



Australian Government

Department of Climate Change, Energy,  
the Environment and Water

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

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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# Executive Summary

***The benefits of harnessing consumer energy resources are vast.***

1. Australians have enthusiastically embraced consumer energy resources (CER), with the highest proportion of households with rooftop solar photovoltaic (PV) systems in the world.
2. The uptake of household batteries and electric vehicles is forecast to follow a similar growth trajectory and play a large role in the energy system.
3. CER technologies contribute to Australia's emissions reduction commitments and present enormous opportunities for consumers and the power system. With advances in technology and communication, CER can be harnessed to:
  - reduce network congestion and the need for network augmentation
  - reduce wholesale market costs and market price volatility
  - offset large-scale generation requirements by generating electricity locally
  - contribute to system security services (for example battery storage providing frequency support or voltage control)
  - reward customers for the value their CER provides to the system.
4. The estimated benefits of utilising CER in these more sophisticated ways are vast, with multiple analyses valuing different types of CER benefits to be in the billions of dollars in the coming decades.

***CER value is maximised when it is effectively integrated into power system and market operations. To do this we need to clarify what's expected of market participants, and formalise roles.***

5. Realising the potential benefits of CER is not a given. A high CER system has different operational characteristics and requirements than the system of the past, so new ways of doing things are needed.
6. We require more and better-quality data and information about CER devices and how they behave in real time, and new tools and frameworks to orchestrate (rather than just accommodate) CER. We need to accurately account for CER in our planning and operating frameworks and harness CER to help balance supply and demand, manage congestion and contribute to system security.
7. To achieve these outcomes the roles, expectations and accountabilities of all parties involved in integrating CER need to be clear, formally assigned and standardised across the NEM.
8. This consultation paper represents a key deliverable for two National CER Roadmap workstreams, being:
  - M3 - Redefine roles for market operations, and
  - P5 - Redefine roles for power systems operations.
9. The project seeks to define and assign the roles and responsibilities for distribution market and power system operations in a high CER future.



***We have defined and assigned the roles and responsibilities for a high CER future, to form a base case for change (Chapter 3).***

10. 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. Our capability mapping exercise provides a foundation from which gaps can be determined and alternative options can be explored.
11. We have mapped 232 “use cases”, or individual activities, that we consider must be undertaken to effectively integrate CER into the distribution system in a way that achieves the outcomes described in the CER Roadmap. The activities were identified with respect to NEM processes, and jurisdictions such as Western Australia are already progressing ahead to integrate CER, most of the activities identified will be necessary requirements in any high-CER power system.
12. For each activity, we have assigned a ‘role’ which represents the *type* of organisation responsible for undertaking the activity and an ‘actor’ which represents the *actual existing* NEM-based organisation responsible for undertaking the activity. The roles are purposefully actor-agnostic so different actors can be assigned to roles in different jurisdictions, or different future arrangements.
13. The capability mapping exercise provides a base case and provides a common language and framework to explore options for change.
14. Through the mapping we demonstrate that the majority of activities required to operate the power system and market with high levels of CER are being performed by existing actors – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes.<sup>1</sup> But there are some gaps particularly when considering how to support the higher levels of CER expected in the future.

***We have focused on the key roles involved in organising CER to maximise its value (Chapter 2)***

15. As CER grows as a proportion of total resources in power systems around the world, there is a growing focus on how best to organise it so that its value can be maximised and delivered back to consumers. There are several roles that are crucial to achieving this objective:
  - distribution system operators (DSOs)
  - distribution network operators (DNOs)
  - customer agents, and
  - other roles that interact directly with customers or their devices.

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<sup>1</sup> 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.



16. A **distribution system operator (DSO)** (although the exact definition varies) broadly refers to a party responsible for real-time system operation of the distribution network.
17. A **distribution network operator (DNO)** is responsible for building and maintaining the assets that form the distribution network in a way that enables the safe, secure, and reliable transfer of electricity between parties connected to the distribution network.
18. In the NEM, distribution network service providers (DNSPs) perform the roles of DSO and DNO, alongside other roles relating to owning and planning the distribution network. The role of DNO is clearly defined with the expectations and accountabilities formalised in regulatory frameworks and processes.
19. The role of DSO, however, is not clearly defined or formally assigned for CER, and is becoming increasingly important in a high CER power system.
20. DNSPs are the natural entity to continue to undertake the DNO and DSO roles going forward, absent of substantive institutional reform.
21. We therefore need to make sure that DNSPs have the right information, tools, frameworks and policy guidance to undertake DSO activities in a way that maximises CER value and delivers it back to consumers while supporting secure system outcomes.

***Based on our capability mapping exercise the immediate priority is to clarify, formalise and standardise roles, expectations and accountabilities in six key areas (chapter 3).***

22. Chapter 3 identifies six areas of focus (contributing to three major outcomes) where we consider that **roles, expectations and accountabilities** for all parties involved need to be **clarified, formalised and standardised** as an immediate priority.
23. These areas of focus, arranged under relevant outcomes are:

**Outcome 1:** CER is **visible and predictable** and can be used effectively as part of power system operations. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- i. defining, collecting, updating, maintaining quality, and sharing **device-level data and information**
- ii. defining, collecting, aggregating, updating, maintaining quality, using and sharing **CER monitoring data**.

**Outcome 2:** CER is **orchestrated effectively** to deliver value for consumers and the power system. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- iii. establishing and using **off-market mechanisms** (flexibility services, dynamic operating envelopes (DOEs), dynamic network prices (DNPs)) and communicating relevant information to enable widespread adoption of these.
- iv. **monitoring and compliance** of non-conforming CER, that is, CER or aggregated CER portfolios, that do not respond as agreed when participating in off market mechanisms.

**Outcome 3:** CER plays a central role in **system security and emergency management** frameworks and processes. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:





- v. accounting for, using or controlling CER as part of **system security** and emergency management frameworks
  - vi. **monitoring and compliance** of CER within security frameworks.
24. We propose action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities relating to these six areas of focus.
  25. We consider these actions to be necessary first steps to support any CER future. They will support the evolution of distribution-level tools and mechanisms within the current framework to accurately account for and ultimately harness CER in planning and operating the power system and market.
  26. With the proposed role clarifications, the current framework can be evolved to capture more CER value than today and deliver it back to CER customers as rewards for behaviour that contributes to power system outcomes. Ultimately, all consumers will benefit through lower costs.
  27. We consider that role clarifications made to evolve current frameworks can and should be achieved in a way that does not limit the possibility of making more significant structural changes to market or governance arrangements in the future.
  28. For each of the six immediate areas of focus, we are seeking stakeholder feedback on
    - who should be responsible for clarifying, formalising and standardising the roles, expectations and accountabilities and through what mechanisms
    - what factors should be considered when clarifying, formalising and standardising the roles, expectations and accountabilities.

***We have examined the potential to capture additional value, beyond what can be achieved through immediate role clarifications, by integrating CER through a real-time energy market in the future (Chapter 4).***

29. “Off market” mechanisms and tools that are emerging under current frameworks to leverage CER (e.g. DOEs, DNPs and flexibility services) may be limited in how much they can maximise the benefits of CER in the future. Integrating CER into a real-time market, whether the current wholesale market or a new distribution-level market, could potentially capture more value from CER. It would do this by enabling real-time optimisation and coordination of CER and the network, ensuring resources are predictably dispatched when and where they are most valued.
30. In this paper we explore three real-time market designs based on advice from Cambridge Economic Policy Associates (CEPA). The designs illustrate the available range of market approaches that could be taken to integrate CER into the wholesale market and the broader power system. They are not intended as an exhaustive list of all possible options. While the designs are intended to be fit-for-purpose in a future scenario with high levels of CER, they are also intended to guide near-term thinking by ensuring that more immediate reforms are scalable and consistent with possible longer-term designs.
31. The design options are:
  - Focused evolution of status quo arrangements to improve visibility of unscheduled CER. While it does not introduce real-time market arrangements at the distribution-



level, unscheduled CER is explicitly considered in the existing wholesale market through retailer forecasts (**Design A**)

- Real-time distribution-level market that optimises participating CER and then iterates with the transmission-level market (**Design B**)
- Integrated distribution and transmission level market that optimises participating transmission and distribution-level resources in a single optimisation solution (**Design C**).

32. The question for stakeholders to consider is whether off-market mechanisms will remain an effective way of leveraging CER opportunities in the future, or whether there will come a time where the benefits of real-time market arrangements will be sufficient to offset their costs and complexity.

33. We are also asking stakeholders to consider what conditions might indicate that the benefits of introducing real time market arrangements for CER outweigh the cost and complexity of implementing what would be significant reforms.

***We have also considered whether DNSPs have the right governance and institutional arrangements to perform the DSO role into the future. (Chapter 5)***

34. As CER grows as a proportion of total generation in global power systems, there is a growing focus on how best to organise these resources so that their value can be maximised and delivered back to consumers.

35. The already high and growing levels of distribution-connected resources in the NEM make it all the more crucial that distribution system operations activities are done and done well. This consultation paper explores the question of whether DNSPs have the right incentives, objectives and governance arrangements to perform the DSO role into the future.

36. The reason this question is being asked is because there are potential issues with DNSPs playing the role of DSO alongside its role of DNO including a potential:

- lack of consistency in systems and processes across distribution regions
- lack of whole of system perspective, and
- preference for network solutions.

37. This consultation paper explores four options for institutional or governance reform (“governance options”) which are to:

1. separate DSO regulatory and/or accounting functions within a DNSP
2. move DSO functions to a new independent organisation
3. create a new entity responsible for consistency and coordination of systems and processes across DNSPs (a ‘coordination and facilitation body’)
4. pursue regulatory reform within the existing framework to address or mitigate the identified issues.

38. Each governance option explored in the paper addresses different problems and each has different implementation challenges, complexities and costs that are likely to be material.



39. We are seeking stakeholder views on whether DNSPs have the right incentives, objectives and governance arrangements to perform the DSO role into the future in a way that maximises the value of CER and delivers the best outcomes for consumers in general.

40. If not, the alternatives are to:

- make changes to how DNSPs make decisions about and undertake DSO activities (governance options 1, 3 and 4), or
- (at the extreme) make arrangements for some/all DSO activities to be undertaken by an independent entity instead of the DNSP (governance option 3).

41. The problems stakeholders consider to be a priority when considering whether or not DNSPs can perform the role of DSO effectively will inform whether and which reform options warrant further investigation.

***The options presented in this paper can be progressed individually, together or in a staged approach***

42. This paper seeks stakeholder feedback on three types of reforms:

- Focused evolution of current arrangements to clarify, formalise and standardise roles, expectations and accountabilities such that existing actors can effectively undertake the activities required to integrate CER into the power system and market in the near term (chapter 3).
- Structural changes to market arrangements to incorporate distribution-level CER into a real-time market (chapter 4).
- Structural amendments to governance arrangements to change how decisions relating to distribution system operations are made, and by whom (chapter 5).

43. The reform pathways are not mutually exclusive – in fact, we consider the priority actions to clarify roles proposed in this paper to be necessary first steps to any CER future.

44. Imagining the world in which the immediate role clarifications proposed in chapter 3 have been progressed (along with the many other reforms that are underway through the National CER Roadmap, market bodies and industry work plans) may inform stakeholders' views on whether structural changes to market and governance arrangements are needed.

45. Stakeholders may consider that the evolution of current frameworks will be enough to effectively integrate CER into the power system and market.

46. Alternatively, stakeholders may consider that evolution of current frameworks will be too slow or ineffective, or that conditions are likely to arise to make the benefits of structural changes to market or governance arrangements outweigh the cost and complexity of implementing them.

47. The structural changes to market and governance arrangements explored in this paper could also be progressed in a phased way with the more modest options (such as market design A or the governance option to establish a coordination and facilitation body) progressed before considering whether more reforms are needed.

***Stakeholder feedback will inform recommendations to Ministers***



48. We are seeking stakeholder feedback on options explored in this paper to improve integration of CER by improving how activities are performed and/or who performs them.
49. Feedback from stakeholders will be crucial to informing and shaping our recommendations to Ministers in Q4 2025.
50. Written submissions responding to this consultation paper must be lodged by the due date specified on the Have Your Say website, [consult.dcceew.gov.au](https://consult.dcceew.gov.au).
51. There will be other opportunities for you to engage with us, such as one-on-one discussions, industry briefing sessions and a public forum.
52. Formal submissions received in response to this consultation paper, as well as stakeholder feedback gathered through the project working group and stakeholder meetings will inform our next stage of work.

### Box 1: Full list of consultation questions

#### Stakeholder feedback on capability framework

Chapter 3 introduces the “capability framework” we used to identify, define and assign all the activities we consider are necessary to integrate CER into the power system and market. More information on the capability framework is included in Appendix C and the outputs published alongside this paper. In relation to the capability framework, we are seeking stakeholder feedback on the questions below.

1. Have we captured all the activities (or ‘use cases’) required to operate power systems and markets in a high CER future? If identifying ‘missing’ use cases, consider whether they are a sub-set of an existing activity.
2. Have we assigned each of the activities to the appropriate role and existing actor?
3. Should any of the actor assignments be reconsidered now or in the future? When explaining why, please refer to our assessment criteria in Appendix A.

#### Stakeholder feedback on near term actions to clarify roles

Chapter 3 (and the additional detail in Appendices D-F) identifies six areas of focus where we consider that roles, expectations and accountabilities for all parties involved need to be clarified, standardised and formalised as an immediate priority. These areas of focus are:

- device-level data
- CER monitoring data
- off-market mechanisms
- conformance and compliance of CER participating in off-market mechanisms
- CER in system security frameworks
- conformance and compliance of CER within security frameworks.

In our final report to Ministers, we intend to propose an implementation approach to progress action in these areas (if recommended). The recommendations and implementation approach will be informed by stakeholder responses to the questions below.

4. Do you agree that clarifying, formalising and standardising the roles, expectations and accountabilities in these six areas is an immediate priority? Are there any specific timeframes within which the actions should be delivered?



5. Are there any other areas where roles, expectations and accountabilities need to be clarified, formalised and standardised as an immediate priority?
6. For each of the six areas of focus, **who** do you think should be responsible for clarifying, formalising and standardising the roles, expectations and accountabilities (e.g. governments, market bodies, industry) and **through what mechanisms** (e.g. rules or other regulatory instruments, policy guidance, investment)?
7. For each of the six areas of focus, **what factors** should be considered when clarifying, formalising and standardising the roles, expectations and accountabilities? For example, are there:
  - a. any actors that should or should not have a particular role (e.g. being responsible for updating and maintaining device level data over the lifetime of the asset may only be practical for one or two actors)?
  - b. specific benefits or risks in doing the component activities one way vs. another (e.g. making standardised off-market information available on a shared platform versus publishing it in a standardised format on individual platforms)?
  - c. any practical considerations that would limit an actor from playing the optimal role (e.g. technology limitations, lack of regulatory authority/licence to perform a role, conflicts of interest)?
  - d. any implementation approaches that would limit the ability to maximise CER value into the future including locking out a future market design or governance option? (e.g. how and when DOEs can or should be used (e.g. only as emergency backstops or more regularly))?

**Stakeholder feedback on distribution-level market designs:** referring to the discussion of distribution-level market designs in chapter 4:

8. Do you think off-market mechanisms, along with other actions to improve visibility and predictability, support effective orchestration and embed CER in system security frameworks will, over time, be able to capture most (if not all) of the benefits of market orchestration of CER?
9. Do you think the long term benefits of distribution-level market arrangements would outweigh the cost and complexity of implementation?
10. What triggers/conditions in the future might indicate a need for more fundamental reform to more comprehensively integrate CER into the NEM wholesale market?
11. Which of the models described in the chapter are most appropriate to integrate CER into the NEM wholesale market? Are there any other market designs that you think should be considered, compared to Designs A-C in this paper?
12. What complementary measures would be necessary, for example in retail markets, to support effective implementation of the models described in the chapter?

**Stakeholder feedback on governance options:** referring to the discussion of governance options in chapter 5:





13. Do stakeholders agree with the potential issues we have identified when considering whether or not DNSPs can perform the role of DSO effectively? Which issues do you consider to be the highest priority to address?
14. When considering how best to integrate CER into the power system and market are the institutional arrangements that govern how decisions are made within a DSO a priority for you?
15. Noting the near-term, no-regrets actions identified in chapter 3 to improve the delivery of DSO functions under a high CER future, do you consider there is a need for an independent DSO in the future? If so, why?
16. Would you support further investigation of any of the other governance reform options, and if so, which one/s and why?
17. Are there governance reform options that we have not identified that should be considered?



