



Australian Government

Department of Climate Change, Energy,
the Environment and Water

Appendices for Redefining roles and responsibilities for power system and market operations in a high CER future

Appendices to support consultation Paper to progress M3/P5 workstreams of the National CER Roadmap

Consumer Energy Resources Taskforce





Australian Government

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- CER Taskforce Reference Group – made up of senior executives from industry and consumer representative groups, in addition to members with deep expertise in relevant areas. This reference group was updated at key points in the project, providing an opportunity to raise areas of interest and concern.

Acknowledgement of Country

We acknowledge the Traditional Owners of Country throughout Australia and recognise their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.



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A. Appendix A: Project requirements

The M3/P5 combined project to **Redefine roles for market and power systems operations** **workstream** is described in the National Consumer Energy Resources (CER) Roadmap is as follows:¹

- **M3: redefine roles for market operations:** Define the roles and responsibilities of distribution level market operation and drive alignment of incentives between market participants for CER integration
- **P5: Redefine roles for power system operations:** Define the roles and responsibilities of power system operation with high CER and drive alignment of incentives between industry actors for CER integration.

To achieve this task, the CER Taskforce outlined the following project requirements:

- Define the strategic goal of distribution system operations in relation to participants in a distributed high-CER environment.
- For both the **distribution system operations** and **distribution market functions**:
 - define the functions that occur now and need to occur in the future with respect to generators, operators (network, system, and market), retailers, other participants, and consumers
 - define the links between distribution system operations and market functions that occur now and need to occur into the future as CER penetration increases
 - assess the options for how these functions can be performed under the status quo and outline future model options including pros, cons and, where possible, timeframes and prioritisation for implementation
 - assess and propose who is best placed to perform the necessary functions for distribution level market and power system operation under the status quo and future model options, noting:
 - different jurisdictions' institutional arrangements and regulatory frameworks
 - broader market reform options
 - identified risks, benefits and opportunities to inform future research.

¹ See chapter 5 of the [National Consumer Energy Resources Roadmap](#) for more detail on specific workstreams



- Seek national consistency where possible, and consider jurisdiction-specific variations for distributions system operation and market functions, particularly for non-NEM jurisdictions.

The project is being led by the CER Taskforce with support from the Australian Energy Market Commission (AEMC). The outcomes of this workstream will inform CER Working Group recommendations for Ministerial consideration at the end of 2025.

A.1. Assessment criteria to guide actor assignment

With input from stakeholders, we developed assessment criteria to guide decision-making, particularly in relation to actor assignments. The proposed criteria are shown figure 13 below, along with some questions we considered when assigning actors to certain activities where there was more than one potential existing actor to perform a role.

Figure 13: Assessment criteria to guide actor assignment

Holistic design considerations			
<ul style="list-style-type: none"> • Is this allocation linked to allocation of other functions? If so: <ul style="list-style-type: none"> • Is allocation to a party consistent with other allocations? • Do we need to consider this allocation jointly with other functions? • Does this align with reform outside this workstream and outside of the CER roadmap? How are we coordinating with those reforms? 			
Expertise	Incentives and accountability	Coordination costs and challenges	Implementation
<ul style="list-style-type: none"> • Do the functions align with the capability, skills and remit of the organisation(s)? • Are they related to other functions, or likely future functions, of the organisation? • Could the requisite capability or expertise be developed in the organisation(s) over time? 	<ul style="list-style-type: none"> • Will the party face incentives to undertake the function effectively and efficiently to meet the CER roadmap vision? If not, can these be created? Does allocating to a party allow for competition in providing the service to drive efficient incentives? • Are obligations regarding performance available? • Who bears the risk if the functions are not performed effectively? • Does the party have any conflicts of interest in performing the functions and if so could these be mitigated? 	<ul style="list-style-type: none"> • Will a particular model result in high transaction costs once implemented? Does this allocation create costs or inefficiencies for other organisations? • Would assignment to a party create coordination challenges with other organisations (eg, does it facilitate the necessary data availability and sharing)? 	<ul style="list-style-type: none"> • What are the likely costs of assigning the function to a particular entity? Are there legal barriers to an entity undertaking the functions? • Are there other implementation complexities that would need to be taken into account (for example, jurisdictional divergences)?



B. Appendix B: Links with other work

This project seeks to define and assign all the capabilities required to run a power system and market. As such there are links between this project and other workstreams in the CER Roadmap and other work underway by governments, market bodies and industry to integrate CER into the power system and market.

Key links are summarised in table 8 below. This is not an exhaustive list of all relevant projects, but focuses on those referred to in the consultation paper.

B.1. National CER Roadmap workstreams

Table 8: links between CER Roadmap workstreams

National CER Roadmap workstreams			Links with M3/P5
Consumers	C1	Extending consumer protections for CER	Proposed action 3 in M3/P5 links with the C1 Better Energy Customer Experiences (BECE) project. The BECE project acknowledges the value customers can capture by engaging in the market through agents and will explore the risks that customers may be exposed to when seeking to capture the value of CER through customer agents. It will also explore the potential solutions through reforms to the consumer protections framework.
	C2	More equitable access to benefits of CER	Proposed action 3 in M3/P5 seeks widespread implementation of off-market mechanisms that would enable more equitable access of the benefits of CER.
	C3	CER information to empower consumers	Proposed actions 1 and 2 in M3/P5 contribute in various ways to improving data relating to CER. This may underpin actions to use CER information to empower customers.
Technology	T1	Nationally consistent standards including vehicle to grid	Proposed action 3 in M3/P5, which mentions the setting and updating of certain standards, seeks to complement rather than duplicate the work and outcomes of T1.
	T2	National regulatory framework for CER to enforce standards	The assignment of actors for many of the regulatory capabilities identified in the capability model will be informed by the co-design process underway in the T2 workstream. Proposed actions 4 and 6 in M3/P5, to establish monitoring and conformance frameworks for CER during operations, will seek to complement rather than duplicate the outcomes of T2. Governance option 3 in M3/P5 – a coordination and facilitation body – could also complement the work of T2 if pursued.
	T3	Establish secure communications	No direct links.



		systems for CER devices	
Markets	M1	Enable new market offers and tariff structures to support CER uptake	Proposed action 3 in M3/P5 would contribute in various ways to enabling new market offers and tariff structures that would support CER uptake and enable it to be effectively orchestrated to deliver value for the power system and consumers.
	M2	Data sharing arrangements to inform planning and enable future markets	There are a range of interdependencies between M3/P5 and M2. Both projects utilise a common capability model (described in Appendix C) that identifies, defines and assigns the activities required to integrate CER into the power system and market.
	M3	Redefine roles for market operations	M.3.1 – Redefining the roles and responsibilities – is the subject of this consultation paper. M3.2 is focused specifically on the role of distribution network service providers (DNSPs) to achieve equitable two-way market operations, including in owning/operating community batteries and kerbside EV chargers, and other distributed resources. This will be informed by decisions made in M.3.1 about the broader role of DNSPs now and in the future. Outcomes from both projects will inform the upcoming M.3.3 workstream, including the implementation of any new roles and responsibilities.
Power system operations	P1	Enable consumers to export and import more power to and from the grid	Proposed action 3 in M3/P5 seeks to support widespread implementation and uptake of dynamic operating envelopes (DOEs) by providing clear policy guidance to underpin a common approach to calculating, using and communicating DOEs to third parties.
	P2	Faster harmonised CER connections processes including EV chargers	No direct links.
	P3	Improve voltage management across distribution networks	Proposed action 5 in M3/P5 includes consideration of CER operations during disturbances including voltage ride-through.
	P4	Incentivising distribution network investment in CER	Chapter 5 explores some matters relating to DNSP investment in CER focusing on the incentives, objectives and governance arrangements that underpin the decisions to invest.
	P5	Redefine roles for power system operations	Subject of this consultation paper.

B.2. NEM review

An expert panel (the NEM review) has been convened to consider the wholesale market settings required to continue to promote investment in firmed, renewable generation and storage capacity in



the National Electricity Market (NEM) beyond the closure of the CIS in 2027. The panel is considering:

- emerging operational pressures in the evolving spot market
- liquidity and access challenges in medium-term financial markets
- structural barriers to long-term investment
- consequences for customers.

Reforms stemming from the NEM review may affect the investment and operating environment for generators, the contract market and retail market operations.

This project and consultation paper consider similar issues to the NEM review but with a focus on maximising the value of CER by considering roles and responsibilities for power system and market operation particularly at the distribution level. The reforms explored in this consultation paper may also affect retail market operations and the investment and operating environment for generators and the contract market insofar as orchestrated CER at the distribution level offsets a proportion of the need for wholesale market resources. While the matters considered through the NEM review and this project clearly intersect, we consider the reforms explored in each are complementary and both are focused on the same objective of promoting efficient investment in a low emissions power system, and maximising the use of those resources into the future.

B.3. Previous and current studies

To inform the distribution system operational and market requirements, as well as the options to meet these requirements, we have drawn on previous and ongoing studies in related areas. A summary of the most relevant studies is in table 9 below.

Table 9: Previous and current studies on integrating CER

Work program	Area of investigation
ENA/Australian Energy Market Operator (AEMO) Open Energy Networks	The Open Energy Networks program brought together AEMO, DNSPs and wider stakeholders to consider the changes required to market frameworks, alongside network and system operations to help deliver these goals and realise new value streams for CER. ² The program developed four high level frameworks to illustrate the different market design options which might be used to integrate CER more completely into the electricity system.

² CER was previously encompassed in the term “distributed energy resources”, or DER. DER is commonly used for similar but often larger technologies that are directly connected to the distribution network in front of the meter. For brevity, this paper generally refers to CER but the issues are also relevant to DER.



AEMO Engineering roadmap to 100 per cent renewables	<p>This 2022 report provides stakeholders with an overview of engineering challenges and associated actions that will need to be undertaken to operate the NEM for the first period of 100% instantaneous penetration of renewables, and an indication of actions required to satisfy more regular operation at 100% renewable penetration.</p> <p>The predecessors to the Engineering Roadmap (the Renewable Integration Study in 2020 and Engineering Framework in 2021-2022) outlined the power system and system integration challenges, and technical gaps that need to be addressed with increasing penetration of rooftop solar, and the emergence of storage, electric vehicles and responsive demand.</p>
AEMO work assessing system security challenges associated with increasing rooftop solar	<p>AEMO planning publications in recent years have reported on the impacts of increasing rooftop solar on system security, including the Electricity Statement of Opportunities, System Security Reports and the General Power System Risk Review.</p>
ESB's post-2025 market design CER workflow	<p>The former ESB worked with the AEMC to produce its final report on CER and the transformation of the NEM.</p> <p>The report summarises the key insights and lessons learnt across the CER reform journey to date and outlines a forward pathway for CER integration through a series of priority areas.</p>
DNSP CER Integration Strategies	<p>DNSPs are expected to include CER Integration strategies as part of their regulatory proposals in accordance with the AER's <i>Distributed energy resources integration expenditure guidance note</i>.³ Many of the activities to integrate CER into distribution-level operations identified in our capability framework are described in detail in individual DNSP CER Integration Strategies. These documents are available on the relevant network determination pages for each of the DNSPs on the AER website.</p>
<p>DNSP trials including:</p> <ul style="list-style-type: none"> • Edith • EDGE • Symphony • Jupiter 	<p><u>Edith</u>: Project Edith began as a demonstration project between Ausgrid and Reposit Power in late 2021. After the initial success, more partners joined the project to explore new ways for customers with batteries to participate in energy markets via VPPs. The project showcased how dynamic pricing can help facilitate the participation of CER in the energy market while remaining within distribution network capacity limits. The "Edith model" is a system in which network charges are based on the actual conditions for a particular customer at a specific time and location. This model is opt-in and can be accessed through retailers, making it easy for customers to participate.</p>

³ AER, DER integration expenditure guidance note, June 2022, available [here](#).



EDGE: Project EDGE (Energy Demand and Generation Exchange) was a multi-year project to demonstrate an off-market, proof-of-concept CER Marketplace that efficiently operates CER to provide both wholesale and local network services within the constraints of the distribution network. The project was a collaboration between AEMO, AusNet Services and Mondo, with financial support from the Australian Renewable Energy Agency (ARENA).

Symphony: Project Symphony was an innovative pilot in Western Australia (WA) from 2021 to 2024, where approximately 900 CERs such as rooftop solar, batteries, and other major appliances across 500 homes and businesses were orchestrated into a virtual power plant (VPP). The pilot demonstrated that value can be created from CER orchestration in WA's main electricity system, the South West Integrated System (SWIS) and that creating conditions for CER aggregation in the short to medium term is in the long-term interests of customers.

Jupiter: Project Jupiter is an active project running from 2025-2028 that aims to integrate CER such as rooftop solar and residential batteries at scale within the SWIS. It aims to recruit up to 100MW of CER nameplate capacity into a VPP via aggregator/s (including the use of third-party aggregators) to actively provide network and market services.



C. Appendix C: Capability framework used to assign activities to roles and actors

One of the key objectives of this project is to define and assign the activities required to effectively operate a power system and market with high levels of CER. This exercise provides a foundation from which alternative options can be explored. This Appendix:

- explains the capability framework we used to identify the required capabilities (more information on this process is included in a capability framework user guide published alongside this paper⁴)
- explains how roles and actors have been assigned to form a base case and highlight gaps.

C.1. We identified required capabilities using a structured capability framework

To define the operational requirements of the distribution system and market we developed a structured capability model using a top-down and bottom-up approach.

At the highest level we identified five domains (also called level 1 capabilities): oversee, plan, connect, operate and trade. Together, these reflect the major stages of the lifecycle of CER as it is integrated into the energy system and markets. Separating lifecycles into different stages helped us think through the required capabilities in a methodical way.

Below each domain are increasing levels of detail (level 2 and 3 capabilities) which culminate in 232 “use cases” (referred to in this consultation paper as “activities”) that we consider must be undertaken to effectively integrate CER into the distribution system.

For stakeholders interested in the detail we have published the capability framework outputs alongside this paper. They include:

- capability framework user guide
- the full list of 232 activities, with assigned roles and existing actors
- use case diagrams (a visual representation of the list of 232 activities)
- activity diagrams which show the critical interactions between some key activities
- glossary of roles and actors

⁴ See Capability framework user guide (made available at consult.dcceew.gov.au) for more detail on the capability framework.



Figure 14 below shows the level 1 and 2 capabilities to give stakeholders a sense of the ground we have covered.

