ISON

DER Integration

Innovations in Managing Increasing DER Penetrations

December 2025

ercot
Your Power. Our Promise.

ENERGINET

EirGrid

California ISO

NESO
National Energy System Operator

AEMO

Important notice

Purpose

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Version control

Version	Release date	Changes
1.0	15/12/2025	First issue

Contents

Glossary, definitions and taxonomy

Glossary

A_DER or DER_A	Aggregated distributed energy resources
aFRR	Automatic frequency restoration reserve
AMI	Advanced metering infrastructure
ASEFS	Australian solar energy forecasting system
AWEFS	Australian wind energy forecasting system
BESS	Battery energy storage system
BRPs	Balance Responsible Parties
BTM	Behind the meter
CER	Consumer energy resources
CGM	Common grid model
CGMES	Common grid model exchange standard
CIM	Common information model
CPUC	California Public Utilities Commission
DAM	Day-ahead market
DDR	Dispatchable demand response
DER	Distributed energy resources
DERA	Distributed energy resource aggregator
DERP	Distributed energy resource provider
DFS	Demand forecasting system
DIDF	Distribution investment and deferral framework
DPV	Distributed photovoltaic (solar)
DR	Demand response
DRP	Demand response provider
DRZ	Distribution restoration zone
DSO	Distribution system operator (referred to in some jurisdictions as distribution network operator/distribution network service provider), generally meaning the distribution network owner and operator with active control functional responsibilities)
DSU	Demand side units
ECRS	ERCOT contingency reserve service
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EUFR	Emergency under-frequency response
EV	Electric vehicle
FCAS	Frequency control ancillary services
FERC	Federal Energy Regulatory Commission
FMM	15-minute market
FSP	Flexibility service provider
HV	High voltage
HZ	Hertz

IBR	Inverter-based resources
ICCP	Inter-control center protocol
IEC	International electrotechnical commission
IGM	Individual grid model
ISON	International System Operators Network
kV	Kilovolt/s
kW	Kilowatt/s
LDES	Long duration energy storage
LESR	Limited energy storage resource
LFC	Load frequency controller
LSAT	Look-ahead security assessment tool (EirGrid)
LSE	Load-Serving Entity
LV	Low voltage
mFRR	Manual frequency restoration reserve
MMS	Market Management System
MV	Medium voltage
MW	Megawatt/s
NEM	National Electricity Market (east coast Australia)
NERC	North American Electric Reliability Corporation
NGR	Non-generating resource
NWA	Non-wires alternatives
OMS	Outage management system
OPDE	Operational planning data environment
PDR	Proxy demand response
PDR-LSR	PDR – load shift resource
PN	Physical notification
POE	Probability of exceedance
PV	Photovoltaic/s
QSE	Qualified scheduling entity
RCC	Regional coordination centre
RDRR	Reliability demand response resource
REP	Retail electric provider
RES	Renewable Energy Sources
RoCoF	Rate of change of frequency
RTM	Real-time market
SC	Scheduling coordinator
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
STPASA	Short-term projected assessment of system adequacy (AEMO)
TDUs	Transmission and distribution utilities
TSO	Transmission system operator (referred to in some jurisdictions as transmission network operator/transmission network service provider)

UDG	Unregistered distributed generation (ERCOT)
UFLS	Under frequency load shedding
WDAT	Wholesale distribution access tariff
WDT	Wholesale distribution tariff
WEM	Western Australia's wholesale electricity market

ISON definitions of distributed energy resources (DER) and consumer energy resources (CER)

AEMO

The following framing was adopted by policy development in 2021:

- The term **distributed energy resource (DER)** is still commonly used in the broad sense and encompasses all the resources connected to the distribution system (as distinct from the bulk electricity or transmission system). This includes behind the meter (BTM) resources connected at low voltage (LV) (CER defined below), which may not be participating in the centralised market. DER also includes larger installations connected at medium voltage (MV) on the distribution system, including MV-connected solar farms, community batteries and synchronous plant providing local back-up to critical loads such as hospitals and data centres. DER is often referred to as **embedded** generation and storage in transmission and distribution utility planning documents.
- **Consumer energy resources (CER)** are consumers' resources that generate or store electricity, connected behind the meter or on the LV network. CER can include flexible resources that can be aggregated and can alter their input or output in response to external signals[1]. CER includes, but is not limited to rooftop solar, batteries, electric vehicle (EV) chargers, and controlled loads such as water heaters and air conditioners.

ERCOT

ERCOT defines DER as generation, energy storage technology, or a combination of the two located at the customer's point of delivery and is interconnected at or below 60 kilovolts (kV) and operates in parallel with the distribution system.

Further, there are three distinct categories of distributed generation:

- **Unregistered distributed generation (UDG)** – not registered with ERCOT, typically less than 1 megawatt (MW) able to inject to the grid. UDG are best aligned with CER, as these resources are consumer-centric and generally not visible or dispatchable by ERCOT.

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[1] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/consumer-energy-resources-working-group#:~:text=The%20interjurisdictional%20Consumer%20Energy%20Resources,provide%20increased%20value%20to%20consumers.

- **Settlement only distributed generation** – registered with ERCOT and self-dispatched. Typically, >1 MW but <10 MW injecting to the grid.
- **Distributed generation resources:** registered with ERCOT and dispatched by ERCOT.

NESO

There is a recognised lack of harmonisation in CER/DER data taxonomies across the industry in Great Britain, with persistent gaps due to delays between technological change and standards implementation. While NESO has initiated a forum to promote best practices, formal governance is lacking, leading to interoperability issues that will be addressed through emerging Reference Data Management capabilities.

CAISO, EirGrid and Energinet

CAISO, EirGrid and Energinet do not make an official distinction between DER and CER, or a formal taxonomic distinction between DER connected to distribution networks and smaller, BTM DER connected at domestic level, such as rooftop solar photovoltaics (PV).

Adopted taxonomy for this report

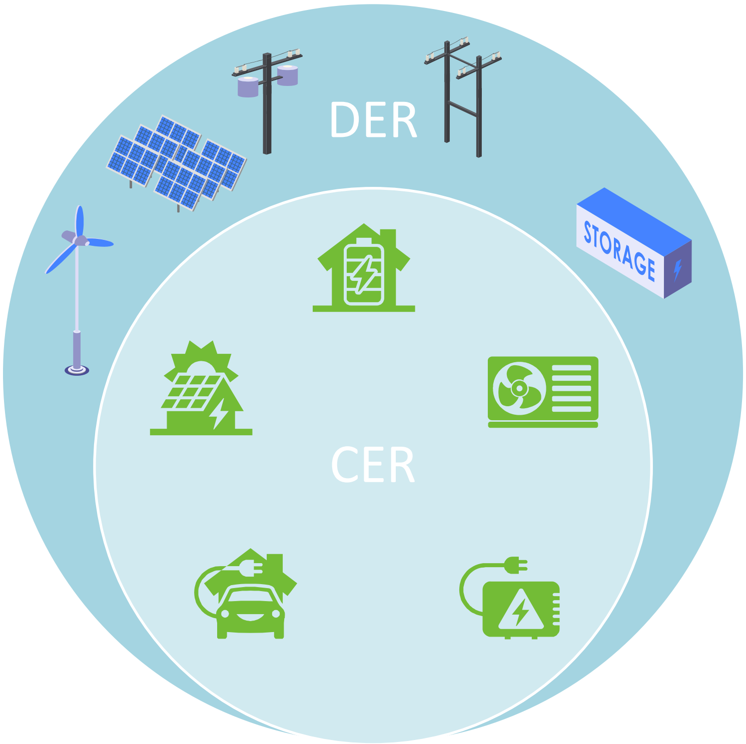
For the purposes of this report, the taxonomy used is:

- DER are considered to be the broad class of small-scale, energy resources. DER specifically in this context refers to both the resources directly connected to the MV distribution network and CER (described below).
- CER are a sub-category of DER, considered to be resources connected behind the meter in industrial, commercial or domestic facilities via the LV networks. CER can generally be aggregated into demand response market participants to get access to energy markets.

Figure 1 Proposed definition of DER and CER and categorisation for the purposes of the report

Distributed energy resources

All resources not connected to the bulk electricity (transmission) system. Can be directly participating in the market or aggregated.



Consumer energy resources

DER that is connected behind-the-meter, or at LV. CER can be aggregated to participate in markets.

Executive summary

The accelerating integration of distributed energy resources (DER), including rapidly increasing consumer energy resources (CER), is reshaping power systems globally. As highlighted in this report, system operators in the International System Operators Network (ISON) are navigating a complex transition – balancing the promise of decentralised, flexible energy with the operational, regulatory, and technical challenges it introduces.

The report identifies seven current or emerging risks:

- common mode failure and resource performance
- resource uncertainty
- resource adequacy and load variability
- extreme weather vulnerability
- transmission and distribution network constraints
- dynamic stability and fault ride-through, and
- emergency operations.

Each system operator is facing each risk to a varying degree, and the speed of transition is presenting capability gaps that must be addressed to ensure secure, reliable, and efficient grid operations in a high-DER future. The seven capability gaps to meet rising DER penetrations identified in the report are:

1. standardisation of taxonomy and best practice sharing
2. data management and exchange
3. modelling and simulation
4. operational forecasting
5. visibility and controllability
6. market mechanisms and participation, and
7. leveraging DER during emergencies.

ISON members are pioneering a range of innovative solutions. From AEMO's advanced DER modelling and forecasting to EirGrid's Look-ahead Security Assessment Tool (LSAT) stability analysis, and from CAISO and ERCOT's evolving DER participation models to NESO's innovative work on black start and restoration and Energinet's data architecture, system operators are actively developing tools, frameworks, and regulatory pathways to integrate DER more effectively. These efforts are complemented by emerging market mechanisms, such as flexibility services and aggregator participation in markets, which are beginning to unlock the full value of distributed assets.

However, the report also underscores that technology is advancing faster than institutional and regulatory frameworks. To bridge this gap, ongoing collaboration across Transmission System Operators (TSOs), Distribution System Operators (DSOs), regulators, and industry stakeholders is essential.

Ultimately, the transition to a DER abundant grid is not only a technical evolution but a systemic transformation. It requires rethinking roles, responsibilities, and operational paradigms which are underpinned by hardware and software technology advances.

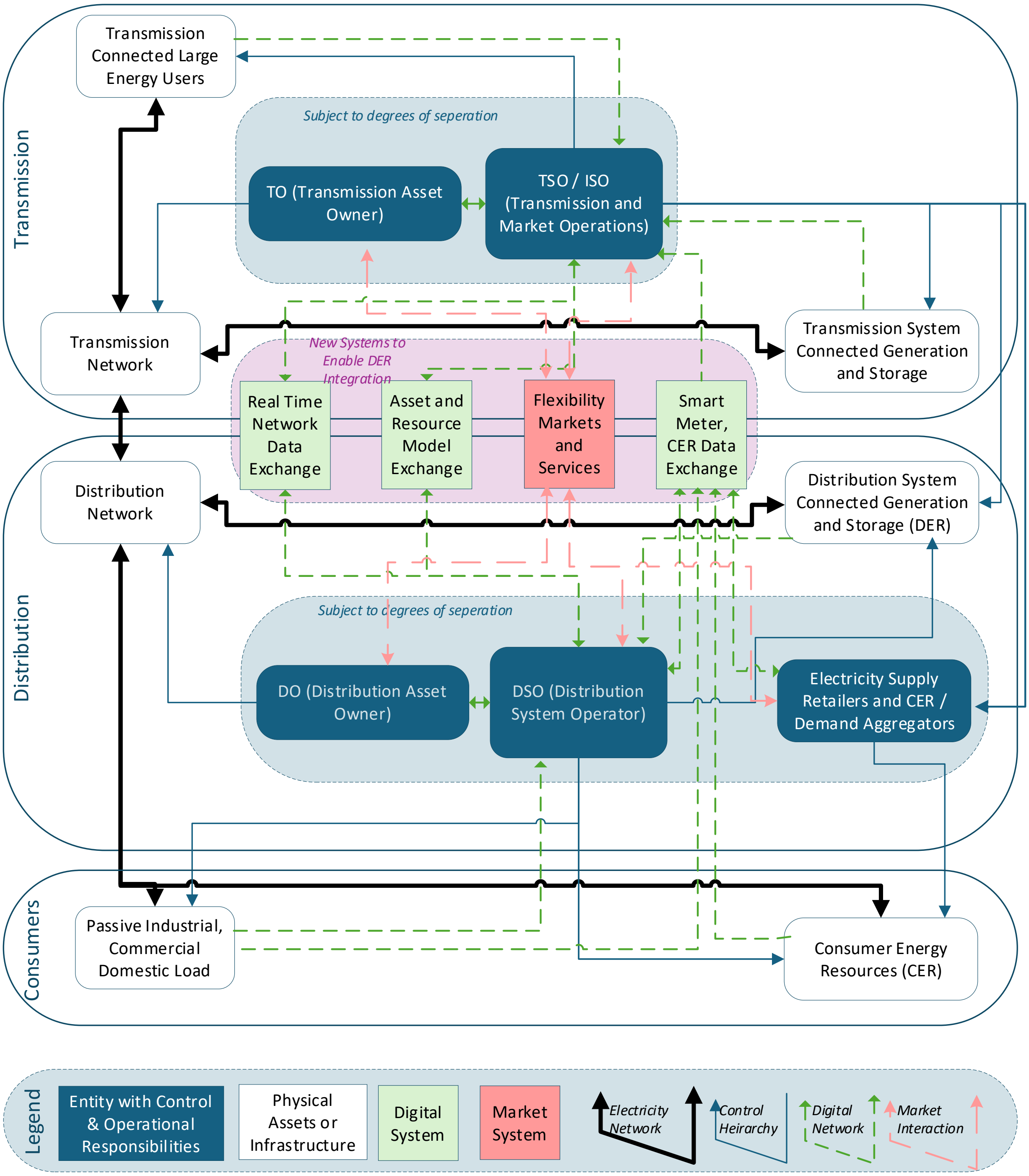
The ISON community's shared learnings and innovations offer a valuable foundation for this journey – one that must continue to evolve in step with the energy systems of tomorrow.

