



TRANSPOWER

TSO–DSO coordination: Operational requirements

Discussion document

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1 Overview

The electricity system is becoming more distributed, dynamic and data-dependent. Distribution-connected generation, batteries, controllable demand, electric vehicle charging and large new loads can increasingly affect demand forecasts, power flows, voltage, system security, emergency demand management and restoration. At the same time, transmission conditions and wholesale market outcomes can affect distribution network operation. The System Operator's recent Strategy consultation¹ highlighted this complexity in priorities 4 and 5, which aim to enable secure whole of system operation and strengthen industry resilience.

This paper defines an initial set of proposed no-regret operational requirements to progress the coordination between transmission-level and distribution-level operations where this is needed by the System Operator to perform its role. It focuses on operational needs, and builds on the Electricity Authority's roadmap which considered a broader range of outcomes.

Different distributors will face different needs depending on their network characteristics, and the pace of distributed resource uptake by consumers. Some distributors may not need any kind of DSO operation for many years. Likewise the operational needs driving higher levels of interaction with the System Operator may first present regionally, rather than nationally. Establishing common foundations now where needed can help avoid fragmented approaches emerging over time.

This paper is designed to progress the establishment of foundational arrangements needed to operate this more integrated system securely and efficiently. The five requirements discussed in this paper are considered no-regret because they support existing operational responsibilities under a range of future TSO–DSO models. In considering these issues we believe that requirements should be driven by a defined operational use, provided by the party best placed to provide accurate and timely information, proportionate to operational consequence, and standardised enough to avoid fragmented solutions.

#	Requirement	Outcome sought
1	Clear operational accountabilities	Roles, decision rights, escalation and coordination for normal, abnormal and emergency conditions.
2	Minimum static information	Trusted standing information on material resources, network characteristics and expected behaviour.
3	Minimum dynamic information	Timely information on operational conditions, forecasts, resource availability, actions, outages and constraints.

¹ <https://www.transpower.co.nz/invitation-comment-system-operator-strategy-second-stage-consultation-closed>

#	Requirement	Outcome sought
4	Interoperable information exchange	Common definitions, identifiers, quality expectations and governed interfaces matched to operational criticality.
5	Predictable technical performance	Aligned outcome-based expectations and compliance information where resource or asset behaviour can affect system outcomes.

These requirements are consistent with recent work by Electricity Networks Aotearoa (ENA) and Baringa Partners². They are also complementary to the Electricity Authority's recent roadmap³ for DSO operation.

The requirements in this paper are proposed for industry discussion. They do not create new obligations or predetermine future regulatory, funding or implementation decisions. Any implementation would be subject to further definition, assessment and the appropriate regulatory and governance processes.

We are seeking industry input on whether the proposed requirements are complete, proportionate and practical. In particular, we want to know what should be changed, added or removed; whether the likely source of information is correct; and which requirements should be defined or tested first. Following engagement, the System Operator will consider industry feedback and refine the proposed requirements and information exchange priorities. The intent is to make practical progress on priority no-regret information exchanges, while avoiding premature investment or new obligations before the relevant processes have been completed and the benefits, costs, roles and implementation responsibilities are understood.

² <https://www.ena.org.nz/our-work/resources/webinar-on-potential-dso-models-for-aotearoa/document/1544>

³ [A roadmap for the future of distribution system operation in New Zealand](#)

2 Why these requirements are needed

Transpower, as the Transmission System Operator (TSO), is responsible for maintaining power system security and operating the wholesale electricity market in real time. These functions increasingly depend on an accurate view of the combined effect of resources connected across transmission and distribution networks. Better coordination can improve forecasting, security assessments, outage planning and event response. It can also reduce the need to rely on conservative assumptions when information is incomplete, thereby enabling more efficient market and power system operation and outcomes for the long-term benefit of consumers.

Distributors increasingly need to actively manage their network to incorporate increasing amounts of DER and CER. They are looking for information from the System Operator on the state of the transmission system including special protection schemes, GXP constraints, regional demand and generation forecasts, and market information to optimise the use of their networks.

What is CER and DER?

Consumer energy resources (CER) are consumer-controlled and customer-owned assets – which could include household solar, EVs or batteries, and smart energy appliances. Distributed energy resources (DER) are resources controlled inside the distribution network, and often includes CER but could also include resources used by the distribution network (e.g., small BESS installations used for voltage management) and larger-scale commercial solar and battery installations.