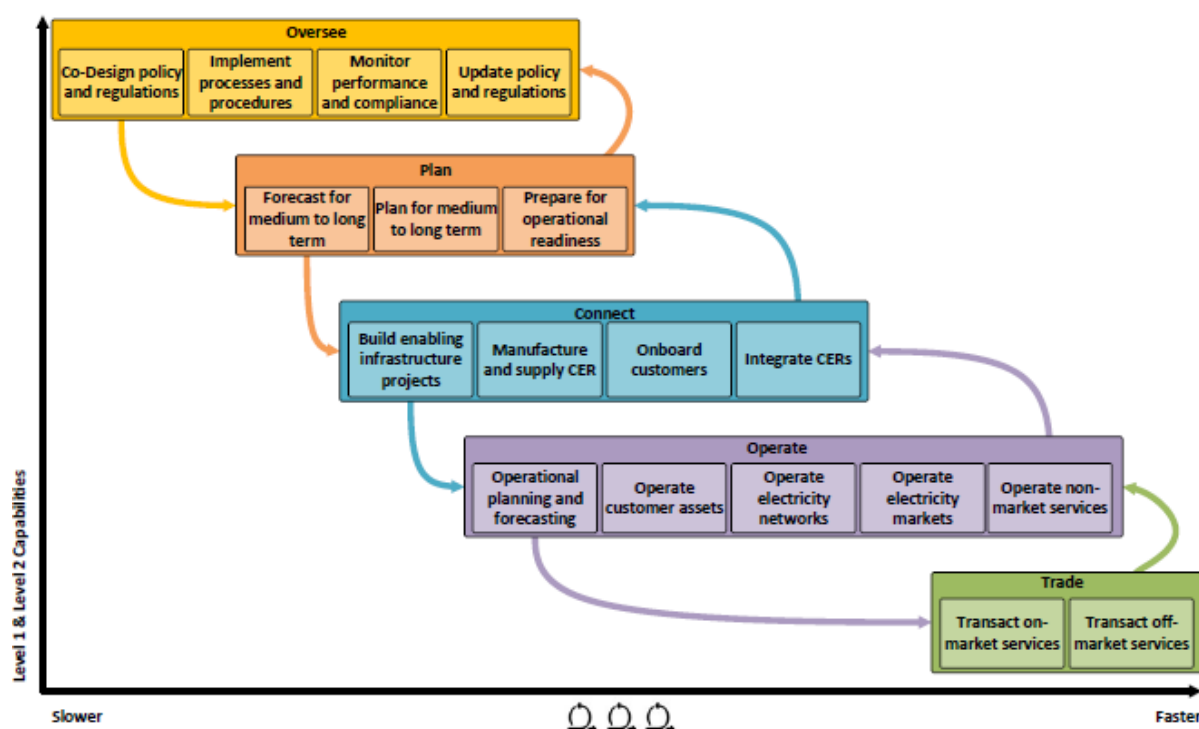


Figure 14: Level one and two capabilities

The capability framework was developed for the specific purposes of the CER Roadmap’s **M2 - Data sharing arrangements to inform planning and enable future markets workstream** and **M3/P5 Redefine roles for market and power systems operations workstream**, but it is expected that the capabilities will inform and be informed by a range of other CER Roadmap workstreams.⁵ The activities were identified with respect to NEM processes, however most of them will be necessary requirements in non-NEM jurisdictions.

C.2. This project tried to separate the ‘what’, the ‘who’ and the ‘how’

The discussion about how best to integrate CER into the power system and market involves three separate ideas that often get mixed together. These are:

1. the “what” – the activities required to operate the power system and market
2. the “who” – the *type* of organisations (roles) that should undertake the activities and the *actual* organisations (actors) that should undertake them in the NEM context
3. the “how” – the frameworks and processes that guide how the activity is undertaken.

⁵ Potential links with other CER Roadmap workstreams are outlined in Appendix B.



This project has specifically tried to separate these three ideas.

Our capability framework identifies and defines all the “whats” that we consider important in effectively integrating CER into the power system and market – now and in the future.

For each of the “whats” we have assigned a “who”, that is a:

- ‘role’ which represents the *type* of organisation responsible for undertaking the activity
- ‘actor’ which represents the *actual existing* NEM-based organisation responsible for undertaking the activity.

The roles are purposefully actor-agnostic so that, in theory, different actors could be assigned to roles in different jurisdictions, or different future arrangements.

Chapter 3, 4 and 5 of the consultation paper explore *how* the activities can be undertaken in a way that maximises the value of CER.

C.3. We assigned the capabilities to existing actors to provide a base case

The capability mapping exercise was undertaken primarily to ensure that all capabilities required to operate the power system and market in a high CER future were identified, defined and assigned.

The mapping:

- provides a comprehensive overview of what is involved in operating the distribution system and market with high levels of CER
- clarifies responsibilities for all activities, but particularly activities where responsibility is currently unclear or not commonly known
- highlights gaps where capabilities are not being performed or performed to expectations
- provides a reference framework to underpin discussions about potential reforms.

The capabilities will likely evolve over time, as may the actors performing them.

Having a base case provides a common language and framework to explore options for change.

Due to the high levels of CER in Australia’s power systems and markets, the majority of activities that we have identified as necessary for a high CER future are already being performed by existing parties – at least to the extent that current levels of CER can be managed. We are using this consultation



process to help identify which activities are not performed sufficiently to manage and maximise increasing levels of CER into the future or where responsibility for an activity is unclear.⁶

D. Appendix D: Proposed actions to improve visibility and predictability of CER

The capability mapping exercise completed as part of this project and described in Appendix C identifies the activities that need to occur to effectively operate a distribution system with high levels of CER, and to achieve broader system and market objectives. It clarifies what is required and who is accountable now.

It shows that the majority of activities required to operate the power system and market with high levels of CER are being performed by existing actors to some extent, as part of their existing roles. These actors have the expertise, tools and inputs to deliver the capabilities assigned – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes.

There are nonetheless opportunities to improve how these activities are undertaken and pave the way for the evolution in capability uplift required.

Chapter 3 identifies two proposed actions where clarifying, formalising and standardising roles, expectations, and accountabilities can **improve visibility and predictability** of CER for network, system and market operation. This appendix explores the actions from chapter 3 to **improve visibility and predictability** of CER in more detail.

For each of the proposed actions we are seeking stakeholder feedback (see the consultation questions set out in section 3.8). Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended

⁶ This workstream has not allocated roles related to the regulatory capabilities identified in the capability model to specific actors. The final assignment of actors for these regulatory capabilities will be determined through the ongoing co-design process within the CER Roadmap's T2 workstream.



D.1. Proposed action #1: Defining, collecting, updating, and maintaining quality device-level data and information

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- **Defining and standardising** device level data and information needs and specification across use cases.
- **Collecting** device-level standing data at the time of installation. This includes simplifying the collection, updating and maintenance of device-level data and information.
- **Updating and maintaining the quality** of device-level data over the lifetime of the installation. Data that is likely to change over the lifetime of the installation includes ownership and operating information such as whether the CER is participating in a VPP or responding to other tariffs or incentives and the mode of that response (e.g. fixed, remote-controlled, autonomous).

Further detail is provided in the sections below.

D.1.1. Background

Sufficient device level standing data is essential for network and power system operators and planners to understand what CER devices are installed within the network and how they operate. Standing data is the static, non-changing or infrequently changing information about installed CER devices and includes information such as:

- **Identification and location:** e.g. asset ID or registration number, address or GPS coordinates, grid connection point or feeder ID, owner information
- **Physical capacity technical specifications:** technology type, manufacturer and model, rated capacity, storage capacity, inverter specifications, operating voltage and frequency
- **Compliance and certification:** applicable standards for performance, standards compliance, gride code compliance, testing and commissioning reports
- **Mode of operation:** static or dynamic limits on device or site-level output, autonomous grid support, emergency control capability, availability windows or operational constraints
- **Customer agent, ownership and regulatory information:** if there is a customer agent managing the CER device on the customer's behalf, market participation details (e.g. participating in a VPP), tariff class or applicable incentives affecting how the device operates.



Under the National Electricity Rules (NER), AEMO has obligations to establish, maintain and update standing data on DER⁷ (including CER) and demand side participation.⁸ AEMO achieves this through:

- **The DER Register:** information provided to AEMO by DNSPs who are required to collect information on new or amended battery storage and rooftop solar installations devices at residential or business locations.
- **The Demand Side Participation Information Portal (DSPIP):** information provided to AEMO by Registered Participants on demand side participation within their customer portfolios. Connections are grouped under the following categories: market exposed, fixed time-of-use tariff, dynamic event tariff, directly controlled (fixed schedule), directly controlled (dynamic operation) and other.⁹

The Clean Energy Regulator also collects and manages a range of information including, small-scale installation data aggregated to postcode level.¹⁰ This is relied upon by policy makers, industry participants and a range of other stakeholders.

DNSPs also collect additional CER and DER data at the time of connection application and installation. In some cases, this is a richer dataset than what is captured through the DER register process. However, the exact information collected depends on the DNSP region and tends to be more complete in regions where DOEs are available.

D.1.2. Problem

The existing methods to collect and update standing data on CER installations are not be effective for a high CER future. For instance, the DER register:

- has issues with data accuracy, meaning there is a lack of confidence in the data to be used as a single source of truth for forecasting and power system modelling purposes, which typically use data from the Clean Energy Regulator and other sources
- does not capture the mode of operation for the asset (e.g. participation in VPP) or, if captured, not updated the mode beyond initial instalment
- does not include responsive loads and EVs at this stage
- has a data update compliance requirement of 20 days, which may not be sufficient for increasing aggregated participation e.g. to cover new customers signing up and customer churn between providers.

As a result, different operational actors typically use different sources, with no identified, single 'source of truth' known and referenced across parties on the CER fleet.

⁷ See Rule 3.7E of the NER.

⁸ See Rule 3.7D of the NER.

⁹ AEMO, [Guide to Demand Side Participation Information Portal](#), 3 April 2023, p. 7.

¹⁰ Available on the CER's [website](#).



We are also aware of issues with installers' collection of standing data at the time of installation and provision of this data to relevant parties (DNSPs, AEMO and government regulators), such as:

- compliance with requirements is low and DNSPs have raised concerns about limited visibility over CER connections in their own networks
- CER installers have also raised concerns about difficulties navigating connection and other administrative processes across the different DNSP networks and different types of connections.

The M2 – Data sharing arrangements workstream has also identified the need for more standardised and comprehensive CER data collection and platforms to enable access by systems and parties that need it.

D.1.3. What's being done

AEMO is working closely with DNSPs on an ongoing basis to improve the quality of data in the DER Register. This has included validation and correction of data using trusted sources (e.g. the Clean Energy Regulator data), input data validation measures to address data quality issues at the source, and enhancements to better track applicable performance standards.

The issues with installers collecting standing data at the time of installation are also being considered in the ongoing NSW government consultation on measures to introduce an emergency backstop mechanism and CER data installer portals.¹¹ The NSW Consumer Energy Strategy includes development of a CER Installer Portal, including:

- a new digital compliance system, facilitating testing and enrolling of devices with Common smart inverter profile Australia (CSIP-Aus) with DNSP utility servers. It is expected there will be automated compliance and enforcement mechanisms enabling installers to close out installations accurately and correctly¹²
- installers uploading data required under the DER Register to the Portal, which would then be sent directly to AEMO and DNSPs.

AEMO is currently engaging with the industry on frameworks for collecting, managing and utilising EV-related data for distribution, system level and market level purposes.¹³ The project involves:

- defining immediate EV-related data needs.
- evaluating existing data collection mechanisms
- proposing non-regulatory activities to address immediate data needs and improve EV (and/or their related load) visibility within networks.

This is intended to lay the foundations for development of an integrated EV data framework in the long term, and the necessary reforms to achieve this.

¹¹ Department of Climate Change, Energy, the Environment and Water, NSW Emergency Backstop Mechanism and Consumer Energy Resources Installer Portal, Consultation paper, February 2025, available [here](#).

¹² CSIP-AUS, or the Common Smart Inverter Profile – Australia, is a technical guide and set of standards developed to facilitate the deployment, monitoring, and management of CER within the Australian electricity network. It provides a standardised way for CER inverters to communicate with utility networks.

¹³ AEMO, [Electric Vehicle Data](#), website



Resources participating as voluntarily scheduled resources (VSR) in the wholesale market using arrangements that will be implemented through the ‘Integrating price-responsive resources into the NEM’ (IPRR) rule change, will need to provide accurate standing data. This is expected to improve the accuracy of standing data once IPRR is fully implemented in May 2027.¹⁴

D.1.4. Proposed action

To address the issues outlined above we are proposing to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- **Defining and standardising** device level standing data and information needs and specification across use cases. This can include standardised data formats and information models.
- **Collecting** device-level standing data at the time of installation. This includes simplifying the collection process, updating and maintaining accurate device-level data and other relevant information relating to device operation. This requires clarifying requirements for:
 - data quality requirements and benchmarks
 - data input validation
 - validation against other sources.
- **Updating and maintaining** trusted sources of device-level standing data over the lifetime of the installation. Data that is likely to change over the lifetime of the installation includes ownership and operating information such as whether the CER is participating in a VPP or responding to other tariffs or incentives and the mode of that response (e.g. fixed, remote-controlled, autonomous).

This action is related to proposed actions 1 and 2 (CER data sharing strategy, coordination plan and data sharing arrangements minimum viable product (MVP)) identified as part of the M2 – Data sharing arrangements to inform planning and enable future markets workstream.

Table 10: Relevant use cases for device-level standing data

Use case name	Use case ID	Assigned role	Proposed Actor
Operate Dx data registries	OTN24	DNO	DNBP
Update CER Asset Data registry	CI21	CER installer	CER installer
Operate Tx data registries	OTN37	TNO	TNSP

¹⁴ AEMC, [Integrating price-responsive resources into the NEM, Rule determination](#), 19 December 2024



D.2. Proposed action #2: Defining, collecting, aggregating , updating, maintaining quality, and using CER monitoring data

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- **Defining CER monitoring data needs and data specification** across operational use cases. CER monitoring data includes time-series measurements from devices and management systems, meter data and measurements of actual power flows, at site level and at different levels within the distribution network (at LV and HV levels).
- **Collecting, aggregating, updating and maintaining quality CER monitoring data** for sufficient observability of CER within the distribution operating zone in transmission system operations. Includes:
 - high speed monitoring at strategic locations within the distribution network and automated data collection following disturbances, for incident analysis and model validation
 - data and inputs required for aggregate representation of CER in network and forecasting models, including location of CER within the network topology and zonal groupings.
- **Using CER monitoring data** in forecasting, planning and operation of the power system. This includes developing improved tools, systems and processes to use and share monitoring data to:
 - predict CER responses to changing power system conditions
 - forecast the impact of CER on net load at the transmission-distribution interface (such as CER with dynamic connections, community batteries, CER providing network support).

D.2.1. Background

The lack of visibility or predictability of CER for DNSPs impacts their ability to manage and operate their network. It is critical for understanding the impact of CER on their networks, assessing hosting capacity, and a range of other activities that flow from this.

