers to reserve capacity and guarantee that the service can effectively be delivered if called by the DU. By contrast, the Dynamic and Restore products intend to support grid operations in unplanned abnormal conditions.[32] These services intend to avoid the cost of unplanned network abnormality (up to a largescale unplanned outage). Because the activation of these products is more opportunistic in nature, they do not involve capacity reservation payments: providers may respond when called by the DU, if available, and are paid only based on actual utilization.

A distinctive feature of the Flexible Power initiative is its multiphase approach to service pricing based on market maturity in each CMZ. Initially, service prices are fixed administratively when the amount of flexibility offered locally does not provide enough competition among service providers. Fixed prices (for advanced and/or utilization payment, depending on the service product) are typically the same across all CMZs. In this first phase, the DU simply compares the cost of the conventional upgrade(s) to the fixed prices, to determine if flexibility services from third party providers could be a cost beneficial alternative.

Australia

As Australia continues its journey towards an energy transition, the significance of DERs in the energy system is growing exponentially. According to AEMO's 2022 Integrated System Plan (ISP) Step Change scenario,[33] it is projected that by 2032, over 50% of detached homes in the National Electricity Market (NEM) will be equipped with rooftop solar, with capacity reaching 65% and 69 GW by 2050. Additionally, AEMO's 2022 Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) predicts a substantial increase in distributed PV capacity in Western Australia's southwest region, with an annual growth rate estimated between 5.6% to 7.8% over the next decade. This could potentially result in the doubling of distributed PV capacity

[31] https://www.flexiblepower.co.uk/

[32] *Procuring Distribution Services from Distributed Energy Resources: Progress Reports from United Kingdom and France*. EPRI, Palo Alto, CA: 2021. 3002024647.

[33] AEMO, 2022 Integrated System Plan, June 2022.

from 2888 MW in 2022-23 to 5658 MW in 2031-32, even though the peak demand in the WEM is currently around 4000 MW and expected to grow only marginally. Furthermore, the transition towards electric vehicles (EVs) and the electrification of households, businesses, and industries will further amplify the demand for the energy system.

In Australia, the participation of distributed energy resources (DER) in wholesale markets is gaining traction as the energy landscape evolves. Several initiatives and programs have been implemented to facilitate the integration of DER into wholesale markets. Here are some key aspects of DER participation in wholesale markets in Australia:

- **Virtual Power Plants (VPPs)**. Virtual power plants enable the aggregation of DERs, such as rooftop solar systems, battery storage, and electric vehicles, into a single coordinated entity. VPP operators can participate in wholesale markets by leveraging the combined capabilities of the aggregated DERs to provide services and sell electricity.
- **Demand Response Programs**. Demand response programs allow DER owners to adjust their energy consumption in response to market signals or system needs. DER owners can earn financial incentives and support grid stability by curtailing or shifting their electricity usage during peak demand periods.
- **Frequency Control Ancillary Services (FCAS)**. DERs can provide valuable FCAS essential for maintaining grid frequency within the desired range. Certain DER technologies, such as battery storage systems, can respond quickly to frequency deviations and help stabilize the grid.
- **Wholesale Electricity Market (WEM)**. Western Australia operates a wholesale electricity market where DERs can participate. DER owners and aggregators can submit bids and offers to sell electricity, provide ancillary services, or participate in demand response programs within the market framework.

The Distributed Energy Integration Program (DEIP)[34] in Australia is an industry-led collaborative initiative that aims to facilitate the integration of distributed energy resources (DER) into the electricity grid. It brings together key stakeholders from the energy sector, including network operators, regulators, government agencies, technology providers, and research institutions, to address the challenges and opportunities associated with the growing deployment of DER. The DEIP was established in 2018 and is focused on fostering collaboration and knowledge sharing among participants. Its primary objective is to develop and implement innovative solutions that can effectively integrate DER while ensuring grid stability, reliability, and cost-effectiveness. The program operates through a series of working groups and projects, each targeting specific aspects of DER integration. These working groups focus on technical standards, market frameworks, regulatory reforms, data management, and consumer engagement. By collaborating across these domains, DEIP aims to create an environment that supports the seamless integration of DER into the grid and maximizes the benefits for all stakeholders.

[34] DEIP, DER Market Integration Trials, Summary Report, September 2022. Available on: https://arena.gov.au/assets/2022/09/der-market-integration-trials-summary-report.pdf

One of the key features of DEIP is its emphasis on pilot projects and demonstrations. These initiatives allow participants to test new technologies, business models, and regulatory approaches in real-world settings. By piloting different solutions, DEIP seeks to identify best practices and lessons learned that can inform future policy and regulatory decisions.

Multiple advanced trials and pilots are currently underway to investigate the potential of distributed energy resources (DER) in providing services and participating in energy markets. These initiatives aim to ensure that DER operations remain within the physical system limits while offering attractive products and services to consumers. Notable among these trials are project EDGE, project Symphony, project Edith and project Converge. Table 6 provides an overview of the various approaches the trials and pilots are exploring under DEIP. The detailed information for those jurisdictions is in appendixes F, H, I and J.

Table 6. Technical setting of the market integration trials on DER market integration in Australia (based on [31])

Project	EDGE	SYMPHONY	EDITH	CONVERGE
Metering Point	Connection Point or Sub-metering	Connection Point	Connection Point	Connection Point
Energy Market Bidding	Model consistent with scheduled BDU[35] from IESS[36]	Bids into balancing and contingency reserve raise markets	Current bidding process for FCAS[37]	Bids first sent to DSO
DOE[38] Allocation	Various	Various	Subscription model	Bid-optimized
Local Constraints	DOE	DOE	DOE	DOE
Network Support	Local services exchange	Contracted network services	Dynamic network price	Real-time RIT-D[39]
Data Transfer	Data-hub	Platform integrations	Point-to-point	Point-to-point
Local Constraints Communication Protocol	CSIP-AUS[40] (only using schema)	CSIP-AUS	CSIP-AUS extended with pricing)	CSIP-AUS

[35] Bidirectional Unit

[36] Integrating Energy Storage Systems rule change

[37] Frequency control ancillary services

[38] Dynamic operating envelope

[39] Regulatory investment test distribution

[40] Common Smart Inverter Profile Australia

3 NEEDS IN PROCURING AND DISPATCHING GRID SERVICES FROM DER

Dispatching DER poses several needs related to timing, magnitude, location, visibility, measurement, and settlement. These challenges stem from the unique characteristics of DERs, such as their diverse types, distributed nature, and intermittent generation.

Timing, in the context of distribution service and wholesale market opportunities, involves the establishment of specific time intervals, minimum response times, and other temporal parameters that define the temporal aspects of such opportunities. It allows for precise scheduling and activation of services to align with the dynamic requirements of the electric grid. The magnitude of flexibility services refers to the capacity or volume of the service that DERs can provide. Accurate measurement and prediction of the required magnitude of flexibility services are essential to ensure that the grid receives the appropriate level of support without over- or under-provision. Also, the location of DERs plays a crucial role in determining where and how these services are deployed. Dispatching resources to specific grid nodes or areas with identified constraints or needs enhances grid efficiency and reliability. Real-time visibility into the performance and availability of DERs is essential for grid operators. Visibility allows them to monitor the status of DERs, assess their capabilities, and make informed decisions about when and where to dispatch these resources. Finally, the measurement and settlement involve quantifying the actual provision of these services by DERs and the compensation process for services provided by those units. The following sections address each of these needs.

Service attributes encompass a collection of technical parameters that distribution operators employ to describe and assess distinct distribution service opportunities Table 7 illustrates the attributes and the specific elements for location, timing and magnitude that aim to characterize a grid service opportunity.

Table 7*: Categories of common service attributes*[41]

Attribute Categories	Question(s) Being Addressed	Description
Location	Where	The electric point on the distribution system where the service can be delivered. Multiple locations and/or multi-point delivery may be allowed to satisfy a given operational need.
Timing	When, how fast, for how long, how often	The specific time intervals, minimum response times and other durations characterizing the temporal aspects of the service.
Magnitude	What, how much	The real and/or reactive power capacity required, which may be time specific.

[41] *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2021. 3002022405.

The distribution utility may determine the attribute values for each category based on their planning and operational requirements. Prior to committing to provide a service, the service provider possesses complete knowledge of these attributes for the specific distribution service opportunity. The common service attributes remain independent of various factors:

- **Technology**. Demand response, PV, storage, and so on.
- **Point of connection**. Behind the retail meter (BTM) vs. front of the retail meter (FTM).
- **Size of resource portfolio**. Standalone vs. aggregated DER.
- **Readiness**. New vs. existing resources.
- **Commitment term to perform service**. Next hour, up to multi-year commitment.
- **Service settlement**. Payment and/or penalty mechanisms.
- **Value stacking strategy**. Single vs. multi-use applications.

Visibility

Irrespective of the existing level of awareness about DER, the identification of DER assets, including those behind-the-meter, and their potential impacts on the distribution system are becoming increasingly crucial for effective distribution system operation. Therefore, enhancing the visibility of DER is necessary to gain a deeper understanding of the quantity and behavior of connected DER, enabling better planning and operation of the distribution system.

Visibility, in this context, refers to the temporal, geospatial, and topological awareness of all grid variables and assets. Achieving visibility in distribution grids involves dealing with a number of complexities, which includes several factors such as:

- Feeder branches and laterals
- Unbalanced circuits
- Poorly modelled circuits
- Large numbers of attached loads and devices
- In the case of feeders with inter-ties, time-varying circuit topology

Furthermore, distribution circuits typically operate in a time-varying and unbalanced state, requiring visibility into all three phases independently. As DER can be dispatched to provide services to DSOs the need for visibility arises, leading to the development of a sensing, measurement, and control architecture. Extensive sensing and data collection capabilities are essential and foundational for control and grid management purposes. Integration of DER necessitates increased visibility, as these devices need to be monitored and controlled by DSOs.

Presently, utility visibility into DER operation is limited and primarily influenced by metering approaches that vary across jurisdictions based on regulatory requirements and policy objectives.

The lack of DER visibility for distribution system operations can be attributed to two main situations. Firstly, insufficient telemetry contributes to this issue, which can arise from either a lack of monitoring equipment or the limitations of existing equipment that cannot directly measure DER production. For example, some meters measure net load to/from the grid, combining it with DER production rather than separately measuring gross load and DER production. Secondly, even when sufficient telemetry exists, there may be significant delays or latency in transmitting data to operators. This can occur when measurements are recorded at certain intervals (for example, every 15 minutes) but are only transmitted once per day, or when the sampling frequency is too slow for the specific application (for example, one measurement per hour when 15-minute data is required).

When utilities employ single meter approaches,[42] they face a lack of visibility into DER generation, volts, and vars. As a result, DER is not acknowledged as an active participant in the grid capable of providing grid support. However, by adopting a separate meter solution, utilities can attain visibility into DER operations in two distinct ways:[43]

1. **Measurement Visibility.** By monitoring DER parameters such as real and reactive power, as well as voltage, the utility can accurately determine its generation output. If communication-enabled meters are in place, the utility gains visibility into how the DER is operating and its current levels. This information enables the utility to make informed decisions regarding feeder operations and recognize the DER as an active grid participant. Additionally, the DER owner can benefit from access to the metered generation data.
2. **Management Visibility.** With management visibility, utilities can monitor and actively control DER, including real and reactive power as well as voltage, to adjust its operation and provide grid support with a high degree of accuracy. This capability empowers utilities to optimize the operation of both grid assets and DER in a coordinated manner, maximizing their combined efficiency and effectiveness.

The existing metering infrastructure and communication systems may pose limitations on the metering of DER output, thereby impacting the available visibility options. It is evident that the chosen metering approach has implications not only for the visibility perspective of grid operators but also for the ability of DER to actively participate in grid operations. Understanding this correlation will guide grid investment decisions and enable the establishment and appropriate configuration of infrastructure to support the future integration of DERs. It is essential to consider the role of DERs and ensure the provision of necessary visibility to effectively accommodate their utilization.

[42] No separate meter installed to measure DER. DER generation is behind the meter. DER production appears as a reduction in customer load.

[43] *Making the connection: The importance of DER visibility to grid support and modernization*. EPRI, Palo Alto, CA: 2018. 3002013388.

As previously stated, communication technologies play a crucial role in monitoring and controlling DERs. The significance of this role becomes even more pronounced as the penetration of flexible resources advances from grids where DERs are infrequent, scattered, and have minimal impact on the grid (Level 1 in Figure 2), to grids where DER capabilities and data become indispensable tools (Levels 3 and 4 in Figure 2).

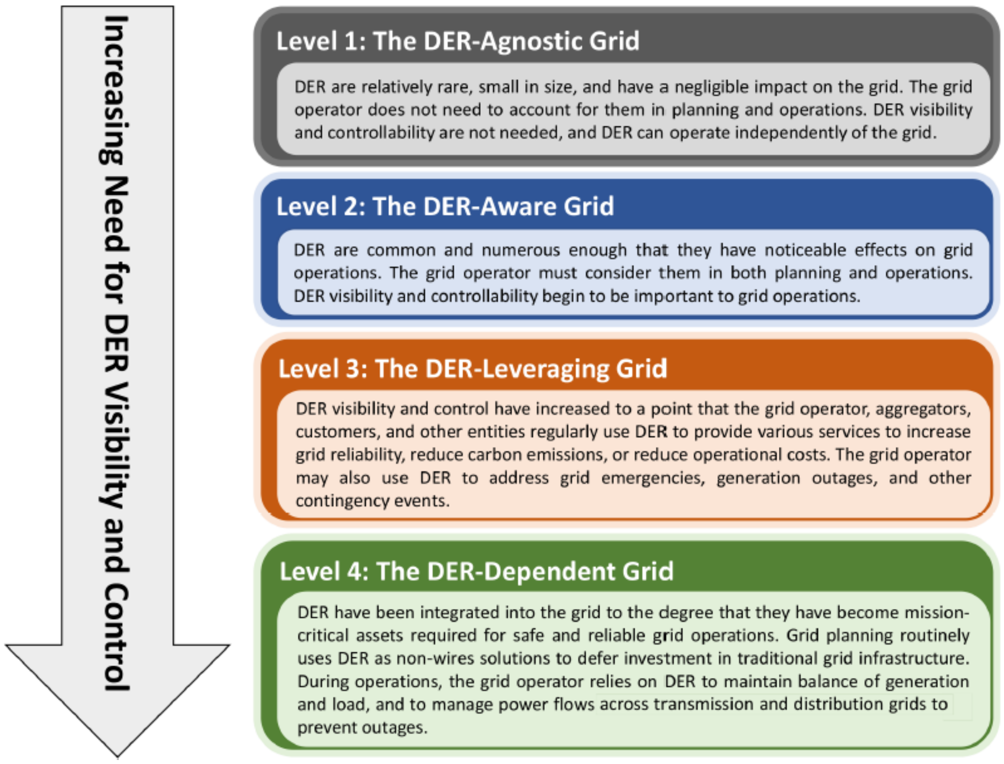


Figure 2*: The four incremental levels of DER integration*[44]

Timing

Traditional power system management practices are designed for centralized power generation and may not align with the dynamic nature of DERs. The limited capabilities of the current systems further exacerbate the challenges.