High levels of uncoordinated distributed resource activity can create new operational risks, including voltage and thermal constraints, congestion, uncertainty in net demand and generation dispatch, and more complex interactions between local distribution conditions and wider transmission system security. Consumers may not receive their expected benefits unless the TSO and distribution system operators (DSOs) coordinate more directly.

Connection to the System Operator Strategy

The changing operational context facing system operations was thoroughly canvassed through the two phases of consultation undertaken to inform the System Operator Strategy. It was clear from that process, and our analysis, that increasing our ability to effectively leverage and integrate CER and DER was important to lower overall system cost. This paper supports the progression of the following two strategic priorities as proposed in the System Operator Strategy:

- **Priority 4: Leveraging data and distributed energy resources:** Enable secure whole-of-system operations through shared visibility, common standards and data, and TSO–DSO coordination, so that DER/CER can integrate anywhere without undue operational risk. This priority seeks appropriate whole-of-system visibility, common data standards and protocols, and effective TSO–DSO–participant coordination.
- **Priority 5: Strengthening industry resilience:** Strengthen industry preparedness, coordination and restoration response for unplanned outages as event frequency and severity increases.

This priority seeks clearer roles, shared situational awareness and stronger preparation, response and restoration for high-impact events.

Appendix B provides more information on the linkages to the System Operator Strategy.

Principles for developing operational requirements

We recognise that data sharing and increasing the operability of systems can be costly and will require new capabilities, particularly in distribution businesses. However, there is urgency in progressing no-regret activities in a measured way before these resources become more ubiquitous. Many jurisdictions have tried to play catch up which is typically costly and fragmented. New Zealand has the opportunity to learn from this experience and put frameworks in place in a timely fashion. To ensure that we keep moving forward while containing the scope of this initiative we have grounded the operational requirements outlined in this document in the following principles:

1. **Operational need first:** Every requirement must support a defined operational decision, assessment or action needed to maintain system security and effective market outcomes. This may be local, regional or national depending on the operational need.
2. **Two-way and source-led:** Information should flow in both directions as required and come from the party best placed to provide it. We expect the System Operator will need to provide data to EDBs and other participants to ensure they can continue to perform their roles as the system evolves.
3. **Proportionate to operational consequence:** Granularity, timing, assurance and cost of information should reflect the operational consequence or risk the information is being used to address. For example, it may be appropriate to invest more in dynamic information where this sufficiently reduces the risk of unnecessary or ineffective demand management.
4. **Scale as required:** Requirements may be introduced first where material operational needs emerge and adopted elsewhere later as needed.
5. **Aggregate where sufficient:** GXP or portfolio information is preferred where asset-level data is not necessary. It may be sufficient to aggregate DER/CER at a GXP or regional level to maintain forecast accuracy, rather than at distributor feeder level.
6. **Secure and resilient:** Access, cyber security, privacy, confidentiality and fallback arrangements are part of the design.

3 Operational requirements

Requirement 1: Clear operational accountabilities

The System Operator, distributors, retailers and aggregators need a shared understanding of who does what when conditions or actions in one network can affect the other. The need is greatest when time is limited or more than one party can influence the same asset/resource or outcome.

In our view, industry needs to define and maintain operational arrangements covering:

- normal operational liaison and contact points;
- planned and unplanned outage coordination where there is a cross-boundary effect;
- voltage management across grid exit and injection points;
- notification of material operations, events, emerging constraints and loss of capability;
- coordination where transmission and distribution actions could conflict, including a process to establish primacy;
- emergency demand management, system defence and interaction with AUFLS;
- regional and national restoration, including the role of distributed generation, batteries and controlled demand; and
- escalation, fallback communications, exercising and periodic review.

The existing divisions of operational responsibilities can remain as they are initially while we build detail of the operating arrangements needed to maintain a secure and efficient power system and electricity market.

Clear accountability, stronger coordination: The TSO remains accountable for national transmission system operation and security (including coordinating emergency restoration with participants), along with the operation of the wholesale market. EDBs remain accountable for operating their distribution networks securely and working with retailers and aggregators who may have direct control over CER. Where an action can materially affect both domains, the parties need agreed visibility, coordination and escalation arrangements.

This paper does not propose that the System Operator dispatch or control small distribution-connected resources other than already allowed for under the Code.

International cross-check

United Kingdom work provides a useful functional cross-check. The UK Energy Networks Association Open Networks work identified system coordination, network operation, investment planning, connections, and system defence and restoration as core DSO functions. The National Electricity System Operator's transition work also identified service dispatch, operational liaison, and incident planning and management as coordination areas. The United Kingdom's Grid Code operational liaison provisions focus information exchange on operations or events that may have an operational effect on another system.