Visibility and predictability of CER are also important for wholesale market and transmission operations, without which market outcomes and transmission flows may not be optimal. This is due to the uncertainty associated with CER impact on system balancing and managing constraints.

Where CER acts invisibly, or outside of market systems, this impact will not be accurately reflected in the demand forecast. This contributes to increasing forecast errors, requiring increasing reserves and uncertainty margins within the dispatch process. Currently, CER that actively responds to market



signals represents a small proportion of demand (and demand errors); however, as CER uptake increases, this invisible operation can cause material inefficiencies.

The AEMC’s IPRR rule change investigated the impact of unscheduled price-responsive resources on market arrangements and options to integrate these resources into the wholesale market.¹⁵ AEMC modelling revealed that as the magnitude of unscheduled price-responsive resources grows, the errors become substantial, resulting in a combined efficiency loss of \$1,467-1,832m.¹⁶ The modelling also demonstrated that, absent integration, energy and frequency control ancillary services (FCAS) prices would be substantially higher due to demand forecast errors.

D.2.2. Problem

The lack of visibility or predictability of CER will also impact how DNSPs operate their networks. Without information about how CER, large batteries, and large flexible loads will behave, DNSPs will need to make assumptions and predictions about how these resources will behave. These assumptions will typically be conservative and result in sub-optimal allocation of network capacity to these resources.¹⁷ For instance, a DNSP may need to maintain sufficient headroom in its flexible export limits to account for this unpredictability or provide restrictive static limits.¹⁸ Improved visibility of CER would also assist with planning for performance of the system during minimum system load conditions.

Present reliance on commercial data providers may not be representative of the underlying population of CER devices, with no guarantee that the data will appropriately scale up with uptake.

D.2.3. What’s being done

AEMO is responsible for estimating the level of expected demand required to be met by the dispatch process. It does this using the Demand Forecasting System to understand how demand will change under certain conditions (for example the day and time).¹⁹ AEMO currently uses a range of methods for obtaining information about what CER is connected to distribution networks and how it is operating. These include measured actual output, the DER register and DSPIP, to collect information about CER. These are described in more detail below:

- **Measured actuals:** AEMO’s Australian Solar Energy Forecasting System (ASEFS) produces solar generation forecasts for large solar power stations and small-scale distributed photovoltaic (PV) systems, covering forecasting timeframes from 5 minutes to 7 days. One input into this process is

¹⁵ The AEMC used “unscheduled price-responsive resources” to refer to: the wide range of residential, community, commercial and industrial energy resources and load that are not currently scheduled through the market dispatch process; and do or could respond, individually or as part of aggregation, to market price signals.

¹⁶ AEMC, [Integrating price responsive resources into the NEM, Final determination](#), 19 December 2024, p. iv.

¹⁷ SA Power Networks, [Submission to Integrating price-responsive resources into the NEM Draft Rule Determination](#), 12 September 2024, p. 6.

¹⁸ For instance, in the SAPN distribution network the static export limit is 1.5 kW, compared to the flexible limit of 10 kW. SAPN, flexible exports brochure, accessed 16 April 2025, available [here](#).

¹⁹ AEMO, Power system operating procedure – Load Forecasting, 30 May 2023, p. 8.



actual output measurements from selected household rooftop PV systems from PVOutput.org and Solar Analytics, delivered every 30 minutes.²⁰

- **Demand side participation information portal (DSPIP):** collected annually, the DSPIP contains information about the characteristics of DSP contracts from registered participants. The information is used to inform reliability modelling (Electricity Statement of Opportunities, Energy Adequacy Assessment Projection (EAAP), Medium Term projected assessment of system adequacy (MT PASA) and the Integrated System Plan (ISP)).²¹

AEMO's current forecasting framework assumes that all generated distributed PV (DPV) on the distribution network is unconstrained. With the introduction of Flexible Export Limits (FELs) and DOEs, solar PV is curtailed in response to distribution networks constraints, which is invisible to AEMO.

DNSPs with DOE offers are already receiving real-time (5-minute) site and device-level power and power quality data from participating customers via the CSIP-AUS protocol. In many cases, this information is being used in real or post time to refine DOE calculation mechanisms. DNSPs also procure monitoring data from third party monitoring data providers, advanced metering infrastructure (AMI), and power quality monitoring within their networks.

The AEMC's "Accelerating smart meter deployment" rule change, once fully implemented in July 2026, will provide DNSPs with better access to power quality data from smart meters.²² This data could be used for several use cases to improve DNSPs' understanding of their networks, including compliance monitoring of CER performance.

In response to this, AEMO and SA Power Networks are collaborating on an "T-D Operational Forecasting" trial in which SA Power Networks are providing AEMO real-time visibility of the impact of DOEs on solar production as an input to the ASESF system.

In addition to existing CER monitoring data needs, the IPRR rule change introduces specific data sharing requirements to enable DNSPs to manage distribution-level impacts of VSRs. Under the IPRR framework, DNSPs require sufficient visibility of the distribution-connected qualifying resources that form each VSR to maintain local network security. To support this, the draft VSR Guidelines propose that DNSPs have access to information such as NMIs participating in VSRs, their VSR zones, standing data (including participation status), post-market bid and dispatch data, and aggregate five-minute revenue metering.²³ This highlights the emerging need to align the broader CER monitoring and data exchange framework, being considered under this workstream, with IPRR-specific data sharing arrangements to ensure DNSPs can effectively manage both passive CER and aggregated price-responsive resources within their networks.

²⁰ AEMO, Australian Solar Energy Forecasting System, ASEFS Phase 2, available [here](#), accessed 22 April 2025.

²¹ AEMC, [Integrating price-responsive resources into the NEM, Draft Determination](#), 25 July 2024, p. 29.

²² AEMC, [Accelerating Smart Meter Deployment, Final Determination](#), 2 November 2024, Section 3.2.

²³ AEMO, draft voluntarily scheduled resource guidelines, 3 June 2025 available [here](#)



To understand the impact of CER behaviour in response to power system disturbances, AEMO collects and analyses data from a range of sources including commercial monitoring data providers and inverter OEMs. In collaboration with Network Service Providers (NSPs), AEMO has developed dynamic models to represent the aggregate behaviour of DPV and composite load during NEM power system disturbances.²⁴

The models are intended to be used by Transmission Network Service Providers (TNSPs) to review network stability limits in periods with high levels of DPV generation. The key consideration today is incorporating DPV shake-off during disturbances within assessment of the technical envelope of the power system, and operationalised through constraints.

D.2.4. Proposed action

To address the issues above we are seeking stakeholder feedback on a proposed action to clarify, formalise and standardise the roles, expectations and accountabilities for all parties relating to:

- **Defining CER monitoring data needs and data specification** across use cases.
- **Collecting, aggregating, updating and maintaining quality CER monitoring data** to enable sufficient observability of CER within the distribution operating zone in transmission system operations. This involves coordination between DNSPs, TNSPs and AEMO across several areas, including:
 - operational forecasting of the impact of DNSP activities on net load at the transmission-distribution interface (such as DOEs, community batteries, network support)
 - high speed monitoring at strategic locations within the distribution network and automated data collection following disturbances, for incident analysis and model validation
 - data and inputs required for aggregate representation of DER in network and forecasting models, including location of CER within the network topology and zonal groupings.
- **Using CER monitoring data** in forecasting, planning and operation of the power system. This includes developing improved tools, systems and processes to access and utilise monitoring data to:
 - predict CER responses to changing power system conditions
 - forecast the impact of CER on net load at the transmission-distribution interface (such as CER with dynamic connections, community batteries, CER providing network support).

Consultation questions for the above are outlined in section 3.8.

²⁴ AEMO, Power system model development, available [here](#).



Table 11: Relevant use cases for monitoring data

Use case name	Use case ID	Assigned role	Proposed Actor
Manage power system models	OTN01	System operator (tx)	AEMO
Manage Dx network models	OTN18	DNO	DNSP
Manage Tx network models	OTN39	TNO	TNSP
Develop monitoring and reporting frameworks	PO16	System operator (tx)	AEMO
Develop Dx monitoring and reporting frameworks	PO50	System operator (dx)	DNSP
Install/Access/Maintain monitoring equipment	CI27	DNO	DNSP

D.3. Common to actions #1 and #2: Improved data sharing arrangements for CER standing and monitoring data

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- **sharing** relevant device level data and information between relevant parties
- **sharing appropriately aggregated monitoring data** between relevant parties.

D.3.1. Background

Appropriate sharing and coordination arrangements are needed to ensure that data can be shared among relevant operational actors. Sharing the collected data will be essential in helping to provide the benefits of greater visibility to all parties who need visibility of key CER information and behaviour.

Project EDGE identified that a high CER future requires sensitive data to be shared securely among many organisations and systems to facilitate CER coordination.²⁵ This includes standing data and real time monitoring data that can be used by NSPs and AEMO for incident response, model validation, or real-time situational awareness and by other parties to capture the many and varied opportunities CER present.

²⁵ AEMO, [Project EDGE – Final report](#), October 2023, p. 31.



D.3.2. Problem

There is a range of work underway to improve data sharing arrangements, including through the workstream to establish a data exchange. This work does not yet capture all use cases or present a coordinated, industry-wide solution to enable data sharing to the extent needed to effectively integrate CER into the power system and market.

D.3.3. What's being done

AEMO, TNSPs and DNSPs coordinate and share information across a number of areas, including:

- emergency management activities, such as the solar backstop mechanisms and minimum system load procedures
- network planning and expansion²⁶
- planned maintenance on distribution or sub-transmission network assets that impact the transmission network or market operation
- technical requirements for connections.

The CER Data Exchange Industry Co-Design initiative progressed a Project EDGE recommendation for streamlined organisation-to-organisation data exchange, completing its final report and High-Level Design in April 2025.²⁷ The next stage for a CER Data Exchange as envisaged and recommended by the industry co-design project is to undertake a detailed design effort for the initial infrastructure and priority use cases.

The expansion of the data supported by this infrastructure is identified as part of the M2 – Data sharing arrangements, proposed action #2. There is an opportunity to consider different operational and wider industry use cases for CER data, and progress them through development of data exchange mechanisms.

An approach to sharing this data is being tested in SA Power Networks, Engie, and AGL's Market Active Solar Trial. The objective of the trial is to demonstrate how network DOEs can work in conjunction with retailer solar orchestration offers to stack value for customers. Two integration models are being tested in the trial – one where the DNSP DOE and retailer orchestration signal are both provided directly to the customer's equipment, the other where the retailer sends the orchestration signal to the DNSP who packages it up with the DOE and sends it to the customer site.

The latter model enables DNSPs and retailers to quickly exchange information on network constraints and orchestration signals respectively – improving operational visibility for both parties. This may allow retailers to leverage the digital infrastructure DNSPs have already invested in for DOEs to rapidly enable CER orchestration at scale.

²⁶ NER, Rule 5.14.

²⁷ Summary report and High-Level Design available on AEMO's [website](#).



Energy Consumers Australia has also submitted a rule change request that proposes DNSPs be required to publish data related to a range of information about CER uptake and conditions on their networks.²⁸ Depending on the outcome of the rule change request, this information could be publicly available as part of a revised version of DNSPs' Distribution Annual Planning Reports.

D.3.4. Proposed action

We are seeking stakeholder feedback on a proposed action to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in data sharing arrangements for:

- relevant device level data
- aggregated monitoring data.

This includes considering how different parties access and interact with the data, including data sharing protocols, data hosting and access platforms. There is an opportunity to progress findings from the CER data exchange co-design process and any supporting frameworks and processes.

This action is related to proposed action # 2 (Develop a data sharing MVP) identified as part of the M2 – Data sharing arrangements to inform planning and enable future markets workstream.

Consultation questions for the above are outlined in section 3.8.

Table 12: Relevant use cases for data sharing

Use case name	Use case ID	Assigned role	Proposed Actor/s
Facilitate data exchange	OTN76	CER Data Exchange Coordinator	DNSP / AEMO (may change depending on what data is being shared and for what reason)
Manage coordination between network operators	OTN07	System operator (Tx)	AEMO
Ensure CER regulatory requirements & initiatives awareness	PO04	CER Regulator	Clean Energy Regulator AER
Develop & manage Tx systems & operating procedures for a high DER future	PO33	System Operator (tx)	AEMO
Develop & manage Dx systems & operating procedures for a high DER future	PO51	System Operator (dx)	DNSP

²⁸ Proposed information includes: adoption of solar systems, energy storage systems, electric vehicles, public electric vehicle charging stations, and flexible appliances connected within the low-voltage system; low-voltage consumption, both for native demand and operational demand; smart meter power and power quality data, including usage; change in electrification uptake, including of reticulated gas; and change in energy efficiency. See Energy Consumers Australia, Integrated Distribution System Planning (electricity) rule change request, 22 January 2025, available on the [AEMC website](#).



E. Appendix E: Proposed actions to support effective orchestration of CER

The capability mapping exercise completed as part of this project and described in Appendix C identifies the activities that need to occur to operate a distribution system with high CER. It clarifies what is required and who is accountable now.

It shows that the majority of activities required to operate power system and market with high levels of CER are being performed by existing actors. These actors have the expertise, tools and inputs to deliver the capabilities assigned – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes.

There are nonetheless opportunities to improve how these activities are undertaken and pave the way for the evolution in capability uplift required.

Chapter 3 identified two areas where clarifying, formalising and standardising roles, expectations and accountabilities can enable **effective orchestration of CER** and capture the opportunities presented by increasing levels of CER.

Effective orchestration means having the right frameworks and processes in place not just to manage CER so that the system remains secure, but to leverage CER in a way that promotes *efficient* power system and market outcomes.

This appendix explores the actions from chapter 3 to **support effective orchestration of CER** in more detail.

For each of the proposed actions we are seeking stakeholder feedback (see the consultation questions set out in section 3.8). Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended.

E.1. Proposed action # 3: Establishing and using off-market mechanisms and communicating relevant and standardised information to enable widespread adoption of these mechanisms

We proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **establishing, using off-market mechanisms (flexibility services, DOE's, DNP's) and communicating relevant and standardised information** to enable widespread adoption of them to orchestrate CER.

This includes:

- defining off-market flexibility services and standardising the use of available distribution system flexibility for distribution system, transmission system and wholesale market reasons across the NEM
- enabling the efficient procurement (by DNSPs and potentially other parties) of flexibility services at scale



- calculating available capacity, and calculating, using and communicating DOEs and DNPs across the NEM – as the operational parameters to leverage/use that capacity
- enabling industry investment and uplift to achieve widespread implementation and use of off-market mechanisms to orchestrate CER.

Further detail is provided in the sections below.

E.1.1. Defining off-market flexibility services and standardising the use of available distribution system flexibility.