DERs, such as solar and wind generation, exhibit temporal variability due to changing weather conditions. This variability can make it challenging to predict when DERs will be available and at what capacity, impacting their timing for grid service provision. The time it takes for DERs to respond to grid operator signals or control commands can vary. Some DERs have rapid response times, while others may require more time to ramp up or down. Matching DER response times to grid needs can be complex. Coordinating the timing of multiple DERs across different locations to

[44] *Demand Flexibility for Grid Reliability and Resilience Considerations for Successful Grid Operation*. EPRI, Palo Alto, CA: 2018. 3002025480.

provide grid services can be challenging. Ensuring that DERs activate in a synchronized manner is essential for maintaining grid stability. Many DSOs lack the necessary tools and technologies to effectively book, monitor, and respond to the services offered by DERs (for example, DER forecasting, load forecasting, and switching order management).

The concept of timing is used to establish distinct time intervals, minimum response times, and other durations that characterize the temporal aspects of a distribution service opportunity. To provide clarity, timing attributes can be divided into two sub-groups: one focused on procedural aspects of service activation and another for attributes related to ramp rates. Table 8 presents the first sub-group, composed of attributes unrelated to ramp rates.

Table 8: Example of procedural attributes

Attribute	Value
Booking Time	The time interval(s) when the service provider is required to be "on call" and ready to perform in response to service activation requests or other control signals.
Response Time to Activation	The response time allowed to start performing the service upon activation.
Dynamic Response Time	During a period of performance, the response time allowed to adjust the active and/or reactive power output in response to control signals.
Duration	The length of time a service provider is expected to perform the service after activation.
Recovery Time	The minimal amount of time in-between service calls.
Frequency of Need	The number of times a provider can be called to perform a service in a given period of time (day, week, month, year, and so on).

Depending on the specific distribution service being considered, the response time to activation can vary. Figure 3 presents illustrative ranges to demonstrate the possible values.

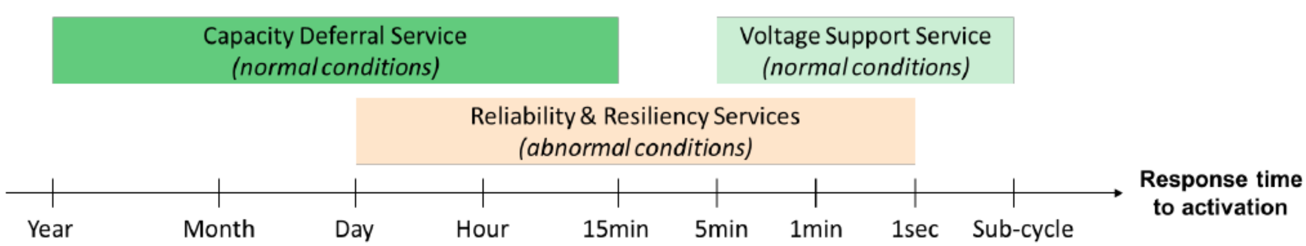


Figure 3: Range of response time to activation for example services[45]

[45] *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2021. 3002022405.

For instance, the duration requirement is always equal to or shorter than the booking time (referred to as attribute. Figure 4 illustrates an example where the duration requirement is shorter than the booking time. In this particular scenario, the distribution operator-initiated service delivery slightly after the start of the booking time, and the service provider successfully delivered the service for the entire required duration.

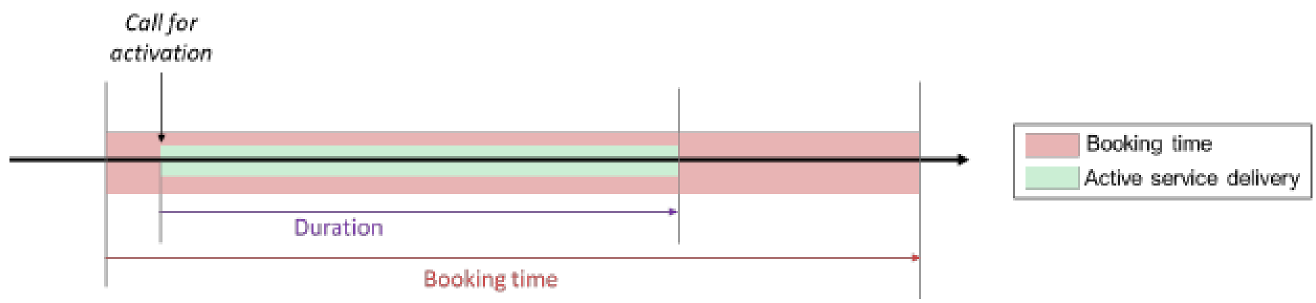


Figure 4: Example with duration less than booking time[46]

Figure 5 consolidates all the timing attributes outlined in Table 8 through an illustrative example. As seen in the previous examples presented in Figure 4, the distribution operator made the decision to initiate the service after the commencement of the booking period.

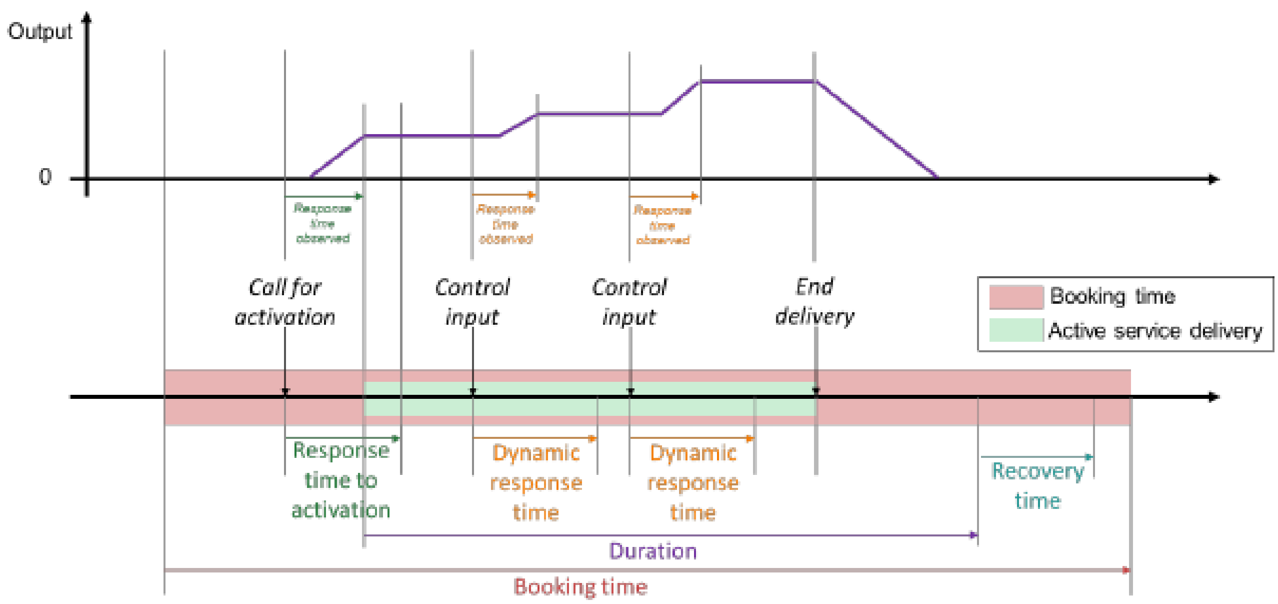


Figure 5*:* Timing attributes (unrelated to ramp rates)[45]

[46] *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2021. 3002022405.

A second subgroup of timing attributes, concerning ramp rates, can be defined as shown in Table 9. Before delving into the details, it is essential to understand the purpose of ramp rates in the context of distribution services and how they may differ from or relate to reliability-driven ramp rate limits (RDRRL). RDRRL can be expressed in absolute terms, such as MW/min or MVAR/min, or in relative terms, such as a percentage of exports per minute. It's worth noting that RDRRLs are typically specified in the DER interconnection agreement (IA), and if existing distribution equipment would impose overly restrictive RDRRL values, upgrades may be required during the interconnection study process. It is crucial to recognize that the response of a DER to distribution needs can manifest in various ways:

- The response can be driven at the local level, such as through autonomous smart inverter functions, or in a centralized manner, such as in response to a dispatch signal from the DSO.
- The response may differ depending on whether the system is operating under normal or abnormal conditions.

Table 9: Examples of timing attributes related to ramp rates

Attribute	Value
Maximum Ramp-up Limit	Maximum rate-of change in output allowed (up) when service is being performed.
Maximum Ramp-down Limit	Maximum rate-of change in output allowed (down) when service is being performed.
Minimum Ramp-up Requirement	Minimum rate-of change in output allowed (up) DER must be capable of performing when service is being performed.
Minimum Ramp-down Requirement	Minimum rate-of change in output allowed (down) DER must be capable of performing when service is being performed.

Location

The spatial distribution of DERs across the grid presents complexities in effectively harnessing their services and integrating them into grid operations. Additionally, the current capabilities and tools for procuring and dispatching grid services from DERs are often limited, hindering their optimal utilization. The attributes in this category assist in defining the following aspects based on the requirements of the distribution grid:

- The specific location(s) on the grid where the service opportunity exists
- Any applicable requirements regarding the number of Service Delivery Points (SDPs)

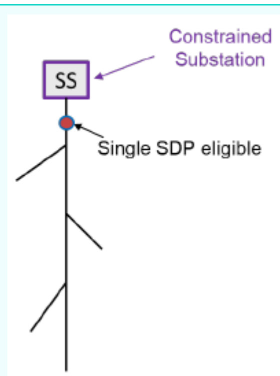
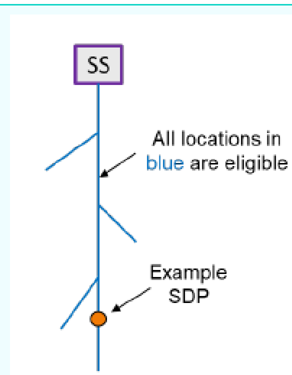
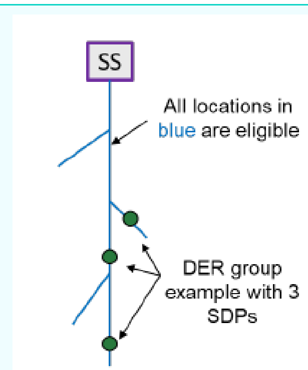
Table 10: Example of Common location attributes

Attribute	Description
Eligible SDPs	Physical or topological location(s) on the distribution system where the service can be delivered.
Minimum number of SDPs Required	Minimum number of SDPs required to deliver the service.
Maximum number of SDPs Allowed	Maximum number of SDPs allowed to deliver the service.

An illustrative example is provided to demonstrate the utilization of location attributes. In Table 11, the first set includes three scenarios for a distribution service aimed at addressing capacity constraints at a substation:

- The DSO may specify a single Service Delivery Point (SDP) for the service (as shown in the second column of Table 11).
- Alternatively, multiple eligible locations can be identified, but the service provider is required to deliver the service at a single SDP (as indicated in the third column of) Table 11.
- Another option is to designate multiple eligible locations and allow delivery from multiple SDPs (as shown in the last column of Table 11). In this illustrative example, up to three SDPs are permitted.

Table 11: Example of location attributes for capacity deferral for substation

Location Attribute	Three Example Scenarios		
Eligible SDP	Single Location	Multiple Locations	Multiple Locations
Minimum of # SDPs Required	1	1	1
Minimum of # SDPs Required	1	1	3
Illustrative Example			

Magnitude

DERs often have limited capacity compared to centralized power plants. The challenge lies in determining the appropriate magnitude of dispatch for each DER to maintain system reliability and balance supply and demand.

As the number of DER installations grows, the grid's demand for their services also increases. This includes services such as voltage regulation, frequency control, and congestion management. However, the limited capabilities of current DERs and their aggregated services can often be insufficient to meet the scale of these requirements. This presents a challenge in procuring and dispatching grid services from DERs at a magnitude that aligns with the grid's operational needs. In addition, the existing capabilities for planning analysis, especially in terms of interconnection and technical review, are often limited. When integrating DERs into the grid, careful planning and analysis are necessary to ensure their seamless integration and compatibility with existing infrastructure. However, the current interconnection processes and technical reviews may not adequately address the unique characteristics and challenges posed by DERs. This creates a bottleneck in the procurement and dispatching of their grid services.

This requires evaluating factors such as DER capacity, grid interconnection requirements, and potential impacts on system stability. By improving the planning analysis process, grid operators can facilitate the procurement and dispatching of grid services from DERs.

Hence, attributes in this category intend to define the real and/or reactive power capacity required from the DER or group of DERs providing a specific distribution service (see Table 12).