Requirement 2: Minimum static information

Standing or static information is required to forecast net demand, build credible power system models, plan outages, assess security, understand the likely response to a power system disturbance and prepare restoration plans. The requirement is not for all available information. It is for the minimum information that can materially improve an identified operational use.

The following table outlines the types of static information required, likely source of information, what the information would be operationally used for, and an initial scope of what information is needed.

Information required	Likely source	Primary operational use	Initial scope
Installed and approved embedded generation by type and capability (exclusive of those providing an Asset Capability Statement)	Asset Owner; EDB; Electricity Authority	Forecasting, network models, security studies, and restoration planning	Aggregate by GXP, with asset data where material penetration exists
Battery capability, including import/export limits and relevant operating characteristics (exclusive of those providing an Asset Capability Statement)	Asset Owner; EDB; Electricity Authority	Forecasting, security studies, and restoration planning	Aggregate by GXP; identify material individual assets
Large loads and data centres, including capacity and expected operating characteristics	Asset Owner; EDB; Grid Owner	Forecasting, security studies, and restoration planning	By GXP and material installation
Controllable demand and known flexibility, including who has operational control and response characteristics	Aggregator; EDB; Grid Owner; Retailer	Forecasting, emergency demand management and restoration	Aggregate by GXP and operator
Relevant network equivalents, impedances, topology boundaries and enduring constraints	EDB; Grid Owner; System Operator	Network models, load flow, fault level, voltage and outage studies	Level needed for the agreed study use case
Technical performance and protection information relevant to aggregate system response	Asset Owner; EDB; Grid Owner; System Operator	Disturbance modelling, AUFLS and compliance	Outcome-based data where system impact of underperformance or maloperation is material

For each dataset, the parties should agree an authoritative source, common definitions and units, the boundary or point of measurement, update triggers, effective dates and quality flags. Where information is incomplete, the limitation should be visible so it can be reflected in operational assessments.

International cross-check

Australia provides useful precedents for standing information. AEMO operates a Distributed Energy Resource Register as a database of device information. Australian distribution planning and data reporting reforms also focus on improved visibility while considering confidentiality, privacy, existing obligations and the need to minimise duplication. These examples support a shared, governed source of trusted information rather than repeated bilateral collection.

Requirement 3: Minimum dynamic information

Static data describes capability, but power system operation also depends on what is happening now and what is forecast to happen. Dynamic information is justified where it can change a security assessment, forecast, outage decision, operating instruction or event response. For example, during a credible extended contingent event, such as the HVDC bi-pole trip, a material volume of DER or CER may not perform as expected. If this response has not been accounted for, scheduled reserves and AUFLS may be insufficient to arrest the resulting frequency decline, potentially contributing to an island-wide or national blackout. Past events, such as the South Australian blackout and the more recent blackout affecting Spain and Portugal, have highlighted this risk. Understanding the actual performance of DER and CER through improved dynamic information means this risk can be more effectively managed.

The following table outlines the types of dynamic information required, likely source of information, what the information would be operationally used for or support, and an initial scope of what information is needed by the System Operator.

Information required	Likely source	Operational use	Indicative timing
Aggregate actual and forecast MW and MVAR at the agreed boundary where material	Asset Owner; EDB	Forecasting, security assessment	Forecast horizons (week-ahead up to real time); real-time where justified
Available and activated controllable demand or flexibility, including confirmation of action	Aggregator; EDB; Grid Owner; Retailer	Emergency demand management and restoration, forecasting	Day-ahead, intraday and event triggered
Material DER availability, constraint or state information needed for an identified use	Aggregator; Asset Owner; EDB	Security, constraint and restoration assessment	Fit to the use case

Information required	Likely source	Operational use	Indicative timing
Material distribution faults, outages, constraints or loss of control capability	EDB	Situational awareness, outage coordination and restoration	Event triggered; near real time

Distributors are also likely to require dynamic information from the System Operator and other parties going forward to effectively manage their networks. At a minimum we would suggest this include:

- relevant demand and dispatch schedules or forecasts by GXP where these support distribution decisions;
- dispatch or market actions affecting material embedded resources;
- system warnings and significant event information;
- material grid outages, transmission constraints and restoration status;
- relevant grid-interface voltage, plant state or special protection scheme information where needed for coordination; and
- instructions, requests or notifications issued under agreed emergency arrangements.