DER Vision Architecture

A harmonised approach to data sharing, control protocols, and market access will be critical to scaling DER integration while maintaining system reliability and resilience. This report develops a network-of-structures DER Vision Architecture (see Figure 2 below).

The aim is to show in a simplified way how network infrastructure, control, data and digital infrastructure and market transactions are interrelated and overlapping. Building on existing systems ISON members have developed, the architecture illustrates the potential for boundary digital systems and markets to increase DER connectivity and penetrations in a structured way.

Figure 2 **DER Vision Architecture**

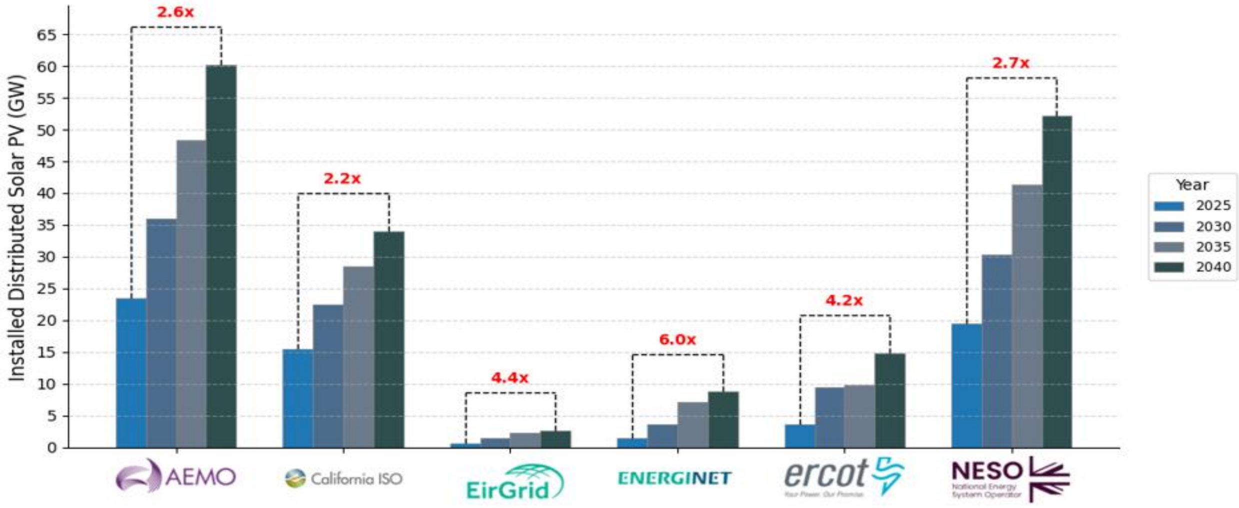


1 The increasing prominence of DER

The proportion of energy being delivered and consumed by DER, and by CER as a sub-category of DER, is increasing worldwide. This trend will continue as the cost of technology manufacturing reduces and technology adoption increases around the world.

Between 2025 and 2040, distributed solar is projected to grow substantially in the ISON power systems, as Figure 3 shows, and the projected energy usage for EV charging is shown in Figure 4[2]. On some networks, technology adoption and installation are moving faster than energy regulation, market services and system development, which is impacting the system operators' ability to plan, develop market mechanisms, monitor, and control the resources.

Figure 3 **Distributed solar PV Projections 2025-2040 for the six ISON operators**



Sources: AEMO – ISP 2024, CAISO, EirGrid 2023 TES, Energinet Planning Datasets, ERCOT Planning Datasets, NESO 2025 FES

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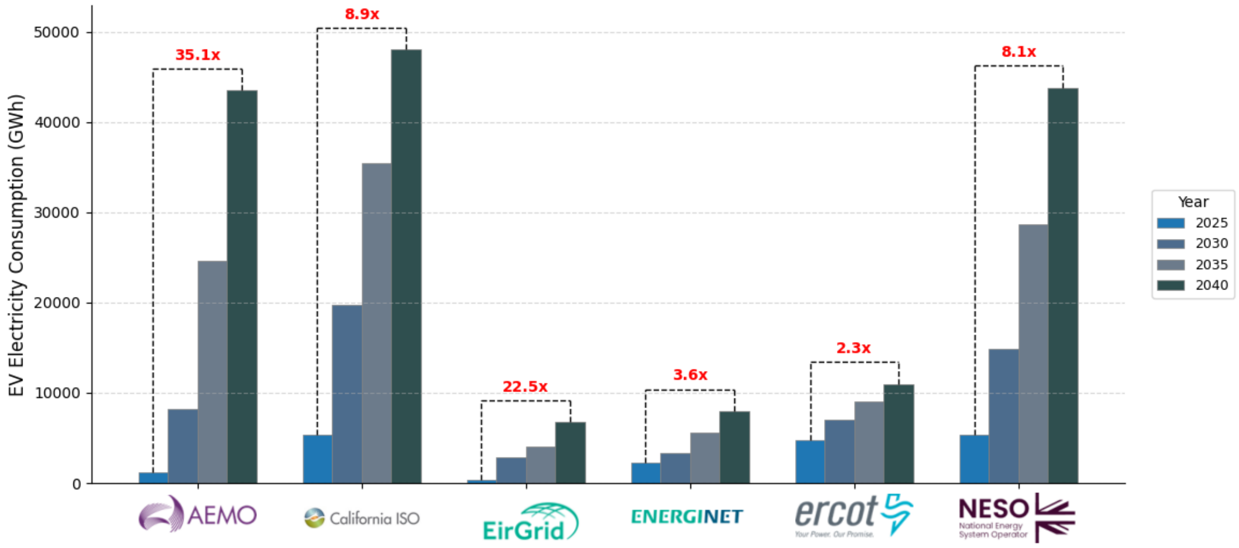
[2] Sources: **AEMO (Australia):** EV electricity consumption was extracted from the 2024 ISP Excel file, using data from Figure 6 (residential) and Figure 7 (business) under the Step Change scenario. Values were summed to obtain total EV demand in TWh. **CAISO (California):** Data was sourced from the CED 2023 Baseline Forecast Excel file, summing the Residential_LDEV and Commercial_LDEV columns in the Form 1.1 sheet. **EirGrid (Ireland):** EV electricity demand is projected to grow from ~300 GWh in 2025 to ~2,880 GWh by 2030. Estimates for 2035 and 2040 (4,000 GWh and 6,750 GWh) were derived using linear growth aligned with national electrification targets. **Energinet (Denmark):** Estimates were calculated by multiplying projected EV fleet sizes with an average consumption of 4 MWh per EV per year. This method is consistent with EU policy modelling and Danish usage patterns, used in the absence of direct forecasts. **ERCOT (Texas):** Based on ERCOT's projection of 6.7 TWh EV charging load in 2029 (~995,000 EVs). Estimates for 2025–2040 were linearly interpolated and extended using national targets and ERCOT's electrification assumptions. **NESO (UK):** For the NEO analysis, EV electricity consumption was derived from the NESO Future Energy Scenarios 2024 dataset. The Electric Engagement scenario was used, considering only the Residential Electric Vehicles Demand component.

Figure 4 2025 and projected to 2040 energy demand for electric vehicles (EVs) for the six ISON operators



Inability to fully integrate DER into operational and market systems will increase the need for investment in grid infrastructure to maintain stable operation of the grid while minimising constraints on intermittent resources and the cost of ancillary services[3].

The challenges of efficiently integrating DER are universal and are being experienced simultaneously, regardless of location or weather conditions. However, the solutions cannot necessarily be universally adopted, due to nuances in regulation, market design and implementation, electricity network ownership, size and design and the nature of broader push towards interconnection.

This report aims to highlight challenges of DER management and how the system operators of the ISON are developing innovations to more efficiently accommodate DER and CER into their energy systems.

Net load reduction – from duck curves to canyon curves

The effect of the primary source of DER and CER (distributed solar PV) on bulk system demand, also known as net demand, has been pronounced in recent years. The so-called duck curve effect – shown in Figure 5Sources: AEMO: based on the chart shared by AEMO. CAISO: 01/01/2025 (Grid Status). EirGrid: 26/06/2025 (EirGrid Dashboard). Energinet: 26/06/2025 (ENTSO-E platform). ERCOT: 01/07/2025 (Grid Status). NESO: 10/06/2025 (NESO Historic Data Sets). for the six ISON operators for a range of 2024-2025 summer days – results in demand during the day being significantly less than demand in evening or at night. This variability and need for fast ramping resource capability presents challenges to system operators in operational planning and real-time operations. As DER is expected to rise in the coming decades, the duck curve is likely to evolve to a 'canyon curve' where net demand in the middle of the day is negative, unless offset by low cost demand or battery energy storage system (BESS) and long duration energy storage (LDES) charging.

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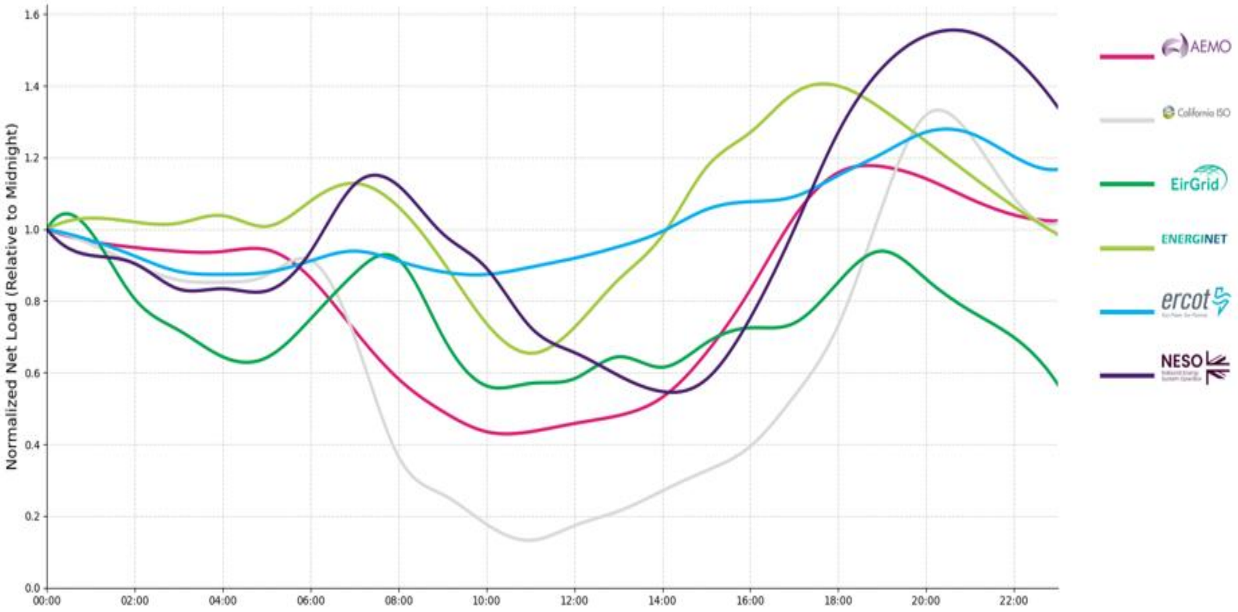
[3] The AEMO Integrated System Plan (ISP) in 2024 estimated an additional grid investment requirement of 4.1 billion AUD without effective control of consumer batteries.

Figure 5 **Effect of high domestic solar PV on random summer weekdays for the six ISON network operators. Showing 00:00 midnight load as normalised at 1 and increasing or decreasing over the day**



Sources: AEMO: based on the chart shared by AEMO. CAISO: 01/01/2025 (Grid Status). EirGrid: 26/06/2025 (EirGrid Dashboard). Energinet: 26/06/2025 (ENTSO-E platform). ERCOT: 01/07/2025 (Grid Status). NESO: 10/06/2025 (NESO Historic Data Sets).

2 System risks with high inverter-based resources, including high DER

Recent major system events

Iberia blackout, April 2025

On 28 April 2025, a major blackout struck the Iberian Peninsula, leaving Spain and Portugal without electricity for up to 10 hours after cascading failures that started with a substation fault in Granada and rapid generation losses elsewhere, collapsing the grid and severing its connection to France. The outage was largely restored by midnight, with full stability reached within 24 hours. A June 2025 government report attributed the crisis to planning and technical failures, such as insufficient voltage control and poor response to initial disturbances, while ruling out cyberattack. The reports to date, including the ENTSO-E report[4], have emphasised that the blackout was triggered by an unlikely chain of events, not any single cause nor specifically by the high share of renewables or DER, although the event has raised concerns about future grid resilience.

Chile blackout, February 2025

On 25 February 2025, Chile suffered a blackout affecting up to 98% of the population and spanning 14 of 16 regions – including Santiago – after a fault in the protection systems of a vital 500 kV transmission line triggered a cascading grid failure. The outage halted essential services, transportation, communications, and major business operations, prompting the government to declare a state of emergency, enforce a nationwide curfew, and deploy the military to aid recovery. By the next day about 90% of households had regained power, although some areas faced ongoing outages as investigations and repairs continued. A formal inquiry into the causes is underway.