Table 12: Example of possible magnitude attributes

Attribute	Description
Real power capacity – injection	The real power capacity required (injection) to successfully perform the service
Real power capacity – absorption	The real power capacity required (absorption) to successfully perform the service
Reactive power capacity – injection	The reactive power capacity required (injection) to successfully perform the service
Reactive power capacity – absorption	The reactive power capacity required (absorption) to successfully perform the service

Measurement, Verification, and Settlement

A significant number of DERs connected to the distribution system are configured in a "behind the meter" arrangement. However, this arrangement brings about challenges in terms of measurement and verification (M&V) and settlement structures that seek to accurately recognize the complete value of DERs without double compensation. DUs that wish to procure distribution services from DERs must establish a Measurement and Verification (M&V) framework that outlines how adherence to service requirements will be verified over time, serving both operational and settlement purposes. Here are the key objectives of M&V in each timeframe:[9]

- **Operational timeframe.** M&V aims to provide real-time visibility to control room operators, enabling them to assess whether service providers are performing as expected. If any under-performance is detected (for example, mismatch between the amount of energy contracted to provide a service and the amount really delivered, DER has a fault and cannot provide the service), operators may choose to initiate contingency measures to address the issue promptly.
- **Settlement timeframe.** M&V is employed to gather all essential data necessary for performance evaluation and financial compensation calculations. This ensures that accurate compensation is provided based on the actual performance of the DERs.

By establishing a robust M&V framework, utilities can effectively monitor and verify the performance of DERs, ensuring operational efficiency and accurate settlement processes.

The M&V requirements for distribution services are typically more rigorous compared to traditional demand response (DR) programs. Traditional DR programs often aim for an aggregated and statistically significant response from a geographically diverse portfolio of resources, addressing resource adequacy and system balancing requirements. Moreover, these programs typically have contingency mechanisms in place, allowing the procurement of substitute services from other participants in the wholesale market to address instances of under-performance.

In contrast, distribution services cater to more localized grid needs, focusing on specific areas within the distribution system. The availability of alternative service providers in such localized contexts is usually limited, if they exist at all. Consequently, there is a greater need for stringent M&V processes to ensure that the distribution services meet the necessary requirements and provide the expected benefits. This emphasizes the importance of robust M&V frameworks for distribution services, given the limited options for substitute services in the event of contingencies.

Data Requirements for Delivery Tracking and Performance Evaluation

DSOs define data requirements for two distinct timeframes: operational and settlement. During the operational timeframe, there are different approaches adopted by DSOs. In some cases, successful service delivery is assumed by the DSOs for real-time operational purposes unless informed otherwise by the control room operator. In other cases, dispatch instructions may require acknowledgment or acceptance from the aggregator, providing initial feedback. System monitoring devices, typically using SCADA, can also be utilized to indirectly confirm that a service provider is delivering the intended service by ensuring the distribution network operates within technical limits. Remote terminal units (RTUs), particularly for larger DERs, make this process more efficient when already installed at the service delivery point.

In the future, it is expected that DSOs will require DERs providing distribution services to offer real-time status messages and metering data to the DU. While some DUs plan to rely on APIs and public communication networks for real-time, two-way communications, others intend to utilize real-time SCADA communications (private networks), particularly for larger DERs.

Regarding settlement, DUs may compare control room action logs (including dispatch commands sent to DER aggregators) with network monitoring reports to assess provider performance. DUs that already collect real-time metering data from DER aggregators may also utilize that information for settlement purposes. DUs with less stringent real-time requirements may request additional metering data to be submitted after each service delivery event or at a specific frequency, such as the end of each month.

Baselining

To evaluate performance and determine payments or penalties for underperformance, metering data is compared post-event to a baseline. There are variations result in differing viewpoints regarding the application of baselines:

- In the case of DERs that offer distribution services, baselines are created to encompass the import and/or export patterns that would have occurred in the absence of these distribution services. These baselines serve as counterfactuals for evaluating the performance of the DERs in question.
- On the other hand, for wholesale market resources, baselines are generally not calculated. This is because the behavior of these resources is predominantly influenced by their participation in the wholesale market. If a wholesale market resource is not dispatched, its baseline would be considered as "zero" since it would not have taken any action.

In the realm of measurement and verification (M&V) practices for distribution services provided by DERs, baselines are utilized to define the expected behavior of a DER or DER aggregation if they were not delivering a specific distribution service. Baselines are represented as a time series in kilowatts (kW), typically with intervals of 30 minutes or even shorter. The performance of service providers is evaluated by comparing their actual performance against this counterfactual baseline.

Table 13 provides an overview of baselining methods that are either pre-approved or being considered by DUs that are already procuring DER-provided distribution services.

Table 13: Summary of baselining methods

Baseline Method[47, 48]	Description	Uses Historical Data?	Compares Subgroup to Other DERs?	Application Timeframe
Nomination Baseline	Service provider develops forecast using method of its choice, and shares with DU.	(At provider's discretion)		Operation and Settlement
Meter Before – Meter After	Flat baseline determined by subgroup behavior immediately preceding service activation.	No	No	Operation and Settlement
Historical Baseline	Baseline calculated from flexibility subgroup's historical power levels.	Yes	No	Operation and Settlement
Regression-based Baseline	Baseline calculated using regression model developed from relevant historical datasets.	Yes	No	Operation and Settlement
Historical K-Nearest Neighbors	Baseline calculated from k historical subgroup profiles most similar to service activation day.	Yes	No	Settlement Only (post calculation)
Geographical K-Nearest Neighbors	Baseline calculated from k DERs geographically close to subgroup.	Yes	Yes	Settlement Only (post calculation)
Peer Group	Baseline calculated from "mirror" DERs historically similar to subgroup.	Yes	Yes	Settlement Only (post calculation)

[47] *Emerging Approaches for Delivery Tracking and Performance Evaluation of DER-Provided Distribution Services*. EPRI, Palo Alto, CA: 2018. 3002024645.

[48] CooodriNet Project, D2.1 Markets for DSO and TSO procurement of innovative grid services: Specification of the architecture, operation, and clearing algorithms.

4 GRID ARCHITECTURES FOR ENABLING DER SERVICES

In the past, the distribution system was a one-way street delivering power from the bulk power system to numerous end-use consumers, but it is rapidly transitioning to a system that exchanges power between various consumers and producers on the distribution and transmission systems. With this transition comes the need for operational coordination between TSOs and DSOs.

There are many factors (for example, decarbonization goals, new market players, participation of DER into energy markets) both internal and external to the power sector, influencing the need to establish coordination frameworks between generation, transmission, and distribution organizations. The combination of these driving factors is reshaping the coordination architectures used today, which are primarily designed to balance centralized supply resources economically and reliably with distributed demand from end-use customers. This coordination will require identification of the roles and responsibilities for all participants to ensure that the value of flexible resources is maximized. A pragmatic approach to defining those roles and responsibilities is to establish a coordination framework or architecture to clearly document how incremental interactions collectively achieve the desired outcome. The final design of the coordination architecture is then a reflection of the unique objectives of demand flexibility within a region.

The motivation for coordination may be different for each actor involved. For example, ISOs and RTOs may be motivated by a need to minimize overall system costs and maintain bulk system reliability. For distribution utilities, the motivation could be to ensure reliable and safe operation of the distribution grid. For resource aggregators, there could be motivation to maximize financial gains, avoid performance penalties, or other factors. While the motivations may be unique to each actor, the ultimate objective of improving TSO-DSO coordination is to better facilitate the use of demand flexibility within the power system.

Defining TSO-DSO Coordination Frameworks

A coordination framework can be defined as the expected actions, responsibilities, and data exchanges between two or more parties performing a function or sequence of functions cooperatively. It is a useful structure for reducing the complexity and costs associated with achieving a collective goal between multiple stakeholders. When properly executed, a coordination framework decomposes a high-level objective (for example, enable DER aggregations to participate in wholesale electricity markets) into a set of clear interactions that can be referenced by stakeholders for a variety of purposes. There are often numerous incremental interactions needed to facilitate a broader end goal, all of which constitute a coordination framework.

In the context of the electric power system, coordination frameworks have been used to define the interactions between historically siloed functional organizations and address challenges that are highly complex, multi-jurisdictional, and span multiple sectors (for example, distribution, transmission, generation, and customers). Although electrically connected, the planning and operation of the bulk and distributed power systems have traditionally been performed independently or with minimal interaction. As the opportunities for distribution connected resources to participate in the grid continues to grow and reshape the broader power system, transmission and distribution system operators will benefit from structured arrangements to conduct information sharing and decision making between actors on a regular basis.

Benefits of TSO-DSO Coordination Frameworks

Developing a clearly defined coordination framework presents a variety of benefits to all stakeholders in the process. As new systems are being designed, planned, and commissioned, a coordination framework assists in specifying the technical requirements of individual components such as analytical tools, operational control systems and data repositories. In operational time frames, a coordination framework serves as a point of reference for the expected actions and responsibilities of all parties. When interfacing with external stakeholders such as customers and resource aggregators, coordination frameworks can also help to avoid conflict and expedite dispute resolution processes. Coordination methods presents several benefits to successfully integrating demand flexibility services including:[48, 49]

- Comprehensive coordination frameworks enable demand flexibility opportunities that go beyond the constraints of conservative rules-based approaches to resource management.
- Coordination frameworks help to clearly define participation mechanisms, and without them resources owners see lost opportunity or decreased value for their flexibility services.
- Coordination frameworks help clearly define roles and responsibilities to ensure operation of demand flexibility does not negatively impact the reliability of the electric grid.

TSO-DSO Coordination Framework Models[49,50]

There are several coordination frameworks for TSO-DSO interactions that have been documented in support of DER providing services to the grid.[51] While variations exist, all describe a comprehensive set of interactions and responsibilities needed to plan systems, connect resources, operate markets, and financially settle service providers. Related industry efforts[52] have characterized the spectrum of architectures into three primary designs: total TSO, total DSO, and hybrid DSO, depicted in Figure 6. Each of these variations has the potential to enable demand flexibility to provide services to both the bulk power and distribution systems and are discussed in more detail in the following sections.

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[49] *TSO-DSO Coordination Frameworks for DER Services*. EPRI, Palo Alto, CA: 2018. 3002025643.

[50] Helena Gerard, Enrique Israel Rivero Puente, Daan Six, Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework, Utilities Policy, Volume 50, 2018, Pages 40-48, ISSN 0957-1787.

[51] De Martini, Paul, Lorenzo Kristov, and Lisa Schwartz. *Distribution systems in a high distributed energy resources future*. No. LBNL-1003797. Lawrence Berkeley National Lab. (LBNL), Berkeley, CA (United States), 2015.

[52] Martini, P. D., L. Kristov, M. Higgens, M. Asano, J. Taft, and E. Beeman. "Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design." *Newport Consortium) (https://aemo.com. au/-/media/files/electricity/nem/der/2019/oen/newport-intl-review-of-der-coordination-for-aemo-final-report.pdf* (2018).

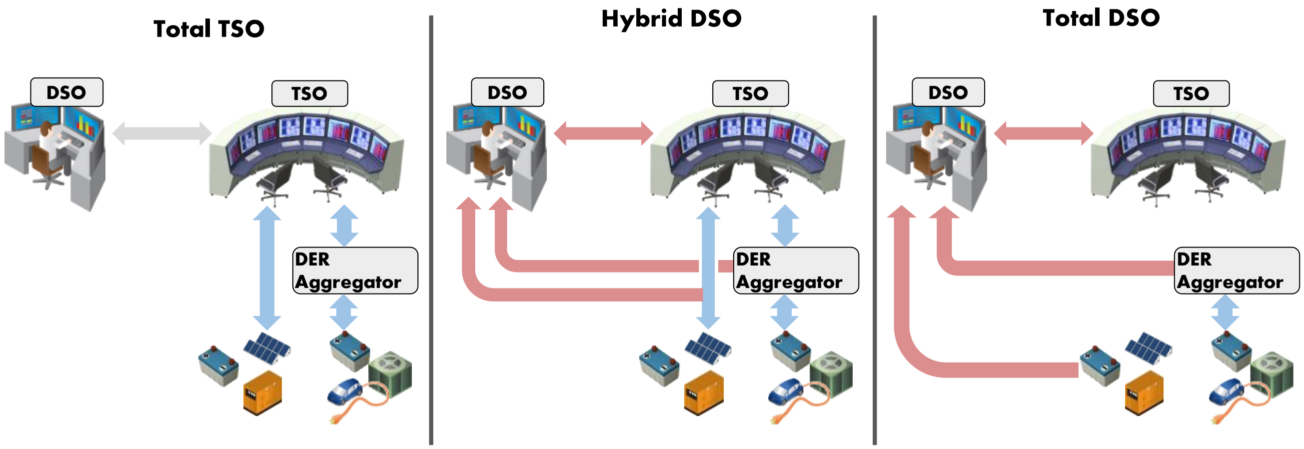

Figure 6: Three primary design models for TSO-DSO coordination

Total ISO

A **total TSO model** describes a framework where TSOs gain sufficient visibility to the distribution system that they can optimize, and dispatch distribution connected resources without input from operators of the distribution system. This model is an extension of the current wholesale electricity market coordination framework (which optimizes, and dispatches centralized generators connected to the bulk power system) for integrating flexible resources connected to the distribution system. In terms of the deliverability of demand flexibility for bulk system services, the total TSO model provides the TSO with the system observability required to dispatch resources with certainty. On the other hand, scaling the current bulk system optimization tools used to include the complexity of distribution systems could be difficult. Furthermore, the total TSO model introduces the exchange of dispatch or control messages that bypass the DSO domain, potentially affecting safety, reliability, security, and power quality at the distribution level. This is because the DSO remains responsible for maintaining safety and reliability on the distribution system but is not able to override the dispatch of distributed resources by the TSO. It is also unclear how distributed resources would be dispatched to resolve distribution system constraints given that the TSO is focused on the broad balance of supply and demand across transmission and distribution. Finally, this model is furthest from the current state of power system operations in the United States, requiring a reimagination of the existing regulatory structure.