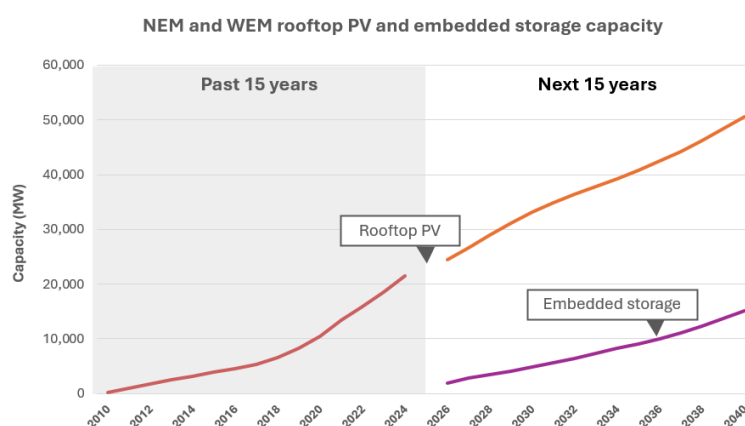
# 1. Context

## 1.1. CER has the potential to provide substantial benefits to consumers

Australians have enthusiastically embraced consumer energy resources (CER), particularly in the form of rooftop solar photovoltaic (PV) systems. Rooftop PV systems are now more than 3 times as common as backyard swimming pools. In Q4 2024 the approximately 4 million rooftop PV systems met 17 per cent of electricity demand in the National Electricity Market (NEM) and 26 per cent in the Western Australian Wholesale Electricity Market (WEM).<sup>2</sup> The number of systems and roles that rooftop PV will play in meeting our energy needs is expected to increase into the future, with the Australian Energy Market Operator (AEMO) estimating that rooftop PV capacity in the NEM will more than double from current levels by 2040.<sup>3</sup>

The uptake of household batteries and electric vehicles (EVs) is forecasted to follow a similar growth trajectory, and these resources are also expected to play a large role in the energy system. The number of electric vehicles in the NEM and WEM regions is expected to grow from around half a million vehicles today to more than 11 million in the next 15 years. Over the same timeframe, around 6.4 GW of storage capacity is expected to start participating as aggregated ‘virtual power plants’ (VPPs), and collectively around 15 GW of aggregated and non-aggregated CER storage capacity is expected to be present – more than 7 times the nameplate capacity of Snowy 2.0.

**Figure 1: Rooftop PV and embedded storage capacity in NEM and WEM, Step Change scenario.<sup>4</sup>**



<sup>2</sup> AEMO, [Supporting secure operation with high levels of distributed resources](#), Q4 2024, p. 15.

<sup>3</sup> AEMO, [Draft 2025 Stage 2 Inputs and Assumptions Workbook](#), Step Change scenario

<sup>4</sup> Embedded storage includes aggregated and non-aggregated distributed storage capacity. Source: Clean Energy Regulator, small-scale installation postcode data; AEMO, Draft 2025 Stage 2 Inputs Assumptions and Scenarios workbook.



**Box 2: What are 'consumer energy resources'?**

Consumer energy resources are made up of a diverse range of small to medium scale energy resources that are located behind the meter at residential, commercial and industrial premises and are owned or operated by the customer. These resources generate, store or shift consumption of electricity and include:

- **flexible loads** that can alter demand in response to external signals, such as shifting hot water heating air conditioning and EV charging to peak periods or periods when excess renewable energy capacity is available.
- **electricity generation** such as rooftop PV systems that meet customer demand and/or export electricity into the distribution network.
- **energy storage** technologies, such as small-scale batteries and EV supply equipment.

The term Distributed Energy Resources (DER) is also 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.

Technology and innovation are enabling increasingly sophisticated coordination of both CER and DER through Distributed Energy Resources Management Systems (DERMS) at different levels, including:

- **Local energy management systems** and gateway devices coordinating the operation of individual devices at the site level (home, building, facility, campus, etc.)
- **Aggregated coordination** of devices over a wide area (for example virtual power plants (VPPs), interacting with local management systems and device level controllers.

CER technologies present opportunities for all consumers to reduce their electricity costs. With advances in small scale energy generation (e.g. rooftop PV) and storage technologies (e.g. batteries), as well as communication technologies, more sophisticated ways of managing CER are possible. With CER able to respond to local and remote signals, and coordinated at the group-level, it can be increasingly harnessed to:

- Allocate network capacity on the distribution network more precisely, in response to real-time network conditions. This can reduce the need for network augmentation more effectively than time of use or capacity tariffs alone.
- Reduce wholesale market costs and large-scale generation and transmission requirements by enabling CER to participate on a level footing with utility-scale generation by generating electricity locally through rooftop PV and exporting electricity from storage during periods of high prices.
- Contribute to the provision of system security services, for example battery storage providing frequency or voltage control.
- Play an expanding role in supply-demand balancing, and the moderation of both peak and minimum demand events, by providing a diverse range of flexibility services.

The estimated benefits of utilising CER in these more sophisticated ways are vast. A range of analyses has been done, each quantifying different types of costs and benefits from CER. For example:



- NERA Economics estimates that load flexibility could save consumers up to \$18 billion in high CER uptake scenarios due to a reduced need for utility scale generation and storage.<sup>5</sup>
- Baringa estimates the total network benefits of efficient CER integration could save consumers up to \$11 billion due to avoided curtailment costs and reduced distribution and transmission augmentation requirements.<sup>6</sup>
- Joint work from the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Energy Networks Australia (ENA) has previously estimated the value of CER integration across the entire electricity value chain to be \$100 billion in lower system costs by 2050, relative to no action.<sup>7</sup>
- The Australian Energy Market Commission (AEMC) engaged Intelligent Energy Systems (IES) to quantify the potential benefits of integrating currently unscheduled price-responsive resources into the dispatch process. This modelling found that as the magnitude of unscheduled price-responsive resources grows, the errors become substantial, resulting in a combined efficiency loss of around \$1.5 – 1.8 billion.<sup>8</sup>
- AEMO's Integrated System Plan (ISP) estimates that effective coordination of CER (for example through VPPs) will deliver \$4.1 billion of benefits in avoided grid-scale investment.<sup>9</sup>

## 1.2. There is a range of challenges in capturing and maximising CER benefits

Realising the potential benefits of CER is not a given. A high CER system has different operational characteristics and requirements than the system of the past, so new ways of managing CER are needed. Active steps must be taken to effectively integrate CER into network and market operations.

AEMO's 2020 Renewable Integration Study highlights the typical trajectory of system challenges with increasing penetration of unmanaged CER. Figure 2 below shows that:<sup>10</sup>

- At low levels, passive CER uptake does not impact power system security or reliability outcomes and is relatively easily accommodated within the distribution network with little restriction or intervention.

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<sup>5</sup> Distributed Energy Integration Program, [DER market integration trials, Summary report](#), September 2022, p. 8.

<sup>6</sup> Distributed Energy Integration Program, [DER market integration trials, Summary report](#), September 2022, p. 8.

<sup>7</sup> Energy Networks Australia, [Open energy networks project, position paper](#), 2019, p. 7.

<sup>8</sup> Intelligent Energy Systems, [Benefit analysis of improved integration of unscheduled price responsive resources into the NEM \(ERC0352\)](#), Final report, 24 June 2024, P. 9.

<sup>9</sup> AEMO, [2024 Integrated system plan](#), p.17

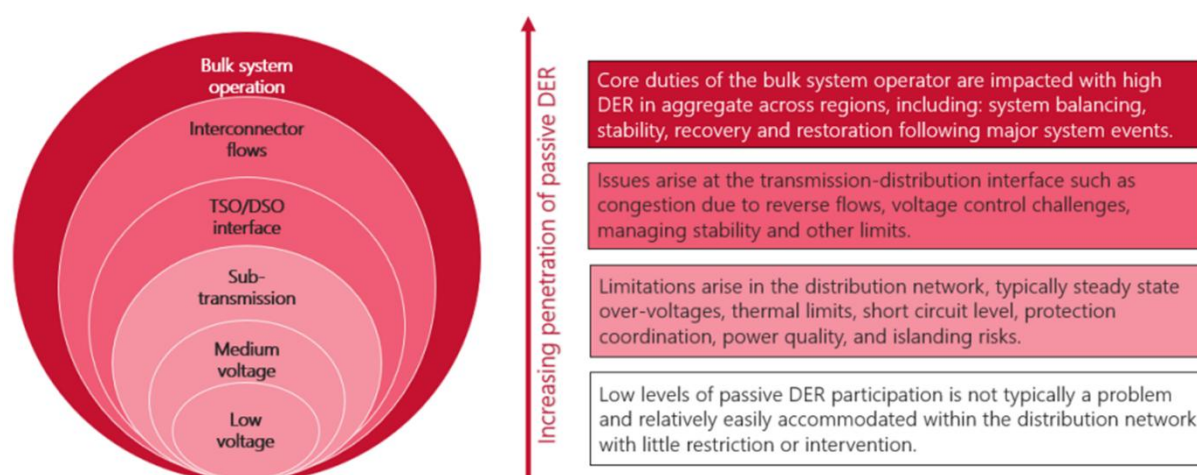
<sup>10</sup> AEMO, [Renewable Integration Study, Appendix A: High Penetrations of Distributed Solar PV](#), April 2020, Section A2.3.2.



- As penetration increases or concentrates in certain areas, limitations first arise within the distribution network, typically voltage management. As clusters of CER continue to grow, they eventually impact the distribution-transmission interface in the co-ordination of voltage control devices and the management of transmission level congestion due to reverse flows.
- Once CER penetration has become significant at the regional level, the inability to see and actively manage CER impacts almost all core duties of the power system operator, including managing the supply-demand balance in real time, system stability, and recovery and restoration following major system events.

Each NEM region is at different points along this trajectory today, and will continue to progress along this trajectory, as rooftop PV uptake continues and behind-the-meter storage and EV adoption begin to scale.

**Figure 2: Typical trajectory of system challenges associated with increasing penetration of CER**



Source: AEMO, AEMO, Renewable Integration Study, Appendix A High Penetrations of Distributed Solar PV, Section A2.3.2 available [here](#)

This highlights the need to be addressed and the opportunities that will flow from effectively integrating CER into the power system and market. Some of the key challenges to integrating CER into the power system and market include:

- **System security and emergency management:** CER is already at sufficient scale that in aggregate its actions have the potential to impact the secure operation of the system without substantial high-cost augmentation and other system integration costs. The collective actions of CER must be sufficiently co-ordinated, controllable and integrated into existing system security processes. High CER can also create new requirements such as maintaining sufficient minimum system load.
- **Visibility and predictability of CER:** The current visibility of CER activity on the network is low. Visibility and predictability of CER are important inputs into system planning and operational decisions to minimise total costs and ensure stable and secure functioning of the system. CER actions must also be visible and verifiable for CER to be rewarded for contributing to system services in some cases.
- **Operational coordination (or orchestration) of CER:** The current ability to holistically coordinate the operation of CER is limited and piecemeal. New mechanisms are required to orchestrate CER in a manner that is informed by both whole-of-system and locational





distributional conditions, such that the collective actions of CER reduce rather than increase overall costs. Of particular importance is an awareness of local network and wholesale market conditions.

- *Local network constraints*: when import or export demand exceeds network capacity it creates network congestion. The actions of CER have the potential to create inefficient levels of localised congestion on the distribution network, given the size of CER loads relative to typical residential loads. Increasing the network capacity to relieve this congestion is costly. Orchestrating CER to better utilise network infrastructure can help defer or avoid the need for network augmentation, improve network reliability and reduce costs for consumers.
- *Wholesale market integration*: wholesale market prices are used to indicate scarcity or surplus of supply. CER can reduce overall generation costs by responding to these price signals while delivering additional value to consumers that have invested in CER.
- **Coordination and alignment across multiple entities**: High CER systems require the management of a very large number of small and medium sized energy resources connected across various distribution networks. This creates the need to both manage conditions on each distribution network more dynamically and coordinate or align these actions across a greater number of entities. These diverse entities include distribution and transmission networks and the system operator, as well as CER and DER owners, energy retailers and CER aggregators / VPP operators.

This paper explores these challenges and the range of roles and responsibilities required now and into the future to ensure safe and secure system operations and to unlock the full value that CER can provide to consumers.<sup>11</sup>

### **Box 3: Why do network operators have to manage low voltage (LV) CER imports and exports?**

At any point in time network infrastructure has a finite capacity to accept CER exports (or imports). As more CER connects to the distribution network, more electricity (e.g. from rooftop solar) is being exported into the network at the distribution level. As battery energy storage systems (BESS) and EVs become more prevalent we can expect the demand for network access for both imports and exports to increase. The amount of electricity that CER can export (or import) is constrained by two technical network limits:

- Electrical pressure limits – referred to as voltage limits.
  - All customer installations can see the voltage (or pressure) in the street. It is the same as the voltage at the customer’s connection when no power is flowing to or from their premises – just like the water pressure at a property is the same as the water pressure in the street if no taps are on.

<sup>11</sup> For an expanded consideration of the challenges associated with integrating CER into power systems, refer to Power Systems Architecture, Report 3: Systemic Issues & Transformation Risks, 2025, CSIRO (Sections 4.2.1 – 4.2.3)



- Voltage differences cause power to flow. If the customer is exporting, then the voltage at their connection is slightly higher than in the street. If the customer is importing, then the voltage at their connection is slightly lower.
- To export power further back into the network the local network voltage must also rise. The greater the volume of CER exports, the more it rises.
- Electrical flow limits – referred to as thermal or current limits.
  - Electricity mains and transformers are not frictionless. Current (i.e. electrons) flowing through them make them hot. If mains and transformers get too hot, then they will ultimately fail.
  - Customer installations cannot see when network current limits have been reached. The customer’s installation can only see the current (electrons) that flow to and from the customer’s premises – just like a water meter can only see the water that flows into a property. The meter can’t see the amount of water that is flowing along the street.

What happens when the voltage and current limits are reached?

- A properly set CER inverter will detect if the upper voltage limit is reached and will stop exporting.<sup>12</sup> This will prevent the voltage from rising further, meaning that appliances and equipment won’t be exposed to voltages that they are not designed for. This means that voltage limits will be met automatically, regardless of the amount of CER installed, without any need to communicate with the inverter.
- If current limits are exceeded, then upstream network fuses will blow to protect the street mains and equipment, interrupting supply to all consumers (approximately 100) connected to that circuit. Network fuse sizes are chosen so that the fuse will blow before the street mains or equipment fail. To avoid breaching current limits, the network operator must limit CER exports (and potentially imports in future), either through fixed limits, or by communicating’ with the CER when network limits are being approached (e.g. through DOEs), so that exports can be curtailed.

At present, in the vast majority of cases for exports, **the upper voltage limit is reached** (and CER self-curtails) **before the network current limit is reached**. Because CER self-curtails when the upper voltage limit is reached, local street mains and equipment should automatically stay within technical limits. This remains the case regardless of the amount of exporting CER that is installed, and without the need for any form of communications or intervention.

There are likely to be some rare exceptions such as commercial/industrial sites connected directly to the distribution transformer, or sites with short underground street mains. Underground mains are thicker than overhead mains (on a like for like capacity basis), so the voltage rise is less.

As noted in figure 2 above, as CER penetration increases issues can also arise at higher levels of the power system. Orchestration of CER dispatch and settings can help to minimise the need to address constraints through network upgrades.

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<sup>12</sup> Many legacy inverters are not properly set. This is an issue that needs to be addressed and is being progressed under the CER Roadmap workstream T.2.

## 2. About this paper

### 2.1. This consultation paper delivers against priority reforms in the National CER Roadmap

Under the National Energy Transformation Partnership (NETP), Australian governments are working together to maximise economic opportunities from the clean energy transformation, to ensure reliable and affordable electricity, and to deliver the greatest benefits for Australian households, businesses and communities.

At the November 2023 Energy and Climate Change Ministerial Council (ECMC) meeting, Ministers recognised the need for a national CER roadmap to promote better coordination and optimisation of CER, which will put downward pressure on bills and overall system costs, reduce emissions and broaden access to CER across communities.

Ministers agreed to the creation of a CER Taskforce to fast track priority projects, and an interjurisdictional CER Working Group to provide strategic direction and highlight priority reforms and sequencing considerations to achieve the vision and outcomes.

A National CER Roadmap (the CER Roadmap) and Implementation Plan was published in July 2024. It identifies priority reforms to realise the benefits of CER. The CER Roadmap builds on the work of jurisdictions, the former Energy Security Board and market bodies, and it sets out a pathway for a range of reform priorities over coming years across 4 workstreams relating to consumers, technology, markets and power system operations. These workstreams are shown in Table 1 and cover the full range of reforms that will be needed to maximise consumer outcomes in a high CER future. Progress against outcomes will be reviewed with an updated Implementation Plan, considered by ECMC on an annual basis.



**Table 1: National CER Roadmap workstreams**

National CER Roadmap workstreams		
Consumers	C1	Extending consumer protections for CER
	C2	More equitable access to benefits of CER
	C3	CER information to empower consumers
Technology	T1	Nationally consistent standards including vehicle to grid
	T2	National regulatory framework for CER to enforce standards
	T3	Establish secure communications systems for CER devices
Markets	M1	Enable new market offers and tariff structures to support CER uptake
	M2*	Data sharing arrangements to inform planning and enable future markets
	M3*	Redefine roles for market operations
Power system operations	P1	Enable consumers to export and import more power to and from the grid
	P2	Faster harmonised CER connections processes including EV chargers
	P3	Improve voltage management across distribution networks
	P4	Incentivising distribution network investment in CER
	P5*	Redefine roles for power system operations
*M3/P5 are being delivered through a single project (this project) and is closely related to M2.		