South Australia, November 2022

On 12 November 2022, a severe weather event led to a major incident in South Australia’s power system when a double circuit transmission tower collapse triggered non-credible disconnection and faults on multiple transmission lines and resulted in the islanding of most of South Australia from the rest of the National Electricity Market (NEM) power system. Storms with damaging winds were sufficient to cause the tower to collapse due to steel corrosion that was subsequently discovered within the tower footings. The incident resulted in no loss of load, transmission or generation, but did cause a 90 MW drop in distributed PV output, mainly from unintended disconnections and required frequency response.

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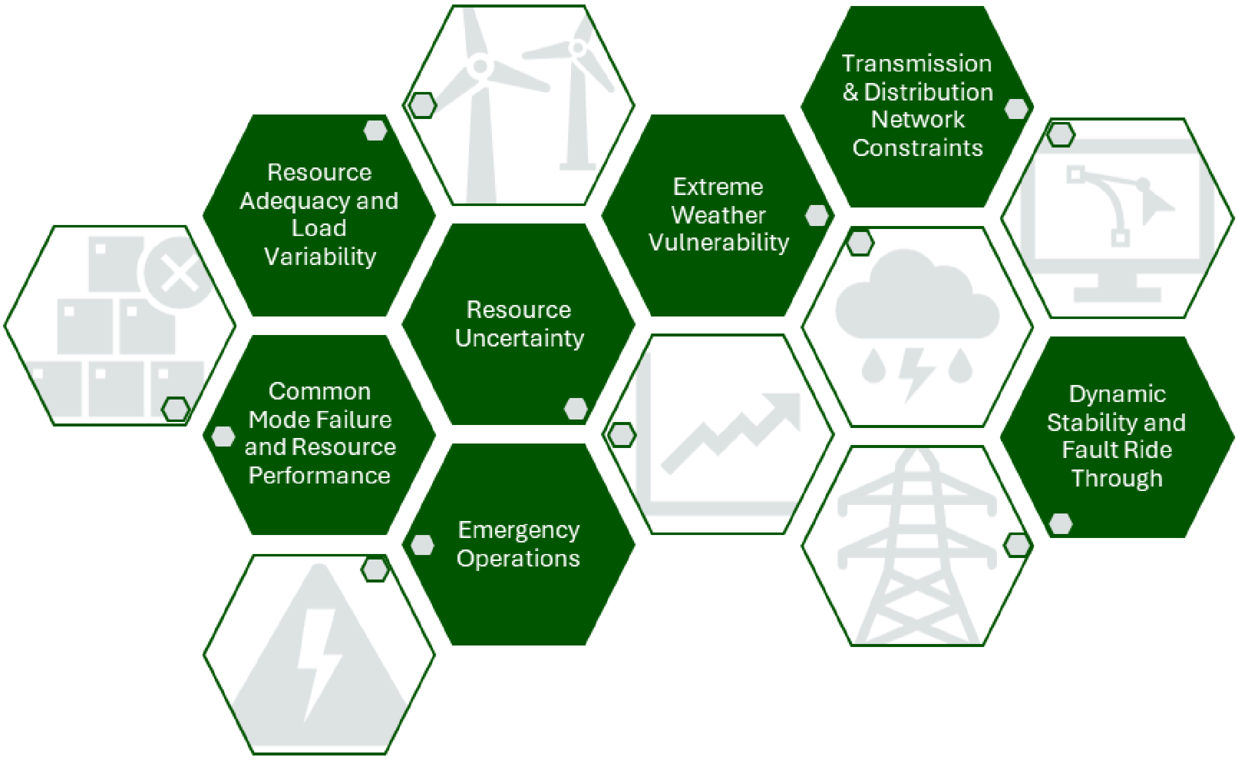
[4] See https://www.entsoe.eu/publications/blackout/28-april-2025-iberian-blackout/#Publications_&_Documents. [Accessed: November 20, 2025].

Risks to system operations

The key risks for ISON system operators' management of DER are summarised and documented below, under the broad headings shown in Figure 6.

Figure 6 Summary of the risks faced by the six ISON operators when operating with high penetrations of DER



Resource adequacy and load variability

- Evening reliability gaps – the ISON system operators regularly highlight concerns about evening reliability as solar output falls and demand persists, increasing the risk of alert conditions and potential load shedding-controlled outages.
- Unpredictable load shapes – increased DER and CER adoption can flatten or shift demand curves in ways that challenge traditional operational models and forecasting accuracy.

Resource uncertainty

- Intermittency of DER – high penetration of solar PV, batteries and other DER increases reliance on variable resources, making it harder to predict and ensure supply during peak demand, especially during evening hours when solar output drops but demand remains high.

Extreme weather vulnerability

- Heatwaves and weather events – operators such as AEMO, ERCOT, and CAISO face heightened risk of blackouts during extreme heat and/or cold weather, which can simultaneously spike demand for air conditioning or space heating and reduce the performance of both thermal and renewable resources.

- Wildfires – in California and Australia particularly, wildfires can threaten both generation and transmission infrastructure, compounding the operational risk during peak periods.
- High wind speeds – during storm events, with high wind speeds, there is a risk of "high wind speed shut down" where wind turbines cut out due to the risk of overspeed.
- Weather variability and rare events – in regions like Ireland, rapid and unpredictable weather changes can challenge the accuracy of renewable forecasts and the required ramping capability. Additionally, rare astronomical events such as solar eclipses can temporarily reduce solar generation, requiring careful operational planning.

Transmission and distribution network constraints

- Congestion and localised overloads – rapid growth in DER can stress local distribution networks and create congestion, particularly if grid infrastructure upgrades lag resource deployment.
- Transmission bottlenecks – the ISON system operators are seeing rising peak loads and more CER, to be managed during daytime peaks. Transmission and distribution capacity and flexibility become critical limiting factors.
- Voltage control coordination – coordinating the boundaries and priority for voltage management across the transmission and distribution boundary, especially with dynamic voltage regulation capability of inverter-based resources (IBR), can pose challenges at high IBR penetration levels.

Dynamic stability and fault ride-through

- Dynamic stability – the dynamic stability, security and grid strength of the bulk transmission network is impacted by the instantaneous generation resource mix. The ability of resources to respond and stay stable during bulk system disturbances and to provide support to the system will always be critical to stable operation. Large quantities of dispersed IBR are more difficult to model and simulate than small numbers of electromechanical resources.
- Fault ride-through – during transient disturbances and faults, some DER may not be able to adequately ride through the disturbances, which may cause loss of active power during undervoltage events and may exacerbate the event over a wider area.
- Fault levels and protection coordination – the fault levels and contributing resources is changing, with new resources. Coordinating transmission and distribution protection settings is more challenging, requiring modelling and simulation.

Common mode failure and resource performance

- Similar technology configurations – having hundreds of thousands of the same power electronic devices with the same configuration exposes the networks to the risk of common mode failures for network issues.

- Non-conformity – there are practical difficulties with testing and validating DER, particularly CER, and increased difficulty rolling out wide-scale codes or standards changes to device configuration.
- IBR underperformance – There is an emerging risk that during critical events, IBR in DER may not perform as modelled and predicted. Examples include: failure modes that have occurred during faults, response to high or low voltage issues and irregular, over-air firmware upgrades.

Emergency operation

- Under frequency load shedding (UFLS) – UFLS relays were traditionally connected to passive distribution feeders to disconnect load as frequency dropped, but with DER exporting at times, UFLS disconnections may have the opposite of the intended effect. Disconnecting less load or a net source of generation instead of demand has the potential to exacerbate under frequency events.
- Black start – DER are generally not used in black start situations. Without controllability, switching DER off in an emergency may be a risk to formation of islands during the restart process.
- Restoration – restoring blocks of load into islands is more difficult with extensive CER. The frequency and voltage may have to be kept high to mitigate the risk of uncontrolled re-connections.

The risks the ISON system operators are facing – summary

The system risk matrix shown below is graded as Low, Medium and High for each of the six ISON operators, based on their risk perception. High indicates that this risk is higher, or issues are more frequently encountered today on the relevant system in the matrix. Medium and low reflect less urgent risk at present. Note that all these risks can be expected to increase across all system operators as DER penetration rises, due to inherent uncertainties in performance, visibility and controllability of so many small installations.

Risks	AEMO	CAISO	EirGrid	Energinet	ERCOT	NESO
Resource adequacy and load variability	High	Medium	Medium	Low	High	Medium
Resource uncertainty	High	High	High	Medium	High	Medium
Extreme weather vulnerability	Medium	High	Low	Low	Medium	Low
Transmission and distribution congestion	High	Low	High	High	Low	Medium
Dynamic stability and fault ride-through	High	Medium	High	Low	Low	Medium
Common mode failure and resource performance	Medium	Medium	Medium	Medium	Low	Medium
Performance during emergency operation	High	Low	Low	Low	Low	Low

3 The capability gaps to address the risks of DER

Gap name	Gap description
1. Standardisation of taxonomy and best practice sharing	The need to agree on a standard definition and taxonomy and architecture for DER and CER.
2. Data management and exchange	The need for robust data management procedures, protocols and infrastructure for secure data exchange between electricity industry entities with ownership or operational responsibilities for DER so that the characteristics of the network DER can be modelled and studied at all levels.
3. Modelling and simulation	The need to develop accurate models of IBR when modelling the dynamic behaviour of DER and to evolve the modelling of IBR to encompass massive quantities of IBR-based CER for dynamic voltage and frequency simulations and fault ride-through in a range of simulation tools.
4. Operational forecasting	The need to enhance the forecasting capability of system operators and enabling enhanced commercial forecasting through enhanced data exchange mechanisms will be key enablers of facilitating more renewable based DER and in optimising the full system resource portfolio, including demand.
5. Visibility and controllability	The need for real-time data visibility of the output of DER and aggregated CER is essential for TSO awareness, short-term forecasting, and planning and as an input to operational technology applications. The ability to directly control DER and CER is subject to regulatory approval, but an ability to indirectly control (through DSOs) may be required in future.
6. Market mechanisms and participation	The need to develop robust pathways for DER and CER participation in all available energy markets to maximize DER utilisation and flexible networks. Given the emerging nature of DER and in particular CER participation, shared experiences and practices will be a key enabler of innovation.
7. Leveraging DER during emergencies	The need to ensure UFLS schemes are coordinated for DER and to leverage DER for black start. Reducing the risk of restoring with DER requires new control strategies, communication protocols, and updates to grid codes as well as visualisation and control technology.

Standardisation of taxonomy and best practices

The integration of DER into bulk transmission systems is hampered by inconsistent definitions, technical standards, and operational guidelines across regions and market participants. This extends at the device level as well as for different forms DER management and coordination. Without standardised taxonomy and best practices, it is challenging to ensure vendor software interoperability, efficient market participation, and reliable system operation.

Regulatory bodies and industry groups are increasingly working to harmonise standards, such as through IEEE 1547-2018, IEEE 2030.5, IEEE 2800 (for transmission), EU RfG, AS/ANZ4777 which set requirements for DER interconnection and grid support functions. However, DER technology maturity and installation timelines are evolving much faster than standards bodies can regulate. Ongoing, global coordination is needed to continue to develop and iterate standards to keep pace with evolving technologies and deployment models.

Gap 1: The need to standardise definitions and taxonomy for DER and CER.

Data management and exchange

DER produce vast amounts of granular, real-time data from potentially millions of distributed sources, creating significant challenges in data collection, management, and secure exchange. TSOs do not always have up-to-date visibility of levels of DER, particularly CER, for operational planning or operational purposes. There is a need to invest in robust IT infrastructure and cybersecurity to protect consumer information and grid integrity, while also enabling seamless data flow between DER, aggregators, grid owners and system and market operators. Effective data management and systems are critical for real-time monitoring, billing, settlement, and market participation. Scalable operational coordination between transmission and distribution operation is critical for the data exchange required for secure and reliable bulk power system operations. DSOs have a central role to provide aggregated observability of the DER within their operating zones to the TSOs.

Gap 2: The need for robust data management procedures, protocols and infrastructure for secure data exchange between electricity industry entities with ownership or operational responsibilities for DER so that the characteristics of the network DER can be modelled and studied at all levels of the grid.

Modelling and stability assessment

Traditional power system simulations were designed for centralised, dispatchable generation and often have difficulty accurately representing the dynamic behaviour of high-DER /CER systems. Enhanced modelling approaches must capture both steady-state and dynamic impacts of DER on voltage, frequency, and protection schemes on the bulk power system. Accurate models appropriately representing the aggregate impact of DER transmission-distribution interface are essential for planning, operational assessments, and reliability studies. Modelling large IBR-based individual DER systems, as well as significant aggregations of small-scale systems, in dynamic simulations is also essential, while at the same time minimising impacts on model complexity and simulation execution time. As systems become more reliant on and responsive to CER activity, the need to accurately model CER dynamic behaviour and the level of granularity to which the respective systems need to be modelled must be clarified on a jurisdictional basis.

Gap 3: The need to develop accurate models of IBR when modelling the dynamic behaviour of DER and to evolve the modelling of IBR to encompass massive quantities of IBR-based CER for dynamic voltage and frequency simulations and fault ride-through in a range of simulation tools, with due consideration to the impact on model complexity and simulation execution times.

Operational forecasting

The variability and unpredictability of weather-based DER, and the evolving nature of domestic electricity demand, make accurate operational forecasting more complex for system operators. Improved forecasting tools, leveraging more robust data exchange as well as advanced analytics and real-time data, are needed to anticipate fluctuations, optimise scheduling and dispatch. Inaccurate forecasts can lead to increased reserve requirements and operational inefficiencies which increase costs and can degrade reliability.