Total DSO

The **total DSO model** stands on the opposite end of the spectrum, with the TSO seeing a single virtual resource at each transmission-distribution interface managed by the DSO but cannot see into the distribution system. This model represents a paradigm shift in the roles and responsibilities of distribution utilities and distribution operators. In this model, the DSO is responsible for aggregating all distributed resources and coordinating the participation and dispatch of those resources in the wholesale market. While the DSO has the necessary visibility and authority to optimize resources across its system, doing so has not traditionally been a primary responsibility. The issues of transparency and priority arise when the DSO is aggregating resources that are utility owned, customer owned, and managed by 3rd party aggregators. This has sparked conversations about the degree of independence needed between the DSO and the distribution utility or distribution owner. In particular, the total DSO model lacks a direct interface between customers or resource aggregators and the TSO, placing the DSO in the middle of those interactions. However, this arrangement can simplify the grid operation for the TSO because a single aggregated resource is present and available at each transmission-distribution interface, as opposed to the numerous aggregations that might manifest under the total TSO or hybrid DSO models.

Hybrid Models

Hybrid models strike a compromise between the total TSO and total DSO models by allowing distribution connected DER to participate in the wholesale market through DER Aggregators while also granting distribution utilities some oversight of the participation and dispatch of those resources as needed to maintain the safe and reliable operation of the distribution system. The Hybrid DSO model has been used for decades to enable demand response to participate in wholesale markets. Because the operation of demand response aggregations has been mutually beneficial for distribution and transmission systems, this model has worked well for its limited use case. In the past, the TSO has not needed visibility into the distribution system to confidently dispatch demand response. In large part, the dispatch of demand response has been aligned with bulk system peaks, and the distribution system can also benefit from peak reduction even if the bulk system and local peaks are not entirely coincident. Avoiding the requirement for the TSO to observe and optimize the distribution system has streamlined the market operation and optimization process, allowing DR to participate in the wholesale market at will. Additional challenges with the hybrid DSO model arise when there are conflicting control signals, potentially resulting from disparate goals and limited visibility between the DSO and TSO. The relevant example here is a resource that has offered services to both the DSO and the TSO, and at times those services may be incompatible. Moreover, the complex and parallel flows of information and decision making can introduce latency in the system optimization process. Although there are clear challenges with the hybrid DSO model, its past use for DR has enabled it as a leading design for the envisioned coordination frameworks aimed at bringing DER aggregations to the wholesale market being developed in the context of FERC Order 2222.

Examples from Industry

Different jurisdictions have varying levels of TSO-DSO coordination. To analyze the TSO-DSO coordination several factors should be accounted such as:

- DER dispatch model (centralized or decentralized)
- Threshold for TSO controllability (if TSO can control some large power units connected to the distribution side)
- Level of DSO visibility and controllability of the DER connected to the distribution side
- Proportion of generating capacity decentralized (connected to the distribution grid)
- Ability for DER to participate in the provision of services to DSO and TSO
- TSO visibility on the small-scale DER connected to the distribution grid (usually BTM)

Table 14. Examples of Grid Architectures for enabling grid services

Characteristic	Great Britain	Spain	Australia	Texas	Ireland and Northern Ireland
DER dispatch Model	Full self-dispatch for all single/aggregated DER	Different levels of dispatch depending on capacity	Central dispatch by TSO for all single/aggregated DER	ERCOT centrally dispatches majority of DER	Full central dispatch run by EirGrid
TSO controllability threshold	Generally, no controllability, though some exceptions	TSO controls DER >5MW	All except 'small-scale DER' like individual solar rooftops	ERCOT controls DER >10MW, some self-dispatch DER 1-10MW	TSO can control all DER above 1 MW
DSO controllability	Some DSOs have DERMS to control HV/EHV flex. connections	Currently no DSO capability to control DER	Local dispatch and control of small-scale DER only	No official DSO; only ERCOT-led central or self-dispatch	Only via TSO instructions or in an emergency situation
Peak distribution voltage	132 kV	132 kV	132 kV	60 kV	110 kV
Proportion of generating capacity decentralized	30% in 2021 28-30% in 2030	~30% by 2030	NEM[53] has approximately 14 GW of distributed solar (~22%)	~2% in 2022 (3 GW out of 143 GW)	Wind generation in distribution 50% (Ireland) and 90% (NI)
Ability for DER to participate in D/TSO services	Bespoke TSO and DSO flexibility services. 1MW min bid for TSO, 10-50 kW for DSO	Certain DER can participate in certain ancillary services. 100 kW min bid size	NEM and WEM[54] have different set ups with separate products. Complexity rapidly developing	Market driven approach to system balancing (nodal pricing). More focus on DER post-2021	Developing new capabilities for DER participation
Level of DSO-TSO coordination	TSO and DSOs are siloed. High coordination needed, but current development still not enough	TSO/DSO coordinate schedules, but not forecasting or DER visibility	DSO required to coordinate dispatch with AEMO	ERCOT receive regular meter data from TDUs and coordinate on system planning	Reduced interaction; on scheduling and activation through "Instruction Sets"
TSO visibility of DER	Very poor visibility, various projects slowly improving it	Real-time visibility of DER >1MW in CECRE	DSO implements dispatch instructions, not AEMO	Visibility > 10MW, for some <10 MW	Regular data exchange established for assets >1MW

[53] Wholesale Electricity Market

[54] National Electricity Market

Core DSO Capabilities for Enabling DER Services

The transition to DSO presupposes that the DERs connected to the distribution grid are managed under a system perspective. This system perspective encompasses not only the management of a grid with increased variability and uncertainty on consumption and generation but also the coordination between network operators and DER and DERA. DSOs must account for a wide variety of consumption and generation scenarios, as contingencies can rise in step with the number of DER connected to the grid. DER, distribution generation (DG), demand response (DR) and storage systems bring new variables to the system. Therefore, the distribution grid needs to be more flexible, not only regarding its operation but also in terms of investments in network infrastructures.

Many utilities and states are embarking on grid modernization initiatives to adapt to changing energy trends and meet evolving customer demands. Grid modernization involves investments in people, processes, and technology to prepare for the future utility landscape. The exact definition of a modern grid can vary from one utility to another, along with the strategies and approaches taken to achieve it.

A fundamental concept in this framework is the "building block" relationship among grid components. Technologies for monitoring, sensing, and measurement provide insight into the behavior and condition of grid assets. Communication systems securely transmit this critical data to central and distributed management systems, enabling operational decisions based on real-time information. Investing in these foundational components offers immediate benefits, such as improved grid safety and reliability, and cost reduction. Moreover, they establish the groundwork for incorporating additional capabilities and applications in the future.

Distributed Energy Resources (DER) is a prime example, as the foundational building blocks, including planning, operations, and supporting technologies, equip grid operators to effectively monitor and manage DER. This, in turn, enables the provision of valuable DER-related grid services, supporting secure, reliable, and resilient grid operations. In essence, effective DER management relies on a robust set of core components. These core elements can be seen as "no regrets" investments because they are essential not only for reliable and affordable electric service but also for accommodating future grid enhancements. The building block concept is depicted in Figure 7.

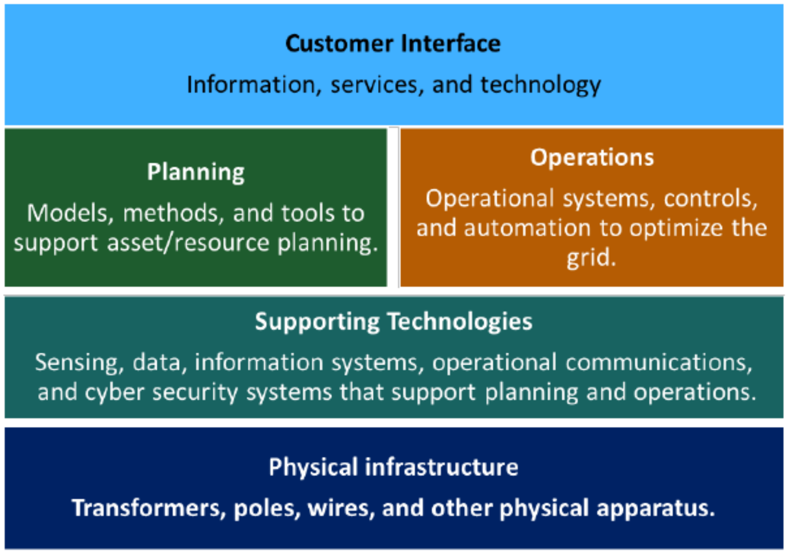

Figure 7: Foundational components of grid modernization[55]

Capabilities define "How" a utility will accomplish its grid modernization objectives through new or enhanced tools, technologies, processes, and people.[55] Grid modernization encompasses numerous capabilities, making it advantageous to commence the roadmap development process with a broad range of potential capabilities in mind. One effective approach is to employ a capability model. These models are typically organized into tiers, commencing at the functional or organizational domain level, which aligns with standard utility functional domains such as planning and operations. The capabilities roadmap will be developed in the next deliverable. However, the next sections provide a set of operational capabilities needed to enable DER services in distribution operations. Outcomes from an EPRI's survey illustrate the state of the industry on these capabilities.

Network Modeling

The availability of accurate and detailed distribution system models forms the basis for the development of processes and tools aimed at modernizing the control center, as illustrated in Figure 8.

[55] *Grid Modernization Playbook: A Framework for Developing Your Plan.* EPRI, Palo Alto, CA: 2022. 3002024809.

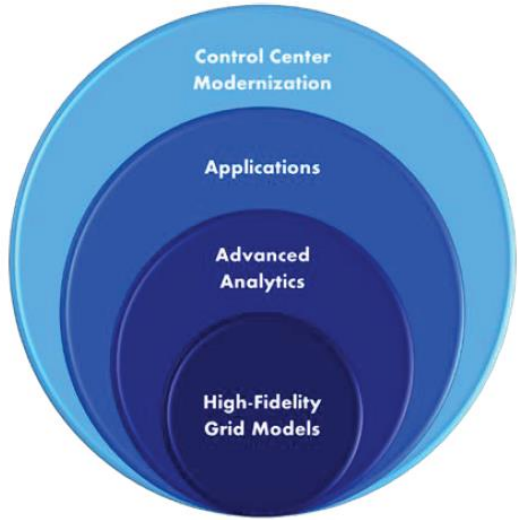

Figure 8: High-Fidelity grid models are at the core of control center modernization[57]

In the distribution operation control room, it is essential to maintain analytical capability while field work is being carried out. Any changes made to a feeder should be reflected in real-time modeling, ideally within a target timeframe of 15 minutes after the event. The data comprising grid representation can be categorized as follows:

- **Physical Data**. Describes the inherent properties of the grid's construction, encompassing the electrical characteristics of equipment, as well as the connections, measurements, and controls associated with the equipment.
- **Situation Data**. Provides information on the operational state of the physical grid, relevant for various analyses. This data includes energy flows in and out of the grid, control area net interchange, switch states, control settings, and operating limits.
- **Solution Data**. Represents a set of values for steady-state variables, primarily voltages and flows, derived from a solution algorithm. This data offers insights into the stable operating conditions of the grid.

A recent survey conducted by EPRI[56] aimed to gather data to better understand the operational tools available to distribution utilities around the world, how they are used, and relevant implementation experiences. This survey represents 18 companies covering service territories across 24 states in USA, in addition to 9 companies with service territories across Canada, Ireland, Lithuania, Portugal, the Republic of Korea, Slovenia, South Africa, and the United Kingdom.

One of the questions was about the years that have passed since DMS began to function in the utilities' system. While 67% of respondents reported having at least 5 years of history with DMS applications operation, 21% reported that they have less than a year of experience with the DMS. Concerning the network modelling, Daily updates are the most common frequency of updates for the DMS model, according to 29% of respondents. A total of 25% of respondents reported DMS model updates with less frequency (from multiple times per week to monthly).

[56] *Distribution Management Systems (DMS) and Other Operational Tools: Survey Results on Availability and Use*. EPRI, Palo Alto, CA: 2023. 3002027189.

Operational Planning

The increasing complexity of the operation of the distribution system is driving the need for new roles and responsibilities that are now commonplace in transmission control centers. Operational planning, which consolidates the existing planning responsibilities within the DCC, is steadily becoming paramount to the distribution control center as utilities continue to deploy new systems to proactively manage resources and grid assets alike. Serving as the interface between long term planning and the distribution operator, distribution operational planning focuses on evaluating and informing operating decisions over the week-ahead, day-ahead, and just-in-time timeframes. Industry advancements are making many critical resources for operational planning readily available, enabling the rapid integration of advanced technologies and DER into the grid.

Initially, these duties may be carried out in an ad hoc manner since they are not required frequently. This includes reviewing complex switching orders, conducting contingency switching analyses, and evaluating proposed Distributed Automation (DA) switch locations. However, as the penetration of DER increases, market opportunities become more widespread, and reliance on grid services becomes the standard, these tasks may transition into a cyclical nature, performed regularly, and potentially daily.

Therefore, conducting hosting capacity analysis using the as-switched model, incorporating short-term load and generation forecasts, and even wholesale market dispatch schedules, will become a fundamental component of distribution operations. In the future, DSOs may be tasked with implementing DER dispatch plans from TSOs or Independent System Operators (ISOs). To determine whether the dispatch plan can be supported by the distribution system, DSOs need to be prepared. Analytics developed for scenario and strategic planning are being integrated into DMS algorithms, enabling real-time optimization of network configuration and DER/demand management.

Figure 9: Future responsibilities of a distribution operational planner[57]

[57] *Distribution Operation Planning: Expanding the Capabilities of a Modern Control Center*. EPRI, Palo Alto, CA: 2022.3002025412.

According to the EPRI's survey, 41% of respondents reported that unbalanced power flow was available, compared to a total of only 28% for DSSE. However, there is an increasing trend of adopting unbalanced power flow and DSSE, with 46% and 38% reporting upcoming implementation, respectively. A total of 67% of respondents either implemented or are in the process of implementing AMI data integration.