## 2.2. This project seeks to define and assign roles and responsibilities for distribution systems and market operation in a high CER future

This consultation paper represents a key deliverable for the **M3 – market roles** and **P5 – power system roles** workstreams established under the CER Roadmap, which have been combined to collectively make the **Redefine roles for market and power systems operations workstream** (M3/P5).<sup>13</sup> The project description in the National CER Roadmap is as follows:<sup>14</sup>

<sup>13</sup> A full description of the requirements to deliver the M3/P5 workstream to redefine roles for market and power system operation is included in Appendix A.

<sup>14</sup> See chapter 5 of the [National Consumer Energy Resources Roadmap](#) for more detail on specific workstreams.



- **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.

The project requirements are further detailed in Appendix A.

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

The M3/P5 combined project is being progressed alongside and in close collaboration with the **M2 - Data sharing arrangements to inform planning and enable future markets** workstream.<sup>15</sup> This is because there are interdependencies between *what* activities are required to integrate CER into the power system and market, *who* is responsible for undertaking them, and the data underpinning these activities. 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. Some of the actions proposed in each project are related. These are noted throughout.

As this project seeks to define and assign all the capabilities required to run a power system and market in respect of CER, there are also links between this project and many other workstreams in the CER Roadmap, the National Electricity Market wholesale market settings review (the NEM review) and other work across governments, market bodies and industry to integrate CER into the power system and market. We have noted links between this project and other relevant work throughout the paper. Links between this project, the NEM review and other CER Roadmap workstreams are outlined in Appendix B.

### **2.2.1. National consistency is sought where possible, noting jurisdictional variations will be necessary**

This project seeks national consistency where possible, but notes that jurisdiction-specific variations for distribution system operation and market functions are necessary in some cases. This is particularly true in Western Australia (WA) and the Northern Territory (NT) where the market structure and regulatory characteristics differ substantially from the NEM.<sup>16</sup>

As well as structural and regulatory differences, the journey to integrate CER into the power system and market also varies. For example, WA's Distributed Energy Resources (DER) Roadmap: DER Orchestration Roles and Responsibilities Information Paper demonstrates the significant work Energy Policy WA has done to provide policy guidance on Roles and Responsibilities of the Distribution

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<sup>15</sup> Made available at [consult.dceew.gov.au](https://consult.dceew.gov.au)

<sup>16</sup> The WEM and North West Interconnected System (NWIS) are characterised by government-owned, vertically integrated utilities that oversee generation, transmission, distribution, and retail functions.





System Operator (DSO), Distribution Market Operator (DMO), and DER Aggregator functions in the South West Interconnected System (SWIS).<sup>17</sup> It outlines a clear pathway to continue progress.

The NT is at an earlier stage of progress in relation to integration of CER into its market and power system given its size and market structure and arrangements.

Regardless of progress, CER integration presents similar challenges and opportunities in all power systems and markets. However, the solutions to address the challenges and capture the opportunities may be different.

For this project we have developed a capability framework<sup>18</sup> (see Appendix C) that defines and assigns all the activities we consider necessary to operate a power system and market effectively with high levels of CER. The activities were identified with respect to NEM processes, however most of them will be necessary requirements in non-NEM jurisdictions. We have assigned each activity to a “role” and an “actor”. The roles are purposefully actor-agnostic so it is possible to assign different actors to roles in different jurisdictions, or different future arrangements.

The broader discussions in this paper will be generally applicable in any jurisdiction seeking to integrate CER into the power system and market as the challenges, opportunities and options for reform are broadly similar. The specific solutions employed in the NEM, compared to WA and the NT, will need to take into account the unique operating environment including what is possible and practical in each jurisdiction.

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<sup>17</sup> Energy Policy WA, [DER Roadmap: DER Orchestration Roles & Responsibilities Information Paper](#), May 2022.

<sup>18</sup> The capability framework documents include 1) capability framework user guide, 2) the full list of use cases with assigned roles and existing actors, 3) use case diagrams (a visual representation of the list), 4) activity diagrams which show the critical interactions between subsets of use cases to clarify roles and responsibilities, glossary of roles and actors.



## 2.3. We approached this work in three components

The strategic goal of distribution system operations is outlined in the CER Roadmap vision, outcomes and principles, shown below in Table 2:<sup>19</sup>

**Table 2: CER Roadmap Vision, Outcomes and Principles**

<b>Roadmap Vision:</b> Consumer Energy Resources are an integral part of Australia’s secure, affordable and sustainable future electricity systems, delivering benefits and equitable outcomes to all consumers through efficient use which smooths the transition, rewards participation and lowers emissions.	
Roadmap Principles	Roadmap Outcomes
<ul style="list-style-type: none"> <li>• Ensure equitable access to benefits of new technology</li> <li>• Fair system that prioritises consumer protection, including emerging energy products and services</li> <li>• Reduce household and business bills and emissions, support power system security and reliability</li> <li>• Integration with sectoral action plans</li> <li>• Consistent and contemporary compliance technical standards and enforcement</li> <li>• Orchestrated management and implementation of CER and enabling infrastructure.</li> </ul>	<ul style="list-style-type: none"> <li>• Benefits for all consumers</li> <li>• Maximise economic opportunities</li> <li>• Reliable and secure systems</li> <li>• Sustainable, future-ready and world-leading.</li> </ul>

We approached the task of defining and assigning roles and responsibilities by progressing three work components in parallel. These are summarised in **Error! Reference source not found.** below.

<sup>19</sup> Energy and Climate Change Ministerial Council, [National Consumer Energy Resources Roadmap: Powering Decarbonised Homes and Communities](#), p.10



**Table 3: Project components for M3/P5**

Project component	1) Status quo capability definition and role allocation	2) Wholesale market design at the distribution level	3) Institutional considerations for distribution system and market operations
<b>Implementation timeframe</b>	Short term focus	Medium term focus	Medium term focus
<b>Key goal</b>	<p><b>a)</b> Identify all capabilities required to operate the power system and market in a high CER future. Assign to most appropriate existing actor.</p> <p><b>b)</b> Identify gaps, or capabilities that could be performed differently or by different existing actors to achieve better integration of CER in the near term.</p>	Articulate and qualitatively assess a range of distribution level market design options that could underpin more efficient outcomes in a high CER NEM. Explain how capability areas and/or actor allocations might need to change to support different market design options.	Issues with current arrangements clearly articulated. Governance options clearly identified. Benefits and challenges explored. Links to component 1 and 2 clearly identified.
<b>Informed by</b>	Based on capability framework developed in collaboration with the M2 Data sharing arrangements workstream and in consultation with DSMO Working Group.	Advice from Cambridge Economic Policy Associates (CEPA) who was engaged to assess market design options to integrate CER into the wholesale energy market. Their full report is available alongside this paper.	Review of international jurisdictions and local regulatory arrangements and outcomes. Input from DSMO working group through consultation on a working paper.
<b>Relevant chapters</b>	<b>Chapter 3</b>	<b>Chapter 4</b>	<b>Chapter 5</b>

## 2.4. How to read this consultation paper

The paper is written for a range of audiences and aims to provide information for stakeholders engaging at different levels of detail. To help stakeholders in navigating the paper, below is a summary of what each chapter seeks to achieve:

- **Chapter 3** explains briefly how we identified and mapped the distribution system operation and market capabilities that are required for a high CER future, and how these have been assigned to existing parties. A separate user guide and capability model artefacts have been published alongside this paper to provide further detail, made available at [consult.dcceew.gov.au](http://consult.dcceew.gov.au). The chapter then proposes **immediate action be taken to clarify, formalise and standardise the roles, expectations and accountabilities** relating to six areas of focus. Further detail on proposed actions is included in Appendices D-F. For each of the six immediate areas of focus, we are seeking stakeholder feedback on:
  - who should be responsible for clarifying, formalising and standardising the roles, expectations and accountabilities and through what mechanisms, and
  - what factors should be considered when clarifying, formalising and standardising the roles, expectations and accountabilities.



- **Chapter 4** discusses future **options for incorporating CER into a real-time market** and qualitatively assesses these options. The key question here is whether, and under what conditions, a real-time market arrangement would offer a better solution to organise CER compared to continuing the current approach that will likely see CER organised through a range of “off-market” mechanisms such as dynamic network prices and flexibility markets.
- **Chapter 5** explores **who should undertake DSO and DMO functions** going forward. Potential issues with the status quo arrangements, as well as alternative options are discussed. The key question here is whether:
  - DNSPs have the right incentives, objectives and governance arrangements to perform the DSO role into the future; or
  - better consumer outcomes could be achieved with changes to how DNSPs make decisions about and undertake DSO activities; or
  - (at the extreme) whether some/all DSO activities should be undertaken by an independent entity instead of the DNSP.

In this paper we separate the functions that are undertaken by DNSPs and other entities into their component parts. Key terms and concepts used in this paper are presented in the glossary.



### 3. Roles, expectations and accountability need to be clarified, formalised and standardised to maximise CER value in the near term

Overview of this chapter:

- Section 3.1 explains briefly the ‘capability framework’ we used to identify, define and assign all the activities we consider necessary to integrate CER into the power system and market. More information on the capability framework is included in Appendix C and the outputs or ‘artefacts’ published alongside this paper.<sup>20</sup>
- Section 3.2 describes key roles that are crucial to effectively integrating CER into the NEM power system and market. It then explains why it’s important for the actors performing these roles to have the right objectives, frameworks, processes, information and tools to do them effectively.
- Sections 3.3-3.6 identify six areas of focus where roles, expectations and accountabilities need to be clarified, formalised and standardised as an immediate priority. Doing this will enable us to evolve the current framework to more effectively integrate CER in the near term, while keeping open the possibility of making more significant structural changes to market or governance arrangements later.
- Section 3.7 provides a summary of proposed actions.
- Section 3.8 sets out questions for consultation.

#### **3.1. We identified 232 activities required to integrate CER and assigned them to existing actors to establish a base case**

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. We did this by developing a structured

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<sup>20</sup> The capability framework documents include 1) capability framework user guide, 2) the full list of use cases with assigned roles and existing actors, 3) use case diagrams (a visual representation of the list), 4) activity diagrams which show the critical interactions between subsets of use cases to clarify roles and responsibilities, glossary of roles and actors



capability model that identified 232 activities (also referred to as use cases) that we consider must be undertaken to effectively integrate CER into the distribution system.<sup>21</sup>

For each of the 232 activities we have assigned a ‘role’ which represents the *type* of organisation responsible for undertaking the activity and an ‘actor’ which represents the *actual existing* NEM-based organisation responsible for undertaking the activity.<sup>22</sup> The roles are purposefully actor-agnostic so that different actors could be assigned to roles in different jurisdictions, or different future arrangements.

The capability mapping exercise provides a comprehensive snapshot of how the system is currently functioning and establishes a base case. It shows that the majority of activities required to operate a power system and market with high levels of CER are being performed by existing actors as part of their existing roles – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes.<sup>23</sup> Having this base case provides a common language and framework to explore options for change.

We are seeking stakeholder feedback on the activities identified and the roles and actors assigned to these (see consultation questions in section 3.8).

### 3.2. System operators, network operators and customer agents have key responsibilities for maximising value from CER

Historically, most of the generation in a power system was located upstream from consumers, connected to the transmission network and coordinated or ‘dispatched’ by AEMO as the system operator to meet consumer demand.

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<sup>21</sup> 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 as well. Potential links with other CER Roadmap workstreams are outlined in Appendix B. The activities were identified with respect to NEM processes, however most of them will be necessary requirements in non-NEM jurisdictions.

<sup>22</sup> Role and actor definitions are published alongside this consultation paper in the “role and actor glossary”, made available at [consult.dceew.gov.au](http://consult.dceew.gov.au)

<sup>23</sup> This workstream has not allocated roles to actors where these assignments are the subject of other workstreams. For example, the final assignment of actors for CER regulatory capabilities will be determined through the ongoing co-design process within the CER Roadmap’s T2 workstream to establish a national regulatory framework for CER to set and enforce standards. Roles and actors to enable secure communications for CER devices through the provision of public key infrastructure (PKI) will be informed by work considered under the T3 workstream.





As CER grows as a proportion of total generation in power systems all over the world, there is a growing focus on how best to organise it so that its value can be maximised and delivered back to consumers. There are several roles that are crucial to achieving this objective:

- Distribution system operators (DSO)
- Distribution network operators (DNO)
- Customer agents and other roles (like communication managers) that interact directly with customers or their devices.

Coordination between roles is also essential to effectively integrate CER.

Sections 3.2.1 to 3.2.3 outline the importance of these roles and explain some of the issues that arise from the fact that these roles are not clearly defined or assigned in the NEM. This provides context for the near-term actions proposed in sections 3.3-3.6 to clarify roles.

More detail on the activities performed by each role can be found in the capability framework outputs or artefacts published alongside this paper.

### **3.2.1. Coordination between key roles is becoming more important with increasing levels of CER**

To date, DNOs have been the primary actor responsible for managing CER. In the early days of CER connecting to the distribution system, the focus was on making sure DNOs had the information, tools, frameworks and processes they needed to manage the impact of CER on the safety and security of network infrastructure.

Now the focus is shifting to enabling DNOs, system operators (both DSOs and AEMO) and customer agents to work together to integrate CER into the power system and market to maximise its value, rather than just accommodating its impact within system and market operations.

While roles and responsibilities for actors such as AEMO, Transmission Network Service Providers (TNSPs), DNSPs, authorised retailers and certain other participants are explicit in the National Electricity Rules (NER) in relation to the wholesale market and transmission system, they are not clear or explicit when it comes to distribution-level operations. High levels of CER penetration blur the lines between these roles which have developed, and continue to develop, relatively organically for distribution-level operations. The key operational roles have been broadly described in Figure 3 below.



**Figure 3: Operational roles to integrate CER**

	Responsibility	Key activities
<b>AEMO and TNSPs</b>	Manage the transmission operating zone	<ul style="list-style-type: none"> <li>Defining technical envelope, operating within the technical envelope, monitoring operating status of the power system</li> <li>Balancing supply-demand through the central dispatch process.</li> </ul>
	Coordinate with the distribution operating zone	<ul style="list-style-type: none"> <li>For system security issues relating to the aggregate contribution and impact of CER</li> <li>Congestion management at the transmission-distribution interface</li> <li>System-level balancing accounting for CER impact and management.</li> </ul>
<b>DNSPs</b>	Manage the distribution system operating zone	<ul style="list-style-type: none"> <li>Connecting and integrating the CER, setting limits, technical requirements and terms of access for CER</li> <li>Procuring and coordinating CER providing local network support and flexibility.</li> </ul>
	Coordinate with the transmission operating zone	<ul style="list-style-type: none"> <li>Provide observability of CER and the distribution operating zone for transmission system operations</li> <li>Manage impact of their DER coordination activities on net load at the transmission-distribution interface</li> <li>Respond to TSO instructions for outcomes within the distribution operating zone for system security and reliability</li> </ul>
<b>Customer agents (e.g. aggregators, communication managers)</b>	Manage fleets of CER devices	<ul style="list-style-type: none"> <li>Participating in the transmission wholesale market and the provision of local network services,</li> <li>Acting on their customers' behalf in the coordination of their devices</li> </ul>
	Apply appropriate control hierarchy	<ul style="list-style-type: none"> <li>To ensure distribution network limits, system security requirements and emergency controls are implemented across their portfolios.</li> </ul>

Through the role and actor assignments set out in the capability framework, we have tried to define and assign roles to the appropriate existing actors consistent with what is developing and evolving organically. However, there are a large number of actors with varying levels of sophistication, working within a framework that is developing in different ways and at different speeds. A key aim of the project is to clarify and formalise role and actor assignments to enable effective delivery of roles and coordination between roles. We are seeking stakeholder feedback on the activities identified in our capability framework and the role and actors assigned to these (see consultation questions in section 3.8).

### **3.2.2. DNSPs play the role of distribution network and distribution system operator in the NEM and a key question is whether they can do this effectively within current governance arrangements**

A **DSO** is a concept being discussed globally as the penetration of CER increases and the distribution system becomes a two way “system of systems” rather than a one way highway for electrons.

The DSO role can be separated from the **DNO** role, although there is some potential overlap in practice.<sup>24</sup> Box 3 below describes the differences between the two potentially intersecting roles.

<sup>24</sup> For example, the DNO must also monitor real-time conditions on the distribution network.