Depending on the operational need for the information, the following should be considered when determining and agreeing information sharing arrangements.

- Not every item needs real-time telemetry.
- The required timing should be derived from the decision it supports.
- Publications or schedules may be sufficient for some information.
- Event-triggered messaging or managed data exchange may suit other uses.
- Secure operational telemetry should be reserved for information whose latency, availability and assurance justify that level of service.

International cross-check

AEMO's Project EDGE demonstrated exchanges between a market operator, network and distributed resource parties, including forecasts, dynamic operating envelopes, offers, dispatch instructions and telemetry. It is useful evidence for two-way data objects and defined time intervals. It does not mean New Zealand must adopt operating envelopes now. Those should be considered only where a defined coordination need and benefit are demonstrated.

Requirement 4: Interoperable information exchange

Operational information only creates value if the parties using it have a common understanding of what it means, and how reliably it can be used to inform decision making. Furthermore, the tools and systems used to exchange this information should be sufficiently accessible and flexible to support a wide range of participants to interact in the system. As coordination needs increase, New Zealand will need a small, governed set of information-exchange platforms or tools. These should be sufficiently standardised to avoid fragmented bilateral arrangements while allowing parties to retain choice over their connecting systems.

Each agreed information exchange should define:

- the business object and operational use;
- units, sign convention, point of measurement and aggregation;
- common identifiers for GXP/GIP, installation, portfolio, controller and resource type;
- timestamp, forecast horizon, update trigger and effective period;
- quality, validation and availability indicators;
- acknowledgement, exception handling and fallback arrangements;
- authorisation, confidentiality, retention and cyber security controls; and
- ownership, change control and issue resolution.

The technical interface should match the information class, and be proportional to the operational need. Existing channels should be reused where they are fit for purpose. Potential channels include published schedules and notices, managed file or application programming interfaces (APIs), participant portals, and secure operational telemetry such as ICCP. A small governed set of interfaces is preferable to bespoke arrangements for each party.

The Electricity Authority has indicated that a 'datahub manager' contract may be beneficial in the future⁴. The service would provide verification and addressing services for the various data transfer requests that happen through the market. Such a service may help address some of the interoperability, verification and routing matters identified in this requirement.

International cross-check

The United Kingdom's Open Networks work reinforces the value of common functional requirements, standardised information semantics, governance and coordinated operating arrangements. AEMO's Project EDGE also demonstrated that dynamic coordination depends on clearly defined information objects, roles, validation rules and exchange intervals, rather than connectivity alone.

Requirement 5: Predictable technical performance

Planning and operational decisions depend on a credible expectation of how connected resources will behave in normal operation, during disturbances and during restoration. As distribution-connected and inverter-based resources increase, the wider power system can be affected by settings, protection behaviour, control modes, response times and compliance with expected performance.

Where material to system outcomes, the industry should work towards aligned, outcome-based expectations and accessible evidence for:

- fault ride-through and protection response;
- voltage and frequency response;
- active and reactive power capability;
- inverter settings and control modes;
- controllability, ramping and response confirmation; and
- commissioning, model validation, monitoring and compliance.

⁴ [Enabling market evolution: Market Operation Service Provider 10-year roadmap](#)

Alignment does not require every distribution network to use identical connection requirements. Different network conditions may justify different settings where allowed for within existing Code and technical standards. The no-regret requirement is that material differences are known, technically justified and represented correctly in models, studies and operational assumptions where they can affect the wider system.

International cross-check

The Australian Energy Market Commission's review of consumer energy resource technical standards highlights the system value of standardised device interactions and improved compliance with technical standards. The United Kingdom Open Networks work also reinforces the need to connect functional requirements, technical capability and coordinated operating arrangements. Together these examples support an outcome-led approach: define the system need and the expected behaviour before selecting the detailed implementation.

Prioritised use cases for application of these requirements

Given our current thinking about the coordination priorities in the New Zealand power system, there are some use cases that we are interested in testing against these five requirements. These use cases are practical areas in which the five requirements outlined in this paper could first be applied, refined and tested with industry, allowing us to build capability while addressing existing and emerging operational challenges. The five use cases are as follows:

- **GXP forecast:** Define the contribution of installed and forecast embedded generation, batteries, large loads and controllable demand to net GXP demand forecasts.
- **Controllable load during an event:** Define available quantity, operator, location, response time, activation status and confirmation needed for emergency demand management.
- **Material distribution event:** Define the event threshold, affected GXP, load/resource impact, expected duration, updates and restoration state needed by the System Operator.
- **Relevant System Operator information:** Define the schedules, constraints, warnings and grid-interface states needed by distributors to avoid conflicting action and support local decisions.
- **DER behaviour during disturbances:** Define the aggregate capability and evidence needed to model ride-through, protection, AUFLS interaction and restoration assumptions.