Background

Flexibility services are used by DNSPs to help balance supply and demand and reduce network congestion. Currently distribution level flexibility is largely utilised for the provision of distribution services to mitigate costs associated with the “standard control service” of planning, maintaining and operating the distribution network. This translates to managing and resolving particular local network constraints one at a time.

Problem

There is currently no standardised definition of what constitutes non-network or flexibility services beyond the existing network planning framework for considering and evaluating non-network solutions and engaging with potential demand-side providers. This assessment is largely undertaken on a case-by-case basis, leading to inconsistent practices across jurisdictions. DNSPs vary in how they interface with flexibility providers and manage this flexibility operationally.

The lack of definition and varied approach across DNSPs limits the availability and use of flexibility services by DNSPs and third parties, within and across networks, and at scale.

What’s being done

When planning investments, transmission businesses must meet an identified network need based on a cost-benefit assessment (the regulatory investment test for transmission or RIT-T) that includes considering if non-network solutions like demand response may be more efficient. Non-network solutions can include engaging with CER to provide services.

DNSPs have more specific demand side obligations underpinned by a requirement that they are not only ‘meeting’ demand for service but also ‘managing’ that demand for service. DNSPs must develop a demand side engagement strategy which sets out the strategy for engaging with non-network providers and considering non-network options for addressing system limitations.

DNSPs must document their demand side engagement strategy in a demand side engagement document and establish and maintain a demand side engagement facility by which parties can register their interest in being notified of developments related to distribution network planning and expansion.²⁹

²⁹ NER Schedule 5.9.



DNSPs are specifically incentivised to procure non-network options through the Demand management incentive scheme and innovation allowance. Some DNSPs have partnered with technology providers to assist in procuring these non-network services.

One example of this is the Piclo Flex platform.³⁰ The Piclo Flex is an online marketplace that identifies and advertises parts of the network that are subject to constraints.³¹ The platform allows DNSPs to quantify the value of alleviating a constraint and the forecast period over which the constraint could be managed through the provision of a non-network alternative.³² This allows third parties, such as CER providers or aggregators, to bid resources to alleviate the constraints and be paid if successful.

Most DNSP have CER integration strategies that include core capabilities and management systems required to enable CER flexibility to participate, be seen and accounted for in distribution system operations. This includes controlled load, efforts by all DNSPs to enable DOEs, and emerging approaches by some DNSPs to use dynamic pricing to interact with demand-side participants and VSRs. Customers enabled for flexible exports also provide opportunities for CER flexibility to be used for system level balancing, for example during minimum system load conditions.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **defining off-market flexibility services and standardising the use of available distribution system flexibility**

Consideration should be given to:

- technical definition of services
- participation requirements
- engagement with DNSP management platforms
- use of available distribution system flexibility in the:
 - distribution system
 - transmission system
 - wholesale market.

We are seeking stakeholder feedback on this proposed action – see the consultation questions set out in section 3.8.

Table 13: Relevant use cases for off-market mechanisms

Use case name	Use case ID	Assigned role	Proposed actor
Ingest Load Forecast & T/D Capacities	OTN02	System Operator (tx)	TNSP
Publish Demand & Market Forecasts	OTN06	System Operator (tx)	TNSP
Generate Load Forecasts	OTN20	System Operator (dx)	DNSP
Calculate & provide Tx/Dx capacities	OTN21	System Operator (dx)	DNSP
Manage Dx Network Constraints Through CER Services	OTN28	System Operator (dx)	DNSP
Settle Dx Network Service Payments	OTN31	System Operator (dx)	DNSP

³⁰ For instance CitiPower and Powercor is utilising this platform, see more [here](#).

³¹ See more information [here](#).

³² AER, [Low-voltage network visibility – Phase 3 final report](#), 31 March 2025, p. 10.



Create load & generation forecast	OTN80	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Create & update retail operational forecasts	OTN81	Energy supplier	Energy Retailer
Create and update Dx operational forecasts	OTN95	System Operator (dx)	DNSP
Trigger dynamic prices	OTN96	DNO	DNSP

E.1.2. Procurement of flexibility services at scale

Background

DNSPs in the NEM today have access to some level of flexibility within their networks that shape net load and outcomes at the transmission/distribution interface. This includes load control programs, contracts for network support, and local network management schemes with larger non-scheduled plant, DOEs and DNPs. The use of CER to deliver off-market network support or flexibility services to the transmission level occurs today only to a limited extent, during abnormal scenarios at the system level only. There is significant opportunity for this to grow in the future with planned roll-outs of DOEs, network/community batteries and evolution in distribution system capability to manage these sources of flexibility.

Problem

There is little clarity on the extent to which the distribution level resources and actions can be utilised for the provision of **system-level** flexibility and how this might work. For example can distribution-level flexibility be used only when lack of reserve (LOR) or minimum system load (MSL) risks are identified in pre-dispatch or more regularly?

There are also interoperability gaps across device level, management platforms and cross-party coordination mechanisms. These gaps, which limit how flexibility services can be used, include:

- CER-related data, which is fragmented and lacks standardisation (explored in Appendix D in relation to visibility of CER information)
- understanding and visibility of what CER services are available at any given time, service dispatch and outcomes, accurate forecasting tools to estimate the future availability or value of CER-based support (explored in Appendix D in relation to visibility of CER operation).
- use cases for operational coordination between relevant parties are not necessarily clearly defined, especially in the context of flexibility within the distribution network being utilised for transmission network or system level benefit.

Furthermore the benefits of increased flexibility services are not limited to DNSPs and are difficult to quantify. The current regulatory framework that closely manages and provides oversight of DNSPs'



expenditures may limit the procurement of any services beyond the immediate needs of the local distribution network.

Lack of policy guidance on the use of distribution system flexibility for transmission system and wholesale market reasons will limit the use of CER as a legitimate, reliable alternative to transmission level resources, and source of flexibility within system-level balancing

What's being done

Most DNSPs have CER integration strategies that include core capabilities and management systems required to enable CER flexibility to participate, be seen and accounted for in distribution system operations – via their efforts to enable DOEs and interact with demand-side participants and VSRs.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **procurement of flexibility services at scale**, across a DNSP's network and not just restricted to addressing identified network constraints.

Consideration should be given to developing options to:

- enable the efficient procurement of flexibility services via CER (by DNSPs and other parties)
- address governance issues that may arise depending on design of information or procurement platforms
- achieve whole of system objectives.

We are seeking stakeholder feedback on this proposed action – see consultation questions set out in section 3.8.

Table 14: Relevant use cases for flexibility services

Use case name	Use case ID	Assigned role	Proposed actor
Ingest Load Forecast & T/D Capacities	OTN02	System Operator (tx)	TNSP
Publish Demand & Market Forecasts	OTN06	System Operator (tx)	TNSP
Generate Load Forecasts	OTN20	System Operator (dx)	DNSP
Manage Dx Network Constraints Through CER Services	OTN28	System Operator (dx)	DNSP
Settle Dx Network Service Payments	OTN31	System Operator (dx)	DNSP
Provide limits advice to the System Operator (tx)	OTN34	TNO	TNSP
Generate medium to long term forecast	PO52	Customer agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Publish Off-market system service needs	PO53	System operator (tx)	AEMO
Define service characteristics and contract terms	PO54	System operator (tx)	AEMO
Engage Off market system services	PO55	System operator (tx)	AEMO



Publish retail flexibility service needs	PO62	Energy Supplier	Energy Retailer
Define retail service characteristics and contract terms	PO63	Energy Supplier	Energy Retailer
Engage retail flexibility service	PO64	Energy Supplier	Energy Retailer
Create load & generation forecast	OTN80	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Create & update retail operational forecasts	OTN81	Energy Supplier	Energy Retailer
Create and update Dx operational forecasts	OTN95	System Operator (dx)	AEMO
Trigger dynamic prices	OTN96	DNO	DNSP

E.1.3. Calculating available capacity, and calculating, using and communicating DOE's and DNP's across the NEM.

Background

In a high CER power system, there are often times and locations when there are more resources that want access to the distribution network than the network can safely allow. Historically, the network became congested (i.e. network access was scarce) at times of peak demand. Increasingly, the network is becoming “export congested” in the middle of the day when solar exports are high.

There are two key tools DNSPs use to signal network scarcity and manage access – network pricing and operating envelopes (or physical limits). For the majority of CER currently in the NEM, operating envelopes and network prices are not passed through to customers in a meaningful or timely way. This means customers have limited incentive to respond to power system needs even if they were able and wanted to. This means that potentially responsive CER is not being used to its full potential to lower total system costs and provide individual consumer value.

The way operating envelopes and network prices are commonly used in the NEM today, compared to how they can be used together to more accurately and directly signal network capacity to consumers (through their agents), is described in Box 5 below.

Box 5: network levers to manage congestion and CER

Operating Envelopes	Network Prices
What are operating envelopes? Operating envelopes refer to the physical limits or amount of electricity that a customer can import from or export to the grid. These limits are determined by the distribution network	What are network prices? Network tariffs or prices are set by DNSPs to recover their regulated revenue from customers. Network prices aim to signal the long-term or “long-run marginal” costs to build



<p>service provider (DNSP) for every customer connection point to ensure the stability and safety of the grid and to facilitate equitable access. They can be static or dynamic.</p>	<p>and operate the network, to serve customer demand.³³ However, true cost reflectivity is currently limited as, for example, the cost of building and operating the network to serve different customers at different locations at different times is different, but network prices are usually static and represent an average cost to serve.</p>
<p>The vast majority of operating envelopes for household solar connections today are ‘static’. This means customers that export solar usually have a fixed ‘limit’ that determines how much they are allowed to export or import. The limit is set based on maintaining integrity in the worst-case scenario (i.e. at peak net-exporting times) in the absence of real-time visibility of the low voltage network.</p> <p>In some cases, where the local network already had large amounts of rooftop solar installed, to ensure a safe and secure network, solar exports were limited to zero and customers were unable to export any electricity to the network. This can lead to high levels of curtailment during peak times (which is the purpose of the restriction) but this approach also restricts export at times when the network could accommodate higher flows.</p>	<p>Network prices are set annually for most household customers. This means customers pay static, average network prices that don’t accurately reflect the actual cost of the network to serve their individual needs. This approach served as a reasonable way to recover the cost of network infrastructure from consumers when consumer behaviour was relatively homogenous and inelastic.</p> <p>A range of targeted cost-reflective and time-varying network tariffs are used to more accurately represent the cost to serve different customers at different times or under different conditions. This includes tariffs with seasonal charging parameters, critical peak pricing, and load control tariffs.</p> <p>Fully dynamic network pricing is being trialled.</p>
<p>What does an operating envelop look like in practice for the majority of customers today?</p> <p>During normal operations, when CER reaches the fixed limit (operating envelope) that applies at the connection point, or if the network reaches its upper voltage limit, the inverter “self-curtails” – switches off or down (see Box 2 in section 1.2).</p> <p>During emergency minimum system load events, DNSPs are also able to curtail CER through emergency backstop mechanisms.³⁴ These mechanisms vary across jurisdictions but generally allow DNSPs to remotely and temporarily limit solar exports from systems with remote communications that were</p>	<p>What do network prices look like in practice for the majority of customers today?</p> <p>Except for some very large customers, network prices are usually charged to the retailer who then passes on the network costs to consumers as part of a bundle of costs. Retail product designs can amplify, dilute, or change the signal that reaches the customer, depending on the retail product or service a customer signs up to. For example, time of use tariffs increase the prices customers pay during common peak periods to encourage customers to decrease demand. Retail products that offer “free energy” during the middle of the day encourage customers to use electricity at that time to soak</p>

³³ Long-run marginal costs pricing is a requirement in the National Electricity Rules (NER) and prices are regulated by the Australian Energy Regulator (AER).

³⁴ Mechanisms are now in place in Queensland, Victoria, South Australia and WA to allow CER to be managed during minimum system load conditions. The NSW and ACT Governments are consulting on implementing an emergency backstop mechanism. For further information for NSW see [here](#) and for ACT see [here](#).



installed or upgraded after a certain date. This mechanism is used as a last resort to manage minimum system load emergencies (primarily when solar generation exceeds demand) and protect system security.	up solar exports and help reduce export congestion on the network. However, most customers do not receive meaningful network price signals through their retail offer that would enable or encourage consumer or CER behaviour that aligns with power system needs – particularly not with any location- or time-specific needs.
Dynamic operating envelopes (DOEs) can more accurately signal the available capacity of the network. DOEs refer to operating envelopes that change over the course of the day to reflect the near-real time hosting capacity of the network. ³⁵ They can be used as the basis for varying the import and export limits for a customer over time and location based on the available capacity of the local network or power system as a whole. ³⁶ The same concept can be applied to imports, for example varying the rate at which an EV can charge during peak demand periods. DOEs are calculated by the DNSP and can be communicated to customer connection points over different pathways.	Dynamic network prices (DNPs) can more accurately signal the available capacity of the network. DNPs change in response to the actual cost to serve customers, ³⁷ based on real or near real-time conditions. ³⁸ Using this information, dynamic prices are calculated and refreshed at a set interval, such as once a day. Dynamic pricing components for both imports (load) and exports (generation) are published for each defined sub-section of a distribution network. Dynamic network prices signal when the network is becoming constrained (that is, when the ability to get additional use from the network is becoming scarce). A consumer would face higher DNPs to use the network at the time their part of the network is becoming constrained and be paid to support the network during that time. When the network is unconstrained customers would face lower (even zero) DNPs.

The application of effective DOEs and DNPs can enable CER to contribute to better utilisation of networks at a local level as well as more efficient power system and wholesale market outcomes, depending on how they are implemented. Retailers and other customer agents will rely on DOEs and DNPs to develop CER products and services that can respond to grid conditions and align with customer preferences.

³⁵ Related concepts include: **dynamic connections** which refer to connection points where the customer has opted-in to an arrangement where the DNSP communicates dynamic operating envelopes (DOEs) remotely to vary the import and export limits for that customer; **Flexible export limits** which describe the result of DOEs with respect to exports only; and **“DOE ready”** which refers to CER devices or aggregators that have the technology and communications to maintain output within the “envelope”.

³⁶ As outlined in the DEIP DOE Working Group’s Allocation Principle’s Workshop Summary, available [here](#).

³⁷ Network tariffs are set based on the long-term costs to serve customers. This is known as long-run marginal cost pricing and is a requirement of the NER.

³⁸ Factors that can be considered when calculating dynamic prices include: typical demand and generation for each customer, weather, CER penetration in each area, and local area network characteristics. See Project Edith report [here](#).