#### **Box 4: Differences between the roles of distribution network operator (DNO) and distribution system operator (DSO)**

A **distribution system operator (DSO)** broadly refers to a party responsible for real-time system operation of the distribution network. While there is some variation across the definitions of a DSO globally, the following four elements are widely recognised as essential functions.<sup>25</sup>

- **Distribution System Operations:** Manage safe, reliable and efficient operation of the distribution system in a two-way power flow environment, ensuring continuous supply of electricity to, from and between end-use customers. This active network management involves the identification and resolution of constraints, congestion management, optimised asset utilisation and the sourcing of beneficial services from CER.
- **Integrated Distribution Planning:** Perform long-term distribution system planning, in consultation with the system operator (AEMO in the NEM) and relevant transmission network, as an integral part of advanced whole-system planning. CER growth scenarios play an integral role in ensuring the necessary system capacity and capabilities are in place, conventional network and non-network solutions are equally considered, and beneficial system services are sourced from CER where more efficient.
- **Distribution Market Mechanisms:** Employ a spectrum of approaches and mechanisms to value, incentivise, procure and operationally coordinate energy, flexibility and other system services from CER. In its most basic form, this may include tariff-based incentives and/or bilateral contracts. In more advanced forms, it may include distribution-level markets for the procurement of network services and/or flexibility.<sup>26</sup>
- **Transmission-Distribution Coordination (TDC):** active coordination between the system operator and transmission network underpinned by end-to-end visibility and operational coordination models. Key functions include sharing data relevant to the joint management of frequency, voltage, congestion, energy flows, essential system services and supply-demand balancing.

A **distribution network operator (DNO)** is responsible for building and maintaining the assets that form the distribution network in a way that enables the safe, secure, and reliable transfer of electricity between parties connected to the distribution network. It also operates the physical infrastructure in concert with operational decisions from the DSO.

A useful comparison is the delineation of responsibilities at the **transmission level** in the NEM. At the transmission level, TNSPs are the transmission network operator (as well as the owner and planner),<sup>27</sup> while AEMO is the transmission system operator and the transmission market operator.

In the NEM, the role of DNO is played by DNSPs and is clearly defined with the expectations and accountabilities formalised in regulatory frameworks and processes. The role of DSO is also played by DNSPs however it is not clearly or formally defined or assigned and is becoming increasingly important in a high CER power system.

DNSPs perform the roles of DSO and DNO, alongside other roles relating to owning and planning the distribution network, as shown in Figure 4. DNSPs are the natural entity to continue to undertake all these roles going forward, absent of substantive institutional reform.



**Figure 4: Distribution system roles**

**DNSPs currently undertake all these roles**

Distribution Owner	Distribution Planner	Distribution Network Operator (DNO)	Distribution System Operator (DSO)	Distribution Market Operator (DMO)*
Owens the distribution assets and is able to earn an investment return on those assets.	Responsible for identifying appropriate distribution system investments.	Responsible for: <ul style="list-style-type: none"> <li>building &amp; maintaining assets that form the distribution network</li> <li>monitoring real-time conditions on network, communicating these to DSO</li> <li>operating distribution network in line with constraints and DSO instructions.</li> </ul>	Responsible for: <ul style="list-style-type: none"> <li>distribution system operations (system optimisation)</li> <li>integrated distribution planning</li> <li>employ distribution market mechanisms</li> <li>transmission distribution coordination</li> </ul>	Operates real-time distribution level markets

\* The role of DMO which is distinct from a DSO and is responsible for market functions at the distribution level. This may primarily relate to operation of a real-time distribution level electricity market (if one were to be established) but could also extend to other market-type services such as flexibility markets or ancillary services at the distribution level. As there are no real-time markets at the distribution level in the NEM, there is no DMO at this time. This is discussed further in chapters 5 and 6.

We have captured a more granular version of these activities in our capability framework (see Appendix C and associated artefacts published alongside this paper) which assigns to the DNSP:

- the role of DNO which, for the purposes of the capability framework, captures activities relating to distribution owner, planner and operator.
- the role of DSO (denoted in the capability framework as ‘system operator (dx)’ which captures DSO activities in line with the description in Box 3.

It is essential to get distribution system operations activities (and therefore the role of a DSO) right both now and in the future NEM as the levels of CER connected to the distribution system grow.

There are potential issues with DNSPs playing the role of DSO including:

- lack of consistency in systems and processes across distribution regions

<sup>25</sup> For an expanded consideration of how DSO objectives and functions are characterised globally, refer to Power Systems Architecture, Report 4: Distribution System Operator (DSO) models, 2025, CSIRO (Sections 7 & 11).

<sup>26</sup> The role of distribution market operator (DMO) is distinct from a DSO (though they are often played by the same entity). A DMO is responsible for market functions at the distribution level. This may primarily relate to operation of a real-time distribution level electricity market (if one were to be established), but could also extend to other market type services such as flexibility markets or ancillary services at the distribution level. As there are no real-time markets at distribution level in the NEM, there is no DMO at this time. This is discussed further in chapters 5 and 6.

<sup>27</sup> AEMO also has an overlapping planning role for major transmission projects under the Integrated System Plan framework.



- lack of whole of system perspective
- preference for network solutions.

These issues, along with some options to address them are explored in detail in chapter 5. In that chapter we are seeking stakeholder feedback on whether:

- DNSPs have the right incentives, objectives and governance arrangements to perform the DSO role
- better consumer outcomes could be achieved with changes to how DNSPs make decisions about and undertake DSO activities, or
- (at the extreme) whether some or all DSO activities should be undertaken by an independent entity instead of the DNSP.

Regardless of who and how the role of DSO is performed in the future, it is clear that distribution system operation activities need to be done, and done well, to maximise the value of CER.

We therefore need to make sure that DNSPs have the right information, tools, frameworks and policy guidance to undertake DSO activities in a way that delivers consumer outcomes at the same time as supporting secure system outcomes. Sections 3.4-3.6 propose actions to support DNSPs in balancing their DNO and DSO roles, and in collaborating with other parties to more effectively integrate CER in the near term.

### **3.2.3. Customer agents can turn CER opportunities into realities but the tools and frameworks they will use to do this in the future are evolving**

The customer agent role and a number of other roles that interact directly with CER and their devices, will be pivotal to unlocking the full value of CER for all Australians. They will enable customers to receive rewards for their CER flexibility, and build the trust and confidence needed across customers, industry, and system operators to support innovation and secure system operation.

The vast majority of customers (CER owners or otherwise) do not participate directly in the system or market, but instead do so through an agent. In our capability framework (see Appendix C), a customer agent represents CER customers in managing and optimising the value of their CER assets in line with their preferences and network limits. Customer agents can be energy retail licence holders, aggregators, energy service companies, or customers acting as their own agent. They are the decision-maker when it comes to optimising CER.

There are a number of other roles in our capability framework that interact with CER customers and their devices to effectively integrate CER into the power system and market. These include:

- **Energy Supplier** who engages with end use customers to buy and sell electricity off-market (i.e. not through the wholesale market)
- **Communication manager** who ensures effective communication between CER and others to carry out optimisation instructions and emergency directions



- **DSO** – described in section 3.2.2 and responsible for real-time system operation of the distribution network
- **CER Cyber Coordinator** responsible for mitigating cyber risks associated with CER systems, ensuring their integrity and resilience
- **CER Regulator** - subject to the outcomes of the National CER Roadmap’s T2 workstream but, broadly speaking, enforces relevant energy laws, rules and regulations governing CER systems and their interactions with energy markets, networks and consumer protections
- **CER Conformance Monitor** who collects data to verify adherence to operational and regulatory requirements
- **CER Conformance Assessor** who assesses CER behaviour to ensure conformance with operational and technical standards and determines whether a breach of conformance has occurred
- **CER Enforcement Manager** who enacts approved corrective actions when CER obligations are breached.

Not all of these roles formally exist yet, and where they do, the division of responsibilities between them is sometimes unclear. For example:

- the Customer Agent and Communication Manager roles are currently only recognised within narrow regulatory contexts when actors are registered with AEMO as a retailer licence holder or for specific services, such as demand response or ancillary services (Customer Agent), or under the Relevant Agent framework for emergency solar curtailment in South Australia (Communication Manager).
- The roles of CER Cyber Coordinator, CER Regulator, CER Conformance Monitor, Assessor and CER Enforcement Manager do not yet exist, although each may be clarified in part or in full through other CER Roadmap workstreams.<sup>28</sup>
- There is a lack of explicit definition around which roles can control CER devices and under what conditions. While Customer Agents currently control devices under commercial agreements with customers, DSOs may need to issue emergency commands to preserve system security. These may be delivered via Communication Managers or directly to CER devices.

Because these roles are not clearly defined or formally assigned yet, actors performing these roles are not consistently held accountable to standards and requirements that support:

- customer protections, including transparency, consent, and fair access to CER value<sup>29</sup>

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<sup>28</sup> The T2 workstream is to establish a regulatory framework for CER and may address this in full or in part.

<sup>29</sup> The Consumer workstreams of the National CER Roadmap seek to address the issue of consumer protections through C.1 Extending consumer protections for CER, C.2 More equitable access to the benefits of CER, C.3 CER information to empower consumers.





- coordination with system operators and other industry participants, which is essential for secure and efficient system operation, and
- system visibility and orchestration outcomes, ensuring CER can be integrated predictably and reliably into the broader energy system.

While this consultation paper identifies key areas where roles, expectations and accountabilities need to be clarified and formalised (including for customer agents and other customer-facing roles), it does not explore the complementary actions that may be required to promote the development of attractive customer products and services. Some other pieces of work that are exploring these matters are:

- The C1 National CER Roadmap workstream includes the Better Energy Customer Experiences (BECE) project that, as well as acknowledging the value customers can capture by engaging in the market through agents, will explore the risks that customers can be exposed to when seeking to capture the value of CER through customer agents. It will explore the potential solutions through reforms to the protections framework.<sup>30</sup>
- the AEMC's Pricing Review, which explores the role of pricing and how this is used by customer agents to develop products and services to support the diverse needs of customers.<sup>31</sup>

Clarifying and formalising customer-facing roles and the expectations and accountabilities that go with them will be essential to build trust, ensure accountability, and unlock the full value of customer flexibility in a way that benefits both consumers and the power system.

### **3.3. We have proposed near term actions to clarify, formalise and standardise who undertakes key activities and how**

While assigning existing actors to activities as part of our capability mapping exercise, it became clear that the issues limiting integration of CER were less about who undertakes the required activity and instead related to whether:

- each role is formally assigned
- the expectations and accountabilities relating to each role are clear
- there is a consistent or standard approach to performing the role across the NEM.

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<sup>30</sup> More information on C1 – Better energy consumer experiences (BCEC), including the latest consultation paper, can be found [here](#).

<sup>31</sup> The latest discussion paper from the AEMC's Pricing review, published in June 2025, can be found [here](#). The M.1. CER Roadmap project to enable new market offers and tariff structures to extract greater benefits from CER may also explore the role of the retail market in capturing CER value.



Without these things it's hard to hold relevant actors accountable for undertaking those activities effectively and efficiently. It also means that coordination between relevant parties is ad-hoc and/or ineffective. Ultimately, these elements are required to maximise CER value in the power system and deliver its value back to consumers.

This next section identifies six areas of focus (contributing to three major outcomes) where we consider that **roles**, **expectations** and **accountabilities** for all parties involved need to be **clarified**, **formalised** and **standardised** as an immediate priority.

These areas of focus, arranged under relevant outcomes are:

**Outcome 1:** CER is **visible and predictable** and can be used effectively as part of distribution and wider power system operations. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- i. defining, collecting, updating, maintaining quality, and sharing **device-level data and information**
- ii. defining, collecting, aggregating, updating, maintaining quality, using and sharing **CER monitoring data**.

**Outcome 2:** CER is **orchestrated effectively** to support system balancing and deliver value for consumers and the power system. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties:

- iii. establishing and using **off-market mechanisms** (flexibility services, DOEs, DNPs) and communicating relevant information to enable widespread adoption of these.
- iv. **conformance and compliance** for non-conforming CER participating in off market mechanisms.

**Outcome 3:** CER is accounted for and can contribute to **system security and emergency management**. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties:

- v. accounting for, using or controlling CER as part of system security and emergency management frameworks
- vi. monitoring and compliance of CER within security frameworks.

We propose action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities in these six areas of focus. We consider this a necessary step to support any high CER future as it will enable each party to play their part in integrating CER into the power system and market.

We consider that this can be done in a way that better integrates CER under current arrangements, without limiting the possibility of making more significant structural changes to market or governance arrangements in the future.

Many of the actions link to other work, including workstreams within the National CER Roadmap. These links are noted Appendix B.

Context for the proposed actions are described in sections 3.4-3.6 with further detail in appendices D-G.



### 3.4. Outcome 1: CER is visible and predictable and can be effectively used as part of power system operations.

#### Box 5: Illustrative example of customer experience with improved visibility of CER

##### Now

Tamika is an energy enthusiast. She has lots of CER assets and monitors their performance. She is frustrated because she's noticed that the amount of solar energy she can export seems to be limited.<sup>32</sup> This is because she has a static limit that does not allow her to export more than 1.5kw at any time.

At the same time, AEMO – and generators who are trying to bid competitively – are struggling to respond to unpredictable energy flows arising from the increasing number of CER assets. This is leading to higher system and wholesale market costs for consumers.

##### Future

Tamika is much more satisfied with the service her network company provides. While there are times that her PV exports are curtailed, she can see in her app that this happens less frequently, for smaller periods, and with less significant curtailment.

AEMO has better visibility of CER and uses this to develop more accurate views on future market conditions, which helps AEMO's forecasting. Greater visibility and CER participation also improves competitive processes in the market, all to the benefit of consumers. The consequent cost savings and extra income help Tamika to upgrade to a home energy management system.

#### 3.4.1. Visibility and predictability of CER means having accurate information to base planning and operational decisions on

Visibility of CER refers to the ability to see what resources are connected where, and to see how they operate and understand the impact they have on the network and wider system. Predictability of CER refers to the ability of network operators to effectively estimate and forecast the impact of CER across both operational and planning timeframes.<sup>33</sup> Observability is a broader concept relating to the ability to combine sensed data (providing visibility) with grid models and various types of computations (analytics, estimators, forecasters) to generate actionable grid state information, to inform decision and control processes required for distribution and transmission system operations.

Visibility, predictability and observability of CER are currently enabled in the NEM through:

- AEMO's DER register and the Clean Energy Regulator's data on installed small generation and battery units

<sup>32</sup> The majority of solar systems are on a static export limit, which is a fixed maximum amount of solar that can be exported back into the grid.

<sup>33</sup> See Taft, J., Melton, R., Kelley, B., Shankar, M., & Widergren, S. (2019). Grid Characteristics: Using Definitions and Definition Structure for Decision-Making. Pacific Northwest National Laboratory (PNNL). Available at: [https://gridarchitecture.pnnl.gov/media/methods/Grid\\_Characteristics\\_Definitions\\_and\\_Structure.pdf](https://gridarchitecture.pnnl.gov/media/methods/Grid_Characteristics_Definitions_and_Structure.pdf)



- monitoring from selected sites or procured commercially from metering and other data providers
- monitoring of actual power flows at different voltage levels in the distribution network.

DNSPs use these outputs and other statistical tools to inform their real-time operations and longer-term planning forecasts. AEMO uses this data to estimate the impact of CER on operational demand forecasts and representation of CER in power system modelling. Participants and other organisations use it to inform their activities in the power system and market.

### **3.4.2. We need CER to be visible and predictable to be able to capture the opportunities and manage the risks of high levels of CER**

Increasing levels of CER will impact power system operation at all levels. Effective visibility and predictability of CER will ensure that networks are operating within their limits and markets are operating efficiently by accurately accounting for the impact of CER. Aggregated CER participating in the wholesale market can be visible to market operations through bids and offers. Non- market CER energy flows are accounted for through forecasts used in balancing supply and demand.<sup>34</sup>

Under the current arrangements, CER is generally operating outside of markets. This CER is currently not directly visible and must be accurately forecast to be effectively integrated into the power system and market.

### **3.4.3. Lack of visibility or predictability of CER will make it challenging to deliver optimal power system and market outcomes**

Distribution networks are experiencing a rapid growth of CER connecting to their network. Without visibility of, or sufficient predictability in, how these resources will act, it will become increasingly challenging to accurately forecast and therefore plan and operate the power system and market to deliver optimal outcomes. Lack of CER visibility impacts the:

- accuracy of demand forecasts, which are used by a range of parties to plan and operate their businesses and the power system
- ability of distribution and transmission networks to manage flows on the networks
- ability of retailers to manage their overall load profile, provide ancillary services and substitute large-scale generation investments with CER or accurately forecast their hedging requirements.
- hosting capacity of the distribution network and the size of credible contingencies.

Without sufficient visibility, DNSPs and AEMO need to make assumptions about how CER will behave. These assumptions are necessarily conservative to manage the uncertainty in how CER will respond

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<sup>34</sup> For further consideration on the importance of visibility and its relationship to alternative DSO models, refer to Power Systems Architecture, Report 4: Distribution System Operator (DSO) models, 2025, CSIRO (Sections 10.5)



to different conditions. Conservative assumptions may result in over-investment in network capacity and/or lower access to export capacity for CER than is optimal and could be achieved with more accurate information.<sup>35</sup> This directly impacts consumers through higher network and system integration costs and/or lower value realised by their CER assets.

Specific issues with visibility and predictability that relate to clarity, formalisation and standardisation of roles, expectations and accountabilities include that:

- trust in and use of the DER Register as a single source of device level data is limited because the data is not comprehensive, relevant, up to date or accurate, and sharing arrangements are unclear
- monitoring of the LV network is limited and there is a reliance on commercial CER monitoring data providers that may not provide data that is representative of all CER. There are limited or siloed systems and processes to collect and analyse the data to understand and predict CER responses to a range of scenarios. There are no formal arrangements or infrastructure to share CER monitoring data among relevant industry participants. Informal coordination is limited.