4 Progressing these requirements

This discussion paper has introduced a range of proposed no-regret operational requirements that the System Operator is interested in progressing with relevant stakeholders. The material is currently at a high level to test industry's appetite to move forward with this work.

We welcome feedback from all interested parties, including EDBs, generators, retailers, aggregators, flexibility providers, equipment providers, regulators, on whether and how to progress these requirements. We are particularly interested in evidence from current operating experience, planned investments and existing exchanges.

The following questions are provided to help structure a response to this discussion paper but should not constrain your input.

1. What should be changed, added or removed from the five operational requirements?
2. For each information item listed, is the proposed source best placed to create and maintain an authoritative value?
3. Is the proposed level of aggregation and timing proportionate to the operational use?
4. Which requirements can already be met through existing information, systems or processes?
5. Where are the material information, quality, access or capability gaps?
6. Which initial information exchange(s) should be prioritised for early definition or trial?
7. Are there relevant initiatives or standards we should align with to avoid duplication?
8. Do you agree with the priority use cases that we have identified? If not, which would you consider are higher priority?

Following engagement, the System Operator will consider industry feedback and refine the proposed requirements and information exchange priorities. We are open to different ways to progress this work but suggest the establishment of a small working group with interested stakeholders and the Electricity Authority to:

- Confirm which requirements can be met through existing arrangements, systems or processes;
- Identify where common definitions, data quality improvements or improved access are needed;
- Select a small number of priority information exchanges for definition (including clarifying roles and responsibilities) or trial;
- Work through the appropriate governance and, where necessary, funding requirements, before implementation decisions are made; and
- Keep longer-term coordination capabilities under review as the power system, participant capability and regulatory settings evolve.

How to respond: Please send your feedback to system.operator@transpower.co.nz. We will acknowledge receipt of all feedback. Submissions will be published on our website on our System Operator consultations page.⁵

⁵ <https://www.transpower.co.nz/system-operator/system-operator-consultations>

If your submission contains confidential material, please ensure this is clearly identified and provide a version of your submission that can be published.

Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982. Clause 7.20(4) of the Code also requires that the System Operator provide a copy of each submission received to the Electricity Authority.

Consultation closes at 5pm, 6 November 2026.

Appendix A: International practice

International practice is used as a cross-check, not copied as a complete design. Institutional roles, market arrangements and regulatory frameworks differ and each element must be tested against New Zealand operational needs.

Source	Published work*	Relevant element	How applied here
UK ENA	DSO Functional and System Requirements	System coordination, network operation, planning, connections, and system defence/restoration; use-case-led requirements.	Completeness check for operational functions and role interfaces.
UK NESO	Enabling the DSO transition	Coordination across development, markets and operations, including dispatch, operational liaison and incident management.	Two-way requirements and event coordination.
UK Grid Code	Operating Code 7: Operational liaison	Notification concerning operations and events that may have an operational effect on another system.	Materiality and event-triggered exchange principle.
UK Open Networks	Programme specifications and standards	Functional capability, market coordination, governance and systems interoperability.	Common semantics, governance and scalable exchange.
Australia AEMO	Distributed Energy Resource Register	Standing device information collected in a national register and published in aggregated form.	Trusted standing data and reduced duplicate collection.

Source	Published work*	Relevant element	How applied here
Australia Project EDGE	DER marketplace demonstration	Forecasts, dynamic operating envelopes, offers, dispatch instructions and telemetry exchanged through defined objects.	Two-way dynamic objects; envelopes treated as a possible later mechanism.
Australia AEMC	CER technical standards review	Standardised device interaction and improved compliance with technical standards.	Predictable performance and evidence requirements.
Australia AEMC/AER	Distribution planning and reporting reforms	Improved network visibility while considering confidentiality, privacy and duplication.	Proportionality, governance and non-duplication principles.