The potential benefits of effective DOEs and DNPs, depending on how they designed and utilised, are enormous and include:

- enabling more CER export to be used in response to market conditions, offsetting the need for wholesale market resources and lowering wholesale prices for all customers
- fairer network capacity allocation based on consumer preference rather than driven by physics which generally results in those furthest from the distribution transformer being constrained off
- flattening network load and increasing network utilisation, which ultimately minimise network expenditure
- allowing CER to ‘self-organise’ to ration the system to its highest value uses
- greater interoperability between customers, the network and the market
- versatility to manage different network conditions
- revealing how much consumers might value an expansion to the network
- reducing the reliance on network control mechanisms
- flexibility compared to existing network-led procurement approaches.

Problem

Currently, the approach to calculating and using DOEs and DNPs and then communicating relevant information to third parties, is managed individually by each DNSP. There is a lack of policy guidance on how and when DOEs can or should be used (e.g. only as emergency backstops or more regularly) and the extent to which (and how) DOEs and DNPs and their role in distribution system operation can and should be relied on for the purposes of whole of system operations and planning.

Without a standardised approach to calculating and using dynamic signals, and with no common framework for communicating, their widespread use in orchestrating CER is limited.

In the absence of DOEs, DNPs or other tools to encourage CER to be responsive and to allocate network access fairly are limited in their ability to manage network hosting capacity. There is a growing risk that network hosting capacity will be exhausted by passive CER and future CER connections would then be subject to conservative limits applied to their output.

What’s being done

DOEs are emerging as the preferred way of integrating CER into power system operations. This is because they allow DNSPs to manage network hosting capacity more dynamically and efficiently than traditional static limits, enabling better network utilisation and higher contributions from customers’ solar and battery systems when there is more hosting capacity on the local network and more equitable treatment of customers at times when network access is limited.³⁹

Few networks have fully implemented DOEs at scale, but work is underway within all DNSPs to do so over time. Examples include:

³⁹ As explained in Box 2 in section 1.2, CER will, in the large majority of cases, self-curtail or cease exporting when the inverter detects that the voltage limit has been reached and before thermal limits are reached.



- Energex and Ergon Energy’s “Dynamic connections” option which uses DOEs to vary exports between 1.5kW/phase and 10kW/phase depending on the network conditions (unless there is a significant emergency event requiring all solar PV generation to stop). Dynamic connections are increasingly used for new connections in Queensland compared to a static maximum of 5kW per phase on a basic connection (or 2 kW for premises connected to a regional single wire network).⁴⁰ Dynamic connection standards in Queensland allow communication of dynamic export and import limits to CER.⁴¹
- SA Power Network’s “flexible exports” which give eligible CER connections a flexible export limit between 1.5kW and 10kW/phase compared to a fixed export limit of 1.5kW/phase at all times.⁴² Flexible exports are now the preferred option in South Australia (SA) with around 85% of new connections opting-in.⁴³

The P.1 workstream in the CER Roadmap to “enable consumers to export and import more power to and from the grid” is seeking to fast track implementation of flexible exports component of DOEs by network operators to enable increased CER flexibility, third party participation and maximise benefits to the system and customers.

DNPs are being trialled through Project Edith which began as a demonstration project between Ausgrid and Reposit Power in late 2021. After the initial success, more partners joined the project to explore new ways for customers with batteries to participate in energy markets via VPPs. The project showcased how dynamic pricing can help facilitate the participation of CER in the energy market while remaining within distribution network capacity limits. The “Edith model” is a system in which network charges are based on the actual loading of the network that a particular customer is connected to at a specific time. This model is opt-in and can be accessed through customer agents (retailers or aggregators), often packaged up as a part of a broader VPP offering and managed through technology, making it easy for customers to participate.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **calculating available capacity, and calculating, using and communicating DOEs and DNPs**, as the operational parameters to manage network access and incentivise efficient utilisation of this capacity in operational timeframes.

DOEs are based on the underlying physics of the network but calculating them requires an understanding of both physical capacity and modelling techniques and limitation. There are a range

⁴⁰ See [Energex’s website](#) for further details.

⁴¹ See Energex and Ergon Energy’s [Standard for Low Voltage EG Connections](#) (STNW3511), effective from 23 February 2025.

⁴² See [SA Power Network’s website](#) for further details.

⁴³ See [SA Power Network’s website](#), accessed 25 June 2025.



of approaches to calculating and using DOEs with very different customer and market trade-offs.⁴⁴ Consideration should be given to developing options to ensure:

- the methodology for calculating DOEs and DNPs achieve agreed consumer-focused objectives
- the guidance on how DOEs and DNPs are used is clear and includes appropriate consideration the conformance monitoring framework and control hierarchy proposed in action 4 and 6)
- there is a common framework for communicating relevant information to third parties (e.g. common information models for key parameters, application guidance key functions) so that customer agents and product vendors can develop compliant customer products and services that align consumer preferences with power system needs.

It may be appropriate to consider a mechanism for regular review of and policy guidance or frameworks as the power system continues to develop.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions in section 3.8.

Table 15: Relevant use cases for calculating and communicating DOEs and DNPs

Use case name	Use case ID	Assigned role	Proposed actor
Calculate and provide Dx Network Constraints	OTN27	DNO	DNSP
Generate & publish DOEs	OTN22	System Operator (dx)	DNSP
Analyse market and off-market opportunities	OTN41	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Forecast Portfolio (VSRs) Capacities	OTN43	Customer Agent	Aggregator Energy Retailer Energy Service Companies
Ingest DOEs and apply/reflect within bids.	OTN44	Customer Agent or CER customer (where connected directly)	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner

⁴⁴ See [Project EDGE Final Report](#), October 2023, sections 4.3.1 on the spectrum of DOE design options and 4.3.2 on fairness in DOE objectives.



			investor Active DER/CER
Provide ongoing Bids	OTN46	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Manage CERs in their VSRs	OTN50	Customer Agent or CER customer (where connected directly)	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Establish system goals & create strategies to effectively utilise CER	PO24	Policy Maker	AEMC

E.1.4. Enabling industry investment and uplift to achieve widespread implementation and use of off-market mechanisms to orchestrate CER.

Background

An effective, widespread roll out of DOEs and DNPs will rely on consumer and industry trust which requires significant investment in data and technology and a concerted effort to develop the coordination and communication architecture and associated roles for all parties involved.

The success of DNPs as a tool to manage congestion in line with consumer preferences and power system needs relies heavily on each part of the industry playing a role and coordinating across roles. This is necessary to build consumer trust and industry confidence that these dynamic signals can be relied upon as a legitimate and reliable alternative to network solutions and interventions.

If DOEs are calculated and communicated effectively, then the task of gaining consumer trust falls to customer agents to incorporate the ability to receive and act on DOEs and DNPs into products and services that are accessible and attractive to consumers.

For example, innovative retailers could offer consumers a range of 'exposure' to DOEs or DNPs. Those who are more responsive may wish for the full exposure to the signal while less risk-tolerant consumers may want products which combine the opportunity to respond to DNPs along with a DOE-supported price ceiling.



How and how well they do this will be a crucial part in integrating CER and is the subject of the AEMC's Pricing review.⁴⁵ The pricing review is investigating the products and services that future consumers will need and the market and regulatory arrangements which will deliver them.⁴⁶ This review will consider how the diverse needs of consumers and their CER assets can be met and utilised while delivering a low cost, reliable, and low carbon transition. A discussion paper was published in June 2025 to test and validate with stakeholders the problems identified, why they are occurring, and whether they will persist in the future in the absence of reform.⁴⁷

The distribution system can act as a platform for CER flexibility by providing consumers and their agents to receive signals aligned with underlying network and system needs. In doing so, this sets an environment for innovation in products and services that consumers need, including those which reward consumers for responding to network and wholesale market conditions.

Problem

Industry investment and uplift will be required from:

- DNSPs to incentivise and installers to install and enable DOE and DNP-ready devices.
- DNSPs to invest in DOE and DNP calculation methods and operationalise them within their systems, starting to unlock network capacity quickly. While some DNSPs may not need to go beyond using simple approximation methods, without good data and calculation models, DOEs and DNPs may continue to be calculated conservatively to account for uncertainty when some specific network areas may benefit from more advanced network model based calculations, and CER may continue to be constrained more than needed in these areas.⁴⁸
- The electricity retail sector to integrate DNPs within their retail offers and how they manage their portfolios by developing attractive consumer products and services and pass these signals through to at least a portion of CER customers.
- Aggregators to respond effectively on behalf of consumers. As VPP operations mature, the tracking resources and capacity will likely increase the ability for consumers to be price responsive. Consistency of DOE formats and interfaces would assist adoption.

DNSP investment may be overseen by the AER to ensure it is prudent and efficient and in line with a network's CER penetration levels. For example there could be periodic analysis (as part of regulatory oversight) of DOEs against historical actual network limits to ensure CER is not overly constrained beyond what is deemed appropriate – as was suggested in the findings from Project EDGE.⁴⁹ The benefits of DOEs and DNPs and the systems and processes to support them are not limited to DNSPs and are difficult to quantify. The current regulatory framework that closely manages and provides oversight of DNSPs' expenditures may limit DNSP investment beyond the immediate needs of the DNSP.

⁴⁵ AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Discussion paper, June 2025.

⁴⁶ AEMC, [The pricing review: Electricity pricing for a consumer-driven future, Consultation paper](#), 07 November 2024.

⁴⁷ AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Discussion paper, June 2025.

⁴⁸ See [Project Edge Final Report](#), October 2023, p.128, 158-159.

⁴⁹ See [Project Edge Final Report](#), October 2023, p.31.



What's being done

DOEs and DNPs are in their infancy in the NEM. However, all DNSPs have committed to implementing DOEs within the CER/DER integration strategies, with some trialling DNPs. For example, industry has already invested in building DOE capability to support the South Australian DOE rollout and have been tested and certified by SA Power Networks.

This is in the process of being converted to a national process via Standards Australia Committee EL-062, aligning on CSIP-AUS v1.2, ahead of the NSW emergency backstop implementation. This has led to over 98% of solar inverter manufacturers that sell in Australia developing and certifying DOE capability, with minimal testing required to support the national process.

Further work is required to ensure that other devices (including solar, battery, chargers and other smart loads) can co-ordinate behind-the-meter to respond to the site-wide DOE signal. As retailer / customer agent led CER orchestration becomes more prevalent, some development work will be required to integrate DOEs into CER dispatch engines to inform and shape market-based response.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **enabling industry investment and uplift to achieve widespread implementation and use of off-market mechanisms to orchestrate CER.**

Consideration should be given to:

- ensuring investment is prudent and efficient and delivers whole of system outcomes
- consumer protections are in place to ensure the opportunities and risks are appropriately balanced – noting that the National CER Roadmap consumer workstreams are focused on this issue
- complementary developments in retail markets are progressed so that DOEs and DNPs are leveraged via products and services that are accessible and attractive to consumers, noting that AEMC's pricing review is considering these matters.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions in section 3.8.

Table 16: Relevant use cases for enabling industry uplift

Use case name	Use case ID	Assigned role	Proposed actor
Calculate and provide Dx Network Constraints	OTN27	DNO	DNSP
Generate & publish DOEs	OTN22	System Operator (dx)	DNSP
Provide limits advice to the System Operator (tx)	OTN34	TNO	TNSP
Analyse market and off-market opportunities	OTN41	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER



Forecast Portfolio (VSRs) Capacities	OTN43	Customer Agent	Aggregator Energy Retailer Energy Service Companies
Ingest DOEs and apply/reflect within bids.	OTN44	Customer Agent or CER customer (where connected directly)	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Provide ongoing Bids	OTN46	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Manage CERs in their VSRs	OTN50	Customer Agent or CER customer (where connected directly)	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Generate medium to long term forecast	PO52	Customer agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Publish Off-market system service needs	PO53	System operator (tx)	AEMO
Publish retail flexibility service needs	PO62	Energy Supplier	Energy Retailer
Create load & generation forecast	OTN80	Customer Agent	Aggregator Energy Retailer Energy Service Companies Participating CER/DER owner investor Active DER/CER
Create & update retail operational forecasts	OTN81	Energy Supplier	Energy Retailer
Create and update Dx operational forecasts	OTN95	System Operator (dx)	AEMO
Establish system goals & create strategies to effectively utilise CER	PO24	Policy Maker	AEMC



E.2. Proposed action # 4: Conformance and compliance for non-conforming CER participating in off-market mechanisms

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties participating in off-market mechanisms (flexibility services, DOEs, DNPs) to ensure compliance. This includes clear roles and associated expectations and accountabilities for these roles in relation to:

- testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER participating in off market mechanisms and the application of DOEs for aggregated CER participating in the wholesale market
- formalising the control hierarchy applying to different coordination signals sent to CER devices so that they respect network and system limits and behave appropriately during normal, abnormal and emergency conditions.

We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER is underway and may address this in full or in part.

Further detail is provided in the sections below.

E.2.1. Testing, monitoring, assessing compliance, enforcement and rectification arrangements for CER participating in off-market mechanisms

Background

Several components are required for a robust framework that ensures off-market mechanisms can be relied on – both at the device level and across aggregations – to help balance supply and manage congestion. These are testing, monitoring, assessing compliance, enforcing compliance and arrangements to ensure non-compliance is rectified.

Problem

There is no formal conformance monitoring and compliance framework to ensure aggregated device operation complies with dynamic signals. This limits confidence in dynamic signals applied at the device level and across aggregations at scale, which in turn limits trust in the overall power system and markets.⁵⁰

What's being done

⁵⁰ See [Project Edge Final Report](#), October 2023, p.341-346



The T2 workstream to establish a regulatory framework for CER is underway and may address this in full or in part.

The focus of this action is to ensure roles, expectations and accountabilities are clear during operations so non-compliance can be identified and appropriate action can be taken to rectify the situation and hold responsible parties accountable in a timely manner.

Proposed action

We are seeking stakeholder feedback on a proposed action to clarify, formalise and standardise the roles, expectations and accountabilities for all parties **participating in off-market mechanisms (flexibility services, DOEs, DNPs) to ensure compliance with those off-market mechanisms.**

This includes roles, expectations and accountability relating to testing, monitoring, assessing compliance, enforcement and rectification arrangements for:

- non-conforming CER participating in off market mechanisms
- the application of DOEs for aggregated CER participating in the wholesale market.

We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part. We also note that there are likely to be operational roles associated with DOE conformance that will need to be considered through this review.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.

Table 17: Relevant use cases for conformance and compliance of CER participating in off-market mechanisms

Use case name	Use case ID	Assigned role	Proposed actor
Monitor Conformity of DOEs	OTN23	System Operator (dx)	DNBP
DOE Conformity Assessment	OTN73	CER Conformance Assessor	Subject to T2
Provide breach report/notification	OTN93	CER Conformance Assessor	Subject to T2
Calculate and provide Dx Network Constraints	OTN27	DNO	DNBP
Generate & publish DOEs	OTN22	System Operator (dx)	DNBP

E.2.2. Formalising the control hierarchy applying to different coordination signals sent to CER

Background

Historically, distribution level resources and constraints were not a material concern for system security and reliability. However, with high levels of CER, distribution system outcomes are now a



crucial consideration in balancing supply and demand at the system-level, and managing system security at the transmission-distribution interface.