Actions to address these issues are proposed in section 3.4.5.

### 3.4.4. Work is underway to improve visibility and predictability of data

A large amount of work has already been done or is underway to improve visibility and predictability of CER, including through:

- AEMO's DER Register which contains information on new or amended rooftop solar and battery storage installations (potentially with EV chargers in the future) at residential or business locations. It shows the number and installed capacity by region to a post-code level, but not the level of control or operation of those devices.<sup>36</sup>
- AEMO's Australian Solar Energy Forecasting System (ASEFS2)<sup>37</sup>, which produces regional distributed PV generation forecasts for various forecasting timeframes from 5 minutes to 7 days using a combination of inputs, including: weather data and satellite imagery; real-time monitoring data from a sample of rooftop PV systems; and standing data on installed systems.
- Demand side participation information portal (DSPIP), which contains information about DSP contracts from registered participants. The information is used to inform reliability modelling (Electricity Statement of Opportunities, Energy Adequacy Assessment Projection Medium Term projected assessment of system adequacy and the ISP).<sup>38</sup>

The AEMC recently made a new rule – the Integrating price responsive resources (IPRR) rule – that sets out new data-sharing arrangements between AEMO and DNSPs for aggregated CER participating

<sup>35</sup> SA Power Networks, [Submission to Integrating price-responsive resources into the NEM Draft Rule Determination](#), 12 September 2024, p. 6.

<sup>36</sup> AEMC, [Integrating price-responsive resources into the NEM, Draft Determination](#), 25 July 2024, p. 29.

<sup>37</sup> AEMO, Australian Solar Energy Forecasting System, ASEFS Phase 2, available [here](#), accessed 22 April 2025.

<sup>38</sup> AEMC, [Integrating price-responsive resources into the NEM, Draft Determination](#), 25 July 2024, p. 29.



in the wholesale market and a new monitoring and reporting framework to monitor and better understand the impact of unscheduled price-responsive resources.<sup>39</sup>

The AEMC’s “Accelerating smart meter deployment” rule change from 2024 will also provide DNSPs with better access to power quality data from smart meters.<sup>40</sup>

### 3.4.5. We have proposed near-term actions to clarify, formalise and standardise the roles, expectations and accountabilities to improve the visibility and predictability of CER

There is still a lot to be done to ensure we have sufficient visibility and predictability to capture the opportunities presented by increasing levels of CER. We have identified two areas where clarifying, formalising and standardising roles, expectations, and accountabilities can improve visibility and predictability of CER.

**Proposed action one:** 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. Standing data is the static, non-changing or infrequently changing information about the CER installation that is essential for planning, operation and coordination of the power system.
- **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** 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).
- **Sharing** relevant device level standing data and information between relevant parties. This includes considering how different parties access and interact with the data.

This action is focused on data insofar as there are gaps in the roles, expectations and accountabilities related to device-level data. We note there is a range of other work underway to explore data and information needs, priorities and gaps.<sup>41</sup>

<sup>39</sup> See clause 3.10A.3(b) of the NER.

<sup>40</sup> AEMC, [Rule determination - National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule. 2](#), November 2024, Section 3.2.

<sup>41</sup> Work underway to address data issues include: M2 data sharing workstream; [CER data exchange co-design process](#); and a [rule change request on integrated distribution system planning](#).





**Proposed action two:** Clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

- **Defining CER monitoring data needs and data specification** across use cases. CER monitoring data is measured time series data of device behaviour. It includes monitoring from selected sites or procured commercially from metering and other data providers and monitoring of actual power flows at different voltage levels in the distribution network.
- **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 in relation to:
  - 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)
- **Sharing appropriately aggregated monitoring data** between relevant parties.

This action is focused on data insofar as there are gaps in the roles, expectations and accountabilities related to monitoring data. We note there is a range of other work underway to explore data and information needs, priorities and gaps.<sup>42</sup>

We propose action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities relating to device-level and monitoring data and information. We consider this a necessary step to support any high CER future as it will enable each party to play their part in improving visibility and predictability of CER.

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<sup>42</sup> Work underway to address data issues include: M2 data sharing workstream (made available at [consult.dcceew.gov.au](https://consult.dcceew.gov.au)), CER data exchange co-design process, a (pending) [rule change request on integrated distribution system planning](#).



There is a range of ways that roles, expectations and accountabilities could be clarified, formalised and standardised when it comes to CER device-level and monitoring data and information. For example:

- Given the number of parties that benefit from access to CER device-level data, it may be that the standardisation of data needs and specifications (e.g. formats) may be just as, if not more important than the formalisation of roles to collect, update, maintain its quality and share it.
- Depending on who is assigned the role of defining device-level data and information needs and specifications, they could focus on what is needed to underpin planning and operations now, or could look ahead to the range of possibilities we may want to enable in the future. The first approach risks locking in devices for 15-20 years that are limited in how they can be integrated into power system and market operations. The second approach risks over-specifying (and increasing the cost of) devices. There is a balance between these outcomes.
- Granular LV monitoring data is currently the purview of DNSPs. When considering how to define, collect, aggregate, use and share CER monitoring data, it will be important to consider what level of aggregation is useful for other parties (e.g. AEMO and TNSPs) and determine roles, expectations and accountabilities based on that. Effective coordination can be used as a tool to achieve necessary outcomes, rather than expanding or duplicating roles.

We consider that clarity, formalisation and standardisation of roles, expectations and accountabilities can be done in a way that improves visibility and predictability under current arrangements but does not lock us out of alternative futures, including structural changes to market design or governance arrangements.

Some additional detail on proposed actions 2 and 3 is provided in Appendix D. We are seeking stakeholder feedback on who should be responsible for delivering each action and how – see section 3.8 for specific consultation questions.

Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended



### 3.5. Outcome 2: CER is orchestrated effectively to deliver value for consumers and the power system

#### Box 6: Illustrative example of customer experience with effective orchestration of CER

##### Now

Sam bought a house kitted out with solar and a battery, but she does not have the time or inclination to worry about the electricity system. After the battery stops functioning, she decides it's easier to upgrade her whole solar and battery system.

However, she finds out that a fixed limit has been applied to her energy exports back to the grid, and that this limit is below the rating of her new bigger solar/battery installation.

Fed up, Sam looks for a better retail offer, but only finds packages which seem to undervalue her assets.

Meanwhile, she notices that the network component of her bill keeps increasing, and reads in the news that distribution businesses are having to spend more to accommodate all the uncoordinated CER on the network.

##### Future

Sam has had to replace her CER assets a number of times. Each time has been a smooth process, with each installer and her customer agent making it easy for their assets to 'talk' to the DSO, who only curtails her energy exports when there is no spare capacity on the network.

When Sam searches for better retail packages, she notices a wide range of possible services that her CER assets can provide and earn money from. Sam selects a new retailer who remotely configures all her assets to respond automatically in a way that maximises the amount she can earn from her CER. She is impressed with the potential savings to her future bills.

Sam also sees the network component of her bills fall, and reads about the Chair of the regulator celebrating excellent and improving network utilisation.

#### 3.5.1. Effective orchestration means having the right frameworks and processes in place to not just manage, but leverage 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.

Historically, the approach to managing CER focused on preserving the integrity of distribution network infrastructure. The rapid, widespread uptake of rooftop solar (compared to other countries) has resulted in distribution network and system level challenges, throughout the NEM and WEM. The focus to date has largely been on building systems and capabilities to manage CER to ensure secure power system outcomes.

In recent years the focus has shifted towards innovative ways to better integrate CER, and orchestrate it with the aim of aligning consumer preferences with power system needs to deliver value for both.

Frameworks and mechanisms to orchestrate CER (rather than just accommodating its impact within system and market operations) allow them to respond to accurate signals that show when and where energy and other services are valued most. Effective orchestration of CER is important so that the energy generated or consumed by CER can be accurately:



- considered in longer-term planning of the power system to ensure efficient investment in the power system, particularly distribution network infrastructure
- incorporated into real-time power system operations to efficiently balance supply and demand, reducing the need to use management mechanisms to manage constraints and meet system security obligations.

### **3.5.2. Effective orchestration of CER enables CER to become a trusted alternative to traditional network investment.**

Effective orchestration provides benefits for all customers (not just those that own assets) by lowering total system costs.<sup>43</sup> Orchestrated CER can contribute an increasing portion of the “lowest combination of resources to meet demand” helping:

- balance supply and demand to support, rather than challenge, system security.
- increase distribution network utilisation and investment efficiency
- decrease the need for generation and transmission in the bulk power system.

Effective orchestration of CER can also reshape how consumers engage with the power system, revealing the value of CER to the power system and unlocking substantial benefits.

### **3.5.3. Increasing levels of CER are offering enormous orchestration opportunities but we lack the tools and frameworks to leverage these**

In a high CER power system, there are often times and locations when more resources want access to the distribution network than the network can safely allow.

The historic approach in these situations in the NEM has been to limit CER exports to manage network infrastructure and to share limited capacity between multiple users. This is partly because the technical capability, data, frameworks and processes were not in place at scale to enable CER to respond to dynamic signals such that it can be relied upon in system operations and be considered a reliable alternative to network solutions over planning timeframes.

Arrangements vary across the distribution network service areas, retailers and other customer agents across the NEM, impacting orchestration opportunities and readiness, including differences in:

- Connections frameworks. These vary across the NEM resulting in fragmented standards and enforcement and poor data integration, which limits orchestration opportunities and readiness.
- Interoperability requirements. There is inconsistent consideration of interoperability across devices and platforms, or other requirements that would enable orchestration of CER at scale.

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<sup>43</sup> For further consideration on the importance of operational coordination and its relationship to alternative DSO models, refer to Power Systems Architecture, Report 4: Distribution System Operator (DSO) models, 2025, CSIRO (Sections 10.6)



- Control boundaries. There is a lack of clarity around where the boundaries of control start and end for distribution and transmission level network operators, system operators, customer agents and others, particularly when it comes to using off-market mechanisms to organise CER and reward customers for CER behaviours that help to meet power system needs.

There are two key tools DNSPs currently use to signal network scarcity and manage access to the network:<sup>44</sup>

- network tariffs or prices, which aim to signal the long-term or “long-run marginal” costs to build and operate the network, to serve customer demand<sup>45</sup>
- operating envelopes, which define the physical limits or maximum amount of electricity that a customer is allowed to export to the grid.

For the majority of CER currently in the NEM, network tariffs are set annually and operating envelopes are static. This means that signals about the network’s hosting capacity do not reach customers in a meaningful or timely way, either directly or through customer agents. This means customers have little incentive to respond to power system needs even if they wanted to.

All these issues ultimately result in conservative operation of the distribution network and CER being constrained off when it could be safely and efficiently used to lower total system costs and provide individual consumer value.

Specific issues that relate to clarity, formalisation and standardisation of roles, expectations and accountabilities include that:

- Mechanisms to orchestrate CER are in their infancy. They are not defined and there are inconsistent approaches to calculating and using them across the NEM. Communication of relevant information about mechanisms to orchestrate CER is limited and inconsistent. This creates barriers to third party use of these mechanisms and limits their effectiveness in maximising CER value.
- There is no conformance and compliance framework to ensure devices (individually and in aggregate) comply with dynamic signals. It is not clear which signals or instructions sent to CER devices and management systems are more important and can override less important ones. This limits confidence in off-market mechanism application at the device level and across aggregations.

### **3.5.4. Work is underway to develop and test tools that would enable effective orchestration of CER**

A large amount of work has already been done or is underway to develop standards, tools and processes to enable effective orchestration of CER. Work underway to support orchestration of CER includes:

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<sup>44</sup> See Appendix E for more detail on how network pricing and operating envelopes work.

<sup>45</sup> Long-run marginal costs pricing is a requirement in the National Electricity Rules (NER) and prices are regulated by the Australian Energy Regulator (AER).



- Setting and updating technical standards with a focus on supporting minimum interoperability requirements and enabling CER to be “orchestration ready”.<sup>46</sup> Australia is a world leader in integrating rooftop solar and progressively developing CER integration standards including through the CER Roadmap T1 workstream. The T1 workstream’s priority is to develop nationally consistent standards, including electric vehicle to grid.
- Implementation of National Connection Guidelines to standardise the connection of CER into the grid. These are used by network companies as a template to develop connection agreements that are nationally consistent.<sup>47</sup>
- Access to flexibility services within distribution networks, including load control programs, contracts for network support, and local network management schemes with larger non-scheduled plant. Currently this flexibility is largely utilised by DNSPs for the provision of the “standard control service” of planning, maintaining and operating the distribution network, translating to managing particular local network constraints one at a time. CER providing standard control services are locked out of other markets and mechanisms. There is potential for the DNSP, in their role as DSO, to play a more proactive ongoing role in hosting and managing flexibility services across the network. This would reduce network operating costs that are ultimately paid for by consumers.
- Non-network options that DNSPs are incentivised to procure through the Demand Management Incentive Scheme and Innovation Allowance. Some DNSPs have partnered with technology providers to assist in procuring these non-network services.
- Dynamic signals (DOEs, flexible export limits (FELs), dynamic connections,) are emerging as an increasingly common tool 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.<sup>48</sup> Depending on who is controlling CER within the DOE, DOEs can help capture CER value by enabling higher levels of energy exports 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 access is limited.<sup>49</sup> The AER export limit guidance note provides a framework for the application of export-side DOEs.<sup>50</sup>

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<sup>46</sup> There is a process underway through Australian Standards to develop the Australian version of [IEEE 1547 – a standard for interconnection and interoperability of distributed energy resources with associated electric power systems interfaces](#)

<sup>47</sup> The guidelines provide a level of consistency across DNSPs, however each DNSP is influenced by their own unique mix of customers, geographic conditions and business model, rules, regulations and performance criteria. They can be found [here](#)

<sup>48</sup> As outlined in the DEIP DOE Working Group’s Allocation Principle’s Workshop Summary: <https://arena.gov.au/assets/2021/09/doe-workshop-summary.pdf>

<sup>49</sup> As explained in Box 2, CER will, in the large majority of cases, self-curtail or ceases exporting when the inverter detects that the voltage limit has been reached and before thermal limits are reached.

<sup>50</sup> AER Export limit guidance note is available [here](#)





- Development and trialling of dynamic network prices (DNPs) which change in response to the actual cost to serve customers.<sup>51</sup> DNPs are ideally based on real or near real-time conditions. DNPs signal to consumers when the relevant part of their network is becoming constrained. For example, where there is an excess of solar export in a consumer's part of the network, the cost to export would increase. Conversely, if high demand is driving congestion on the network, the cost to use the network to export would decrease. This will mean lower costs for consumers to use the network when it is unconstrained. It will also potentially mean near zero network costs or even rewards (negative DNPs) for consumers who are willing to consume when the network is export-constrained or to export when the network is demand-constrained. DNPs and DOEs would work together – the more efficient the response to DNPs the smaller the role for DOEs. In the future, sophisticated consumer products could offer a choice of different packages of DNPs and DOEs where a narrower DOE meant a more stable and less risky DNP and vice versa.

For the purposes of this paper we refer to the tools and mechanisms currently used to organise CER at the distribution level (DOEs, DNPs and flexibility services) as “off-market” to distinguish them from real-time markets such as the wholesale market that organises transmission-connected resources. Specifically:

- “off market” refers to any services procured outside a real-time market. Note that “non-market services” are a subset of off-market and refer to 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.
- “market” refers to electricity or frequency control ancillary services (FCAS) procured through the NEM real-time wholesale market (or, potentially in the future, a distribution-level real-time market – this is discussed further in chapter 4).

***A standardised playing field will enable customer agents to participate in the task of orchestrating CER.***

If meaningful signals about network capacity can be sent to customers (through agents), then customers can signal when and how much they value access to the network through their responses. This will allow CER to ‘self-organise’ and prioritise the highest value uses of the network at times of congestion. This will reduce the reliance on network decisions and control mechanisms that currently govern how and when CER can access the distribution network.

We do not expect all CER customers to engage directly in the power system or market. However, tools and frameworks to enable effective orchestration of CER can create a playing field for retailers, aggregators and other service providers that allow them to develop products and services that are both attractive to customers and aligned with power system needs. It should be noted that unless this is a standardised playing field across the NEM distributors, then the barriers to participating are much higher for retailers, aggregators and other service providers, which will delay or limit participation.

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<sup>51</sup> DNP is being trialled through Project Edith, which began as a demonstration project between Ausgrid and Reposit Power in late 2021. 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. More information [here](#)



Figure 5 below shows the ‘playing field’ where opportunity-based products (DOEs, DNPs) can be used to organise CER using incentives that deliver consumer value, while also aligning CER behaviour with power system needs. If CER is orchestrated effectively, there is less need for structured engagement or interventions by networks.