Distribution Management System and Distribution Automation[58]

Distribution Automation is a system comprised of field switching devices, field measurement devices, and communications and information technology systems. Ultimately the key benefit of DA is a dramatic improvement in reliability performance, reducing both the number of and duration of outages due to faults on the primary feeder mains. Indeed, DA covers a wide range of control and monitoring solutions deployed on the electric distribution system. In some discussions DA may include Distribution SCADA (DSCADA), Optimal Network Reconfiguration

(ONR), Fault Location Isolation and Service Restoration (FLISR), Integrated Volt-VAR Control (IVVC), Conservation Voltage Reduction (CVR), and a variety of other applications on the distribution system.

In EPRI's survey, 46% of respondents reported that automatic FLISR (Fault, Location, Identification and Service Restoration) is currently operational, while 33% indicated that this function is upcoming. The response is similar for non-automatic FLISR and short circuit analysis for fault location. 58% of respondents reported VVO for voltage consistency, and CVR and optimal network reconfiguration are already in use or upcoming, while 58% reported that DER-integrated VVO is unavailable in their systems. Only 4% reported that DER-integrated VVO is a frequently used function, while none reported it is an essential function; however, 33% reported that this function is upcoming.

Situational Awareness

Distribution telemetry involves the deployment of sensors, intelligent electronic devices (IEDs), and communication systems throughout the distribution grid. These devices provide real-time data on various grid parameters, including voltage levels, current flows, power factor, and line conditions. By collecting and analyzing this telemetry data, grid operators gain a comprehensive understanding of the grid's operational status, enabling them to monitor system health, identify potential issues, and respond proactively to mitigate disruptions.

Advanced metering plays a vital role in enhancing situational awareness by providing granular data on energy consumption, load profiles, and customer behavior. Advanced meters, such as smart meters, enable real-time or near-real-time collection of energy consumption data from individual customer premises. This data helps grid operators gain insights into load patterns, identify peak demand periods, and optimize grid operations accordingly. Moreover, advanced metering facilitates outage detection and restoration, as grid operators can quickly identify affected areas based on metering data and prioritize their response.

[58] *Advanced Distribution Management System with Distributed Energy Resources: Distribution Automation/Fault Location Isolation and Service Restoration*. EPRI, Palo Alto, CA: 2016. 3002007990.

As depicted, 62% of respondents reported that data from faulted circuit indicators is available for operations, and 42% reported this data being updated hourly. According to 62% of respondents, DER generation data is not available for operations. Among those who reported having access to the data, the majority of them reported an hourly update frequency (25%). AMI demand and voltage data were reportedly available to about 40% of the respondents, with daily (20% approx.) and hourly (8%) update frequencies being the most common. Data on electric vehicle charging stations were reported as not available by 96% of the respondents.

DER Management

To effectively handle these distributed resources, several key topics need to be addressed, including microgrid management, grid services, and the role of TSO (Transmission System Operator) and ISO (Independent System Operator) aggregation.

Traditional DMS is morphing into an integrated system of systems to accommodate DER through advanced applications within DMS. The applications provide functionality to monitor and control resources and to provide additional grid and workforce optimization tools. Other utilities are looking to deploy separate management systems to manage both DER and demand response resources, typically viewed as a subset of DER. DMS will assume additional operational tasks that involve monitoring and controlling DER and demand response as the smart grid evolves. Outside of the core components, DMS can be viewed as a collection of advanced applications performing grid operational and optimization functions. The functions of advanced applications include monitoring and controlling the distribution system and the connected DER, locating, and isolating faults, managing outage restoration, dispatching crews, managing switching, and optimizing the grid. As the number of DER and demand response devices increases, utilities are looking for robust tools to handle the new generation and load control devices being added to the distribution system.

However, based on EPRI's survey, around 45% reported DER management and microgrid management or monitoring are not currently available. DER management is upcoming for 50% of respondents, whereas microgrid management or monitoring is upcoming for 38%.

International Examples of Existing or Developing DSO Capabilities

In the UK, the Implementation Plan for DSO has been developed as part of Workstream 3 within the ENA Open Networks Project (ONP)[59]. It is released alongside the online DSO Roadmap, an interactive tool available on the ENA website[60]. The DSO Implementation Plan and online DSO Roadmap offer a snapshot of the present perspective at the time of publication and will be periodically updated to incorporate new information pertaining to activities and timelines.

In order to explore different allocation models for DSO activities, it was conducted an analysis of multiple Future Worlds options, resulting in the identification of five distinct scenarios with varying roles and responsibilities.

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[59] ENA, Open Networks Project DSO Implementation Plan – 2021 WS3 Implementation Plan Report

[60] https://public.tableau.com/app/profile/open.networks/viz/ENADSORoadmapQ32021/Roadmap

The DSO Roadmap is structured around the core DSO functions outlined in the "Functional and System Requirements" report from May 2018.Error! Bookmark not defined. These functions serve as the f oundation for the current DSO Implementation Plan. To provide a more comprehensive understanding of these functions and activities, the Smart Grid Architecture Modelling (SGAM) was utilized tool to develop an expanded perspective on processes and data exchanges. The eight core DSO functions: system coordination, network operations, investment planning, connections and connection rights, system defense and restoration, services/market facilitation, service optimization and charging.

In the context of the transition from DNO to DSO, Ofgem has also published position papers[61] or guidance to outline its perspective on the roles and responsibilities of DSOs. These position papers may aim to provide clarity on the regulatory framework, promote consistency across different DSOs, and align industry practices with the objectives of the energy transition.

The paper includes Figure 10, which presents a simplified illustration of different DSO functions, emphasizing the essential processes and activities required for their successful implementation. This representation is based on a comprehensive review and synthesis of relevant literature and analyses pertaining to the demands of an intelligent and adaptable electricity network. Each function encompasses the provision of multiple services, and various entities may be involved in delivering these functions. Hence, we propose that specific functions should not be limited to exclusive providers.

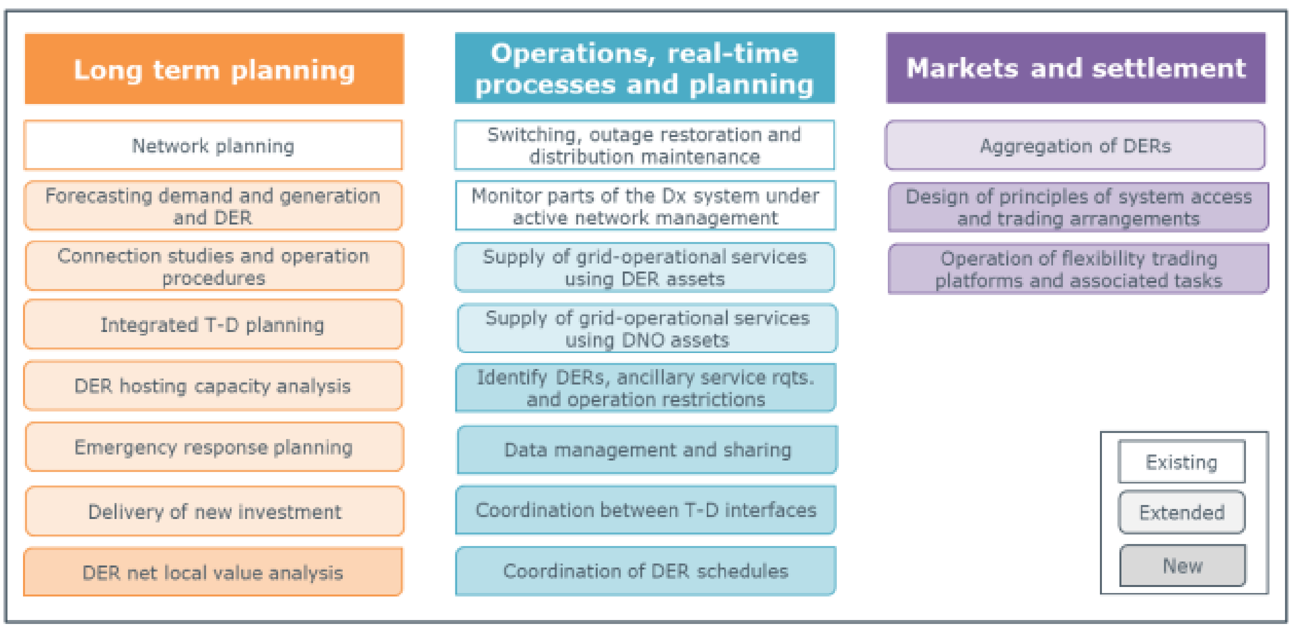

Figure 10: Functional breakdown of DSO functions analyzed in the Ofgem position paper[61]

[61] Ofgem, Position Paper on the Distribution System Operator.

For example, the DSO Northern Powergrid in the UK, is actively contributing to the evolution from being a DNO to becoming a Distribution System Operator DSO, ensuring that this transition brings value to all their customers. The DSO Development Plan[62] defines the company strategic direction, which has been shaped through input and feedback from stakeholders, providing transparency regarding their actions and inviting additional insights. The plan of the Northern Powergrid has two parts. Part 1 of the document outlines the ongoing actions they are taking in areas where they have clear confidence in the required direction. One significant focus is the initial phase of our customer flexibility plan implementation, which is widely acknowledged as a fundamental aspect of our DSO transition. In turn, Part 2 outlines their projected trajectory up until 2030.

Regarding part 2 (where next), the industry in the UK is concerned to create the sense of the DSO. This involves a decentralized control framework, where transmission and distribution networks are interconnected but operate independently with high level of coordination. This system is designed to enable self-healing and fragmentation using network control mechanisms, while also benefiting from the flexibility offered by distributed energy resources and distribution-connected storage. In this evolving energy landscape, the responsibility for system operation is shared between DSOs, who manage regional issues, and the ESO, who oversee the overall system and long-term planning.

The DSO development plan from another distribution utility in the UK, National Grid Distribution (former Western power Distribution) outline the key enabling functions and proposed actions that are deemed essential to facilitate WPD's transition to DSO.[63] This DSO roadmap includes the following workstreams: Data Accuracy and Completeness, Integration with Energy Markets, Information Technology (IT) Systems, Customer Propositions and Equipment (see Annex B).

Also, another DSO, UK Power Network, has defined its roadmap in which the focus is the DER flexibility.[64] The underlying is to utilize flexibility from DER more extensively. The objective is to deliver increased energy while minimizing the need for additional network infrastructure. This approach aims to reduce costs for the customers. To effectively communicate the future flexibility requirements of the market, the company have developed a Flexibility Roadmap. This roadmap enables potential providers to assess the commercial opportunities available and encourages their participation in forthcoming flexibility procurements. Within the roadmap, it detailed the flexibility needs in different network areas, explained the approach to contracting for flexibility services, and outlined the collaboration with flexibility providers.

E.DSO (European Distribution System Operators), launched a report[65] that outlines an approach to various forms of DER flexibility, focusing on the actions undertaken by DSOs to ensure the stability of network operations. It emphasizes the significance of network visibility in activities associated with technical (operational) DER flexibility and highlights the mechanisms that should be considered when defining processes related to market-based DER flexibility.

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[62] Northern Powergrid, DSO Development Plan, 2019. Available on: https://www.northernpowergrid.com/DSO

[63] WPD, DSO Strategy RIIO-ED2.

[64] UKPN, Flexibility Roadmap, 2019. Available on: https://smartgrid.ukpowernetworks.co.uk/wp-content/uploads/2019/11/futuresmart-flexibility-roadmap.pdf

[65] E.DSO, The Road Map on Go4Flex, Grid Observability for Flexibility, June 2022.

5 CONCLUSION

Within the electric utility industry, distribution system operations is evolving to meet a growing set of dynamic challenges and realize emerging opportunities. One of those opportunities is the prospect for DER to deliver services to the grid, both at the distribution level and through participation in wholesale energy and ancillary services markets. However, this is driving a desire to shift the paradigm of DER integration, allowing DER to operate beyond static minimum hosting capacity levels and in abnormal conditions. Such a change will require distribution system operators to progress and develop the capabilities needed to operate in an unfamiliar landscape. The application of hosting capacity analytics in operational timeframes is an example of the pace of transition underway in the industry. While hosting capacity for planning and interconnection was at the bleeding edge of utility capabilities less than a decade ago, using these same analytics with real-time or forecasted load and generation conditions layered onto the as operated model is well within the realm of consideration for today's DSOs.

In fact, there are a number of capabilities that are being added to the building blocks of a distribution operations organization. High-fidelity grid models, granular load and DER forecasts, and powerful analytics are becoming readily available, providing the catalyst for control center modernization. However, making the best use of these emerging resources will require utilities to rethink how they staff the control center, and will even necessitate new roles – like operational planning. Depending on the types of grid services and coordination architectures being considered, DSOs will have a new set of responsibilities and require additional capabilities to support real-time operations.

The designs and functional specifications for a DSO are wide ranging and might include enabling DER participation in wholesale electricity markets, procuring DER to provide services to the distribution system, or actively managing DER and the distribution system in concert to provide ancillary services to the bulk system operator. In many jurisdictions, utilities are still working towards defining a strategic direction for greater integration of DER that provides services to the grid. To date, approaches to control center modernization have varied from utility to utility, with Europe and Australia leading the global charge. In the United States, the combination of regulatory structure, utility business models, and customer preference for DER services is resulting in a spectrum of strategies for enabling grid services to be procured from DER Regardless of approach, utilities can begin to identify which capabilities they need today and over the course of the next few years to ensure they evolve their DCC to meet the needs of a changing distribution system. The next report in this series will describe a framework for developing a strategic roadmap that enables the next generation of DSOs to leverage distribution resources and address the changing distribution landscape head-on.

A NETHERLANDS

In the Netherlands, the GOPACS[66] platform was developed through a collaboration between the Transmission System Operator (TSO) TenneT and six DSOs. This initiative aimed to reduce congestion management costs and attract more flexibility providers to the market. GOPACS serves as an intermediary platform connected to an existing market platform, such as an intraday trading platform. Currently, it is integrated with the intraday market from ETPA (Energy Trade Platform Amsterdam), and discussions are underway with other market players like EPEX SPOT.