CER devices and management systems respond to signals and instructions from a range of parties. Some are signals for voluntary consumer actions, some for contracted actions and some for emergency interventions by system operators. For example, emergency interventions may include curtailing rooftop PV remotely (e.g. via CSIP-Aus communications), whereas voluntary actions may include charging batteries in response to dynamic prices to absorb excess generation, increasing demand at certain times of day to receive a discount (e.g. hot water load shifting, EV charging, industrial load flexing).

A clear control hierarchy is required to ensure more important signals and instructions take precedence over less important ones. This enables:

- network and system operators to have confidence in managing the technical envelope of their asset
- retailers and other customer agents to have a clear understanding about how to manage customer devices under their control and clear expectations for their fleets under normal and abnormal conditions.

Problem

There is currently no uniformly applied, formal hierarchy of control for signals or instructions sent to CER devices and management systems to ensure more important network and system security limits and responses take precedence over discretionary ones, supporting customer agents to optimise CER value within grid limits.⁵¹

There are no compensatory controls and pre-determined autonomous failsafe behaviours to safeguard against contradictory instructions and to ensure DOE application even when communications are lost.⁵² Without a hierarchy, control signals communicated by different actors have the potential to overlap and be in conflict under certain scenarios. Ultimately this can result in conservative:

- use of distribution-level resources as part of whole of system operations. This is particularly relevant to flexibility services at the distribution level.

⁵¹ See [Project Edge Final Report](#), October 2023, p.347

⁵² This is not an explicit requirement today but being considered within DNSP DOE implementations. CSIP-AUS explicitly requires all devices to support autonomous failsafe behaviours. Both SA Power Networks and Energy Queensland Limited use a 1.5kW communications failsafe today. Fallback conditions are also used in Victoria for the backstop implementation. Project EDGE identified the need for failsafes and processes in place between the aggregator, DNSPs and AEMO in case of a communications outage or other events leading to the aggregator or their devices being unable to receive dispatch signals, and procedures for a ‘graceful’ return to norm operation once communication has been restored.



- planning processes that do not incorporate CER in a way that reflects the realities of what's actually occurring in the system. This can result in a less efficient and/or more expensive network.

What's being done

Roles and responsibilities for AEMO, TNSPs, DNSPs, retailers and certain other participants are formalised through the NER. These roles and responsibilities are explicit when it comes to each participant's role and the hierarchy of instructions in the wholesale market and transmission system. However, the roles, responsibilities and hierarchy of instructions that support integration of distribution-level CER have developed relatively organically – based loosely on what happens at the wholesale level. For example, the current framework implicitly leads to arrangements where:

- AEMO and TNSPs are responsible for managing the transmission operating zone and coordinating with the distribution operating zone for system security, congestion management at the transmission/distribution interface and system-level balancing.
- DNSPs are responsible for managing the distribution system operating zone, including: setting limits and terms of access for CER within their networks; procuring and coordinating CER providing local network support; coordinating with the transmission operating zone; providing observability of CER and the distribution operating zone for transmission system operations; identifying the impact of their activities on net load at the transmission-distribution interface; and identifying outcomes within the distribution operating zone required for system security and reliability.
- Customer agents are responsible for participating in the wholesale market and the provision of local network and retailer flexibility services, and acting on their customers behalf in the coordination of their CER fleets. This includes applying an appropriate control hierarchy within their fleets to ensure distribution network limits are respected, and minimum technical requirements are met.

While this project and consultation paper assigns roles and actors to each of the activities (or use cases) that we have identified as being required for power system and market operations, there is no work underway to explicitly formalise the control hierarchy for distribution-level operations through Rules, guidelines or other legal instruments.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in participating in market and/or off-market mechanisms (flexibility services, DOEs, DNPs) to ensure conformance and compliance.

This includes **formalising the control hierarchy applying to different coordination signals sent to CER devices so that they respect network and system limits and behave appropriately during normal, abnormal and emergency conditions.**

Consideration should be given to:

- Functional prioritisation at the device level, appropriately prioritising different control signals e.g. protection actions, DNSP DOEs, provision of local network support, responding to DNPs and wholesale market participation.



- System management action: for normal, abnormal and emergency conditions in the distribution network and transmission system.

We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.

Table 18: Relevant use cases for formalising control hierarchy

Use case name	Use case ID	Assigned role	Proposed actor
Develop & manage Tx systems & operating procedures for a high DER future	PO33	System Operator (tx)	TNSP
Develop & manage Dx systems & operating procedures for a high DER future	PO51	System Operator (dx)	DNSP



F. Appendix F: Proposed actions to embed CER in system security frameworks

The capability mapping exercise completed as part of this project and described in Appendix C identifies the activities that need to occur to operate a distribution system with high CER. It clarifies what is required and who is accountable now.

It shows that the majority of activities required to operate power system and market with current levels of CER are being performed by existing actors to some extent. These actors already have the expertise, tools and inputs to deliver the capabilities assigned – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes. There are nonetheless opportunities to improve how these activities are undertaken and pave the way for the evolution in capability uplift required.

Chapter 3 identified two areas where clarifying, formalising and standardising roles, expectations and accountabilities can enable CER to be **integrate CER into system security and emergency management frameworks**.

System security includes the ability to maintain or quickly return system operations to within defined technical limits following credible events in the power system. Emergency management encompasses the capabilities, systems and procedures that are used to recover and restore supply during extreme, abnormal system conditions.

This appendix explores the actions from chapter 3 to **integrate CER into system security and emergency management frameworks in more detail**.

For each of the proposed actions we are seeking stakeholder feedback (see section 3.8 for stakeholder consultation questions). Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended.

F.1. Propose action #5: accounting for, using or controlling CER as part of system security and emergency management frameworks

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved **accounting for, using or controlling CER as part of system security and emergency management frameworks**. This includes:

- **Performance during disturbances** including the roles, expectations and accountabilities for setting and updating technical standards to include appropriate fault ride-through capability.



We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part.

- **Emergency CER curtailment** including the roles, expectations and accountabilities for:
 - establishing DPV curtailment schemes
 - ensuring all new DPV systems (up to 5 MW) are captured within these schemes
 - assessing and monitoring site-level compliance
 - testing and validating scheme performance and robustness
 - coordinating the effective operation of the emergency backstop mechanism.
- **System restart and emergency restoration** including the roles, expectations and accountabilities for:
 - assessing the impact of increasing CER on system restart, including modelling DPV impact on system restart pathways
 - managing DPV on restoration pathways
 - operational coordination between the transmission and distribution operating zones for system restart.
- **Emergency frequency management** including the roles, expectations and accountabilities for:
 - setting and updating technical standards to include appropriate frequency response capability (we note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part)
 - evolving the frameworks for emergency under-frequency response in the context of high CER.

Further detail is provided in the sections below.

F.1.1. Performance during disturbances

Background

CER performance during system disturbances is an important system security consideration given the current and increasing scale of CER. In aggregate, rooftop PV already represents the single largest generator in nameplate capacity terms in all NEM regions (other than Tasmania) and the WEM.⁵³ The simultaneous disconnection of a large proportion of a region's rooftop PV adds to the contingency size that needs to be managed by contingency FCAS reserves. Without action, this will become increasingly unmanageable operationally with the potential to result in widespread and prolonged outage situations.

⁵³ AEMO, Draft 2025 Stage 2 Inputs and Assumptions Workbook, available [here](#).



Since 2018, AEMO has been collecting and analysing data from a wide range of sources to understand the behaviour of CER during disturbances. This has been used to:

- provide an evidence base for uplift to technical requirements for small-scale inverters, leading to the changes to the AS/NZS4777.2 national standard in 2020
- Analyse CER compliance with AS/NZS4777.2 after the 2020 update, and provided an evidence base for industry uplift
- Assessment of CER and load-side behaviour for relevant power system incident investigations.⁵⁴

Simultaneous disconnection of rooftop PV or other CER devices can occur when inverter settings are not configured to withstand disturbances (such as frequency or voltage fluctuations). In large numbers, this can cause a large aggregate “shake-off” of CER systems, in response to the initiating event for the disturbance (e.g. sudden disconnection of a large generating unit). In such cases the largest credible contingency in a region becomes the size of the generating unit plus the amount of DPV generation that shakes off.⁵⁵ This increases the difficulty and cost of maintaining the system in a secure state, capable of being returned to target operating conditions within 30 minutes of any credible contingency event.

Problem

The AS/NZS 4777.2 standard specifies the expected performance and behaviour of inverters at low voltages (such as households or small-scale commercial) and the necessary tests for compliance. At present AS/NZS4777.2 only applies to small scale inverters (including rooftop PV and battery storage) connected to the distribution network. It doesn't apply to larger systems or other kinds of CER. It was estimated in 2022 that 30-50% of new rooftop solar inverter connections were non-compliant with AS/NZS4777.2.⁵⁶

There is also a significant legacy fleet of CER that predate the current standard and lack necessary ride-through functionality. This increases the need for newer systems to be compliant and for their behaviour to be predictable and modelled accurately in system studies.

What's being done

The risk of cascading rooftop PV inverter disconnections has been considered in updates to the technical standards that apply to grid-connected small-scale inverters. These changes include:

⁵⁴ Further information available on AEMO's website, [DER behaviour during disturbances](#).

⁵⁵ AEMO, [Supporting secure operation with high levels of distributed resources](#), Q4, 2024, p. 25

⁵⁶ AusNet, [Review into consumer energy resources \(CER\) technical standards – submission to consultation paper](#), November 2022, p. 1.



- AS/NZS 4777.2 was updated in 2020 to ensure that inverters would remain connected following temporary grid disturbances.⁵⁷ It also introduced region unification on inverter settings in order to make installation and commissioning more straightforward for installers, improving compliance rates. The standard was updated again in August 2024 to include generation limit control parameters, electric vehicle supply equipment specific clauses and other changes.
- AS/NZS 4777.1 specifies installation requirements of grid connected energy systems via inverters. The standard was updated in 2024 to extend to vehicle-to-grid (V2G), allowing EV supply equipment to export energy to the grid, potentially helping meet energy needs at peak demand times while also mirroring the grid-protection capabilities of rooftop solar inverters and home batteries.

DNSPs across Australia have varying levels of compliance management capabilities, which ensure CER is installed and operated in conformance with grid connection requirements. For example, SA Power Networks have a mature compliance program which holds solar retailers accountable for installation conformance.⁵⁸

The program tracks whether CER has been installed correctly including that it is DOE responsive, conforms to static export limit arrangements, and has the correct AS4777 region setting (proxy for ride-through settings). If the percentage of a given solar retailer's compliant installations falls below 90% they are issued 3 formal warnings prior to being locked out of submitting further applications. The program has helped lift closeout average compliance levels from 40% to 95%.

The national regulatory framework for CER to set and enforce standards, which is currently being progressed through a co-designed process under the CER Roadmap T2 workstream, will play an important role in establishing and enforcing standards that support predictable responses to disturbances.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **ensuring appropriate performance of CER during disturbances**. This includes formalising and standardising roles, expectations and accountabilities for:

- updating and maintaining technical standards (e.g. ride-through performance)
- ensuring effective compliance mechanisms
- enabling monitoring of CER conformance (including firmware and operational behaviour)
- integrating accurate CER models into the technical envelope for system studies and operations.

⁵⁷ The 2020 update to AS/NZS 4777.2 followed several years of collaboration between AEMO, industry and university researchers to analyse the response of DPV systems to transmission-level disturbances like a sudden trip of a generators or network asset.

⁵⁸ See SA Power Network's [website](#).



We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.

Table 19: Relevant use cases for performance during disturbances

Use case name	Use case ID	Assigned role	Proposed Actor
Monitor market trends influencing CER uptake and operation	PO02	CER Regulator	Subject to outcomes of CER regulatory framework workstream
Accreditation and registration process	PO06	CER Regulator	
Develop & refine conformance frameworks	PO07	CER Regulator	
Authorise CER product certification & testing requirements	PO12	CER Technical Regulator	
Define CER product technical standards development framework	PO13	CER Technical Regulator	Subject to outcomes of CER regulatory framework workstream

F.1.2. Emergency CER curtailment

Background

Electricity generated from rooftop PV reduces demand for electricity from large-scale, synchronous connected generators. While this is a potential source of cost savings for consumers, at present there is a ‘minimum system load’ (MSL) that must be maintained in order to securely operate the power system. This is because a minimum number of large-scale generators are required to be operational at a given time to provide essential system services including system strength, inertia, voltage control and reactive power management.

The rapid increase in rooftop PV over the past years has driven a corresponding reduction in minimum demand in the NEM. This declining minimum demand has led to operational demand across NEM regions gradually falling to MSL thresholds required for secure operations, and projected for the NEM mainland under some plausible conditions soon. AEMO estimates there is a greater than 10 per cent



chance of NEM minimum demand dropping below the MSL threshold in normal conditions by 2027 and greater than 50 per cent chance by 2029, under a Step Change trajectory (see figure 15).

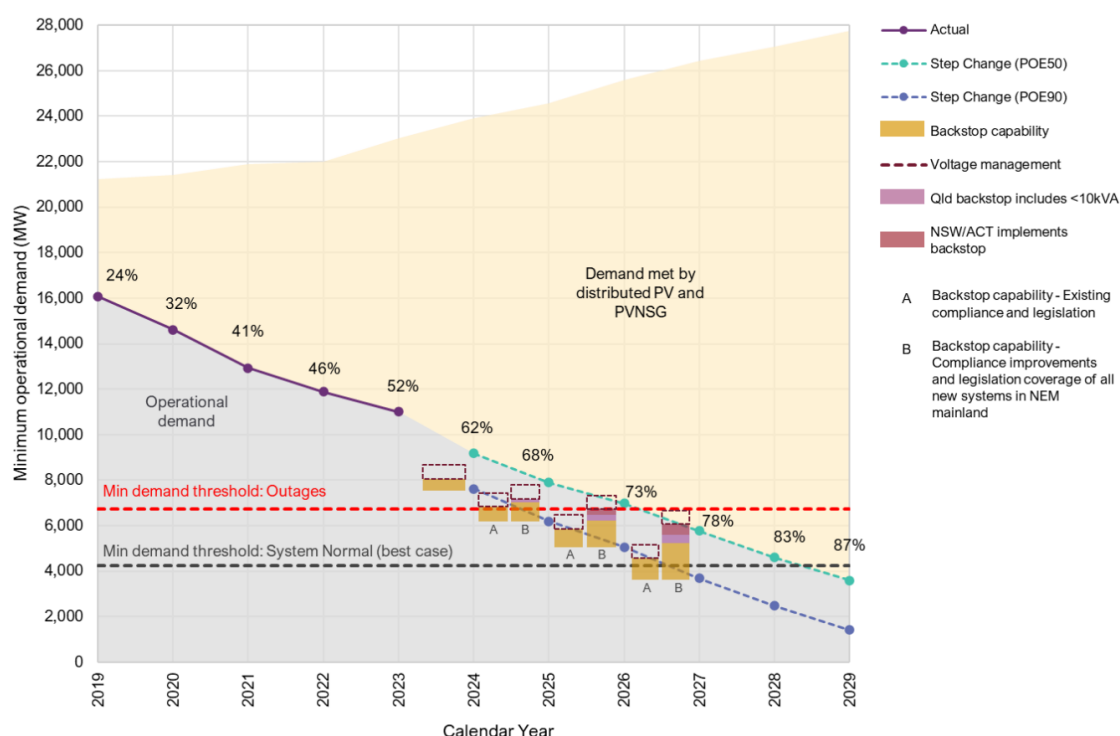


Figure 15: Minimum demand in the NEM. Source: [AEMO, 2024](#).