Gap 4: The need to enhance the forecasting capability in system operators or enabling enhanced commercial forecasting through enhanced data exchange mechanisms, will be key enablers of facilitating more renewable based DER and in optimising the full system resource portfolio.

Visibility and controllability

High DER penetration leading to reduced net load can reduce grid operators’ visibility and control over the supply-demand balance, especially for CER and particularly during periods of high solar penetration. Limited access to real-time data on DER locations, status, and output complicates operational planning, congestion management, balancing, voltage regulation, and protection coordination. Large ramps and cloud-based fluctuations have to be managed by system operators. System operators and utilities are reporting increasing difficulty managing bidirectional power flows and ensuring system reliability without advanced monitoring and control systems.

Gap 5: The need for real-time data visibility of the output of DER and aggregated CER is essential for TSO awareness and planning and as an input to the operational technology toolkit. The ability to directly control DER and CER is subject to regulatory approval, but an ability to indirectly control (through DSOs) may be required in future.

Market mechanisms and services for DER and CER

DER, including CER, can provide valuable market services such as demand response, frequency regulation, and voltage support. However, current market designs can often lack mechanisms for small, distributed assets to participate effectively, either locally or into a larger interconnection. Aggregators can participate in most markets and have been helping in some jurisdictions to pool DER to meet minimum market thresholds, but regulatory and technical barriers remain. Expanding access to ancillary service markets and developing new products tailored to DER capabilities are essential to unlock their full value. In addition, the TSOs or market operators, with responsibility for balancing, should have monitoring and control capability of aggregation platforms, to ensure grid reliability.

Gap 6: The need to develop robust pathways for DER and CER participation in all available energy markets to maximize DER utilisation and flexible networks. Given the emerging nature of DER and in particular CER participation, shared experiences and practices will be a key enabler of innovation.

Emergency operations, black start and restoration

UFLS has been a standard last line of system defence for decades, but the paradigm is now shifting with increased DER with potential for net infeed from DER on distribution feeders. Historically, system restoration after a whole or partial system blackout relied on large, centrally located thermal or hydro generators. The practice to date has been to disregard renewable energy resources generally, and DER particularly, while the system was restored using traditional procedures. As DER proliferate, their potential role in black start and system restoration is being explored, but technical, operational, and regulatory challenges persist.

Gap 7: The need to ensure UFLS schemes are coordinated for DER and to leverage DER for black start. Reducing the risk of restoring with DER requires new control strategies, communication protocols, and updates to grid codes as well as visualisation and control technology.

4 ISON innovations to address the gaps

Gaps	AEMO	CAISO	EirGrid	Energinet	ERCOT	NESO
1. **Standardisation of taxonomy and best practice sharing**	Established	Developing	Developing	Developing	Developing	Developing
2. Data management and exchange	Developing	Developing	Established	Enhanced	Enhanced	Developing
3. Modelling and simulation	Enhanced	Established	Enhanced	Enhanced	Developing	Developing
4. Operational forecasting	Enhanced	Enhanced	Established	Established	Established	Established
5. Visibility and controllability	Developing	Developing	Enhanced	Developing	Established	Developing
6. Market mechanisms and participation	Developing	Developing	Established	Established	Established	Established
7. Black start and restoration	Established	Developing	Developing	Developing	Developing	Established

Maturity descriptions			
	Developing maturity means very limited capability or early-stage development	**Established** maturity means basic technology exists to address the gap but further enhancement is required	**Enhanced** maturity means the technology is innovative and pioneering to global operators

The following section describes identified innovations to help close the seven key capability gaps that contribute to the risks identified with greater DER penetrations, focusing on the key innovations that ISON system operators have made in recent years.

Standardisation of taxonomy and best practice sharing

Global Industry Spotlight – IEEE Standardisation Efforts

Global standards such as IEEE 1547 and IEEE 2800 play a pivotal role in harmonizing how DER and IBR interact with the electric grid. IEEE 1547-2018, focused on DER connected at the distribution level, defines mandatory requirements for interconnection, including voltage and frequency ride-through, voltage regulation, and interoperability via communication protocols[5]. It supports advanced grid-support functionalities, enabling CER/DER like solar PV, wind, and battery systems to contribute to grid stability and resilience. Complementing this, IEEE 2800-2022 addresses the interconnection of IBR—such as utility-scale solar and wind plants—to transmission and sub-transmission systems[6]. It sets uniform technical minimum requirements for performance, including dynamic voltage and frequency support, active and reactive power control, and system protection, ensuring that IBRs can operate reliably under both normal and abnormal grid conditions. Together, these standards form a foundational framework for the global energy transition.

ISON Spotlights

AEMO has worked to develop a reasonably standard taxonomy for DER and CER as described in the Glossary, definitions and taxonomy section at the start of this report. Other system operators are considering similar adoptions to align terminology, functional requirements and solutions for the challenges of DER integration.

In **NESO**, there is a recognised lack of harmonisation in CER/DER data taxonomies across the industry, with persistent gaps due to delays between technological change and standards implementation. While NESO has initiated a forum to promote best practices, formal governance is lacking, leading to interoperability issues that will be addressed through emerging Reference Data Management capabilities.

Data management and exchange innovations

Global Industry Spotlight – Common Grid Model Exchange Standard

The Common Grid Model Exchange Standard (CGMES) is a standardized data exchange framework developed by ENTSO-E (European Network of Transmission System Operators for Electricity) to facilitate the seamless sharing of electricity grid models among European TSOs. Built on the Common Information Model (CIM) – a suite of standards developed by the International Electrotechnical Commission (IEC), particularly IEC 61970 and IEC 61968 – CGMES enables the exchange of detailed grid data such as equipment, topology, state variables, and dynamic behavior[7]. Each TSO creates an Individual Grid Model (IGM), which is validated and merged by Regional Coordination Centres (RCCs) into a pan-European Common Grid Model (CGM). This unified model supports critical operational processes like coordinated capacity calculation, security analysis, outage planning, and short-term adequacy assessments. The exchange of data is facilitated through the

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[5] See https://standards.ieee.org/ieee/1547/5915/.

[6] See https://standards.ieee.org/ieee/2800/10453/.

[7] See https://www.entsoe.eu/data/cim/cim-for-grid-models-exchange/.

Operational Planning Data Environment (OPDE), ensuring interoperability, data quality, and compliance with European network codes.

In addition, over the past number of decades a large body of work has been built up in the standards domain for managing DER in transmission and distribution networks. These include:

EC 61968-5:2020 ***Application integration at electric utilities - System interfaces for distribution management - Part 5: Distributed energy optimization***

'CIM for DER' focused on 'enterprise integration' of DERMS functions, specifically between the distribution utility's DMS and a DERMS, it includes use cases relating to how 'DER groups' are managed – including how groups are created, maintained, monitored, forecast, dispatched.

IEEE 2030.11:2021 ***IEEE Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification***

This standard is related to DERMS interactions with individual devices and includes functions relating to device information, control functions, monitoring, etc.

ISON Spotlights

AEMO has historically relied on a centralised and specialised data exchange architecture through the supervisory control and data acquisition (SCADA) system for real-time data exchange with market participants. While this was adequate for a small number of larger entities, it presents challenges for smaller generators and demand-side resources due to cost and technology options.

AEMO's 'SCADA Lite' initiative[8] enables a lighter-handed operational data exchange for DER aggregators and demand response providers in the NEM. This aims to enable a secure, streamlined and direct alternative to traditional SCADA systems when connecting to AEMO. SCADA Lite supports ICCP and DNP4 communication protocols, an integrated front end within AEMO's EMS accessible via secure private network and real-time telemetry to support forecasting and system operations.

AEMO maintains DER register databases across both the NEM and Western Australia's Wholesale Electricity Market (WEM)[9]. These databases aim to serve as an up-to-date source of standing data on the location, capacity, and technical characteristics of DER installations. They rely on a data collection process administered by distribution utilities during installation processes, working with installers to capture data, and upload to the central register.

AEMO also has access to customer meter data through the market management functions, but this does not yet have any direct 'operational' use - except for demand forecasting. One NEM region has nearly complete advanced metering infrastructure (AMI) coverage via the distribution utility, however, other regions rely on retailers and separate metering coordinators.

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[8] Australian Energy Market Operator, "SCADA Lite," AEMO. [Online]. Available: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/scada-lite. [Accessed: Jun. 27, 2025].

[9] Australian Energy Market Operator, "Distributed Energy Resource Register," AEMO. [Online]. Available: https://aemo.com.au/energy-systems/electricity/der-register. [Accessed: Jun. 27, 2025].

There are a number of ongoing measures to accelerate AMI roll out in Australia, with provision for DSOs to gain access to data[10,11].

For **NESO** currently, DER are modelled in aggregate form through data exchange with DSOs for system planning and operation. Ongoing work to improve modelling of sub-transmission DSO networks and CER data registry is being pursued.

Energinet and ERCOT have mature smart meter programs in Energinet's DataHub[12] and Smart Meter Texas respectively. For **EirGrid**, Ireland is rolling out smart meters to all premises. While the smart meter data hubs can be used for domestic data usage and for third party energy suppliers to create and optimise new tariff products, the data has not been leveraged by system operators for insights on CER usage for legal reasons and IT product development priorities. However, data on the aggregated installed capacity of CER is exchanged regularly between TSO and DSO in Ireland.

In Great Britain, for **NESO**, tooling, data management standards, and data sharing infrastructure are all currently being established or embedded to support DER integration and coordination. Improvements in industry-wide data sharing and data standards are being actively pursued.

CAISO uses CIM based modelling to represent all DER and DER aggregations participating in the CAISO market at the point of interconnection with the bulk electric system. Data is provided by the resources consistent with the requirements for the specific resource. Interconnection and communication requirements of CER are guided by IEEE 1547 and IEEE 2030.5. Specific distribution system limitations must be reflected in outage cards to manage the DSO limitations.

Modelling and simulation of DER and CER innovations

ISON Spotlights

AEMO has advanced capability for modelling inverter-based DER and employs the DER_AUS model within PSS®E[13]. This model reflects real-world disturbance behaviour – such as momentary cessation and dynamic voltage support – aligned with the updated AS/NZS 4777.2:2020 inverter standard. These improvements have enhanced model realism, particularly in high-PV-penetration regions, and support scenario-based analysis for undervoltage and frequency events. AEMO's custom model, DER_AEMO, adapts the United States-developed DER_A model to Australian conditions. It includes features like:

- multi-stage frequency and rate of change of frequency (RoCoF) tripping
- graduated voltage tripping, and
- frequency-watt control behaviour.

This model is starting to be embedded into grid simulations across AEMO and TSOs in the NEM to reflect aggregated CER impact and performance in stability assessment for the transmission system. Experience to

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[10] AEMC Ruling: https://www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment.

[11] AEMO Smart meter data project page: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment.

[12] Energinet, "DataHub," Energinet. [Online]. Available: https://energinet.dk/data-om-energi/datahub/. [Accessed: Jun. 12, 2025].

[13] Australian Energy Market Operator, "PSS®E models for load and distributed PV in the NEM," AEMO, Nov. 25, 2022. [Online]. Available: https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en. [Accessed: Jun. 12, 2025].

date indicates that DER_AEMO[14] continues to represent fault behaviour reliably without requiring recalibration, especially in scenarios with low system inertia.

AEMO has also developed robust post-event analysis capabilities, leveraging SCADA data, analysis monitoring data from third-party monitoring of sample DER systems in the field, bench testing and system event logs to investigate DER performance. These insights inform model refinements and help guide national efforts on standard updates, compliance programs, and the development of future DER integration frameworks.

EirGrid's Look-ahead Security Assessment Tool (LSAT) is an advanced, real-time decision support system designed to enhance the operational security and stability of the all-island power system, particularly as renewable generation increases. LSAT continuously assesses the system's security for a wide range of contingencies and transfer scenarios, using forecast system conditions and planned network changes to predict potential instabilities up to 24 hours ahead of real time. Drawing on data from EirGrid's Market Management System, load forecasts, interconnector schedules, and planned outages, LSAT enables grid controllers in Dublin to proactively identify and address risks before they manifest. The tool's assessments are updated every five minutes, leveraging high-performance computing to run millions of security tests daily.

LSAT is now fully integrated into control room operations, helping facilitate higher levels of instantaneous renewable generation while minimising constraints and curtailment, and ensuring the secure, reliable operation of the Irish grid in a rapidly evolving energy landscape. All IBR above a certain size is expected to be modelled in LSAT and the model is continually being refined based on actual events on the network.

CAISO and other industry stakeholders undertook a series of coordinated actions after the widespread solar PV disturbances in California during summer 2021[15], to bolster inverter resilience and system reliability. CAISO issued breach notices to affected Generating Owners, citing failure to meet voltage ride-through and data reporting requirements in their interconnection agreements. In partnership with manufacturers, operators implemented firmware updates that altered inverter trip thresholds and enhanced ride-through – measures which demonstrably improved inverter performance during subsequent grid disturbances. Furthermore, CAISO revised its standard Generator Interconnection Agreements to require stronger coordination between plant controllers and inverter systems, ensuring faster reconnection following fault events. In the United States, at the regulatory level, the disturbances hastened the adoption of updated interconnection standards, notably IEEE 1547-2021, and prompted Federal Energy Regulatory Commission (FERC)-approved rule changes mandating enhanced fault ride-through, synchronisation, and reconnection capabilities for inverters.