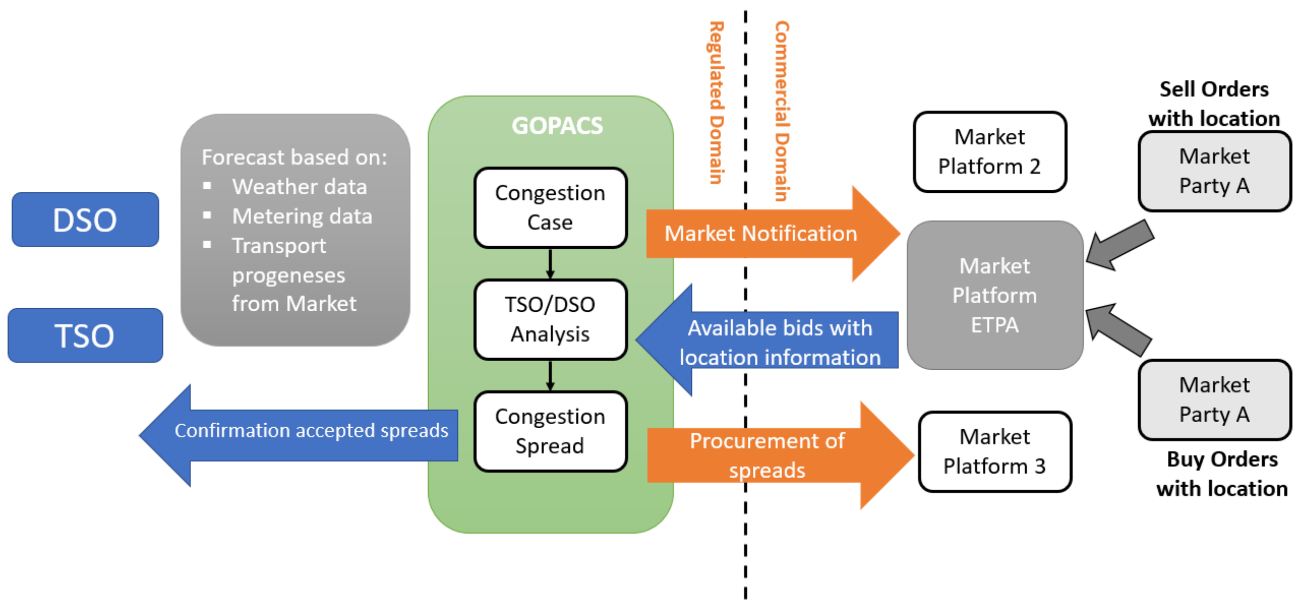

Figure 11: GOPACS architecture, with the regular intraday market, and the congestion management

The Dutch market-based approach to congestion management has facilitated the implementation of GOPACS (Grid Operators Platform for Congestion Solutions). This initiative has driven the establishment of a new framework for DSO congestion management in the recently approved Electricity Network Code. The code incorporates provisions that enable coordinated procurement of flexibility, including:

- **Collaboration between DSOs and TSO** through coordinated measures, allowing them to utilize each other's options for redispatch requirements. The code does not explicitly specify whether these measures are limited to information sharing or extend to joint procurement.
- **Direct communication among system operators**, ensuring that all operators provide support to the DSO of the affected congestion area once local congestion is identified.
- **Introduction of the Congestion Management Service Provider (CSP)**, acting as an aggregator for capacities smaller than 1 MW. CSPs are required to establish a Balancing Responsible Party (BRP) agreement, which may impose limitations on the participation of independent aggregators.

[66] https://en.gopacs.eu/

- **Provision for DSOs to procure long-term capacity products** based on availability and/or activation fees. These agreements are the outcome of a market-based tendering process and are bilateral in nature.

Ensuring interoperability between markets is another crucial aspect for the successful participation of DER into the electricity markets. Interoperability allows flexibility providers to benefit from value stacking, which involves bundling multiple value streams from different grid services. The concept is straightforward: non-activated bids in local congestion management markets can be forwarded to Transmission System Operator (TSO) markets with similar requirements, such as mFRR (manual Frequency Restoration Reserve) and RR (Replacement Reserve), as long as they don't create additional congestion in the local grid.

B NORWAY

From 2019 to 2022, two Norwegian DSOs (Agder Energi and Glitre Energi) and the national TSO, Statnett, are jointly running NorFlex,[67] an extensive demonstration project. This project primarily focuses on leveraging flexibility to defer network expansion and manage congestion within the distribution system. The remaining flexibility is aggregated to provide mFRR (manual Frequency Restoration Reserve) services to the TSO. The pilot project consists of three development phases: the proof-of-concept phase (2019-2020), the proof of market phase (2020-2021), and the market-ready phase (2021-2022). It is during the final phase that flexibility trading occurs, while the earlier phases involved successful data exchanges and the development of necessary tools such as congestion forecasting for the DSOs and asset optimization for FSPs (Flexibility Service Providers). Notably, independent aggregators were able to participate in this pilot project due to an exception granted by the current regulatory framework in Norway.

The NorFlex project introduced a marketplace where flexibility can only be procured by network operators, with a priority given DSO over the TSO. The trading of flexibility services to DSOs is organized based on congestion areas within the 132 kV grid and below. Once the DSOs have fulfilled their requirements, any remaining flexibility becomes available to the TSO market for the mFRR from the winter of 2021/2022 onwards. This flexibility is traded in minimum blocks of 1 MW. Trading begins when the purchasing DSO posts on the marketplace the volume of flexibility needed and the bidding price for the upcoming week, within the time window of 7.00–19.00. Aggregators are allowed to submit their bids up to 2 hours before activation, while the purchasing network operator can adjust their bids during the trading period. The gate closure time, set 2 hours before delivery, serves multiple purposes, including ensuring coordination with the wholesale balancing market, where any flexibility offers that remain unmatched are forwarded.

[67] https://nodesmarket.com/case/norflex-tso-dso-making-local-flexibility-available-to-mfrr/

C GERMANY

ENERA initiative[68] was launched by EPEX Spot (market operator), EWE (energy producers) and the network operators EWE NETZ, Avacon Netz and TenneT focused on the northern area of Germany. It is an initiative that establishes a regional market platform aimed at coordinating local flexibilities to address congestion management challenges faced by the DSOs. By adopting an integrated model for the flexibility market, DSO's order books serve as a centralized platform for aggregating flexibility offers. These offers can then be utilized by the operators to alleviate congestion within the networks (transmission and distribution).

As depicted in Figure 12, system operators (TSOs and DSOs) evaluate their flexibility needs, including location, time, and quantity, and exchange information about their grid constraints with other system operators. This collaboration ensures efficient congestion management and prevents the occurrence of new congestion. Concurrently, certified flexibility providers submit their bids in the order books specific to the relevant market areas. It is essential to note that the traded products solely involve commitments to modify physical schedules within a designated market area. Subsequently, these load or production adjustments are retrospectively validated by a "verification platform." This platform compares the actual metered inflows and outflows of assets with a baseline defined by the schedules.

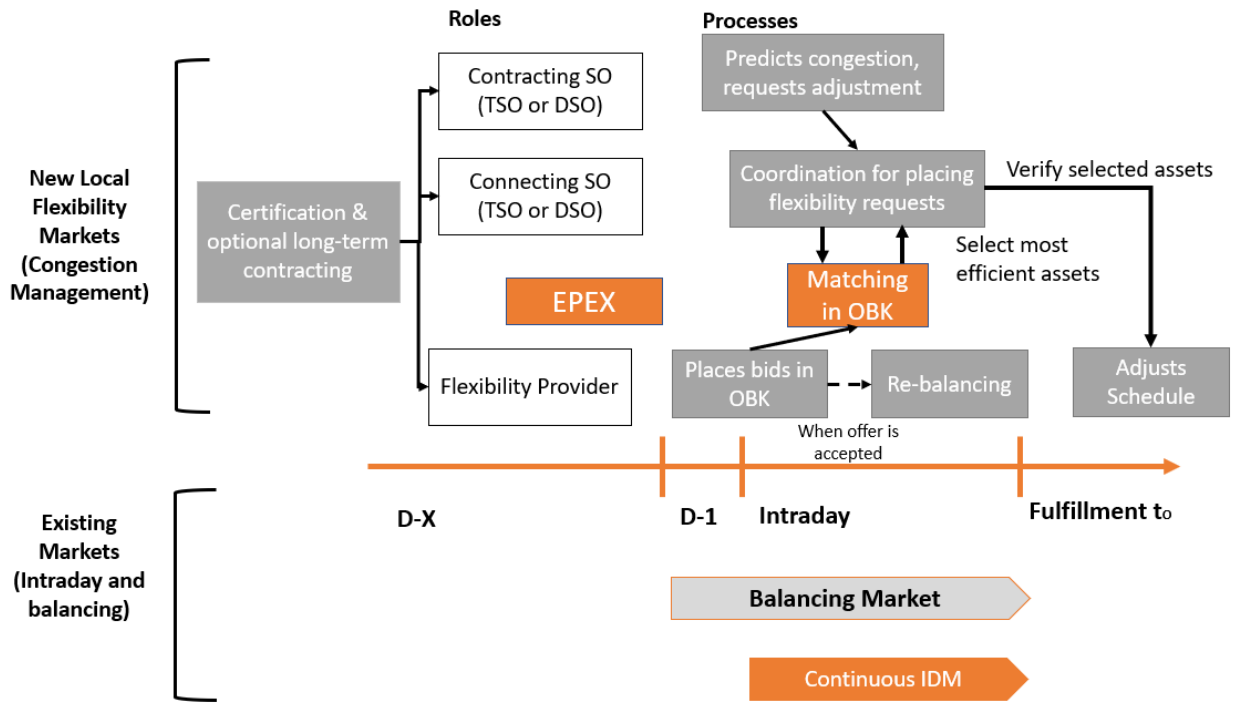

Figure 12: Representation of Enera process

68 https://projekt-enera.de/

When the schedule of an asset is altered, it has a direct impact on the portfolio of the party responsible for balancing that asset. As a result, the portfolio requires rebalancing, typically through participation in the intraday market. However, there is no explicit connection between the Enera platform and the wholesale intraday systems. Each market participant retains individual responsibility for maintaining their own balance, regardless of flexibility activations. For instance, if a load is increased through the Enera platform to alleviate congestion, the load asset receives compensation for the physical activation but still needs to procure energy separately.

D SWEDEN

The sthlmflex[69] flexibility marketplace has been implemented in the Stockholm area as a response to the insufficient network capacity. It is an extension of previous pilot projects that focused on local flexibility markets developed elsewhere in Sweden under the CoordiNet project.[70] The primary flexibility services targeted by sthlmflex encompass investment deferral, operational congestion management, and the enhancement of network resilience. The overarching goal of sthlmflex is to improve coordination between TSO and DSO and among DSOs themselves.

Within the sthlmflex framework, DSOs purchase congestion management services from Flexible Service Providers (FSPs) and engage in the trading of network subscription capacity rights among each other. Meanwhile, the TSO acquires services related to manual Frequency Restoration Reserve with a duration of 15 minutes (mFRR[71]). The provision of flexibility services is localized within three regional areas, namely Stockholm north, Stockholm south, and Stockholm city.

Originally, this pilot project was scheduled to run from December 1, 2020, to March 31, 2021. However, a decision was made to extend it for two additional winter periods to further refine the operational details and enhance incentives to encourage greater participation in the market. Initially, only Svenska kraftnät (TSO), Ellevio (a regional DSO), and Vattenfall Eldistribution (another regional DSO) were participants in the pilot project. E.ON Energidistribution AB, a local DSO, opted to join starting from the winter of 2021/2022. Notably, the two regional DSOs manage the network within voltage ranges of 24 kV to 220 kV, while E.ON Energidistribution AB is one of the 15 local DSOs in the examined area responsible for operating below 24 kV.

Participation in the sthlmflex market involves a diverse group of stakeholders, including industrial and commercial customers, entities engaged in the power and heat sectors, and smaller assets facilitated through aggregators. This includes both independent aggregators and other intermediaries currently active in the market.

Trading operates by aggregating flexibility assets into portfolios for each congestion area, namely Stockholm north, Stockholm south, and Stockholm city. Seasonal contracts are obtained through an auction process. Offers are assessed based solely on the price of the availability component. For weekly contracts, auctions are initiated as needed, covering the upcoming 7 days. The buying network operator issues an announcement, and the market platform (NODES) sends email notifications. Both seasonal and weekly contracts employ a pay-as-bid clearing method, except for the availability component of weekly products, which is predetermined by the buying network operators (as discussed in the previous section).

[69] https://nodesmarket.com/project/sthlmflex/

[70] https://coordinet-project.eu/

[71] mFRR – manual Frequency Restoration Reserve

The “free bids” short-term market operates continuously on a pay-as-bid basis. Flexible Service Providers (FSPs) have the flexibility to submit flexibility offers as early as one week in advance of the scheduled flexibility delivery, up until two hours before delivery. Most of the purchases by DSOs occur between 9:30 AM and 10:30 AM on the day preceding the delivery. Consequently, it is advisable for FSPs to submit their bids on the market no later than 9:00 AM on the day before the scheduled delivery. Any remaining flexibility offers that qualify for manual Frequency Restoration Reserve with a duration of 15 minutes (mFRR) services are then made available to the TSOs.

E FRANCE

In June 2020, the main French DSO, ENEDIS, initiated its inaugural flexibility tender.[72] Since then, tenders have been regularly conducted each year, resulting in three tenders to date and a total of 19 opportunities for upward flexibility services. ENEDIS has expanded its scope to include downward flexibility (increase in consumption or stopping reinjection) to address injection congestion issues through the ReFlex project. The tenders target various flexibility services, such as investment deferral, short-term congestion management, and reliability enhancement (for example, activating flexibility during planned maintenance or after a network outage). The tenders are organized based on specific congestion areas referred to as "opportunity zones."