The ability to curtail rooftop PV output if required for system security under certain conditions is an essential emergency capability to maintain system security as rooftop PV capacity continues to increase. This is referred to as a **'backstop'** capability. In the near term, this capability is required as a last resort measure to manage MSL risks and the risk of DPV disconnection during disturbances. Other reasons may emerge into the future, including:

- managing large net load ramps due to the impact of cloud cover on aggregate rooftop PV
- maintaining interconnector flows within limits where multiple regions are experiencing high PV output
- managing the impact of rooftop solar on the system restart process under restricted or limited communications network availability
- providing a secure and robust means to 'isolate and defend' devices under the control of compromised third-party management systems.

Problem

Backstop capability is required today in several NEM regions if extreme abnormal conditions (e.g. regions islanding from the NEM) were to occur during high solar, light underlying demand periods. As noted above, AEMO has assessed the need for the emergency DPV backstop to maintain MSL requirements across the NEM mainland balancing area, under some plausible conditions, as early as October 2025 and under normal conditions by October 2027.

However, the majority of rooftop PV in the NEM today cannot be curtailed by DNSPs or AEMO, even in case of extreme abnormal conditions due to:



- low rates of device-level inverter compliance and inadequate testing of scheme performance
- implementation issues leading to devices being configured incorrectly
- unclear roles and accountability for scheme development and operation.

AEMO estimates there will be a gap in backstop capability in all mainland NEM regions from October 2025 (see figure 16).

		Oct-23	Oct-24	Oct-25
SA	Backstop capability required for regional system security	~ 426 MW	~ 697 MW	~ 857 MW
	Backstop capability available*	~ 548 MW	~ 665 MW	~ 780 MW
	Shortfall	-	~ 32 MW	~ 77 MW
VIC	Backstop capability required for regional system security	~ 71 MW	~ 468 MW	~ 957 MW
	Backstop capability available*	~ 477 MW	~ 477 MW	With baseline compliance levels: 577 MW With major uplift in compliance: 908 MW
	Shortfall	-	-	With baseline compliance levels: 379 MW With major uplift in compliance: 48 MW
QLD	Backstop capability required for regional system security	-	~ 119 MW	~ 643 MW
	Backstop capability available*	-	~ 226 MW	With continuation of present compliance and legislation: 261 MW With major immediate uplift in compliance and expansion of coverage to <10kVA systems: 516 MW
	Shortfall	-	-	With continuation of present compliance and legislation: 382 MW With major immediate uplift in compliance and expansion of coverage to <10kVA systems: 127 MW
NSW/ ACT	Backstop capability required for regional system security	-	-	~ 400 MW
	Backstop capability available*	-	-	~ 192 MW
	Shortfall	-	-	~ 208 MW

* Excludes shedding of reverse flowing loads to increase regional demand.

Figure 16: Summary of emergency backstop status in mainland NEM regions. Source: AEMO, 2024.

Existing backstop mechanisms in the NEM and WA today are established via jurisdictional instruments. Currently, there is no explicit NER obligation for DNSPs to deliver a robust backstop capability and no clear DNSP role for designing, implementing and maintaining emergency CER curtailment capability. This has resulted in a lack of consistency across DNSPs in terms of functional requirements for effective scheme operation. This limits the extent to which emergency backstop mechanisms can be relied upon if required for system security.

In addition, the effectiveness of a nationally consistent emergency backstop mechanism for rooftop PV will be limited unless operational coordination between parties is formalised.

Currently there are operational uncertainty and coordination issues including issues relating to:

- control hierarchy (see proposed action 4 and 6) and inability to discriminate for CER devices providing grid support during MSL conditions
- the ability for system operators to identify and potentially exempt CER devices from backstop curtailment when they are providing other necessary grid support services



- timely coordination chain between TNSPs and DNSPs when activating emergency backstop procedures. This is important in the context of AEMO’s obligation to return the power system to secure operating state within 30 minutes
- consistent notification and reporting from DNSPs to AEMO after backstop activation, in terms of actual curtailment and CER still online
- sufficient coverage of backstop capability requirements across the full range of CER device types, sizes and connection topologies
- insufficient holistic capability requirements for orchestrating CER during normal operation as well as emergencies
- how alternative backstop mechanisms (e.g. hot water load control) can be utilised within the backstop mechanism as well as a source of flexibility that can alleviate or reduce the need for backstop activation (responsibilities and pathways for participation for alternative backstop mechanisms are not defined and considered on a case-by-case basis)
- funding pathways and consensus with the AER and Governments on building alternative backstop mechanism
- technical specifications (e.g. response speed, latency) clearly defined or standardised across networks
- ability to estimate aggregate rooftop PV under control and available for curtailment, as well as to validate actual curtailment.

What’s being done

The technical capability for emergency backstop already exists. Mechanisms are being progressively implemented state-by-state, and are now in place in all jurisdictions except NSW/ACT and Tasmania where there is policy work underway to implement them in the future.

- South Australia has had a regulatory framework that includes a backstop mechanism in place since 2020, however compliance rates with the mechanism were initially poor. SAPN has undertaken a major work program to improve compliance and has built significant curtailment capacity since 2020. This capability has been relied upon to maintain energy security. Further work is still required to achieve the levels of compliance needed for ongoing operational effectiveness.
- Queensland has implemented a backstop mechanism for inverters larger than 10 kVA, however compliance rates have been extremely poor, with only ~16% of assessed systems performing as required.⁵⁹ There is now work under way to achieve the levels of compliance needed for ongoing operational effectiveness.
- Victoria introduced a backstop mechanism in October 2024, however the capability is small at present. Experiences in South Australia and Queensland suggest considerable efforts will be required to achieve the necessary levels of compliance.
- New South Wales is engaging with AEMO and network service providers on recommendations to introduce a backstop mechanism as soon as possible, but a framework is not yet in place.

⁵⁹ AEMO, [Supporting secure operation with high levels of distributed resources](#), Q4 2024, p. 8.



- In Western Australia, Western Power curtail embedded generation (mostly commercial and industrial PV sites) in their network, mostly via SCADA. Since 14 February 2022, new DPV sites ≤ 5 kVA which receive buyback payments through the Distributed Energy Buyback Scheme (DEBS) must be on state-owned retailer Synergy's Emergency Solar Management (ESM) backstop mechanism.

Rooftop PV curtailment can also be achieved through other mechanisms. For example, AEMO may request that DNSPs use overvoltage to increase curtailment of rooftop solar through Emergency Voltage Management.⁶⁰

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **emergency CER curtailment** including the roles, expectations and accountabilities for:

- establishing DPV curtailment schemes across all jurisdictions with sufficient scale and robustness
- ensuring all new DPV systems (up to 5 MW) are harnessed within these schemes
- assessing and independent monitoring of site-level compliance
- testing and validating scheme performance and robustness
- establishing compliance obligations for scheme conformance, validation, and rectification
- coordination required for emergency backstop operation

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.

Table 20: Relevant use cases for emergency CER curtailment

Use case name	Use case ID	Assigned role	Proposed Actor
Direct TNSP and DNSP to maintain energy demand level	OTE2	System operator (Tx)	AEMO
Direct to action emergency plans	OTE4	System operator (Tx)	AEMO
Advise available curtailment quantity	OTE7	System operator (Dx)	DNSP
Generate and provide emergency commands	OTE8	DNO	DNSP
Monitor conformity of backstop commands	OTE10	DNO	DNSP
Initiate Backstop process	OTE12	TNO	TNSP
Receive emergency commands to curtail generation	OTE17	Customer agent	Aggregator, Energy retailer, Energy service companies

⁶⁰ AER, 2023 – [Export services network performance report](#) p 17.



Receive and action backstop commands	OTE19	Communication manager	Aggregator Energy Retailer Energy Service Companies DNSP Equipment Manufacturer Large Independent Networks Microgrids
Receive and action backstop commands	OTE20	CER customer	DNSP, AEMO
Define CER product technical standards development framework	PO13	CER Technical Regulator	Subject to outcomes of CER regulatory framework workstream
Develop & publish emergency operating protocols	PO17	System Operator (tx)	AEMO
Direct Customer Agent, DNSP and TNSP to modify CER energy flow	OTN10	System Operator (tx)	AEMO
Adjust the energy flow on network in response of LOR2/MSI2 forecast	OTN19	System Operator (dx)	DNSP

F.1.3. System restart and emergency restoration

Background

Currently, system restart relies on restart-capable large generators and predictable load blocks for the restoration process. The ongoing growth of rooftop PV generation reduces the availability of stable load blocks required for the system restoration process.⁶¹

With large quantities of passive or uncoordinated rooftop PV generation, it will become increasingly difficult to manage the impact of rooftop PV variability on the restoration process. The inadvertent and uncontrolled energisation of large amounts of rooftop PV generation on system restart pathways during the restoration process could cause large signal voltage and frequency oscillations and inadvertently disconnect restored generators (including black start services) or sensitive load.⁶²

A means of managing uncontrolled rooftop PV generation during the restart process, even without internet connectivity (which may not be available during a system black event), is required. This could require adapting system restoration processes and potentially revising inverter standards so that they autonomously respond during a prolonged outage (such as a delayed ramping of export) so that stable load blocks can be maintained.

Problem

⁶¹ AEMO, [2024 Transition Plan for System Security](#), December 2024, pp. 57-58

⁶² AEMO, [Renewable integration study, Stage 1, Appendix A: High penetrations of distributed solar PV](#), April 2020.



System restart is coordinated by AEMO, working closely with NSPs, and contracting with utility-scale plant providing restart and restoration support services. In the context of high levels of CER, DNSPs will need to play an increasing role in the restart process. There are also opportunities for CER aggregators and resources within the distribution system to contribute to the restart process. However:

- there is a gap in capability to model and assess the impact of increasing CER on system restart pathways – only basic models exist today and comprehensive studies (covering various scenarios, different CER mixes, etc.) and model validation are lacking
- there is lack of coordination when it comes to modelling, understanding and assessing the feasible system restart and restoration pathways
- it is unclear how this could or should happen e.g. how an aggregator of batteries might be instructed to support a black start, or a DNSP systematically block or coordinate CER during grid energisation
- procedures (and possibly enabling technologies like remote CER disconnect during restart) are not yet standard, representing a gap in operational readiness.

Without a sophisticated understanding of the behaviour and potential impact of CER on system restart and in the absence of an adequate system restart plan that effectively accommodates high levels of CER penetration, AEMO may be forced to wait until the evening when solar insolation levels drop and sufficient levels of stable loads are available to effectively restart the system. This would prolong the length of system black events.

What's being done

AEMO has prepared Technical Advice to inform the Reliability Panel review of the NEM System Restart Standard (SRS) considering both the system restart regulatory framework and new settings for the system restart standard.⁶³ This has considered the impacts of CER on the restart process, and pathways for these impacts to be managed, including:

- enhanced coordination with DNSPs to effectively account for and manage the impact of rooftop solar on the restart process, and the data and models required to do this
- the ability to manage rooftop solar on restart pathways.

AEMO is undertaking system restoration studies for high rooftop PV conditions.⁶⁴ AEMO has identified this as a capability likely required in the next 5+ years.⁶⁵ AEMO's Engineering Roadmap

⁶³ AEMO, [System Restart Technical Advice](#), June 2025.

⁶⁴ AEMO, [Engineering roadmap to 100% renewables, FY2024 priority actions](#), 2023, p. 16.

⁶⁵ AEMO, [2024 Transition Plan for System Security](#), December 2024



analysis will assist them in determining options for both the upcoming 2026-29 System restart ancillary services procurement round, and longer-term procurement from 2030 onwards.⁶⁶

CSIP-AUS capable solar equipment required under DNSP, DOE and backstop schemes already have the capability to return to a reduced default export limit in the event of a power outage. Under system restart conditions, these devices would remain curtailed to this default limit until the device receives a new instruction from the DNSP. With all new solar installations compliant with this standard in South Australia and Victoria, and soon to be in New South Wales, this provides a foundational capability that could be leveraged and adapted as needed. This will require development of effective autonomous responses at the device level and operational coordination across parties.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **system restart and emergency restoration** including the roles, expectations and accountabilities for:

- assessing the impact of increasing CER on system restart, including modelling DPV impact on system restart pathways. This includes formalising:
 - DNSPs' roles in modelling their network assets and CER on system restart pathways and sharing this information with relevant parties
 - TNSPs' roles in assessing the impact of DPV on restart pathways and consideration of support services and other means that might be able to mitigate this impact
- managing DPV on restoration pathways including the potential to formalise operational responsibility for the DNSP to be able to actively manage DPV on restoration pathways, if assessed to be necessary
- operational coordination between the transmission and distribution operating zone for system restart.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.

⁶⁶ AEMO, [2024 Transition Plan for System Security](#), December 2024, p.57.



Table 21: Relevant use cases for system restart and restoration

Use case name	Use case ID	Assigned role	Proposed Actor
Operate and adapt restoration strategy	OTE6	System operator (Tx)	AEMO
Prepare and implement system restart	OTE11	DNO	DNSP
Prepare and implement system restart	OTE13	TNO	TNSP
Operate disaggregated process per system restart	OTE18	Customer agent	Aggregator, Energy retailer, Energy service companies
Develop monitoring and reporting frameworks	PO16	System operator (Tx)	AEMO
Integrated grid planning account for CER impact and potential opportunities	PO19	System operator (Tx)	AEMO
Develop a restoration strategy	PO21	System operator (Tx)	AEMO
Approve emergency operating protocols under high CER system security conditions	PO26	Jurisdictional System Security Coordinator (JSSC)	Jurisdictional Bodies
Develop Dx emergency operating protocols & restoration strategies	PO39	System operator (Dx)	DNSP
Develop Tx emergency operating protocols & restoration strategies	PO43	TNO	TNSP

F.1.4. Emergency frequency management

Background

Emergency frequency control schemes (EFCs) are designed to arrest severe, rapid frequency changes resulting from major non-credible loss of generation or load in the power system. Frequency is an indicator of instantaneous supply-demand balance in AC power systems.