ERCOT uses the DER_A aggregated model for DER in dynamic stability studies. Similarly, following the 2021 Odessa solar PV disturbances[16], ERCOT implemented key corrective actions to improve primarily transmission-connected IBR disturbance performance. These included firmware updates to inverter settings (e.g., voltage ride-through and momentary cessation logic), improved root-cause tracking with affected plants, and enhanced interconnection and performance standards. ERCOT updated its operating guides to

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[14] For more information about DER management in AEMO: https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/power-system-model-development.

[15] North American Electric Reliability Corporation (NERC), "Multiple Solar PV Disturbances in CAISO and Industry Response," April 2022. [Online]. Available : https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf. [Accessed: Jun. 12, 2025].

[16] NERC, *Odessa Disturbance Reports and Reliability Guidelines*, 2022. [Online]. Available: https://www.nerc.com/pa/rrm/ea/Pages/Odessa-Disturbance-Reports.aspx.

reflect new software-based ride-through (updated control settings) provisions, while North American Electric Reliability Corporation (NERC) issued advisories for model validation and compliance with updated standards like IEEE 2800. These measures significantly strengthened IBR reliability under grid disturbances.

Operational forecasting innovations

Global Industry Spotlight – Predico by Elia

ISON understand that Elia Group, in collaboration with Portugal's INESC TEC, has developed Predico, an operational forecasting platform that is believed to enhance the accuracy and efficiency of renewable energy and demand forecasts. Predico is a collaborative forecasting and data market platform which enables companies to pose forecasting challenges, which are addressed by multiple forecast providers who are compensated based on the accuracy and value of their predictions. Using machine learning, Predico aggregates and optimizes individual forecasts to produce high-resolution probabilistic outputs, particularly for offshore wind and demand ramps. The platform also quantifies the value of each data contribution, fostering a transparent and incentive-aligned ecosystem. Currently Predico is being tested in an operational setting with Elia[17].

ISON Spotlights

CAISO, a leading system operator with a central dispatch model, requires advanced forecasting capabilities to effectively manage demand, DER, and renewable energy sources (RES). They integrate demand response (DR), RES, and DER through various participation models supported by sophisticated forecasting and measurement techniques, as summarised below:

- **System demand forecasting** – CAISO develops load forecasts based on historical gross load data, weather forecasts, day-of-week effects, and calendar variables, adjusting for temperature, seasonality, and special events.
- **Demand response and DER forecasting** – Demand Response Providers (DRPs) and aggregators submit daily availability and resource forecasts indicating expected load changes as part of the scheduling process.
- **Baseline forecast methodologies** – CAISO uses approved baseline methods to estimate customer load absent a DR event.
- **Ten-in-ten and five-in-ten methods** averaging previous similar non-event days.
- **Control group methodology** comparing participants with matched non-participants.
- **Weather matching selecting baseline** days with similar weather conditions.
- **Meter Generator Output (MGO)** combining behind-the-meter generation with load baselines for DER.
- **Advanced measurement and verification** – techniques such as FLEXmeter apply statistical analysis and control groups to enhance accuracy in assessing DR and DER performance, enabling precise event analysis and integration.

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[17] See https://innovation.eliagroup.eu/en/projects/predico-collaborative-forecasting-platform.

- **Integration and scheduling** – aggregated DR and DER resources are scheduled and dispatched through CAISO's market platform, with settlements based on actual metered data versus baseline estimates, ensuring fair participation alongside traditional generation.

AEMO provides comprehensive operational forecasts as part of its responsibilities to undertake the central dispatch process in the NEM and WEM[18]. These include five-minute dispatch forecasts extending up to eight days ahead, covering both electricity demand and renewable generation such as wind and solar power. These forecasts are crucial for key market processes, including the pre-dispatch schedule and the Short-Term Projected Assessment of System Adequacy (STPASA), with day-ahead forecasts for pre-dispatch and two-to-seven-day forecasts for STPASA provided for each NEM region.

AEMO's Demand Forecasting System (DFS) uses a wide range of data inputs, including historical metered demand, real-time SCADA load data, weather forecasts (temperature, humidity), satellite imagery to generate nowcasts and forecasts for non-scheduled wind and solar generation through the Australian Wind Energy Forecasting System (AWEFS)[19] and the Australian Solar Energy Forecasting System (ASEFS)[20].

AWEFS produces detailed wind generation forecasts using real-time SCADA data from wind farms, numerical weather predictions, farm-specific data, and turbine availability. Forecasts cover multiple timeframes from five-minute dispatch intervals up to two years ahead for all significant wind farms (≥30 MW) across the NEM.

ASEFS Phase 2 (ASEFS2) focuses on small-scale distributed PV systems (<100 kilowatts [kW]), leveraging global weather predictions, data from a sample of household rooftop PV systems (including device-level monitoring output data and static data on the capacity and location of these systems, aggregated capacity by postcode), and satellite imagery to forecast solar generation from five minutes to seven days ahead[21].

Together, AWEFS and ASEFS generate various uncertainty and intermittency generation forecasts[22], including individual generator, regional, NEM-wide, and uncertainty forecasts expressed as probability of exceedance (POE) for pre-dispatch and STPASA processes. These forecasts underpin AEMO's ability to integrate renewable energy sources effectively and maintain system reliability.

At present the ASEFS2 aggregate distributed PV forecast is undertaken at 30-minute granularity, primarily for system-balancing purposes. AEMO is currently working towards five-minute temporal granularity and lower spatial granularity to enable this data to integrate with other operational processes, such as constraints that rely on a state estimation of the amount of rooftop solar online.

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[18] Australian Energy Market Operator, "Operational forecasting," *AEMO*. [Online]. Available: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting. [Accessed: Jun. 12, 2025].

[19] Australian Energy Market Operator, "Australian Wind Energy Forecasting System," *AEMO*. [Online]. Available: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-wind-energy-forecasting-system. [Accessed: Jun. 12, 2025].

[20] Australian Energy Market Operator, "Australian Solar Energy Forecasting System," AEMO. [Online]. Available: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system. [Accessed: Jun. 12, 2025].

[21] Australian Energy Market Operator, "Load Forecasting," AEMO. [Online] Available: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3710-load-forecasting.pdf. [Accessed: Jun. 27, 2025]. See Appendix C.

[22] Australian Energy Market Operator, *Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS)*, AEMO, Aug. 2023. [Online]. Available : https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/australian-wind-energy-forecasting-solar-energy-forecasting-system.pdf. [Accessed: Jun. 12, 2025].

Energinet invokes various forecasting and machine learning disciplines to proactively operate and balance a renewable energy-dominated electricity grid. Below follows a list of innovative forecasting disciplines:

- Forecasting of traditional load consumption and wind & PV production – meteorological forecasts on wind speed, wind direction and solar radiation are collected from several weather data service providers. This enables Energinet to forecast the VRE production in high temporal and spatial resolution (week ahead to real-time, up to five-minute resolution). The forecast VRE production and traditional load forecast act as inputs for the short-term imbalance forecast (next bullet) and forecast of flows/loading on the internal grid and on interconnectors.
- Short-term imbalance forecast – Energinet deploys a proactive balancing approach, meaning that the manual frequency restoration reserve (mFRR) (tertiary reserve) is activated based on a forecasted imbalance, rather than reacting to a measured imbalance. Energinet's own imbalance forecast takes into account 1) consumption forecasts on e.g., households and industrial demand, 2) wind and solar generation forecasts, 3) operational schedules submitted by market participants, and 4) the measured imbalance stripped for balancing actions. Any imbalance that remains after the mFRR market is handled by the automatic frequency restoration reserve (aFRR) (the secondary reserve), which is activated reactively based on the measured remaining imbalance through a Load Frequency Controller (LFC).
- In parallel to the short-term imbalance forecast, Energinet also uses the forecast for loading in the grid to proactively use mFRR in specific geographical areas to resolve congestions. This is further described under Gap 6 (Market Mechanisms and Services for DER and CER Innovations) below.
- Dynamic dimensioning of ancillary service quantities – Energinet uses dynamic dimensioning of mFRR, and soon aFRR too. When procuring mFRR capacity early the day before operations, forecasts for conditions such as solar and wind production are fed into a machine learning model. The model predicts the amount of mFRR capacity needed in the market to achieve the desired security level. With dynamic dimensioning of mFRR, Energinet improves the operational security level by procuring more mFRR capacity in situations with high needs and reduces the costs in periods with low needs by procuring less.

ERCOT uses smart meter data to create a forecast of distributed PV output for the upcoming 168 hours.

NESO has an established methodology for operational forecasting in the use of renewable DER assets but recognises it needs to expand this to cover other dominant fuel types (such as batteries). Operational visibility of DER assets remains a challenge, and these are needed to improve energy forecasts while validating out-turn records. NESO continues to develop new forecasting methods using artificial intelligence and machine learning techniques and will seek out new datasets in due course.

Visibility and controllability

Global Industry Spotlight – Southern California Edison EV Fleet Management

Southern California Edison (SCE) (and other California transmission and distribution utilities) is advancing the visibility, monitoring, and controllability of EV fleets through a comprehensive, AI-enabled infrastructure platform and DER management system (DERMS)[23]. As part of a five-year initiative to support fleet electrification, SCE is deploying a scalable, secure, and high-uptime EV charging network across its 50,000-square-mile service area. The system integrates real-time monitoring, remote diagnostics, and secure data handling, enabling fleet managers to maintain full operational visibility and control over EV charging activities. The DERMS platform will be designed for critical utility operations and ensures high reliability for emergency response and field services, while also incorporating load management tools and API integrations to support evolving energy strategies.

ISON Spotlights

EirGrid has implemented a range of technical and regulatory measures to enhance DER visibility and coordination with the national DSO. Ireland operates a central dispatch model, managed by the TSO, which primarily focuses on large-scale generation units connected to the high-voltage grid. Since the early 2000s, EirGrid has mandated that all generator units above 1 MW must provide SCADA visibility to the system operator. Furthermore, generator units above 1 MW are required to be controllable, subject to Active Power Control or Central Dispatch (based on requirements outlined in the Distribution Code and Grid Code). For demand sites to take part in the wholesale market arrangements, they would need to be part of a Demand Side Unit which, either individually with that site or as part of an aggregation with other sites, must have a capacity of greater than or equal to 4 MW, meaning it would be subject to Central Dispatch.

The level of controllability depends on the type of resource. For instance, historically relevant renewable generators with priority dispatch would have requirements to be controllable so that their maximum output could be limited but would not need to be fully dispatchable. However, in future, following changes required by Regulation (EU) 2019/943 to enable non-priority dispatch renewables, relevant renewable generators without priority dispatch would need to be fully dispatchable. The Grid Code definition of Central Dispatch outlines further thresholds for the application of dispatchability to generation units and other resource types, including that all relevant energy storage power stations would be subject to Central Dispatch.

All dispatchable market participants are required to submit physical notifications (PNs), which indicate their intended generation output, excluding any balancing actions taken by the TSO. These notifications are essential for system planning and real-time operations. In contrast, non-dispatchable participants are not obligated to submit PNs, which can limit visibility into their operational behaviour. However, for those non-dispatchable participants which have visibility requirements, such as controllable renewable generation units, visibility is available through TSO forecasting of the availability of the resource and SCADA measurements of the real-time availability of the resource. For smaller resources to which those visibility requirements do not apply, the TSO coordinates with the DSO to get data on the installed capacity of these resources to estimate the availability forecasts.

The TSO also coordinates with the DSO in regard to Demand Side Units (DSU) in situations where the distribution network is limited or congested in areas where the DSU sites are located. In these cases, the DSO will provide information ("instruction sets") to the DSU on the limits they are applying to the operation of those sites - the DSU must operate in such a way that they do not exceed these DSU limits.

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[23] SCE DERMS Information. [Online]. Available: https://www.energy.gov/oe/articles/ferc2johnsonsce#:~:text=%E2%80%A2%20Advanced%20Distribution%20Management%20System,Grid%20Device%20Management%20Capabilities%20(GDM). [Accessed: Dec. 12, 2025].

In general, the final PN position of dispatchable units is considered the starting point for their dispatch. Decisions to dispatch such units away from this position are taken based on balancing market merit orders to meet the system wide energy balance and system and/or local constraint requirements. For controllable units which are not dispatchable, such as priority dispatch renewables, in the base scenario they operate at their maximum availability without a dispatch instruction from the TSO and may be controlled down by the TSO to manage system-wide or local issues. Those control decisions are not based on merit order, and therefore the level of control is typically carried out on a pro-rata basis across the set of units which can contribute towards meeting the particular system or local need, with a regulatory framework in place for considerations including various tie-break scenarios and the order in which different control actions should be taken to meet different needs occurring at the same time.

The role of the DSO in the dispatch process is not specified in the current legislation (either European Union level or national level in Ireland). However, the evolution of DSO procurement of market-based services to address local distribution issues will lead to more active DSO roles to control and activate local DER. This requires an upgrade of Ireland's current activation/dispatch process. As an isolated power system, the issues related to the security of supply and system stability are paramount to the activation/dispatch process, mainly when a significant amount of generation capacity/DER is connected to the distribution grid, during high wind and or high solar periods. The current activation/dispatch process is well established for large PPMs connected to the transmission grid and distribution grids at HV (110 kV and 38 kV) and MV (20 kV and 10 kV). Changes and adjustments may be needed for the development of new roles for the DSO, the provision of services from DER to the DSO and TSO and demand-side participation in the energy markets.

The DSO/TSO Joint System Operator Programme Multi-Year Plan[24] in Ireland is a strategic framework jointly developed by EirGrid and ESB Networks to ensure coordinated operational planning and system development across both the transmission and distribution networks. Improving DER visibility and controllability is a key focus of the DSO/TSO Joint System Operator Programme. It includes enhancing real-time data sharing, aligning forecasting methods, and upgrading control centre capabilities to actively monitor and manage DER.