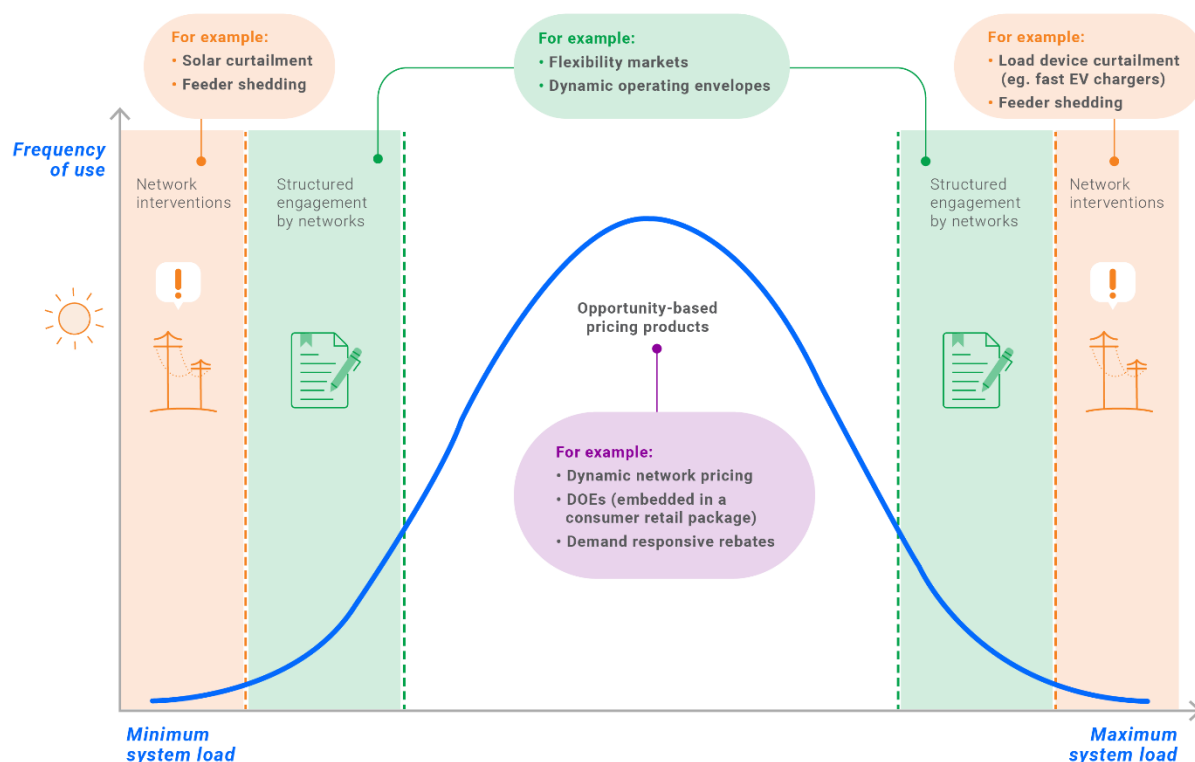


Figure 5: Actions to incentivise and control CER to maintain network integrity

### 3.5.5. We are proposing near-term actions to clarify, formalise and standardise the roles, expectations and accountabilities to enable effective orchestration of CER

There is still a long way to go to ensure we have the right tools and frameworks to support effective orchestration of CER. We have 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.

**Proposed action three:** Clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in **establishing and using off-market mechanisms (flexibility services, DOEs, DNPs) and communicating relevant and standardised information** to enable widespread adoption of these mechanisms 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.



- Developing options to enable the efficient procurement (by DNSPs and potentially other parties) of flexibility services at scale that address governance issues raised and allow for achieving whole of system objectives.
- Standardising the approach to calculating available capacity, and calculating, using and communicating DOEs and DNPs across the NEM, which are the operational parameters to manage network access and incentivise efficient utilisation of network capacity in operational timeframes.
- Enabling industry investment and uplift to achieve widespread implementation and use of off-market mechanisms to orchestrate CER.

**Proposed action four:** Clarify, formalise and standardise the roles, expectations and accountabilities for all parties **participating in off-market mechanisms (flexibility services, DOEs, DNPs)** to ensure conformance and compliance. This includes:

- 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 are underway and may address this in full or in part.

We propose action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities relating to off-market mechanisms. We consider this a necessary step to support any high CER future as it will enable each party to play their part in orchestrating CER to maximise its value to the power system and consumers.

There is a range of ways that roles could be clarified and formalised, and expectations and accountabilities clarified, formalised and standardised to enable effective orchestration of CER. For example:

- The way network capacity is calculated and applied could encourage or restrict CER use as a legitimate option to alleviate network constraints.
- How and when DOEs can or should be used (e.g. only as emergency backstops or more regularly) may determine the confidence that CER aggregators can have in their portfolios. Who is controlling CER within DOEs has a significant impact on the consumer value proposition (e.g. aggregators that can orchestrate CER can derive value from responding to market price signals whereas DNSPs and other parties may not value this).
- The extent to which (and how) DOEs and DNPs can and should be relied on for the purposes of whole of system operations and planning will have an impact on whether CER becomes a legitimate alternative to transmission-level resources.



We consider that clarity, formalisation and standardisation of roles, expectations and accountabilities can be done in a way that enables effective orchestration under current arrangements but does not lock us out of alternative futures, including structural changes to market design or governance arrangements.

Some additional detail on these proposed actions is provided in Appendix E. We are seeking stakeholder feedback on who should be responsible for delivering each action and how – see section 3.8 for specific consultation questions.

Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended.



### 3.6. Outcome 3: CER plays a central role in system security and emergency management frameworks and processes

#### Box 7: Illustrative example of customer experience with CER integrated into system security frameworks

##### Now

Sandy's retailer pays her a feed-in tariff for her solar and battery exports. Her retailer also manages her battery, charging the battery from her solar panels, as well as from the grid when tariffs are low, and using or exporting the stored power when tariffs are high. Sandy's assets are not, however, used to address system security and emergency situations. Rory is a manager at the system operator, AEMO. He is responsible for system security. To avoid blackouts, Rory must make sure that there is enough electricity available, even if a large generator breaks down or a large transmission line fails unexpectedly. To do this Rory has to buy standby capacity from large generators, and from transmission connected batteries. These can be called on to provide large amounts of energy to the power system in a matter of seconds. This standby capacity is paid for by consumers. Rory thinks that he could get a better deal for consumers if he could also buy standby capacity from CER, like batteries or appliances that can be turned off at short notice.

##### Future

Sandy buys a product which, by default, has the capability to contribute to system resilience. She also has the opportunity to be rewarded for contributing to system resilience. In many cases, she is unaware of her participation, as a solid set of standards and automated processes help to integrate her CER to respond to system needs. Rory is also confident that CER will behave as expected, so that he doesn't need to be as conservative in the safety margins he applies and in the way he runs the power system. He knows that CER will ride through faults and that it will respond to emergency backstop and other instructions. He also knows that CER can reliably provide some of the system services he needs, so that he can now procure things like standby capacity from CER batteries, increasing competition with traditional generators, and reducing total costs for consumers.

#### 3.6.1. System security relates to the power system's resilience to disturbances

System security relates to the ability to maintain or quickly return system operations to within defined technical limits following a disturbance. Emergency management encompasses the capabilities, systems and procedures that are utilised to restore the power system to its normal operating state following extreme, abnormal system conditions and potential supply disruption.

Disturbances to secure operations can be caused by sudden changes in voltage or frequency resulting from disconnection of generation, load or network capacity.



There are a well-established set of processes, management methods and services for maintaining system security at the transmission level that help maintain system security. These are managed by AEMO working closely with TNSPs and include frequency control ancillary services (FCAS), network support and control ancillary services (NSCAS), and system restart capabilities. In general, these services are procured by AEMO from a relatively smaller number of large energy service providers.

AEMO also sets the requirements and backup operational plans with NSPs. Some of these plans include setting the amount of load which can be automatically disconnected from the system during a low frequency event (namely under-frequency load shedding (UFLS)) and are developed with NSPs.

While there are links between power system security and cyber security, for the purposes of this paper we have not included cyber security. Cyber security must be integrated into considerations during the conception, design, development and operation of any physical system, energy or otherwise, to mitigate or even eliminate avenues for cyber-enabled attacks. Government will continue working with market bodies and industry to mitigate cyber security risks.

### **3.6.2. Harnessing CER to contribute to system security and emergency management is essential**

Maintaining the system in a secure state is a pre-requisite for a reliable and dependable supply of electricity to consumers in line with their expectations.<sup>52</sup> With increased understanding of how CER can and does respond during disturbances, CER can, at a minimum, be accurately accounted for when planning and operating the power system to remain secure (or respond to and recover from disturbances and other system security events). At best, CER can be harnessed to help manage system security, with the right capabilities and coordination mechanisms enabled.

### **3.6.3. Increasing CER is changing the capabilities required to manage system security**

At scale, CER can impact system security at both the local (distribution) level and whole of system (transmission) level and can change the types of disturbances that need to be managed. Conversely, CER also has the potential to help manage system security, with the right capabilities and coordination mechanisms enabled.

Rooftop PV is already at sufficient scale that it significantly impacts power system operations and, at times, is supplying more than half the underlying demand in the NEM.<sup>53</sup> Growth in rooftop PV is projected to continue. Distributed storage capacity is expected to increase rapidly and is forecast to

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<sup>52</sup> For additional consideration of the wider context of the relationship between CER deployment and system security, refer to Power Systems Architecture, Report 3: Systemic Issues & Transformation Risks, 2025, CSIRO (Sections 4.2.1 and 4.2.3)

<sup>53</sup> AEMO, *Supporting secure operation with high levels of distributed resources*, Q4 2024, p. 15.



exceed the size of the largest individual generator in each mainland NEM region within the next 11 years.<sup>54</sup>

While there are risks that need to be managed, consumers with CER have the potential to benefit by actively providing system security services.

Specific issues that relate to clarity, formalisation and standardisation of roles, expectations and accountabilities include that:

- At scale, CER can impact **system security** at both the local (distribution) and whole of system (transmission) level and can change the types of disturbances that need to be managed. We have limited understanding of how CER behaves in a range of scenarios. Outside of minimum standards for devices and mechanisms to curtail some CER during emergencies, little consideration has been given to how to account for and ultimately harness CER as part of system security and emergency frameworks and processes.
- There is no **conformance and compliance framework** to ensure devices (individually and in aggregate) comply with technical specifications or behave as expected or directed during disturbances of other **system security** events. It is not clear which signals or instructions sent to CER devices and management systems are more important and can override less important ones, and there are no pre-determined autonomous failsafe behaviours, to safeguard against contradictory instructions.

### 3.6.4. Work is underway to integrate CER into system security and emergency management frameworks and processes

A large amount of work has already been done or is underway to consider and embed the role of CER in system security and emergency management frameworks and processes including:

- Updating minimum standards for CER inverters (rooftop solar and storage) to ensure it is resilient and behaves predictably during emergency scenarios.<sup>55</sup>
- Implementing ‘emergency backstop’ mechanisms to manage CER during minimum system load conditions. Mechanisms are now in place in Queensland, Victoria, South Australia and WA (South-West Interconnected System (SWIS)). At present, there is no requirement for distributed PV systems in NSW, ACT, Tasmania or non-SWIS WA to have active management capabilities.<sup>56</sup>

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<sup>54</sup> AEMO, [Draft 2025 IASR Inputs and assumptions workbook](#), Step change scenario.

<sup>55</sup> AS/NZS 4777.1 standard specifies installation requirements of grid connected energy systems via inverters. 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.

<sup>56</sup> Some DNSPs in the NSW/ACT region can curtail embedded generators in their networks, mostly via SCADA. Two NSW DNSPs can shift hot water loads in their networks during MSL conditions. NSW and ACT Governments have released consultation papers in Q1 2025 for implementation of backstop via CSIP-AUS. Further information for NSW here: [Emergency Backstop Mechanism and CER Installer Portal](#), and for ACT here: [Emergency Backstop](#)





- Undertaking system restoration studies for high rooftop PV penetration.<sup>57</sup> This will assist in determining options for considering CER in both the upcoming 2026-29 system restart ancillary services procurement round, and longer-term procurement from 2030 onwards.<sup>58</sup>
- Undertaking studies in 2025 to assess emergency frequency and demand response needs during low demand periods and of the potential for fast frequency response from battery energy storage systems (BESS) to manage large credible contingencies.<sup>59</sup>

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 setting and enforcing standards for CER, providing confidence in the ability of CER to play a meaningful role in system security and emergency management processes.

### **3.6.5. We are proposing near-term actions to clarify, formalise and standardise the roles, expectations and accountabilities to integrate CER into system security and emergency management frameworks and processes**

To capture the opportunities presented by CER to help balance supply and demand to deliver secure power system outcomes, CER must be sufficiently integrated into system security and emergency management frameworks and processes.

We have identified two areas where clarifying, formalising and standardising roles, expectations and accountabilities can support effective integration of CER into security and emergency management frameworks and processes.

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<sup>57</sup> AEMO, [Engineering roadmap to 100% renewables, FY2024 priority actions](#), 2023, p. 16.

<sup>58</sup> AEMO, [2024 Transition Plan for System Security](#), December 2024, p.57.

<sup>59</sup> AEMO, [2024 Transition Plan for System Security](#), December 2024, p. 32.



### Proposed action # 5:

Clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in accounting for, controlling or using CER as part of system security and emergency 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 distributed PV curtailment schemes
  - ensuring all new distributed PV systems (up to 5 MW) are harnessed within these schemes
  - assessing and monitoring site-level compliance
  - testing and validating scheme performance and robustness
  - coordination for emergency backstop operation.
- **System restart and emergency restoration** including the roles, expectations and accountabilities for:
  - assessing the impact of increasing levels of CER on system restart, including modelling distributed PV impact on system restart pathways,
  - managing distributed PV on restoration pathways
  - operational coordination between the transmission and distribution operating zone 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
  - operational coordination between DNSPs, TNSPs and AEMO for under-frequency management.



**Proposed action six:** Clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in the operational performance of CER to ensure conformance and compliance. 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.

We propose action be taken as soon as possible to clarify, formalise and standardise the roles, expectations and accountabilities relating to off-market mechanisms. We consider this a necessary step to support any future as it will enable each party to play their part in integration of CER into security and emergency management frameworks and processes.

There is a range of ways that roles, expectations and accountabilities can be clarified, formalised and standardised to properly integrate CER into security and emergency management frameworks and processes. For example:

- Formalising emergency CER backstop capability as a DNSP system security responsibility would enable DNSPs to confidently invest in establishing and embedding this capability. However, without policy guidance to standardise the approach, inconsistencies across the NEM will remain, leading to more CER curtailed than necessary and ultimately costing all customers more than necessary.
- Clarifying and formalising the role of DNSPs and customer agents in emergency restoration (which is traditionally an AEMO-led process involving large generators and TNSPs) could leverage or lock-out CER as an option depending on how it is done. For example, an aggregator of batteries could be instructed to support a black start, or a DNSP systematically block or coordinate CER during grid energisation. But without a clear control hierarchy applying to different coordination signals sent to CER devices, there will be low confidence that CER can help rather than hinder the process.
- Evolving frequency management frameworks to account for and leverage CER response during frequency events could reduce FCAS costs, but if technical standards for CER are not updated to incorporate frequency control capability, the proportion of devices that can respond will be too low to make a meaningful difference.

We consider that clarity, formalisation and standardisation of roles, expectations and accountabilities can be done in a way that enables CER to be integrated into security and emergency management frameworks and processes now but does not lock us out of alternative futures, including structural changes to market design or governance arrangements.



Some additional detail on these proposed actions is provided in Appendix F. We are seeking stakeholder feedback on who should be responsible for delivering each action and how – see section 3.8 for specific consultation questions.

Stakeholder feedback will inform our final recommendations to Ministers in which we will propose an implementation approach to progress any action recommended.