*Refer to Appendix C for links to references

Appendix B: System Operator Strategy linkages

Operational requirement	Priority 4 contribution	Priority 5 contribution	Related initiatives
Clear operational accountabilities	TSO–DSO governance, interfaces and accountability	Event roles, response, emergency load management and restoration	P4.4; P5.1, P5.2, P5.4, P5.6
Minimum static information	Whole-of-system visibility, standard dataset and data access	AUFLS, emergency management and restoration assumptions	P4.1, P4.3; P5.2, P5.3, P5.4
Minimum dynamic information	Trusted real-time operational insight	Shared situational awareness and coordinated response	P4.1, P4.3, P4.4; P5.1, P5.4
Interoperable information exchange	Common standards, protocols and system integration	Resilient participant communications	P4.1, P4.4; P5.1
Predictable technical performance	Secure integration of DER/CER and aligned requirements	Assured behaviour during disturbances and AUFLS events	P4.4; P5.3

Related System Operator Strategy initiative detail:

- **P4.1 Development of a standard operational data set for industry use:** Establish a common data standard and dataset to enable interoperability between System Operator and other industry participants, initially focused on TSO–DSO interactions.
- **P4.3 Data access and use:** Work with emerging Distributed System Operators (DSOs) to agree and establish data access and use arrangements enabling all parties to have the right level of data and visibility to perform their functions under the Code today and into the future.
- **P4.4 Future System Operator interoperability:** Actively contribute to the Authority’s development of an effective hybrid TSO–DSO functional model for New Zealand given our central position as the System Operator. This includes the ability to effectively monitor the performance of non-transmission and other flexibility solutions that are being implemented across the grid.
- **P5.1 Industry situational awareness:** Improve communication of our System Operator response to an event or unplanned outage, including near real-time power system status to

provide greater situational awareness for industry to enable their coordinated and timely response.

- **P5.2 Evolve black start and restoration processes:** Review and evolve black start and restoration processes so they remain effective as the generation mix changes, DER/CER penetration increases, and restoration coordination becomes more dependent on shared visibility and cross-industry preparedness.
- **P5.3 Maintaining AUFLS capability:** Our AUFLS system has evolved to meet the immediate challenges - particularly in the North Island. However, with increasing distributed energy resources, and with reduced inertia on the system we will need to review it to check it remains fit for purpose.
- **P5.4 Coordinating emergency demand management:** With increasing DER/CER in the power system, and more participants such as retailers and aggregators taking control of demand, including traditional EDB controllable hot water load, it is important that industry agree, operationalise, test and exercise an emergency load and consumer energy resource management protocol suitable for both national and regional events.
- **P5.6 Increase industry response capability:** With increasing system complexity, new participants, and a rising risk of power system events resulting in disruptions to consumers' supply, it is becoming increasingly important for us to work together to test and refine our response capability. To do this, we undertake regional restoration workshops, simulation exercises and pan-industry exercises, which draw heavily on people to plan and execute, and have limitations due to our current training simulator functionality.

Appendix C: References

Energy Networks Association, 2018. Open Networks Workstream 3: DSO Functional and System Requirements. [View source](#)

National Grid Electricity System Operator, 2021. Enabling the DSO transition: a consultation on the ESO's approach to Distribution System Operation. [View source](#)

National Grid / National Energy System Operator. Grid Code Operating Code 7: Operational Liaison. [View source](#)

Energy Networks Association. Open Networks programme materials. [View source](#)

Australian Energy Market Operator. Distributed Energy Resource Register. [View source](#)

Australian Energy Market Operator; AusNet Services; Mondo, 2021. Project EDGE DER Marketplace Demonstration. [View source](#)

Australian Energy Market Commission, 2023. Review into consumer energy resources technical standards: final report. [View source](#)

Australian Energy Market Commission, 2026. Enhancing distribution network planning and reporting: final determination. [View source](#)

Appendix D: Glossary

Abbreviation	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
API	Application Programming Interface
AUFLS	Automatic under-frequency load shedding
CER	Consumer energy resources – Consumer-owned or consumer-controlled DER located behind the meter, including rooftop solar, batteries, EVs, controllable load, and smart appliances (a subset of DER).
DER	Distributed energy resources – Small and medium-scale generation, storage, and flexible demand resources connected to, or operating through, distribution networks that can influence electricity system operation. Includes CER.
DSO	Distribution System Operator
EDB	Electricity distribution business
GIP	Grid injection point
GXP	Grid exit point
ICCP	Inter-Control Centre Communications Protocol
MVAr	Megavolt-ampere reactive, a unit of reactive power
MW	Megawatt, a unit of active power
NESO	National Energy System Operator, Great Britain
SO	System Operator
TSO	Transmission System Operator