As part of this Joint System Operator Programme, a future TSO-DSO Operating Model is under development, which will outline how the TSO and DSO will coordinate the scheduling and activation/dispatch of distribution-connected resources. This can be to use these resources to meet both DSO and TSO needs when the resources are visible to both TSO and DSO, or for the TSO to account for the impact on the power system of the DSO using resources to manage their needs where the resources are not visible to the TSO. The Network Code for Demand Response, which is currently in development[25,26] and will apply across the EU, will also include further requirements for TSO/DSO coordination, including how the DSO can use distribution connected resources to manage congestion needs, and steps to help enable smaller-scale sites to participate in TSO and DSO markets.

In California, once **CAISO** accepts bids and schedules a Distributed Energy Resource Aggregator (DERA), it issues dispatch instructions that specify the quantity and timing of energy to be produced or consumed.

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[24] DSO/TSO Multi-Year Plan 2025-2029: https://cms.eirgrid.ie/sites/default/files/publications/DSO-TSO-2025-2029-Multi-Year-Plan-September-2024.pdf.

[25] See https://www.acer.europa.eu/news/new-network-code-demand-response-will-further-advance-energy-transition.

[26] See https://www.acer.europa.eu/sites/default/files/documents/Recommendations_annex/ACER_Recommendation_01-2025_DR_NC-Annex1_Amended_DR_NC.pdf.

These instructions are considered binding. However, because DER are physically located on the distribution grid, coordination with distribution utilities (for example, PG&E, SCE, SDG&E) is essential for safe and reliable operation. Distribution utilities retain authority over local safety and reliability and may override CAISO dispatches in two primary ways:

- **Grid Outage Declaration** – the utility may declare an outage or local reliability event to CAISO through its Outage Management System (OMS). CAISO then update the market status of the affected DERA, reducing or suspending its dispatch obligations as necessary.
- **Alternate Dispatch Notification** – the utility may instruct a DERA to adjust or cease operations due to distribution-level constraints (e.g., voltage violations, line loading issues). The DERA must communicate this override to CAISO, which will then treat the event as a generation resource outage or operational limitation in its dispatch systems.

A Scheduling Coordinator (SC) is the official certified entity responsible for interfacing with CAISO's wholesale energy markets on behalf of resources such as generators, load-serving entities, DER aggregators, or storage operators. SCs submit bids and schedules for energy, ancillary services, and capacity into the Day-Ahead Market (DAM), 15-Minute Market (FMM), and Real-Time Market (RTM), receive dispatch instructions, and handle settlement and meter data management.

Under FERC Order 2222, any DERA participating in CAISO's markets must either be its own Scheduling Coordinator or contract with a certified SC. This is essential because:

- the DERA (or DER Provider) needs a certified SC to submit bids, receive real-time dispatch signals, and settle market transactions, and
- the SC manages all operational requirements on behalf of the DERA, including telemetry, resource characterisation, and compliance with market rules.

This structure ensures CAISO maintains centralised control over market integration while allowing flexibility for aggregators via trusted SC relationships.

This layered approach ensures that DERAs can contribute to wholesale market operations while maintaining local grid reliability. However, the California Public Utilities Commission (CPUC) has identified key operational needs for a high-DER future, emphasising enhanced visibility and controllability of DERs[27]. For DSOs, real-time awareness of DER output, mutual sharing of operational data, and the deployment of intelligent sensors and automation technologies are essential to improve grid reliability and enable dynamic reconfiguration during disturbances. For CAISO, coordinated access to detailed DER information – including type, location, size, and behaviour – is considered as critical for forecasting, planning, and market operations. Visibility of both market and non-market DER is necessary to maintain situational awareness, especially with growing electrification of transportation. Additionally, DER dispatchability must be improved through secure communications, software platforms for scheduling and control, and frameworks for real-time coordination to support system reliability and flexibility.

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[27] CPUC (2024). High DER Future Workshop 1 Summary: Operational Needs: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M543/K418/543418944.PDF.

Energinet has an overview of prequalified units for ancillary services and can control them by activating bids in the energy activation markets, or if they are procured as frequency reserves. Energinet uses a self-dispatch model, which means Energinet does not directly dispatch Balance Responsible Parties (BRPs)[28] in the way some system operators might centrally dispatch generators. BRPs including DER within aggregators are responsible for operating to their day-ahead and intraday schedules, reflecting their expected production and consumption for each metering point or aggregated portfolio (including DER). BRPs are financially responsible for any imbalances between their scheduled and actual positions; if their actual generation or consumption deviates from their submitted schedules, Energinet balances the system in real time by activating ancillary services and balancing reserves, and the resulting costs (imbalance prices) are settled with the BRP that caused the imbalance. This system incentivises BRPs to maintain balance but leaves the operational dispatch decisions (such as when to run a plant or curtail demand) to the BRPs themselves, rather than Energinet issuing direct dispatch instructions. For ancillary services and balancing products, Energinet may request activation from specific market participants, and the BRP is required to perform as requested if their resources are selected.

In the **ERCOT** market, most CER (PV primarily) do not register with ERCOT or an aggregator and, therefore, are not dispatched or controlled by ERCOT. Qualified Scheduling Entities (QSEs) act as the intermediaries between ERCOT and all market resources, including DER Aggregators (DERAs). QSEs are responsible for submitting energy schedules, market bids, and ancillary service offers on behalf of their represented resources. Once cleared, ERCOT issues dispatch instructions to QSEs via Inter-Control Center Protocol (ICCP) links. These dispatch instructions are binding, and QSEs are responsible for ensuring that DERAs comply with them in real time.

ERCOT serves as the sole authority for dispatch decisions, maintaining operational control using real-time grid data provided by Transmission and Distribution Utilities (TDUs). While TDUs manage the physical delivery infrastructure, they are prohibited from owning generation or energy storage assets, maintaining their neutral role in the deregulated Texas market. TDUs support system reliability by sharing updated power flow, voltage quality, and load forecast data – including the impact of DER – with ERCOT.

To participate in the ERCOT market, DER aggregations must register through a Load-Serving Entity (LSE) such as a competitive retailer, municipal utility, or electric cooperative. Performance of DER is measured and verified through market settlement processes managed by the QSE and ERCOT.

NESO currently has limited visibility and controllability of DER via the Balancing Mechanism and minimally through some DSOs using their Megawatt Dispatch programme. The majority of DER and CER are not real-time visible nor controllable through markets by NESO. Initiatives are being pursued to cover these gaps.

AEMO currently has limited controllability visibility and controllability of DER in both the NEM and WEM. Prompted by the increasing aggregate impact of distributed PV on the system load profile and the sympathetic tripping of these systems during disturbances, AEMO identified the need for last resort control of DER across the mainland NEM in 2020[29]. Since this period, distributed PV curtailment schemes have been implemented across different regions through state-based requirements.

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[28] **BRP** is an entity in the European electricity market responsible for balancing electricity supply and demand within its portfolio. The BRP ensures that the amount of electricity injected into the grid matches consumption and manages any imbalances financially by coordinating with the TSO.

[29] Australian Energy Market Operator (AEMO), "Renewable Integration Study Stage 1 report," 2020 [Online]. Available: https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris. [Accessed: Jun. 27, 2025]. Refer to Action 3.4.

In the NEM, curtailment schemes are the DSOs' responsibility to implement, with necessary systems and processes in place to coordinate with AEMO and transmission utilities as required. The WEM arrangement is based on retailer coordination and management.

DSOs in the NEM and WEM are starting to implement, or committed to implementing through their CER integration strategies, flexible export arrangements for distributed PV connections. This is an evolution from static export limits applied at the DER inverter level as a site level control action, to dynamically change the site level export limit depending on available local network hosting capacity.

Flexible exports fall within the broader categorisation of 'dynamic operating envelopes', which also covers the potential for limiting imports. The first focus in Australia has been on the export case, with the priority on managing the impact of distributed PV on the distribution network. This follows extensive trialling across DSOs that has led to development of an interoperability architecture based on local adoption of IEEE2030.5 communication protocol[30], and regulatory clarity[31].

DSOs are also implementing local flexibility initiatives, including development of management platforms coordinating demand response and CER devices for network support as well as community storage programs. AEMO is engaging actively with DSOs on the coordination required for activities impacting net load as transmission-distribution interfaces to be accounted for in bulk power system operations.

This is being supported by broader policy focus at the national level on how roles and responsibilities for system and market operation in a high DER power system, including formalising expectations and accountabilities for transmission-distribution coordination.

AEMO's Operations Technology Roadmap[32] includes a broad focus on the ingestion, storage and maintenance, and use of CER data within AEMO's operational systems and processes. In addition, AEMO is collaborating with industry through the CER Data Exchange Industry Co-Design initiative[33] on the first stage of development of a national data exchange framework, covering the coordination required across organisations – including AEMO, DSOs, aggregators, retailers and other customer agents.

Market mechanisms and services for DER and CER innovations

Global Industry Spotlight – The Equigy Platform in Europe

ISON understand that Equigy is a European crowd balancing platform (CBP) developed as a joint initiative by several Transmission System Operators (TSOs), including TenneT (Netherlands and Germany), Swissgrid (Switzerland), Terna (Italy), APG (Austria), and TransnetBW (Germany). Its central objective is to unlock the flexibility potential of DER – such as EVs, home batteries, and heat pumps – by enabling their participation in balancing and redispatch markets. Equigy is built on private blockchain technology for secure, transparent,

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[30] Standards Australia, "SA TS 5573:2025 Common Smart Inverter Profile - Australia with Test Procedures," 2025 [Online]. Available : https://www.standards.org.au/standards-catalogue/standard-details?designation=sa-ts-5573-2025. [Accessed: Jun. 27, 2025].

[31] Australian Energy Regulator, "Export Limits Guidance Note," 2024 [Online]. Available: https://www.aer.gov.au/documents/export-limits-guidance-note. [Accessed: Jun. 27, 2025].

[32] Australian Energy Market Operator (AEMO), "Operations Technology Roadmap Executive Summary," June 2022. [Online]. Available: https://aemo.com.au/-/media/files/initiatives/operations-technology-roadmap/executive-summary-report-for-the-otr.pdf?la=en. [Accessed: Jun. 12, 2025].

[33] Australian Energy Market Operator (AEMO), "CER Data Exchange Industry Co-Design". [Online]. Available: https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework/CER-Data-Exchange-Industry-CoDesign. [Accessed: Aug. 19, 2025].

and standardized data exchange between aggregators, TSOs, DSOs, and OEMs. The platform allows aggregators to pool small-scale flexibility assets and offer them as ancillary services, such as aFRR, to grid operators. Equigy's architecture supports national deployments with a shared European core, promoting cross-border scalability while respecting local market rules. Currently operational in several countries, the platform is expanding its reach and functionality, aiming to become a pan-European standard for flexibility integration in support of the energy transition[34].

ISON Spotlights

The participation of DER in wholesale electricity markets, ancillary services, and local flexibility markets is evolving rapidly around the world. While there is broad interest in enabling DER to contribute to grid services, the regulatory frameworks, market access pathways, and operational roles for DER differ significantly across jurisdictions. In some regions, DER are integrated through established aggregator models and real-time dispatch systems, while in others, participation is still limited to pilot projects or constrained by legacy distribution system architectures.

For **AEMO**, the NEM is an energy-only market covering ~80% of Australian electricity consumption. It is a wholesale market, where electricity generators offer bids to supply electricity to the market. The WEM is smaller and operated differently to NEM. It is a vertically integrated market with two state-owned utilities – Western Power and Horizon Power – controlling the majority of electricity generation as well as transmission and distribution.

The NEM wholesale market is administered and operated by AEMO through a centrally coordinated process. With some exceptions, typically units < 5 MW (and often larger units < 30 MW) only participate in the NEM via an aggregator or retailer.

Several initiatives facilitate opportunities for distribution-connected DER less than 5 MW to participate in the wholesale markets:

- The Wholesale Demand Response Mechanism (WDRM) in the NEM enables aggregators to offer DR services to the market via DER reducing their consumption during periods of high demand or system stress.
- Small resource aggregators can participate in the NEM, registering as Integrated Resource Providers allowing them to aggregate small generating and storage units to provide energy and ancillary services[35].
- DER aggregations are currently permitted to participate in contingency frequency control ancillary services (FCAS) markets in both the NEM and WEM. However, participation has been low following the initial trials and demonstrations leading to formalisation of these arrangements in 2021[36].

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[34] See https://equigy.com/2024/02/29/dno-now-offers-afrr-to-its-customers-in-addition-to-mfrr-unlocking-new-potential/.

[35] Australian Energy Market Operator, "Small Resource Aggregators in the NEM- Fact Sheet," AEMO, Jul. 19, 2024. [Online]. Available: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration/register-as-a-small-generation-aggregator-sga-in-the-nem. [Accessed: Dec. 10, 2025].

[36] Australian Energy Market Operator, "Amendment of the Market Ancillary Service Specification (MASS) – DER and General consultation," AEMO, Dec. 8, 2021. [Online]. Available: https://aemo.com.au/consultations/current-and-closed-consultations/mass-consultation. [Accessed: Jun. 27, 2025].

- Initiatives are progressing in both the NEM and WEM to enable more aggregated DER to participate in energy and frequency control ancillary service markets[37] and enabling service providers to separately manage flexible CER from passive loads[38].