### 3.7. Summary of proposed actions

	#	Issues resulting from lack of clarity, formalisation and/or standardisation of roles, expectations and accountabilities	Proposed actions to clarify, formalise and/or standardise the roles, expectations and accountabilities for all parties involved in...	Expected outcomes from clarifying, formalising and/or standardising the roles, expectations and accountabilities
Visibility and predictability	1	Trust in, and use of, DER register as a single source of <b>device level data</b> is limited because the data is not comprehensive, relevant, up to date or accurate, and sharing arrangements are unclear.	Defining, collecting, updating, maintaining quality, and sharing <b>device-level data and information</b>	Accurate device level data underpins all activities relating to planning, management and orchestration of CER.
	2	Monitoring of the LV network is limited and there is a reliance on commercial <b>CER monitoring data</b> providers which may not provide data representative of all CER. There are limited or siloed systems and processes to collect and analyse the data to understand and predict CER responses to a range of scenarios. There are no formal arrangements or infrastructure to share CER monitoring data among relevant industry participants. Informal coordination is limited.	Defining, collecting, aggregating, updating, maintaining quality, using and sharing <b>CER monitoring data</b> .	Accurate gross CER monitoring data will support effective operational forecasting of CER and accurate representation of CER performance during disturbances.
Orchestration	3	<b>Off-market mechanisms</b> are in their infancy but will be crucial to orchestrating CER. DOEs, DNPs and flexibility services are not defined and there are inconsistent approaches to calculating and using them across the NEM. Communication of relevant information about DOEs, DNPs and flexibility services is limited and inconsistent across the NEM. This creates barriers to third party use of these mechanisms and limits their effectiveness in maximising CER value.	Establishing and using off-market mechanisms (flexibility services, DOEs, DNPs) and communicating relevant information to enable widespread adoption of them as key tools to orchestrate unscheduled CER.	A standardised approach to establishing and using off-market mechanisms, including a standardised approach to communicating relevant information to enable widespread adoption of them
	4	There is no <b>conformance and compliance framework</b> to ensure devices (individually and in aggregate) comply with <b>dynamic signals</b> . It is not clear which signals or instructions sent to CER	Testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER participating in off-market mechanisms (flexibility services, DOEs, DNPs).	A robust conformance, monitoring and compliance framework and a clear control hierarchy will maintain confidence in off-market mechanisms as a legitimate option to balance supply and demand



		devices and management systems are more important and can override less important ones. This limits confidence in off-market mechanism application at the device level and across aggregations.	This includes formalising the control hierarchy applying to different coordination signals sent to CER devices	and manage congestion. Customer agents can confidently offer and manage aggregated CER in their control, and network and system operators will have confidence in managing the technical envelope.
System security	5	At scale, CER can impact <b>system security</b> at both the local (distribution) and whole of system (transmission) level and can change the types of disturbances that need to be managed. We have limited understanding of how CER behaves in a range of scenarios. Outside of minimum standards for devices and mechanisms to curtail some CER during emergencies, little consideration has been given to how to account for and ultimately harness CER as part of system security and emergency frameworks and processes.	Accounting for, using or controlling CER during system disturbances, emergency CER curtailment, system restart and emergency restoration and frequency management processes.	With increased understanding of how CER can and does respond during disturbances, CER can, at a minimum, be accurately accounted for when planning and operating the power system to remain secure (or respond to and recover from disturbances and other system security events). At best, CER can be harnessed to help manage system security, with the right capabilities and coordination mechanisms enabled.
	6	There is no <b>conformance and compliance framework</b> to ensure devices (individually and in aggregate) comply with technical specifications or behave as expected or directed during disturbances of other <b>system security</b> events. It is not clear which signals or instructions sent to CER devices and management systems are more important and can override less important ones and there are no pre-determined autonomous failsafe behaviours, to safeguard against contradictory instructions.	Testing, monitoring, assessing compliance, enforcement and rectification arrangements for non-conforming CER as part of system security frameworks and processes. This includes formalising the control hierarchy applying to different coordination signals sent to CER devices.	A robust conformance monitoring and compliance framework, a clear control hierarchy and clear, autonomous failsafe behaviours will maintain confidence that CER can be managed and leveraged as part of system security frameworks.



### 3.8. Consultation questions

#### Stakeholder feedback on capability framework

Chapter 3 introduces the “capability framework” we used to identify, define and assign all the activities we consider are necessary to integrate CER into the power system and market. More information on the capability framework is included in Appendix C and the outputs published alongside this paper. In relation to the capability framework, we are seeking stakeholder feedback on the questions below.

18. Have we captured all the activities (or ‘use cases’) required to operate power systems and markets in a high CER future? If identifying ‘missing’ use cases, consider whether they are a sub-set of an existing activity.
19. Have we assigned each of the activities to the appropriate role and existing actor?
20. Should any of the actor assignments be reconsidered now or in the future? When explaining why, please refer to our assessment criteria in Appendix A.

#### Stakeholder feedback on near term actions to clarify roles

Chapter 3 (and the additional detail in Appendices D-F) identifies six areas of focus where we consider that roles, expectations and accountabilities for all parties involved need to be clarified, standardised and formalised as an immediate priority. These areas of focus are:

- device-level data
- CER monitoring data
- off-market mechanisms
- conformance and compliance of CER participating in off-market mechanisms
- CER in system security frameworks
- conformance and compliance of CER within security frameworks.

In our final report to Ministers, we intend to propose an implementation approach to progress action in these areas (if recommended). The recommendations and implementation approach will be informed by stakeholder responses to the questions below.

21. Do you agree that clarifying, formalising and standardising the roles, expectations and accountabilities in these six areas is an immediate priority? Are there any specific timeframes within which the actions should be delivered?
22. Are there any other areas where roles, expectations and accountabilities need to be clarified, formalised and standardised as an immediate priority?
23. For each of the six areas of focus, **who** do you think should be responsible for clarifying, formalising and standardising the roles, expectations and accountabilities (e.g. governments, market bodies, industry) and **through what mechanisms** (e.g. rules or other regulatory instruments, policy guidance, investment)?
24. For each of the six areas of focus, **what factors** should be considered when clarifying, formalising and standardising the roles, expectations and accountabilities? For example, are there:





- a. any actors that should or should not have a particular role (e.g. being responsible for updating and maintaining device level data over the lifetime of the asset may only be practical for one or two actors)?
- b. specific benefits or risks in doing the component activities one way vs. another (e.g. making standardised off-market information available on a shared platform versus publishing it in a standardised format on individual platforms)?
- c. any practical considerations that would limit an actor from playing the optimal role (e.g. technology limitations, lack of regulatory authority/licence to perform a role, conflicts of interest)?
- d. any implementation approaches that would limit the ability to maximise CER value into the future including locking out a future market design or governance option? (e.g. how and when DOEs can or should be used (e.g. only as emergency backstops or more regularly))?



## 4. Distribution-level markets are an option to fully integrate CER into the NEM wholesale market

In chapter 3 we outlined near-term actions that we consider to be necessary first steps to support any high CER future. They are the actions that are not yet being progressed, or progressed to the extent necessary, to enable us to consider how well CER can be integrated within current arrangements.

This chapter assumes the actions from chapter 3 have been well-progressed and asks stakeholders to consider whether further changes – in this case structural changes to market arrangements at distribution level – are necessary to support CER integration and deliver desired consumer outcomes.

The question explored in this chapter is whether off-market mechanisms will remain an effective way of orchestrating CER into the future, or whether there will come a time when real-time market arrangements offer a better solution.

In parallel to this work, 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 NEM beyond the closure of the Capacity Investment Scheme (CIS) in 2027.

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

For the purposes of this paper:

- “market” refers to electricity or frequency control ancillary services (FCAS) procured through the NEM real-time wholesale market (or, potentially in the future, a distribution-level real-time market as discussed in this chapter)
- “off market” refers to any services procured outside the wholesale market, including services at the distribution level. Non-market services are a subset of off-market and refer to 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.

Real-time markets for electricity involve an integrated set of mechanisms, processes, and technologies that coordinate electricity market operations with real-time grid control. By aligning economic signals with operational needs, a real-time market facilitates transparent pricing, incentivises efficient investment, supports system security and efficiency, and enables the integration of diverse energy resources into the grid. A real-time market at the distribution level can be used to orchestrate CER.

While off-market approaches to managing CER (such as DOEs, DNPs and flexibility services) are expected to keep an electricity system with high levels of CER in a secure operating state, they face limitations in orchestrating CER *efficiently* and realising the full benefits CER offers. A market-based



approach can, in theory, offer a more efficient alternative by enabling real-time optimisation and coordination of CER and the network, ensuring resources are dispatched when and where they are most valued. While such a market would be a major reform of significant complexity, it has the potential to deliver large efficiency improvements if effectively implemented.

Real-time markets have the potential to orchestrate CER resources in a way that:

- manages congestion on the distribution network more efficiently than network pricing and operating envelopes
- enables efficient scheduling and trade-offs between transmission- and distribution-connected resources
- reveals information about intended actions of CER which can help with system operation and system security.

This chapter explores the potential for distribution-level markets in further detail. As part of this, the CER Taskforce engaged Cambridge Economic Policy Associates (CEPA) to develop a set of future-focused market design options to illustrate the range of market approaches that could be taken to integrate CER into the wholesale market and broader power system.

A discussion of the designs is presented below. CEPA's full report is published alongside this consultation paper.<sup>60</sup>

## **4.1. Real-time markets at the distribution level were not previously feasible, but this is changing**

Currently, in the NEM, there is a real-time wholesale electricity market at the transmission level. Activity at the distribution level is considered in the wholesale market primarily through its impact on demand forecasts.

The transmission-level wholesale market can be characterised by:

- a smaller number (relative to distribution) of large transmission assets which can, at relatively low incremental cost, be monitored in real-time
- a smaller number of relatively large generation, load and storage resources connected to the transmission network, which take advantage of sophisticated metering technology
- demand that does not actively participate in the market at scale.

These characteristics have enabled the development of a market that orchestrates energy resources in real-time across the network. Because transmission infrastructure is large and costly, transmission capacity is sized at the efficient level, which results in network congestion. A small number of large

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<sup>60</sup> Made available at [consult.dcccew.gov.au](https://consult.dcccew.gov.au)



generators are then carefully orchestrated in real-time to ensure that supply meets demand, transmission assets operate within their limits, and other system security requirements are met.

The distribution network, on the other hand, has different characteristics that has, in the past, made real-time markets at this level infeasible. These characteristics have included that:

- distribution networks contain a significant number of small passive loads that, in aggregate, followed predictable patterns and could therefore be forecasted relatively accurately
- the cost of individually metering and controlling these small passive loads in real-time was high relative to their beneficial value
- the value of shed load was (and still is) very high compared to the cost of constraining off a generator
- load constraints on distribution networks were (and in general still are) less subtly managed than generation constraints. To constrain consumption, blocks of load were (and still are) turned off in their entirety
- it is more difficult to gather information and monitor system status in the distribution network as it contains many more smaller components than the transmission network
- load diversification decreases and load volatility increases at the granular/local levels of the network
- the mathematics of optimising resources to respect the physical capacity of the distribution network in real-time is computationally challenging.

As a result of these characteristics, orchestration in real-time (as seen at the transmission level) has not been feasible, and instead distribution capacity has been sized to avoid capacity constraints (and therefore interruptions), enabling customers to consume (and in the case of customers with CER, to generate) without considering the wholesale market price or physical network dynamics that occur in other parts of the distribution network and at the transmission level.

Advances in CER and associated communications technologies are beginning to change some, but not all, of these distribution-level characteristics. Different CER can generate and store electricity, and can vary its rate of electricity consumption. It is technically possible to communicate prices and operating intentions between a central market coordinator and a large number of participating CER assets.

## **4.2. CEPA explored three designs to illustrate how CER could be incorporated into the real-time wholesale market dispatch process**

The CER Taskforce engaged CEPA to explore three potential market designs to illustrate the available range of market approaches that could be taken to integrate CER into the wholesale market and broader power system. These are not intended to be an exhaustive list of all possible options. While the designs are intended to be fit-for-purpose in a future scenario with high levels of CER, they are

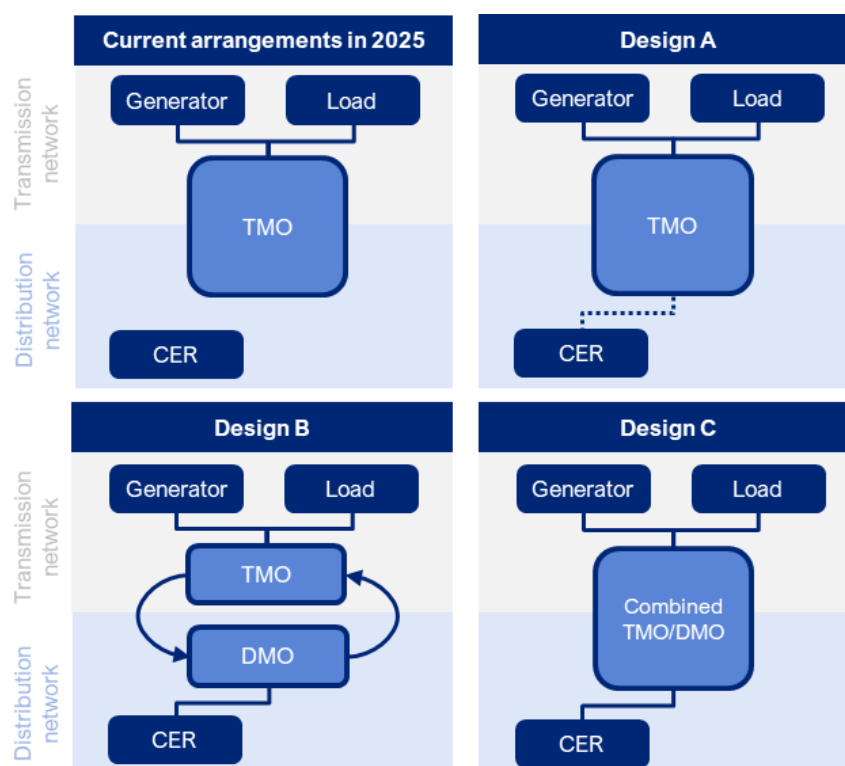


also intended to guide near-term thinking by ensuring that more immediate reforms are scalable and consistent with possible longer-term designs.

The three designs assessed by CEPA were:

1. Focused evolution of status quo arrangements to improve visibility of unscheduled CER. While it does not introduce real-time market arrangements at the distribution-level, unscheduled CER is explicitly considered in the existing wholesale market through retailer forecasts (**Design A**)
2. Real-time distribution-level market that optimises participating CER and then iterates with the transmission-level market (**Design B**)
3. Integrated distribution and transmission level market that optimises participating transmission and distribution-level resources in a single optimisation solution (**Design C**).

These designs are discussed below. A stylised schematic of the designs is shown in Figure 6.



**Figure 6: Stylised schematic of market designs examined by CEPA**

**Box 8: Market design assumptions**

The market design options were developed based on a set of assumptions about the future state of the energy system, with a focus on ensuring each design would be fit for purpose under those conditions. These assumptions include:

- There is high penetration of CER at the distribution level that are responding to market prices.
- Some customers with CER are actively participating in wholesale markets, with their CER forming part of a Voluntarily Scheduled Resource (VSR)<sup>61</sup>. However, a material number of customers choose not to participate, and their CER remain unscheduled.
- When customers with CER choose to participate, this is always voluntary and as part of a VSR, which is operated in the wholesale market by a customer agent, on behalf of customers. This means that while customers with CER can choose to participate in the wholesale market, individual customers are not required to directly interact with it.
- Complementary developments in the electricity retail sector enable retailers to offer a range of products that allow customers to engage with electricity market prices when they choose to do so.
- There are material forecasting errors arising from unscheduled price responsive behaviour that justify a change to how unscheduled demand forecasts are developed.
- Constraints are frequently binding on the distribution network, at least where flows from the CER to the network are concerned. This means there is not enough spare capacity to allow all resources which want to inject electricity to the network to do so, while keeping the distribution network operating within its safe limits. Unscheduled peak load may also cause congestion on the distribution network.

**4.2.1. Design A: Visibility model**

Design A is an evolution of current market arrangements focused on incorporating more accurate forecasts of unscheduled CER into the wholesale market dispatch process. Under this design:

- CER (in aggregate) can voluntarily participate as a VSR in the wholesale market using arrangements recently implemented through the 'Integrating price-responsive resources into the NEM' (IPRR) rule change.<sup>62</sup>

<sup>61</sup> A voluntarily scheduled resource is an aggregation of price-responsive energy resources that can be scheduled and dispatched in the NEM. This is further detailed in the [Integrating price-responsive resources into the NEM, Final determination](#), 19 December 2024.

<sup>62</sup> AEMC, [Integrating price-responsive resources into the NEM, Final determination](#), 19 December 2024.



- Unscheduled CER is explicitly considered in existing wholesale market through retailer forecasts provided to AEMO (the Transmission Market Operator (TMO)).<sup>63</sup>
- The dispatch engine used by the TMO to clear the market remains unchanged (i.e. distribution constraints are not included in the optimisation problem), and the wholesale market continues to be settled at the regional reference price (RRP).
- DSOs continue to rely on off-market mechanisms such as DOEs, DNPs and flexibility services to manage congestion. These mechanisms are more sophisticated than today, reflecting a greater understanding of the distribution network and how the network is used in close to real-time.

Many CER are expected to remain outside the market (i.e. to not participate through IPRR), and will contribute to forecasting errors where retailer and other forecasting approaches do not adequately capture the price-responsive behaviour of these resources.

#### 4.2.2. Design B: Iterative market with regional prices

Design B presents an alternative wholesale market design where the distribution network is co-optimised with the transmission network. This options would require a new the creation of a new role - a Distribution Market Operator (DMO). Under this design:

- The design creates separate distribution and transmission level wholesale markets and market operators. VSRs (aggregated CER) and scheduled resources at the distribution level provide bids/offers to their DMO, instead of directly to the TMO.
- A system-wide clearing solution is achieved through iterative communication between the transmission and distribution markets – similar to how the TMO and transmission-level resources currently interact in pre-dispatch.
- The DMO explicitly considers distribution constraints when clearing the distribution-level market.
- Both market levels continue to settle at the RRP.
- A significant number of resources may remain unscheduled at the distribution level and so DOEs, DNPs, and/or flexibility services are used as complementary tools to manage congestion.
- As in Design A, there are enhancements to the provision of CER forecasting information, but these are now provided to both the TMO and DMO (adjusted to reflect regional conditions) and incorporated into their respective market-clearing processes.