The product specifications for these tenders encompass several elements, including eligibility zones, capacity per predefined period, full activation time, activation duration, neutralization duration between activations (in hours), maximum injection ramp, and notification period. ENEDIS also provides an estimation of the activated flexibility required in MWh/annum, along with the maximum activation period.

Flexibility products generally consist of both an availability component and an activation component. While the product specification characteristics adhere to standardized criteria, the specific parameters vary for each call and opportunity zone. Additionally, each call requests a range of specific product options based on the aforementioned technical characteristics, with evaluation scores assigned to each option in advance for potential participants to consider.

[72] https://flexibilites-enedis.fr/

F AUSTRALIA – PROJECT EDITH

Project Edith[73] is a collaborative trial conducted by Ausgrid and Reposit Power with the aim of testing tools for effectively managing power flows on the distribution network while enabling market participation of DER. The project focuses on leveraging existing systems and processes to streamline the integration of DER, reducing both costs and complexity.

The trial adopts a point-to-point architecture with standardized interfaces, such as CSIP-AUS,[74] facilitating communication between the Distribution Network Service Provider (DNSP) and the trader. The trader operates through established platforms like MarketNet and the Market Management System (MMS). This approach minimizes short-term expenses and allows for an iterative implementation strategy, prioritizing simpler solutions where feasible instead of complex interactions. The pricing signals convey the significance of network support, encompassing both negative and positive pricing, and empower the Trader to optimize their value stack without the obligation to provide network services. In situations where there is a high probability of breaching a critical network constraint, Dynamic Operating Evenelopes (DOEs) serve as protective boundaries.

A central theme of Project Edith is to capitalize on and extend existing infrastructure while also developing tools that offer simpler implementation options. This approach helps mitigate the costs and complexities associated with upgrading systems to accommodate high levels of DER deployment. Within Project Edith, two primary tools are employed to manage network capacity effectively. DOE defines the absolute limits at specific locations within the network. The second tool is Distribution Network Pricing (DNPs), which incentivizes actions that contribute to reducing network costs while staying within these defined limits.

Overall, Project Edith aims to enhance the management of power flows on the distribution network, facilitate market participation of DER, and optimize the integration process by leveraging existing infrastructure and deploying efficient tools for network capacity management. Distribution Network Pricing (DNPs) are fees and incentives that can be adjusted based on the degree of constraint experienced at various locations within the network. Traders and retailers who have price-responsive distributed energy resources (DER) have the option to opt for these dynamic prices instead of conventional network charges. This allows consumers to potentially receive additional rewards for their flexibility while optimizing the utilization of the electricity infrastructure.

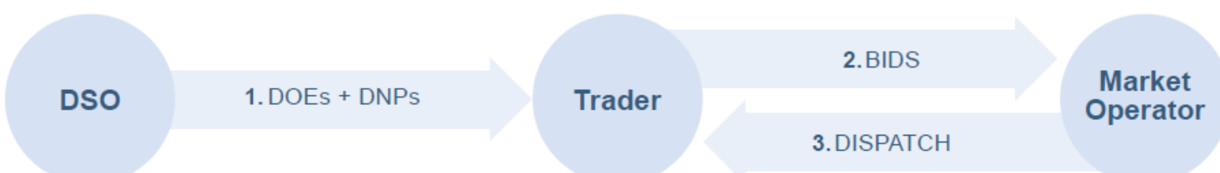

Figure 13: Dynamic operating envelopes and prices sent to the trader before market bidding and dispatch in Project Edith

[73] https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith

[74] Australian Common Smart Inverter Profile. CSIP AUS leverages existing international standards (including IEEE 2030.5) and engineering principles to explicitly define functionality that is specific to the Australian context and to help the industry to unlock greater value of DER for the benefit of consumers.

In this scenario, the DSO, represented by Ausgrid, shares Distributed Operating Envelopes (DOEs) and Distribution Network Pricing (DNPs) with the trader, which in this case is Reposit. The DSO provides DOEs that define the capacity limits for each specific site, and the trader ensures that their capacity bids align with these defined limits.

G AUSTRALIA – PROJECT CONVERGE

Project Converge,[75] the most recent among the four projects, is a collaborative effort involving Evoenergy, ANU, and Zepben. Its primary objective is to test and evaluate tools specifically designed to enhance the benefits derived from distributed energy resources (DER) while ensuring compliance with the physical and operational limitations of the distribution system. Within this project, two key tools are being tested: shaped operating envelopes (SOEs) and a real-time RIT-D[76] system.

Shaped operating envelopes are dynamic and function similarly to how the capacity allocation is managed in the transmission network. Under the Project Converge model, the process unfolds as follows:

1. The trader submits its unconstrained market bids to the Distribution System Operator (DSO).
2. In the presence of a constraint, the DSO prioritizes allocating capacity to sites with lower-cost bids for exporting energy (or higher-cost bids for importing energy). This strategy aims to increase the volume of lower-cost energy available in the market.
3. Subsequently, the trader submits the same bids to the market operator but adjusts the capacity to reflect only the network capacity allocated through the dynamic operating envelope.
4. The market operator issues dispatch instructions to the trader, ensuring adherence to the dynamic operating envelopes.

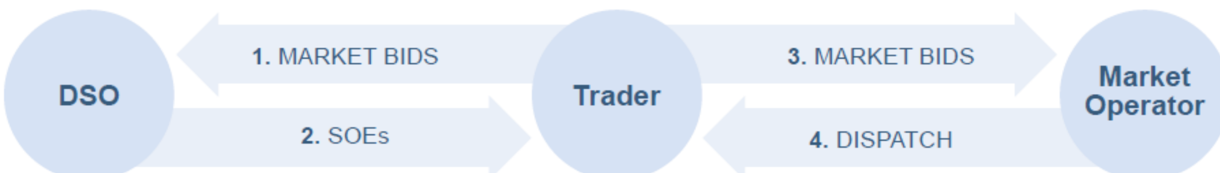

Figure 14: Market bids first sent to the DSO to create shaped operating envelopes in project Converge

By implementing these tools and processes, Project Converge aims to optimize the utilization of DER, enhance network support procurement efficiency, and maximize the benefits while maintaining network stability and operational limits.

[75] https://arena.gov.au/projects/project-converge-act-distributed-energy-resources-demonstration-pilot/

[76] Regulatory investment test distribution.

H AUSTRLIA – PROJECT SYMPHONY

Project Symphony[77] is a collaborative endeavor involving AEMO, Western Power, and Synergy, aiming to test the integration of distributed energy resources (DER) into the Wholesale Electricity Market (WEM) in Western Australia through an in-field Virtual Power Plant (VPP) pilot. This initiative arose from the actions outlined in Western Australia's DER Roadmap, which emphasized the need for a trial to showcase technical and market systems that facilitate the orchestration and seamless integration of DER into the energy system.

To achieve this objective, Project Symphony is establishing three interconnected platforms to facilitate various aspects of DER participation:

- **DSO Platform (Western Power).** This platform is responsible for determining the maximum hosting capacity for renewable energy, forecasting consumer generation and load, and utilizing this information to create Distributed Operating Envelopes (DOEs). These DOEs serve to equitably allocate network capacity to consumers. Western Power plans to leverage and expand on the Evolve solution used in previous National Electricity Market (NEM) trials to develop and communicate DOEs effectively.
- **DER Integration Platform (AEMO).** The DER Integration Platform, operated by AEMO, receives bids from aggregated DER through the aggregator and dispatches them in the wholesale electricity and network support markets in accordance with the requests from the DSO. It ensures that the dispatched DER adheres to the network's operational constraints.
- **Aggregator Platform (Synergy).** The Aggregator Platform, managed by Synergy, is responsible for the onboarding of DER, managing and dispatching flexibility, and conducting post-event analysis. This platform coordinates the aggregation and efficient utilization of DER resources.

[77] https://arena.gov.au/projects/western-australia-distributed-energy-resources-orchestration-pilot/

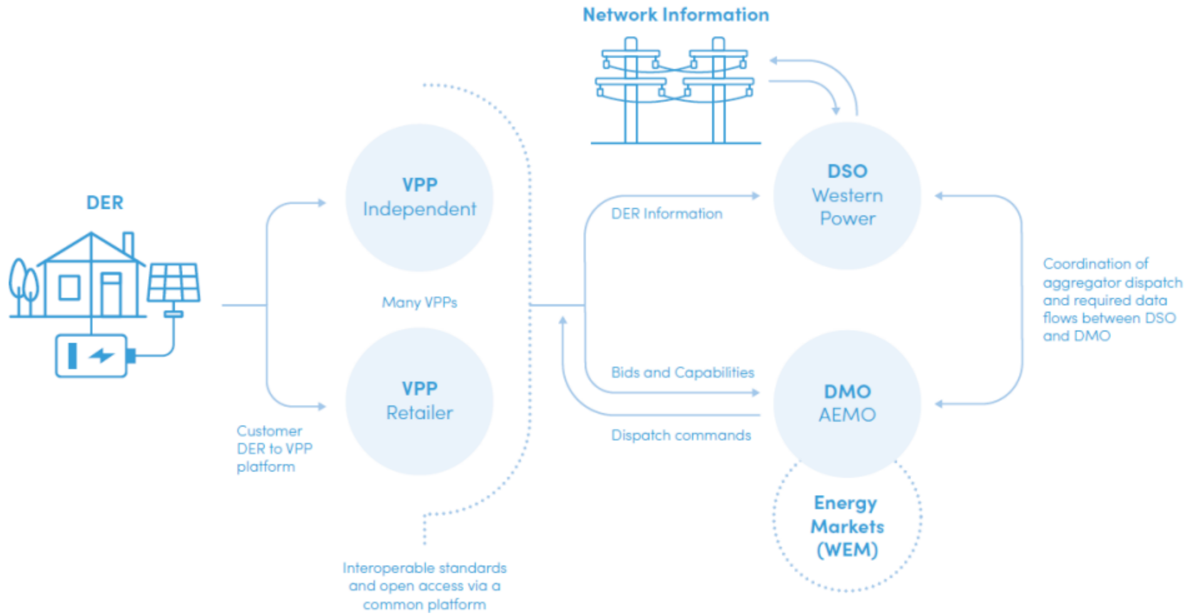

Figure 15: A possible DSO/DMO model for Western Australia described in Project Symphony[78]

Through these interconnected platforms, Project Symphony aims to enable effective market integration of DER, optimize network capacity management, and enhance DER's overall integration into the energy system.

These interconnected systems require seamless integration as they involve exchanging various data elements. The development and integration process necessitates the effective coordination of these systems. Additionally, on the market side, there are four essential on-market and off-market services and scenarios that will be demonstrated:

- **Energy Services – Bi-directional.** This service involves participating in the balancing market, which determines the economically efficient generation dispatch to meet system demand as AEMO manages.[79]
- **Network Support Services.** These services are contracted to assist in managing network constraints. They aim to address distribution-level peak demand and voltage issues identified by the DSO.
- **Constrain to Zero.** In this scenario, the AEMO platform instructs the aggregator platform to restrict the energy output from distributed energy resources (DER) either to zero export (net) or zero output (gross). Market participants or retailers could offer this service.

[78] Project Symphony WP 2.3 – DER Service Valuation Report.

[79] Every registered facility, including aggregated Distributed Energy Resources (DER) generation units, is required to be accessible for participation and must adhere to the dispatch instructions issued by the market operator, AEMO.

Additionally, the aggregator has the capability to either offer (sell) or bid (buy) energy in the balancing market while integrating or complying with a 'dynamic operating envelope' (DOE) provided by the distribution system operator. This DOE is designed to optimize and expand the renewable hosting capacity on the network. It achieves this by disclosing the total available power transfer capacity, considering both load and generation, at any specific point in time.

- **Essential System Services (ESS) Contingency Raise.** This service involves the response of DER to help restore local frequency deviations to normal levels, typically caused by the loss of a large generator or load.

Project Symphony is also conducting trials of network support services (NSS) in which the Distribution System Operator (DSO) forecasts potential capacity shortages or degraded power quality that could be addressed through NSS. Subsequently, the DSO establishes bilateral agreements with aggregators to provide these services. When the need for such services arises, the DSO communicates instructions to AEMO (via the DER Integration Platform), which includes the request as part of the market dispatch process. As part of the project, an evaluation of the costs and benefits of NSS on the network will also be undertaken by Project Symphony

I AUSTRLIA – PROJECT EDGE

Project EDGE[80] is the earliest among the comprehensive trials focused on integrating distributed energy resources (DER), and it is a collaborative effort involving AEMO, Ausnet, and Mondo. The primary objective of this project is to test a DER marketplace where aggregators or traders can offer a diverse range of local and system-level services facilitated through a shared data exchange hub. This data hub enables traders to submit bids to energy markets, receive dynamic operating envelopes, and provide network support capacity through a local services exchange (LSE).

In terms of energy market integration, Project EDGE is examining wholesale bidding models that align with the Trader role outlined in AEMO's Flexible Trading Arrangements (FTA) and Scheduled Lite reforms. It also explores a bidding format that aligns with a Scheduled bidirectional unit (BDU) under the Integrating Energy Storage (IESS) rule change. The trial incorporates various options, including:

- Allowing aggregators to submit load and generation bids within a single portfolio (or DUID) comprising up to 20 price bands, which aligns with the design of IESS.
- Testing three different dispatch methods that could inform the development of Scheduled Lite models:
  - **Visibility**. Aggregators submit capacity bids at different price levels and receive a dispatch target but are not obligated to respond to the target.
  - **Self-Dispatch**. Aggregators self-nominate a dispatch target and must meet that target regardless of price.
  - **Scheduled**. Aggregators bid capacity at different price levels, receive a dispatch target, and are required to meet the specified target.

Through these trial configurations, Project EDGE aims to assess the feasibility and effectiveness of different bidding and dispatch approaches, fostering greater understanding of the optimal models for integrating DER into energy markets.