For **CAISO**, the development of DER in California has largely been influenced by both federal and state-level policies. FERC Order No. 2222 is still relatively new and undergoing compliance. However, CAISO has had a participation model pre-dating Order No. 2222 that aimed to encourage DER aggregations to participate in CAISO markets. DER can participate in the wholesale market operated by CAISO using one of the available market participation models: DERP (Distributed Energy Resource Provider), PDR (Proxy Demand Response), PDR-LSR (PDR – Load Shift Resource), RDRR (Reliability Demand Response Resource), LESR (Limited Energy Storage Resource), DDR (Dispatchable Demand Response), and NGR (Non-Generating Resource). Participation models are typically categorised based on technology type, size limits, and eligibility to provide a subset of wholesale services. For example, aggregations participating via DERP can be homogeneous (that is, only containing individual resources of the same technology type, such as variable energy resources only) or heterogeneous (that is, containing individual resources representing a range of technologies, such as a combination of variable energy resources and storage).

At the interconnection stage, implicit coordination comes from the fact that DER interested in providing wholesale services must first obtain an interconnection agreement from the distribution utility. Importantly, DER seeking to provide wholesale services must connect to the distribution grid under the wholesale distribution tariff (WDT), also called the wholesale distribution access tariff (WDAT). Under this tariff, DER are settled for the energy they exchange with the grid by CAISO, as if they were connected at the transmission level.

In California, the provision of distribution grid services by DER, either individually or through aggregations, is still in an emergent phase with many projects and initiatives currently being discussed or at a pilot stage. Although there have been different projects reaching commercial procurement, most of them have not yet reached the commercial operations stage. Those projects that will provide both distribution and wholesale grid services in the near future are so-called non-wires alternatives (NWA) projects through the DIDF (Distribution Investment and Deferral Framework). Therefore, there is minimal coordination to date between the distribution utilities and CAISO with respect to distribution grid services provided by DER, largely because very few DER currently provide grid services in the region.

For **NESO**, at the distribution level, Great Britain is one of the most advanced regions in terms of emerging market-based procurement of services, with all six DSOs procuring distribution services from connected assets. Since 2019, the British regulator Ofgem has been encouraging the development of local flexibility markets through the implementation of the new price control framework for DSOs, known as RIIO-ED22. At the bulk transmission level, a major reform of the service definitions and procurement processes has been underway over the past few years, and DER assets are currently able to participate in a range of bulk service products.

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[37] Australian Energy Market Operator, “Voluntarily Scheduled Resources Guidelines consultation,” AEMO, Jun. 3, 2025. [Online]. Available: https://aemo.com.au/consultations/current-and-closed-consultations/voluntarily-scheduled-resources-guidelines-consultation. [Accessed: Jun. 27, 2025].

[38] Australian Energy Market Commission, “Unlocking CER benefits through flexible trading” AEMC, Aug. 15, 2024. [Online]. Available: https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading. [Accessed: Jun. 27, 2025].

In Great Britain, there also is a variety of bulk system services open to DER connected at all voltage levels. These services include Dynamic Response, MW Dispatch, Demand Flexibility, and Restoration services, as well as participation in the Capacity Market. For example, NESO is currently enabling limited procurement of transmission constraint management services from small, distributed assets in collaboration with two DSOs (NGED and UKPN) utilising a DERMS management system. This is still in limited regional application only at present (not a universal service open to DERs across Great Britain).

The future objective is to make DER access all markets by default, whereas currently they need to apply individually.

Energinet has established a market mechanism to activate DER and have active DER participation. Currently Energinet has hourly prices (which will soon be replaced by 15 minute prices) available for all end-users. Owners of EVs (87% of new cars in Denmark are EV) respond to price changes, to charge their cars at optimal times. DER aggregators also participate in the Danish market to provide ancillary services.

In addition to this top-down wholesale energy market price response, Energinet also recently introduced a model in the current mFRR energy activation market (regulating power market) and aFRR energy activation market, where it is mandatory to provide geographical tags (so called ‘geo-tags’ indicating the closest grid station) on energy bids. Aggregated bids may have more than one geo-tag. In June 2025, Energinet also introduced geo-tags in the mFRR capacity market. A significant reason for the introduction of this model is Energinet's challenges with internal bottlenecks in the transmission network. In balancing the power system, Energinet will ensure through the geo-tag that balancing energy is not activated (and purchased) ‘behind the bottleneck’, which would prevent use of the balancing energy. The geo-tag also allows Energinet to use the bids to manage local bottlenecks in the TSO network.

In the DSO networks, work is also being done to prevent problems with grid adequacy and local bottlenecks. Today, DSOs use a combination of grid expansions and implicit flexibility through tariffs to ensure grid adequacy. Additionally, DSOs use connections with limited grid access for new customers (Energinet too), and they are also working on a pilot basis with market-based acquired flexibility through tenders and long-term contracts.

Together with the Danish DSOs, Energinet is investigating the potential to expand Energinet’s geo-tag model to include the DSO grid (for example, at the 50 kV and 60 kV level). The primary purpose of expanding the geo-tag solution is to provide DSOs with access to local flexibility, which can help mitigate the grid companies' challenges with local bottlenecks in the MV DSO network. The prerequisite use of the geo-tag model is to demonstrate the need for flexibility before it is actually needed. There are several differences in the possibilities that TSOs and DSOs have for working with flexibility close to real time. The secondary purposes are to investigate the possibility of more coordinated operations between DSOs and TSOs and to give flexibility providers the opportunity to make their flexibility available for multiple purposes (grid adequacy/local bottlenecks, balancing) across markets (increased liquidity) through a uniform solution.

As the share of DER increases across European power systems, system operators are developing new approaches to harness their flexibility in both local and system-wide operations. Traditional grid planning and operation models are being challenged by the variability and decentralisation of resources like rooftop solar, EVs, batteries, and flexible demand. In this context, several European initiatives have emerged to test how DER can be integrated into operational processes and market structures that serve both distribution-level and transmission-level needs. Among the most notable in the Nordic countries are NorFlex and NODES in

Norway, and StockholmFlex in Sweden. These initiatives focus on enabling flexibility to relieve grid congestion, defer infrastructure investments, and provide balancing and ancillary services.

NorFlex focused on activating flexibility to manage local congestion and offering surplus capacity to the TSO, while NODES provided a digital marketplace enabling transparent, multi-level trading of flexibility services. StockholmFlex addressed regional capacity constraints and created market layers to coordinate DSO and TSO flexibility procurement. SmartNet analysed and tested various TSO–DSO coordination models to optimise the use of flexibility across grid levels, emphasising real-time data sharing and market design innovations. Building on SmartNet's foundation, OneNet expands the concept by proposing an integrated, unified market architecture that combines flexibility from distribution and transmission networks, aiming for end-to-end coordination across all system operators, market participants, and DER aggregators.

In **ERCOT**, many self-dispatched generation units and customer loads currently participate in the Emergency Response Service or directly in ERCOT markets as Load Resources. In parallel, BTM battery aggregations are beginning to participate through pilot programs. One notable example is a pilot treating aggregated BTM batteries as load resources, influenced in part by a demonstration project led by Tesla.

In terms of demand-side programs, each investor-owned Transmission and Distribution Utility (TDU) in Texas is required to meet a portion of their annual demand growth through energy efficiency programs. These programs may include load management schemes in which customers agree to reduce demand upon request. While these initiatives are not directly administered by ERCOT, TDUs have agreements in place allowing ERCOT to utilise this DR capacity. Some consumers may also self-administer DR by responding to time-of-use pricing signals and shifting consumption to off-peak periods. Currently, TDUs do not offer non-firm or flexible connections to DER. Currently, Load Resource aggregations are only authorised to provide non-spinning reserves in ERCOT's ancillary services market. However, ERCOT has launched the Aggregate Distributed Energy Resource (ADER) Pilot Program to test the operational feasibility and market integration of diverse DER aggregations:

- Phase 1 of the pilot allows for the development of up to 80 MW of aggregated DER capacity. Participating in aggregations may deliver energy and certain ancillary services, such as non-spinning reserves.
- Phase 2 applied lessons learned from telemetry validation processes and expanded opportunities for ADERs to provide Ancillary Services (the ERCOT Contingency Reserve Service (ECRS), which was not yet in place when phase 1 of the Pilot Project began).

For certain services, customers must register as a Load Resource with ERCOT and undergo facility testing prior to participating in the market. For other services, participation may only require entering into an agreement with a Retail Electric Provider (REP) or a QSE acting as a DR provider.

Emergency operations, black start and restoration innovations

Global Industry Spotlight – China State Grid Smart Fault Detection and Restoration

ISON understand that China's State Grid, through its subsidiary China Southern Power Grid, has trialled the country's first AI-powered autonomous power grid restoration system in Shenzhen. Deployed at a 110 kV substation in the Liuxiandong strategic emerging industry zone, the system leverages artificial intelligence algorithms to detect faults, generate real-time restoration strategies, and automatically switch to backup power sources. During a simulated fault, the system restored power in just 17 seconds, representing a 95% improvement over traditional manual restoration methods. This self-healing grid enhances operational reliability and minimizes downtime, particularly in critical infrastructure zones such as high-speed rail stations and major tech hubs[39]. Similarly AusNet, an Australian energy network business, has also had in place distribution feeder automation capabilities for over 10 years.

ISON Spotlights

UFLS serves as a frequency-arresting backstop by disconnecting blocks of demand at pre-defined thresholds. This model worked for decades, until recent years, where DER can now make up a considerable amount of the load that is to be shed by UFLS protection relays. By tripping a mix of generation and demand instead of just demand, the corrective impact on frequency can be offset or even reversed.

AEMO's May 2024 report reviewed Emergency Under-Frequency Response (EUFR) requirements for South Australia as distributed PV penetration increased. To manage these risks, AEMO proposed a new EUFR target of 700 MW or 60% of operational demand (whichever is higher), sufficient to address about 80% of severe contingency scenarios, such as NEM grid separation combined with generator or distributed PV tripping. The report highlighted the rollout of dynamic arming for UFLS relays (disabling them during reverse flows) and the commissioning of large BESS, which together will help meet the EUFR target 99.8% of the time by 2025. The report recommended other, urgent, low-cost UFLS upgrades in Victoria and continued adoption of dynamic arming across the NEM to further reduce risk as South Australia transitions to a grid dominated by renewables. Despite these improvements, some residual risk remains. EUFR with DER is an ongoing challenge and active area of risk mitigation for AEMO.

EirGrid operates a UFLS scheme in coordination with the DSO. Normal tariff customers are tripped in tranches starting at 48.85 hertz (Hz, off a 50 Hz nominal). The blocks of load are spread proportionally across the jurisdiction and not regionally specific. The frequency has not breached the first UFLS threshold since 2014, however with increasing DER and CER coordination between the TSOs and DSOs in Ireland and Northern Ireland to discriminate between feeders with high DER penetrations or reverse flows will be essential for resilient future operations. DER are not utilised in the emergency restoration or black start process. The current strategy is to disconnect all DER while the system is being restored, understanding that DER will likely continue to produce power as soon as it is reconnected to the network.

The Distributed ReStart project was a UK-led initiative (2019), led by **NESO** with SP Energy Networks and TNEI, funded by Ofgem's Network Innovation Competition. It explored how DER – such as wind, solar, hydro, and batteries connected at distribution voltages (33 kV/11 kV) – could be coordinated to restore power after a major grid blackout, a role traditionally held by large transmission-connected generators.

The project proposed a three-step restoration process:

1. starting the system from one or more DER without external power
2. maintaining a localised power island of DER and loads, and
3. expanding the energised area by linking multiple islands and adding generation.

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[39] See https://english.news.cn/20250303/9f93b26ebed84514b71112645dc15011/c.html.

This approach aligns with the evolving DSO model, giving DSOs new roles in local restoration zones called Distribution Restoration Zones (DRZs). Some key findings included:

- DER must meet specific technical functions (voltage/frequency control, inertia, fault response) to support restoration,
- network readiness and protection coordination are crucial, especially at lower voltages where DER fault current is limited,
- communication systems need to be resilient, secure, and low latency to coordinate DER effectively, and
- live testing revealed challenges like harmonic resonance and transient overvoltages during network energisation, with mitigation strategies including controlled energisation methods and load management.

The restart project developed technology-neutral guidelines for DRZ Controllers to manage restoration zones, emphasising automation to reduce operational complexity and training needs. Successful DRZ deployment requires coordination among ESO, DSOs, and DER operators, with DER ready to respond within eight hours. It represents a shift toward more decentralised and resilient blackout recovery but also demands network investments and tailored restoration planning.

The distributed restart project at NESO has shown that using DER to restart the distribution network is feasible, although significant technical, operational, commercial, and regulatory challenges remain to realise the full potential of DERs in restoration. NESO is currently procuring restoration assets connected to DSO networks according to the learnings from distributed restart.