When demand exceeds supply, synchronous generators slow down and the frequency falls. Underfrequency load shedding schemes (UFLS) are a type of EFCs that automatically disconnect load following contingencies that result in the sudden and large excess demand conditions. Underfrequency load shedding schemes work by tripping high voltage circuit breakers at zone or sub-transmission substations, thereby bringing supply and demand back into balance.

Problem

CER uptake has reduced the effectiveness of EFCs in the NEM. There are a range of issues:

- At present, it is not possible to shed distributed load without also shedding the CER generation (and storage) that is installed in the same premises.



- Most CER is not currently configured to provide frequency response, despite this response being technically possible.
- a real-time estimate of UFLS capability is required to allow for transmission system operations and therefore the impact of CER on UFLS capability at any given time needs to be well understood. However, there are no obligations for DNSPs to provide real-time monitoring (or accurate estimates) of load on UFLS circuits to AEMO. Linked to this, real-time monitoring of load on UFLS circuits has been implemented on a case-by-case basis through DNSPs' revenue determinations and pass-through processes, however there is a lack of clarity regarding expectations for this monitoring and how this data is exchanged between AEMO and DNSP control centres.
- There is also limited real-time or post-event visibility into how much load is actually shed during a UFLS event, particularly as metering and telemetry infrastructure often cannot differentiate CER exports from net load. This lack of granular, time-aligned data makes it difficult to assess whether UFLS schemes are achieving their intended system-stabilising effects.
- It is also not clear which party should lead the redesign of UFLS schemes, how DNSPs choose which load to shed in a high CER environment, what technology changes are needed, and what obligations CER aggregators have in coordinating frequency management.

What's being done

AEMO is undertaking studies in 2025 to assess the supply of frequency reserves during low demand periods and the impact of fast frequency response from battery storage to manage large credible contingencies.⁶⁷

AEMO has also identified other potential options for improving the effectiveness of UFLS schemes in areas with high rooftop PV as part of a Victorian case study, including the potential for:⁶⁸

- dynamic arming of UFLS schemes, whereby the UFLS relay monitors the power flows on the circuit and disarms the frequency trip setting if the circuit has a reverse power flow
- smart meters being used to sense frequency locally and to disconnect individual sites, or to disconnect particular loads or circuits at individual sites.

AEMO recommended a number of areas for further investigation by Victorian NSPs.⁶⁹ Dynamic arming of the South Australian UFLS scheme was completed by SA Power Networks in 2024.⁷⁰

⁶⁷ AEMO, [2024 Transition Plan for System Security](#), December 2024, p. 32.

⁶⁸ AEMO, [Under Frequency Load Shedding: Exploring dynamic arming options for adapting to distributed PV - Victorian case studies A report for the National Electricity Market](#), October 2023.

⁶⁹ Ibid, p.37. AEMO repeated some of these findings and recommendations in its 2024 General Power System Risk Review Report – Draft, May 2024, pp.86-87.

⁷⁰ AEMO, [Emergency Underfrequency Response for South Australia](#), May 2024, p. 6.



AEMO has been engaging with DNSPs across all NEM regions to improve visibility and understanding of UFLS availability. Real-time monitoring of load on UFLS circuits has been implemented on a case-by-case basis through DNSPs' revenue determinations and pass-through processes.

The T1 workstream to develop nationally consistent standards for CER is underway and may address this issue of inverter standards in full or in part.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **Emergency frequency management** including the roles, expectations and accountabilities for:

- Setting and updating technical standards to include appropriate frequency response capability. There is also an opportunity to evolve CER capabilities such as fast frequency response or droop response from batteries or smart inverters and ensure that aggregators or customers can participate in frequency control frameworks. The current market ancillary services specifications (MASS) with regard to CER metering specifications needs to be re-evaluated to ensure appropriate CER participation is enabled. We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part.
- Clarifying and where needed, updating processes for remediation actions to support emergency under-frequency response in the context of high CER, including:
 - agreed roles and responsibilities (primarily between AEMO, TNSPs, DNSPs) and empowerment of responsible parties
 - a process for assessing costs/benefits of various remediation actions and determining which ones are optimal and justified
 - clear funding pathways and consensus with the AER and Governments on an approach
 - frameworks to consider efficient long term emergency underfrequency capability holistically, in conjunction with other DER integration activities and other impacts
 - review of UFLS arrangements in the NER to ensure they are fit-for-purpose and appropriate for most situations.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.



Table 22: Relevant use cases for emergency frequency management

Use case name	Use case ID	Assigned role	Proposed Actor
Publish market emergency notices	OTE1	System operator (Tx)	AEMO
Advise available curtailment quantity	OTE7	System operator (Dx)	DNSP
UFLS or OFGS triggered	OTE9	DNO	DNSP
Adjust the energy flow on network	OTE22	DNO	DNSP
Define CER product technical standards development framework	PO13	CER Technical Regulator	Subject to outcomes of CER regulatory framework workstream
Develop Dx network infrastructure plans and Tx/Dx interface standards	PO31	System operator (Dx)	DNSP
Undertake underfrequency studies and design remediation actions	PO35	System operator (Tx)	AEMO
Develop Dx monitoring and reporting frameworks	PO50	System operator (Dx)	DNSP

F.2. Proposed action #6: Conformance and compliance for non-conforming CER within system security frameworks

In chapter 3 we proposed that action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in the operational performance of CER within system security and emergency management frameworks. This includes:

- testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER within CER connection, participation and system security frameworks and processes
- formalising the control hierarchy applying to different coordination signals sent to CER devices so that they respect network and system limits and behave appropriately during normal, abnormal and emergency conditions.

We note the T1 workstream to support nationally consistent standards, and the T2 workstream to establish a regulatory framework for CER are underway and may address this in full or in part.

Further detail is provided in the sections below.

F.2.1. Testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER within system security frameworks and processes

Background



Robust conformance monitoring and compliance frameworks, including the clear allocation of responsibilities for these activities, will help build trust in CER as a legitimate, reliable alternative to traditional network solutions to manage power system flows in the distribution network. In addition, conformance monitoring and compliance frameworks play a critical role in fostering innovation and new services by providing a coordinated structure for verifying and enforcing performance requirements. This gives certainty to industry and consumers, enabling new technologies and service models to emerge, fostering competition and innovation while ensuring that the power system remains secure and reliable.

An essential part of power system security frameworks is monitoring actions from participants to ensure compliance with technical standards and operational commands.

Problem

Under current frameworks, it is often unclear who is accountable for ensuring CER behaves as anticipated during grid events, particularly when a customer is enrolled in a program (for example a VPP) through a customer agent. Specifically, it is unclear who is responsible for:

- monitoring and assessment of conformance of devices to the physical response stipulated in the standard
- enforcement action when non-conformance has been identified
- rectification triggered through the enforcement action.

This weakens disturbance management responses.

What's being done

The T2 workstream to establish a regulatory framework for CER is underway and may address this in full or in part.

Proposed action

We are proposing action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER within** frameworks and processes relating to:

- CER connection
- participation in the power system e.g. when providing grid support
- system security e.g. emergency CER curtailment.

We are seeking stakeholder feedback on this proposed action – see stakeholder consultation questions set out in section 3.8.



Table 23: relevant use cases for conformance and compliance of CER within system security frameworks

Use case name	Use case ID	Assigned role	Proposed Actor
Backstop conformity assessment	OTE21	CER conformance assessor	Subject to the outcomes from the CER Regulatory Framework Workstream
Monitor conformity of customer's CER	OTN55	Customer agent	Aggregator, Energy retailer, Energy service companies, Participating CER/DER owner investor, Active CER/DER
Monitor and analyse relevant customer DER behaviour	OTN71	CER conformance monitor	Subject to outcomes of CER regulatory framework workstream
Provide breach report/notification	OTN93	CER conformance assessor	Subject to the outcomes from the CER Regulatory Framework Workstream
Develop & refine conformance frameworks	PO07	CER regulator	Subject to outcomes of CER regulatory framework workstream
Test performance of emergency tools	PO18	System operator (Tx)	AEMO
Apply corrective action for non-conformance	PO28	Enforcement manager	Subject to outcomes of CER Regulatory Framework workstream
Implementing corrective measure for breach	PO29	Enforcement manager	AER, CER regulator
Monitor conformance using agreed framework	PO47	CER conformance monitor	Retailer, energy services company
Monitor assessment using agreed framework	PO48	CER conformance assessor	DNSP
Ongoing monitoring of CER conformance to technical standards	PO74	Customer Agent	Subject to outcomes of CER regulatory framework workstream
Verify CER installation compliance	CI30	CER conformance assessor	Subject to outcomes of CER regulatory framework workstream
Sample and verify CER installation compliance	CI34	CER regulator	CER regulator, DNSP

F.2.2. Formalising the control hierarchy applying to different coordination signals sent to CER

The control hierarchy that applies to CER participating in off-market mechanisms will be the same as the control hierarchy applying for the purposes of system security and emergency management frameworks (see section 5.2.2).



Glossary

Term	Definition
Actor	A specific person, organisation, or system that performs a role.
Australian Energy Market Commission (AEMC)	The AEMC creates and amends National Electricity Rules (NER), National Gas Rules (NGR) and National Energy Retail Rules (NERR).
Australian Energy Market Operator (AEMO)	AEMO is responsible for managing and operating the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM), which includes facilitating market settlement, conducting TMO functions, and keeping the power system in a safe and secure operating state.
Australian Energy Regulator (AER)	The AER is responsible for regulating the electricity industry and protect the interests of current and future consumers of energy. This includes through promoting effective competition between persons or entities engaged in the generation, transmission, distribution or supply of electricity.
Capabilities (level 1, 2, 3)	Use case groupings (discussed further in in a separate user guide and artifacts published alongside this paper).
Consumer Energy Resources (CER)	Small to medium scale energy resources located behind the meter at residential, commercial, and industrial premises that are owned or operator by the customer. These resources can include electricity generation such as rooftop solar PV, energy storage such as batteries or EVs, and flexible loads such as hot water heating.
Distributed Energy Resources (DER)	Similar to Consumer Energy Resources (CER), but refers to (often larger) technologies that are directly connected to the distribution network in front of the meter
Distribution Market Operator (DMO)	Responsible for operating markets for energy and other services exchanged between parties connected to the distribution network. There is currently no real-time distribution level markets in eth NEM and therefore no distribution market operator.
Distribution Network Operator (DNO)	Responsible for building and maintaining the assets that form the distribution network in a way that enables the safe, secure, and reliable



Term	Definition
	transfer of electricity between parties connected to the distribution network. DNSPs are the distribution network operator in the NEM.
Distribution Network Service Provider (DNSP)	Responsible for the development and operation of the distribution network following an active network management approach in order to facilitate the secure, safe and reliable delivery of power flows between network connections. DNSPs are distribution owners and currently conduct DNO and DSO functions.
Distribution Owner	Owns the distribution assets that form the distribution network and is able to earn an investment return on those assets. DNSPs are the distribution owners in the NEM.
Distribution Planner	Responsible for identifying appropriate distribution system investments. DNSPs are the distribution planner in the NEM.
Distribution System Operator (DSO)	Responsible for monitoring and managing the distribution system, including real-time system operation, in accordance with system constraints and regulated standards. DNSPs are currently the distribution system operator in the NEM.
Dynamic Network Price (DNP)	Prices that change in response to the actual cost to serve consumers, providing signals to consumers when their part of the network is constrained.
Dynamic Operating Envelope (DOE)	Operating envelopes of the network that change to reflect the near-real time hosting capacity, and can be used as the basis for varying the import and export limits for a customer over time and location. DOEs are calculated by the DNSP and can be communicated to customer connect points over different pathways.
Energy and Climate Change Ministerial Council (ECCMC)	A forum for the Commonwealth, Australian states and territories, and New Zealand to work together on priority issues of national significance and key reforms in the energy and climate change sectors. ECCMC is chaired by the relevant Commonwealth Minister.
National CER Roadmap (CER Roadmap)	The CER Roadmap sets out a national plan to unlock full benefits of CER at scale across Australia. The CER Roadmap is focusing on priority reforms through four workstreams: consumers, technology, markets, and power system operations.



Term	Definition
National Electricity Market (NEM)	The wholesale electricity market that operates in, and connects, Queensland, New South Wales, the Australia Capital Territory, Victoria, South Australia, and Tasmania. Generators and retailers in these states and territories buy and sell electricity through the NEM.
National Energy Transformation Partnership (NETP)	A framework for Australian state, territory and Commonwealth governments to collaborate to transform Australia's energy systems for our net zero future.
Non-market (sub-set of off-market)	Services acquired by AEMO or TNSPs outside of a spot market (i.e. structured procurement) such as system restart and network support control ancillary services.
Off-market	Any services procured outside the wholesale market, including services at the distribution level.
Photovoltaic (PV)	Technology that can generate electricity using sunlight. Synonymous with rooftop PV and solar PV, PV can be a type of CER that allows consumers to generate electricity.
Role	The usual or expected function of an actor, or the part somebody or something plays in a particular action or event. An Actor may have a number of roles. A role could be performed by a number of actors.
Transmission Market Operator (TMO)	Responsible for operating markets for energy and other services exchanged between parties connected to the transmission network. AEMO is the transmission Market Operator in the NEM.
Transmission Network Operator (TNO)	Responsible for building and maintaining the assets that form the transmission network in a way that enables the safe, secure, and reliable transfer of electricity between parties connected to the transmission network. TNSPs play this role in the NEM.
Transmission Network Service Provider (TNSP)	Responsible for the development and operation of the transmission network area to facilitate the secure, safe and reliable delivery of power flows between network connections. TNSPs are transmission owners and conduct TNO functions.



Term	Definition
Transmission Owner	Owns the transmission assets that form the transmission network and is able to earn an investment return on those assets. TNSPs are the transmission owners in the NEM.
Transmission System Operator (TSO)	Responsible for monitoring and managing the transmission system, including real-time system operation, in accordance with system constraints and regulated standards. AEMO is the Transmission System Operator in the NEM.
Use case	Individual system functions or ‘activities’ identified through the capability mapping exercise under component one of this workstream (discussed further in a separate user guide and artifacts published alongside this paper).
Virtual Power Plant (VPP)	CER and DER that are aggregated and operated in a coordinated manner to provide electricity services as a collective.
Wholesale Electricity Market (WEM)	The wholesale market to buy and sell electricity in south-west Western Australia from the South West Interconnected System (SWIS).