Project EDGE (Energy Demand and Generation Exchange) places significant emphasis on examining data transfer processes among the various stakeholders involved. The project operates on the hypothesis that a centralized data hub, where all parties can connect and exchange data, offers a more efficient and preferable solution at scale compared to alternative architectures like point-to-point with standards. An example of point-to-point with standards would involve a trader establishing individual connections with each Distribution Network Service Provider (DNSP) through a common protocol such as CSIP-AUS.

[80] https://arena.gov.au/projects/project-edge-energy-demand-and-generation-exchange/

By evaluating the data transfer mechanisms, Project EDGE aims to assess the benefits and efficiency gained through a centralized data hub approach. This hypothesis suggests that a single point of connection for all parties involved in the project enables streamlined data exchange, leading to improved scalability and operational effectiveness. The project seeks to validate this hypothesis by examining the performance and advantages of the data hub architecture in facilitating seamless data sharing among multiple stakeholders.

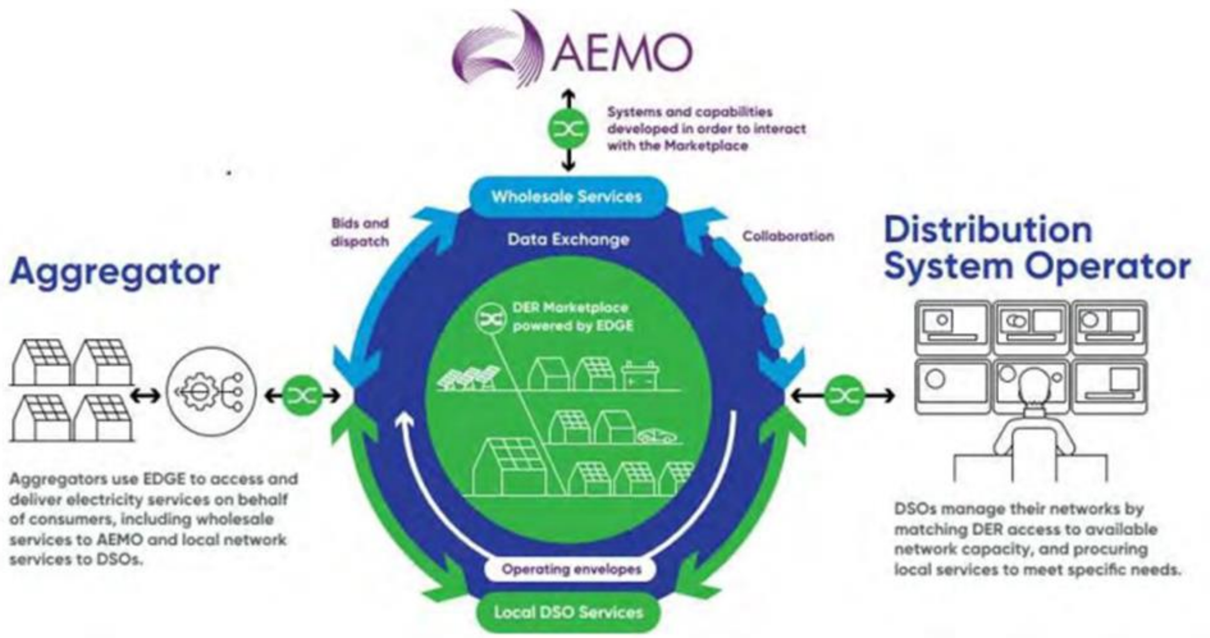

Figure 16: Conceptual view of the DER Marketplace envisioned in Project EDGE[81]

[81] Project EDGE, Final Report Version 2, October 2023. Available on: https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-final-report.pdf?la=en

J GRID ARCHITECTURES FOR ENABLING DER SERVICES – EXAMPLES

In the UK, DER can participate in numerous markets and stacking across multiple products is possible in certain cases. Transmission frequency services require 1 MW minimum bid. The four DNO flexibility products require 50 kW minimum single or aggregated bid, though the DSO UKPN have this lower at 10 kW. However, there are some barriers to DER participating in multiple products. For instance, contractual prohibition of generators behind distribution network constraint managed zones (CMZs) participating in ESO-managed markets. Additionally, DER participating in ESO's Demand Flexibility Service (DFS) cannot also participate in Balancing Mechanism, Ancillary Services, DNO products or Capacity Market. DSOs are generally not explicitly exclusionary, but only the ESO products do it for them, or because the business case for stacking is not clear or existent for DER operators. Regarding the DER visibility and control, Several DSOs have distributed energy resource management systems (DERMS) for controlling flexible connections on the HV (>11kV) grids. These flexible connections require dedicated RTUs, which receive set points from the DERMS. While DER/aggregators set up an API to receive signals, DSOs are not sending APIs to DER or aggregators <10kW.

ESO uses its web-based Ancillary Services Dispatch Platform (ASDP) to dispatch DER. The platform is managed by the Distributed Resource Desk in the control room. The coordination between ESO and DSO is reduced, though there are industry efforts to improve it. Rules are currently being developed by ENA to deconflict DSO and ESO activities in a constrained area. Apart from that, data exchange is a major challenge, as this requires careful coordination, common platforms, and adherence to data privacy. Figure illustrates and example of the rules under development to coordinate the exploitation of the DER flexibility.

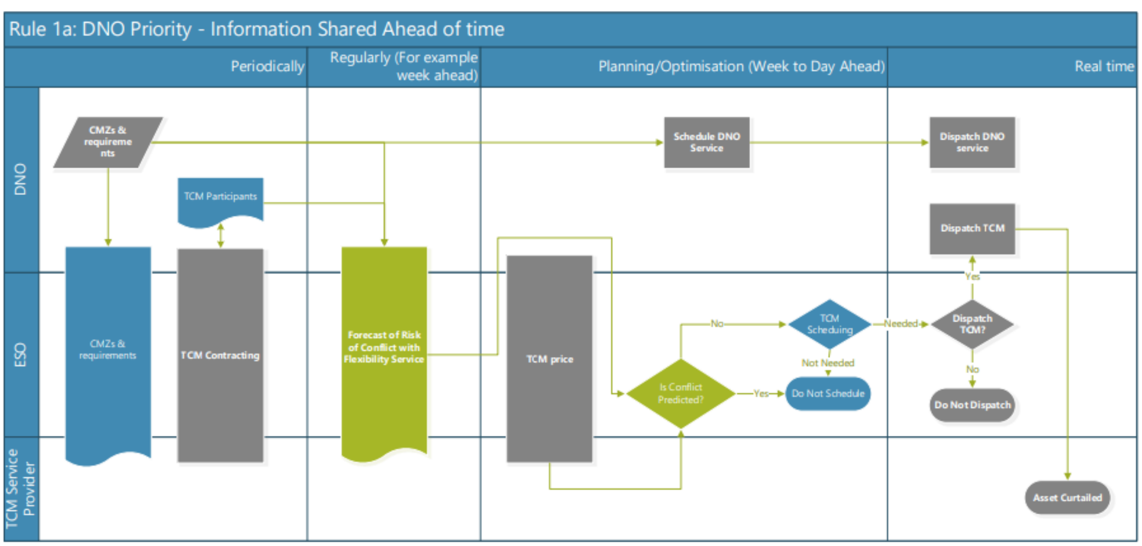

Figure 17: Example of optioneering for information sharing between TSO and DSO in the UK for transmission congestion management[82]

[82] ENA, Open Networks project Primary Draft Rules Increment 1 – Version 1.0 April 2022.

For this rule depicted in Figure 17, the DSO services hold priority over the transmission constrained management (TCM). According to ENA, this rule involves the following main processes:

1. The provision of DNO data on the location and needs of CMZs (already available)
2. The development of DNO risk of conflict forecasts. This will need to build on individual DNO processes for forecasting flexibility requirements.
3. The development of a sharing mechanism for this information. This could be through wider publication on data portals, CSVs shared over email or both.
4. A process for ESO to ingest the forecast and feed into their scheduling.

In Spain, the coordination between TSO-DSO is also making some progresses. Nowadays, there is the CECRE (Control Centre for Renewable Energies), which is composed of an operation desk integrated in the Electricity Control Centre (CECOEL) of the Spanish TSO, where[83] generation facilities:

- ≥1MW and share the same connection point: send real-time telemetry of the active power produced every 12 s.
- ≥5MW and share the same connection point: send additional tele measurements of the reactive power and voltage at the connection point.
- Each wind and PV plant or cluster with a total installed capacity greater than 5 MW receives the active power set-points from the CECRE, which must be followed within 15 min. Real-time data of generating units or aggregations with an installed capacity greater than 1 MW. This data is currently received by the TSO from the generation control centers and it is sent in real-time to the DSO to which the generator is connected. If the congestion is detected on the distribution network by a DSO, it notifies the TSO which units form the bundle and the maximum possible production of the bundle. TSO solves the congestion via the CECRE by limiting, and if necessary, redispatching the units included in the bundle in the same way as if the congestion was located in the transmission network.

[83] G. G. Platero, M. G. Casado, M. P. García, P. J. Madero and D. A. Baeza, "CECRE: Supervision and Control of Spanish Renewable Energies in the Last 15 years," in Journal of Modern Power Systems and Clean Energy, vol. 10, no. 2, pp. 269-276, March 2022.

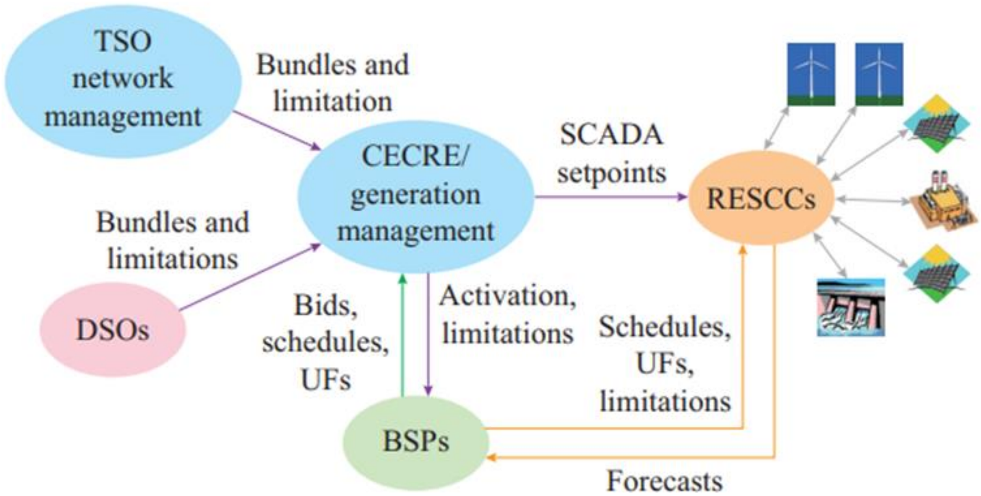

Figure 18: Information exchange for participation in balancing services and congestion management in Spain[83]

Similar developments are being done in other jurisdictions like Australia, Texas, and Ireland. The TSO-centralized model has historically been used in those countries, but the TSO-DSO framework is evolving due to the decentralization of the power system. In Ireland, the TSO optimizes the dispatch decisions based on the minimum cost of moving away from market actor's nominations (the physical nomination). It provides Security Constrained Economic Dispatch (SCED) schedules close to real-time. Nevertheless, new advancements are under development to enhance the TSO-DSO operating model[84]. Flexibility market evolution enabling DER to provide services DSOs as well as TSOs may require the TSO-DSO operating model to also encompass the interaction with other players (for example, aggregators). A large share (around 50%) of renewable generation and small-scale flexibility-providing units are connected to the distribution grid. Under this design and increased integration of small-scale DERs will be important to include the DSO constraints. Currently, the market participation of the smallest generation and demand units is not mandatory; however, in case DSO intends to develop local markets or use DER to solve local problems, it will require the definition of pre-qualification, registration, dispatching, scheduling, market clearing, settlement and new operational procedures for the TSOs and DSOs.

Also, in Australian, the TSO-DSO coordination framework is changing. Several initiatives have been developed to facilitate grid connected DER to participate in the wholesale electricity market:

- Wholesale Demand Response Mechanism (WDRM) enables aggregators to offer DR services to the market via DER reducing their consumption during periods of high demand or system stress.
- Distributed Energy Integration Program (DEIP) aims to collaboratively facilitate integration of DER into the electricity system and explore new market mechanisms frameworks for participation.
- Distributed Energy Resources Register (DER Register): Database to provide real-time information about the location, capacity, and performance of DER installations across the NEM.

[84] DSO/TSO Multi-Year Plan 2023-2027, Joint System Operator Programme, February 2023. Available on https://www.eirgridgroup.com/site-files/library/EirGrid/Multi-year_DSO-TSO_WorkPlanCovering2023-2027.pdf

AEMO is responsible for dispatching large-scale individual or aggregated DER. It corresponds to a central dispatch of generation and DR in NEM and WEM, including DER. AEMO also ensures that distribution-connected assets have fair access to wholesale markets by Exchanging relevant information like dispatch instructions and system conditions to ensure effective coordination of DER. In turn, DNSPs integrate DER into distribution networks via reinforcement, connection standards, and coordinate with AEMO to implement dispatch instructions for DER participating in wholesale markets, including sharing relevant network and DER information. DNSPs have the possibility of locally dispatching and controlling distribution-connected not directly participating in the wholesale market (for example, small-scale rooftop solar). The dispatch of DER in Australia is an evolving process, as the growing penetration of these resources necessitates enhanced coordination, visibility, and management. Hence, a study was conducted to study different TSO-DSO frameworks. This study also estimated the cost of implementing each solution.

Framework	DMO[2]	DSO[2]
Single Integrate Platform (SIF)	AEMO	AEMO. DNSP maintain assets
Two-Step Tier (TST)	DNSP or third party	DNSP
Independent DSO (IDSO)	Third party	Third party. DNSP maintain assets
Hybrid	AEMO or third party	DNSP

Figure 19 TSO-DSO frameworks proposed in Australia[85]

[85] Baringa, Assessment of Open Energy Networks Frameworks, May 2020.

About EPRI

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EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com