5 Summary – towards a DER Vision Architecture – gaps and needs

Capability gap	Current situation	Need
Organisational and functional architecture	• Unclear or overlapping roles among TSO, DSO, and FSPs and market players • Lack of consistent role definitions across jurisdictions • DSO role in flexibility (from DER and load) and system balancing is often undefined	• Clear definition of functional roles: who plans, who activates, who validates DER actions • Implementation of 'primacy rules' to define which party has operational authority under different grid states • Role alignment across market-based and non-market flexibility schemes
System control and operational coordination	• Limited real-time DER controllability • DER often seen as 'must take' or non-dispatchable • TSOs have limited visibility of DER connected to the distribution grids	• Integrated control hierarchies (centralised, decentralised, or hybrid) • DSOs as operational actors capable of issuing setpoints and managing local constraints • DER integrated in operational planning, contingency analysis, and restoration schemes
Data exchange and interoperability	• Static or planning-only data exchange • Poor standardisation in data formats • Eventual manual data sharing between TSO–DSO-market players	• Real-time, bidirectional data exchange (status, forecasts, schedules, capabilities) • Common Information Models (e.g., IEC 61970/61968, CIM extensions for DER) • APIs and cybersecurity models to protect sensitive operational data
DER modelling and forecasting	• DER models are simplistic or aggregated • Many DSOs rely on historical trends, not dynamic forecasting • Lack of weather-linked or behaviourally responsive forecasts	• High-resolution DER models reflecting technology type, controllability, customer behaviour • Real-time and day-ahead probabilistic forecasting, shared between actors • Models that reflect location-specific grid impact and coordination needs • From the transmission perspective, dynamic models that represent DER response to system events (e.g., frequency, voltage excursions)
Market integration and dispatch platforms	• Aggregator-centric pilots, not system-integrated • TSOs and DSOs often activate DER separately • Prequalification and dispatch not harmonised	• Co-optimised market platforms with TSO–DSO coordination engines • Dynamic DER portfolio registration and availability updates • Prequalification based on grid-supportive behaviours, not just energy provision
ICT and digital infrastructure	• Legacy SCADA/EMS/DMS systems not built for DER integration • DERMS platforms still emerging, often proprietary	• Modular and open architectures • Edge control and orchestration at substation or feeder level • Scalable to thousands/millions of devices with secure communication layers

Capability gap	Current situation	Need
Regulatory and governance framework	Regulation is reactive and technology-neutral No harmonised definition of primacy, fallback responsibility, or dispute resolution Licensing, data access, and validation authority are fragmented	Primacy rules: agreed protocols for those who (TSO or DSO) have authority to control/curtail DER under normal and stressed conditions Enabling regulation for DSO-led flexibility procurement Clarity on responsibility for forecasting, activation, settlement Regulatory sandboxes to test new coordination models

Advancing DER architecture for TSO–DSO coordination

Key actions for stakeholders

Regulators and policymakers

- Mandate clear functional roles and develop legally binding primacy rules to govern DER control in real-time operations.
- Establish frameworks for procurement and activation of flexibility provided by DER, which could be joint for both TSO and DSO, or separate for each system operator but with coordinated arrangements which account for each other and set out the approach to stacking the flexibility mechanisms.
- Support regulatory sandboxes and innovation zones to trial coordination mechanisms without penalty risk.

DSOs and TSOs

- Jointly define interface protocols, fallback procedures, and real-time coordination responsibilities.
- Co-invest in interoperability platforms and shared data models.
- Embed DER coordination into operational planning and outage/restoration procedures.
- Enable value stacking – value stacking allows DER to access multiple revenue streams by participating in both wholesale and distribution-level markets. While it improves returns, clear frameworks are needed to ensure service performance is upheld and system operation remains reliable and coordinated.
  - To ensure service performance and protect system reliability, system operators expect DER to fully deliver on all committed services, regardless of market layer. Participation rules must be designed to prevent intentional or avoidable service defaults, reinforce accountability through meaningful deterrents, and require that performance requirements for stacked services are compatible[40].
- Need to establish primacy rules – primacy rules define a clear hierarchy among network services and flexibility options to prevent conflicts when multiple system operators (e.g., TSO and DSOs) request services simultaneously (see the previous point on the value stacking). For service providers contracted with multiple parties – such as a DSO and TSO – primacy rules clarify which party's service request takes precedence, avoiding contradictory commands (for example, increasing generation for one operator while decreasing for another) and promoting coordinated, responsible asset use.

Technology providers

- Prioritise development of open, modular architectures that allow integration across DERMS, ADMS, and TSO EMS.

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[40] For example, the work being developed in the UK by the Energy Networks Association (ENA) outlines three value stacking models: **splitting**, where different capacities are used simultaneously for separate services; **jumping**, where services are delivered at different times; and **co-delivery**, where the same capacity provides multiple services at the same time and in the same direction—each approach enabling distinct revenue streams while supporting system needs. An assessment was also conducted to evaluate value stacking opportunities between distribution and transmission services, helping to identify compatibility and optimise revenue streams. See more information here: https://www.energynetworks.org/assets/images/2024-06-ena-stacking-assessment-v3.0-final-confirmed.pdf?1725791682.

- Offer location-specific DER models that can be embedded into control and planning tools.
- Ensure cybersecurity and digital identity mechanisms that work in multi-party environments.

Aggregator/CER flexibility service providers

- Engage with both TSO and DSO coordination frameworks.
- Provide real-time flexibility availability and forecasting data in standard formats.
- Participate in pilot projects to co-design market and operational interfaces.

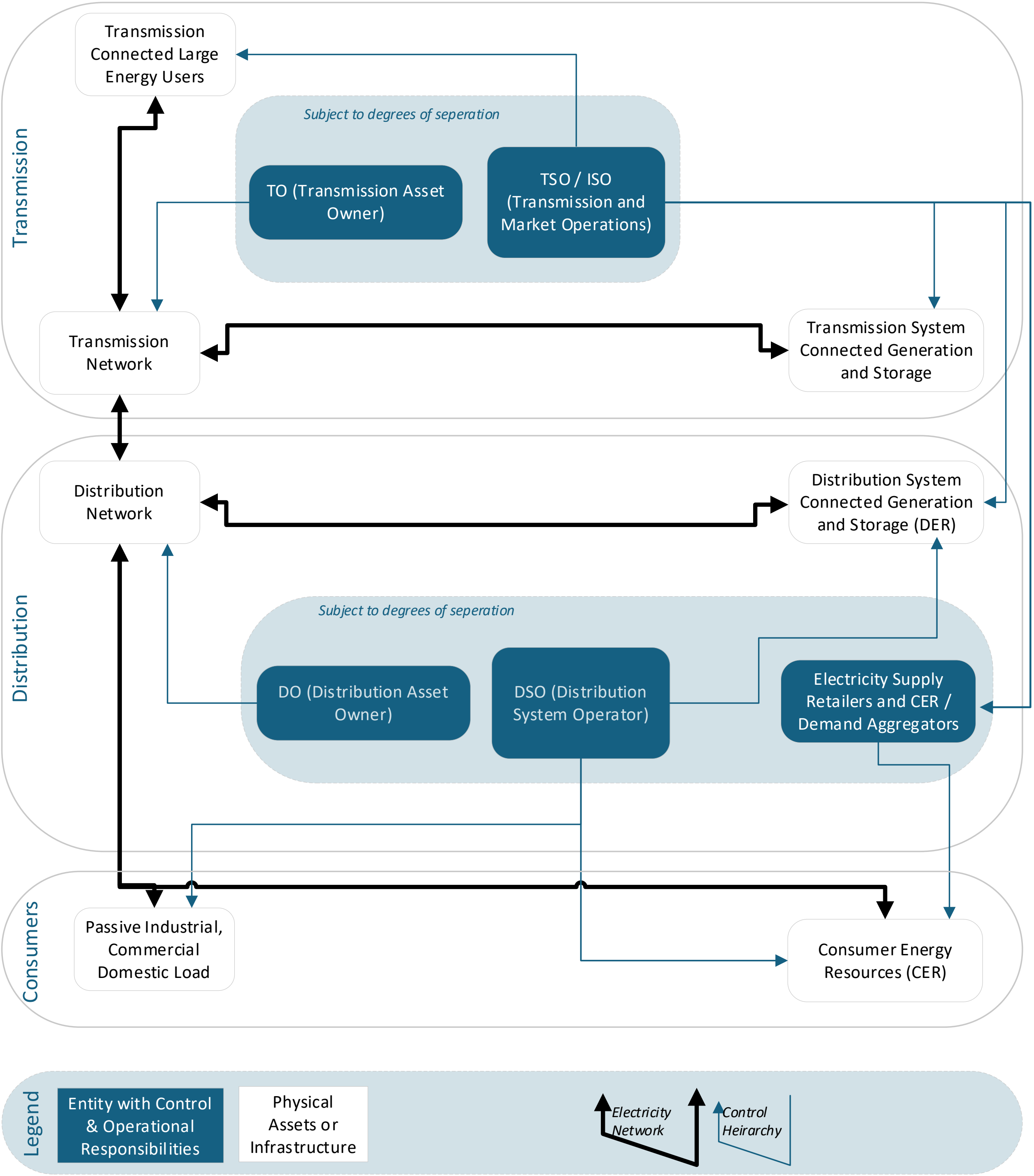
6 DER Vision Architecture

The following DER Vision Architecture is presented as a high level descriptive functional architecture based on the gaps and actions identified in this report, aligning with existing common practices and architecture globally. It could be used to map a path forward or to build on with further details and functional requirements. It does not represent firm or permanent solutions, and the constituent elements are function and country dependent.

DER Vision Architecture for Control

Figure 7 shows a simplified DER vision architecture, based on the described standardised understanding of taxonomy and control hierarchy. It shows electricity network interconnectedness and the control points between entities. The degree of separation between the network operators and owners is to be determined, based on regional regulations.

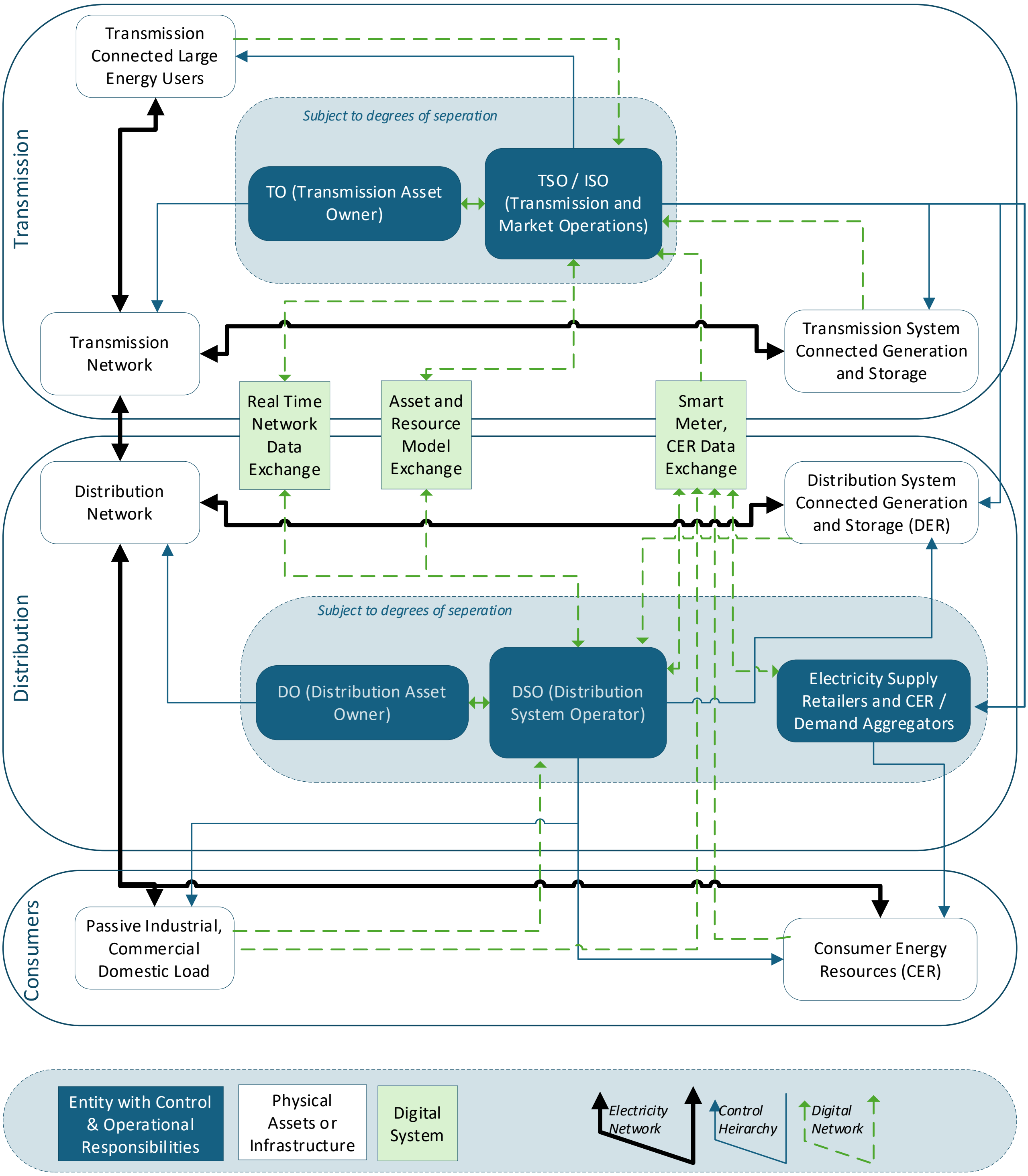
Figure 7 Simplified vision DER Architecture showing physical assets and control hierarchy



DER Vision Architecture for data and model exchange

Figure 8 shows an augmentation to the DER architecture for control with data exchange systems between transmission and distribution control entities. These could be used for real-time network data and market exchange, asset model exchange and for potentially smart meter and other CER/DER specific monitoring data exchange between consumers and system operators.

Figure 8 Simplified vision DER Architecture showing physical assets and control hierarchy and data exchange systems and networks



DER Vision Architecture for flexibility and congestion markets and services

Figure 9 illustrates the complete DER Vision Architecture showing the additional red block for flexibility markets and services between the transmission, distribution and electricity suppliers, and incorporating control, data exchange and markets and services. The key gaps and innovations are highlighted in purple, the cross-boundary systems and platforms for data and model exchange and market services.

Figure 9 Complete vision DER Architecture showing the control and data architectures augmented with a system for flexibility markets and services between the system operator entities