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<sup>63</sup> This includes a model considered under the IPRR rule change whereby retailers can voluntarily submit forecasts of their customers' demand response to the TMO. Retailers are incentivised to provide accurate forecasts through adjustments in ancillary service cost allocation. For further detail see: Creative Energy Consulting, A scheduled lite design to integrate demand response into NEM pricing and dispatch, December 2023





An option was considered by Energy Networks Australia (ENA) and AEMO as part of the Open Energy Networks project that envisaged VSR participation in the energy market settled at regional price via a Two Step Tiered Platform (TST).<sup>64</sup> This option was similar to Design B insofar as the optimisation problem is split between the DSO and TSO, however the TST optimisation did not iterate between the two levels. This lack of iteration limits the theoretical efficiency that can be achieved.

### 4.2.3. Design C: Centralised market with local prices

Design C presents a centralised market to co-optimize the transmission and distribution networks, operated by a combined TMO/DMO. In this design:

- The market optimises dispatch across both the distribution and transmission networks simultaneously. VSRs and scheduled resources at the distribution level provide bids/offers to the combined TMO/DMO, alongside VSRs and scheduled resources at the transmission level.
- Distribution constraints are explicitly considered in market clearing and settlement occurs at local prices.
- Like in Design B, a significant number of resources may remain unscheduled at the distribution level. DOEs, DNPs, and/or flexibility services are used as complementary tools to manage congestion.
- As in Design A, there are enhancements to the provision of CER forecasting information, but these are provided to the combined TMO/DMO and incorporated into the market-clearing process.

The Open Energy Networks project considered a similar model to this, the Single Integrated Platform (SIP) model.<sup>65</sup>

## 4.3. CEPA qualitatively assessed the three market design options

CEPA assessed the three market design options against four criteria, designed to align with the National Electricity Objective (NEO), the CER Roadmap, and enable a qualitative discussion of implementation challenges. The assessment criteria are shown in Table 4 and CEPA's assessment is presented below. See also Chapter 4 of CEPA's published report for more detail.

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<sup>64</sup> Under the TST model, DNSPs would develop their own market platform in addition to AEMO's central wholesale market platform. DNSPs, as DSOs, would manage and operate local markets for CER. See [Open Energy Networks Project](#).

<sup>65</sup> Under the SIP model, the platform would be an extension of the wholesale market. AEMO would provide the platform as part of its market and system responsibilities and along with the individual distribution utilities will develop a single integrated platform. Design C in this paper does not assume AEMO would perform the role of the combined TMO/DMO.



**Table 4: CEPA's market design assessment criteria with links to consumer outcomes**

Criterion	Description	Consumer outcomes
<b>Efficient investment</b>	The market design should promote efficient investment in price-responsive resources across the energy system. This considers whether investment signals reflect the marginal net benefit that price-responsive resources deliver to the energy system, and are available to all price-responsive resources that deliver a net benefit to the energy system.	A design that promotes efficient investment in resources ensures the right amount of generation, transmission and distribution infrastructure is built at the lowest cost to support secure and reliable outcomes.
<b>Efficient operation</b>	The market design should promote efficient operation of price-responsive resources. This considers the visibility of price-responsive resources and network conditions, the extent to which coordination between price-responsive, distribution-connected, and transmission-connected resources is improved, and whether this leads to the highest-value combination of resources being dispatched to meet demand.	A design that enables efficient operation will ensure the most cost-effective resources are used first, lowering total system costs and likely reducing emissions. It will also align power system needs and consumer preferences.
<b>Adaptability</b>	The market design should be sustainable and adaptable to future energy industry developments. This considers if the design is suitable when considering alternative future energy system dynamics, and whether it includes pathway dependencies or precludes movement to alternative market designs.	A design that is adaptable will respond to changing technological, power system and consumer needs, encourage innovation and choice and ultimately support lower cost, lower emission consumer outcomes over time.
<b>Implementation</b>	The market design should be assessed for potential implementation challenges. This considers the extent to which the design considers the underlying physics of electricity systems, the computational feasibility, the scale of structural and regulatory changes needed, and any financial impacts associated with initial and ongoing implementation.	A design must be implementable in practice, meaning the technology exists and the benefits can be realised. The incremental benefits of the reform must outweigh the cost and complexity of implementation.

**CEPAs assessment against the market design criteria***Efficient investment*

Design C is most likely to promote efficient investment in price-responsive resources by settling at local prices, which provide accurate investment signals. Storage assets, in particular, may be incentivised to invest where local price spreads are more favourable than those reflected in the RRP, allowing them to earn higher revenues. In contrast, Designs A and B, which settle at the RRP, could distort investment signals unless congestion costs are accurately accounted for, something that may be partially addressed by sophisticated DNPs, though not as effectively as local prices.

In Design A, congestion on the distribution network can only be managed through off-market mechanisms which, even if materially more sophisticated than today, are unlikely to address congestion as effectively as a market can. For example, to account for this uncertainty between



projected and real-time behaviour, DOEs are set conservatively to ensure the network operates safely. In contrast, Designs B and C rely on a market mechanism to manage congestion across the distribution network for participating resources in real-time, allowing DOEs to be less restrictive. As a result, under Design A, the market operator is unable to fully capture the true value that VSRs can bring to the energy system, leading to inefficient market clearing and prices that do not reflect the true value of energy. This makes Design A the least likely to promote efficient investment signals.

### *Efficient operation*

Design C is more likely to promote efficient operation of price-responsive resources than Designs A or B. While all designs coordinate resources, only Designs B and C explicitly consider distribution constraints in dispatch to enable efficient use of the distribution network. In addition, only Design C is likely to accurately price congestion (through local prices) and send strong price signals for storage assets. In Designs A and B which settle at the RRP, it is unlikely that the same outcomes will be achieved by congestion pricing in DNPs.

### *Adaptability*

Each market design presents varying costs and benefits, with their value depending on how the electricity market develops in the future. It is likely that Designs B and C would be superior in a future where constraints are binding often and there is a high degree of price-responsive resources participating (either actively or passively) in the market. Design A, and possibly other incremental changes to the current arrangements, may be preferred if this does not eventuate.

### *Implementation challenges*

Across the market designs, Designs B and C are materially more complex to implement, due to their broader structural changes. Both require the introduction of a new role, the DMO, and dispatch engines designed to optimise for distribution constraints. These designs will require significant regulatory changes to clarify governance, market rules, and operational standards. Design B is structurally more complex through the creation of multiple DMOs and dispatch engines, while Design C faces significant computational challenges which it may not be possible to overcome.<sup>66</sup> Further work will be required to understand whether the expected benefits from a market approach will justify these costs.

CEPA's assessment was that Design C is the most likely to effectively integrate CER into the wholesale market and deliver system wide benefits in an energy system.

The primary reason why Design C is preferred to Design B, despite Design B also illustrating a co-optimised distribution level market, is because Design C encourages more efficient investment and

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<sup>66</sup> Design B would enable the creation of several DMOs – for instance, one per region or aligned to existing DNSP boundaries. However, there is optionality in the number of DMOs that could be established under Design B, noting that larger DMOs may face more complex optimisation problems. This could introduce computational challenges similar to those seen in the system-wide optimisation problem in Design C.



operation by settling at local prices. Local (rather than RRP) would more accurately signal the “real” cost of available resources at each point in the network, leading to the lowest cost combination of resources being built and used to meet consumer demand over time.

The decision to illustrate Design B with settlement at the RRP and Design C with settlement at local prices is to show that different settlement approaches can apply in the market designs. It would also have been possible to have Design C settle at the RRP and have Design B settle at local prices instead. If this occurred and it was Design B that incorporated local prices rather than design C, then B would be preferred from a market design perspective. If local prices were included in both or neither design, noting that local prices have historically proved difficult to implement in the NEM, then choosing between Designs B and C would come down to weighing up different implementation costs and challenges and whether the expected market efficiency gains can justify these costs.<sup>67</sup>

However, for both designs B and C, there are significant implementation costs and complexity involved. Even if they were technically possible (this project has not explored the question of technical feasibility) the incremental benefits achieved may not outweigh the cost and complexity of implementation. This is explored in more detail in the sections 4.4 and 4.5 below.

#### 4.4. Real-time market arrangements at the distribution level would be expected to deliver more efficient outcomes than off-market mechanisms

A real-time market is likely to have efficiency advantages over other off-market orchestration mechanisms. This is because a market that orchestrates resources based on the price and quantity bids from participants reveals information about the participants’ preferences and willingness to provide services at each time period. Assuming that participants are making bids and offers that reflect their underlying costs and willingness to provide or consume energy, then, this information allows the lowest cost combination of resources to be dispatched and congestion to be managed efficiently.

In the absence of a market to reveal information, DNSPs must instead make informed judgements about how to orchestrate CER. Available off-market mechanisms include **DOEs**, **DNPs** and **flexibility services** (e.g. procurement of services from CER). These mechanisms are required capabilities for distribution system operation, but as a mechanism on their own they have the following drawbacks in relation to real-time markets:

- **DOEs** constrain physical export or import capacity on the basis of expected consumer behaviour. However, markets provide the ability to reflect and respond to how different consumers value access to network capacity at different times.

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<sup>67</sup> While there is optionality in the settlement approach, there may be challenges in having local prices at the distribution level while retaining regional prices at the transmission level. Should local prices be introduced at the distribution level, it is likely appropriate to also introduce them at the transmission level.



- **DNPs** price access to the network based on the expected response from consumers. It is highly challenging to design price signals which efficiently allocate access to manage potential congestion without a ‘pre-dispatch’ information gathering mechanism to understand how different consumers value access and how they might respond.
- **Flexibility services** are procured based on how DNSPs expect network congestion to occur. Where these expectations are inaccurate, this leads to consumers effectively paying too much – or not enough – to manage congestion. There are also issues around market liquidity (and therefore competition and value for money) for highly localised flexibility services, which make inaccuracies in expectations additionally costly for consumers.

These off-market mechanisms rely more highly on forecasts of CER behaviour than a market which enables CER assets to reveal information directly. DNSPs can become more efficient at forecasting responses, but off-market mechanisms are unlikely to determine CER asset preferences as efficiently as a well-functioning market.

Under all designs, it is assumed there will be a material number of customers with CER that cannot, or choose not to, participate in the wholesale market. This means there will always be a role for off-market mechanisms to manage congestion for these resources that remain unscheduled. However, a well-functioning real-time market could reduce the system’s overall reliance on these mechanisms, thereby improving efficiency.

## 4.5. Real-time market arrangements at the distribution level also come with increasing complexity and cost

Designs B and C represent a significant departure from current market arrangements and require substantial structural changes.<sup>68</sup>

Implementation considerations for Design B include the establishment of new DMOs, with new market operator capabilities at the distribution level, and dedicated dispatch engines. This design also introduces governance considerations and subsequent implementation challenges and costs, such as whether DMOs should be independent entities, or integrated with the existing DSO or DNO entities (noting both roles are currently performed by DNSPs). These considerations are discussed further in Chapter 5.

Design B also introduces operational costs given the complexity of operating a market with a very large number of participants at the distribution level. Particularly where multiple DSOs (or actors undertaking DSO functions) were simultaneously addressing these issues, the scarcity of relevant skills would likely place upwards pressure on implementations costs. The ongoing implementation costs of operating multiple distribution level markets could also be substantial. Design B would

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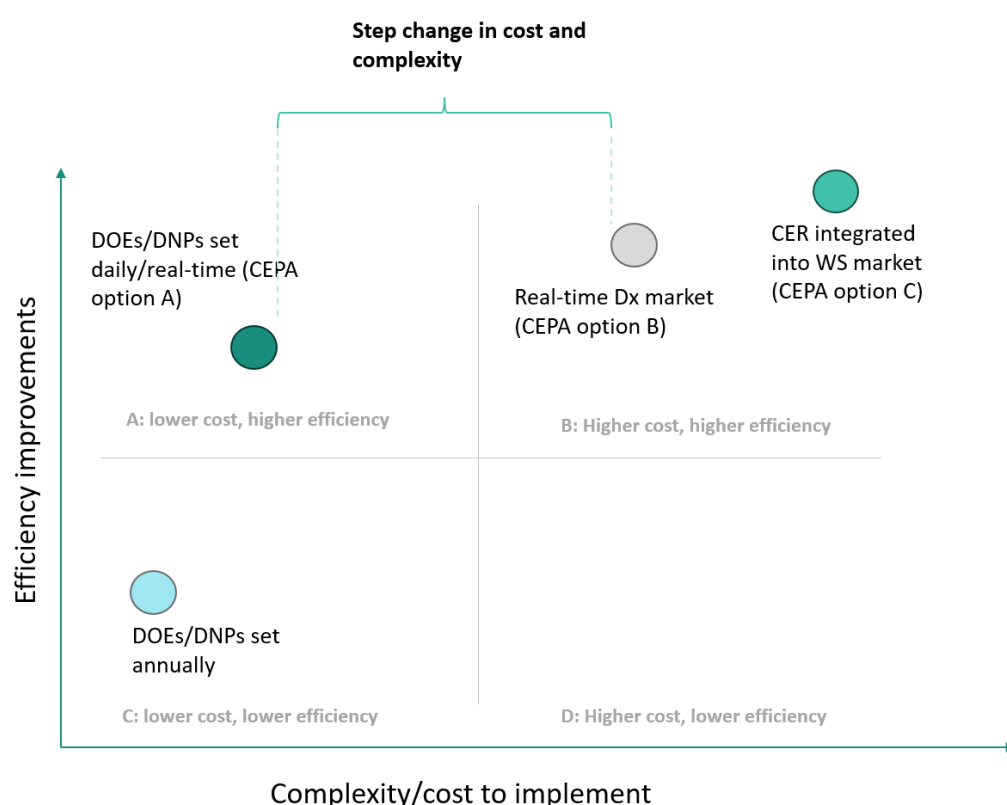
<sup>68</sup> For additional consideration of the relationship between DSO models and distribution-level markets, refer to Power Systems Architecture, Report 4: Distribution System Operator (DSO) models, 2025, CSIRO (Sections 14.3 and 14.4)



require some significant regulatory and governance changes, requiring substantial alterations to the legal framework, rules, and standards.

Design C would also involve significant implementation challenges. This option would involve developing a new dispatch engine(s). Facilitating changes to the rules and regulatory framework would be required. Computation limitations would be a key challenge given the number of resources that would need to be co-optimised in one optimisation problem across the entire NEM. These computational limitations are likely a barrier to implementing Design C at this point in time.

There is a trade-off between potential efficiency and implementation cost and complexity across the market design options, which is shown stylistically below. Figure 7 illustrates that significant benefits can be achieved by improving off-market mechanisms (DOEs, DNPs, flexibility services) and visibility of CER (CEPA Design A) to orchestrate CER. These off-market mechanisms will be required even if real-time market arrangements are introduced, but reliance on them will depend on the proportion of resources that are scheduled in the market. While the benefits and costs of each design have not been quantified, the figure illustrates that implementing CEPA Designs B and C will involve a step change in cost and complexity that may not be outweighed by the incremental gain in efficiency benefits.



**Figure 7: CER Taskforce's stylistic representation of efficiency and implementation complexity of CEPA market design options**



## 4.6. The question is whether and under what conditions real-time, distribution-level market arrangements deliver benefits that outweigh costs

The reforms set out in chapter 3 offer one pathway to a future where unscheduled distribution-level resources are orchestrated through a range of off-market mechanisms (DOEs, DNPs, flexibility marketplaces) to get more effective distribution-level outcomes and deliver value to CER customers and customers more broadly. In this future, a portion of CER will be voluntarily scheduled and included in wholesale market dispatch, CER will be more visible and predictable, and embedded into security frameworks which will reduce the need for network interventions. A range of participants will leverage DOEs, DNPs and flexibility service platforms to structure products and services to leverage CER and deliver value back to consumers.

This chapter, by considering CEPA's real-time distribution-level market designs, offers an illustrative view of what the future could look like if market arrangements were used to integrate a portion of CER into the NEM. The three different designs explored by CEPA offer different futures, but they are common in that a portion of CER remains voluntarily scheduled and retail forecasts of unscheduled CER are considered by the TMO as an additional input to market clearing. Designs B and C use market arrangements to manage congestion across the distribution network for participating resources in real-time.

The pathways are not mutually exclusive – indeed progressing the proposed actions in chapter 3 to improve visibility and predictability, support off-market orchestration of CER and embed CER in system security frameworks and are necessary first steps to all futures.

The question for stakeholders to consider is whether off-market mechanisms will remain an effective way of leveraging CER opportunities into the future, or whether there will come a time where real-time market arrangements offer a better solution to leverage CER.

In its advice CEPA notes that with sufficient investment and the right incentives DNSP judgements should become more accurate over time, and off-market mechanisms will become more sophisticated. However, it is unlikely they will be able to capture the preferences of millions of CER owners, the real-time dynamics of the network, or price congestion as accurately and simply as a market that reveals information on how access to the network is valued in real-time.

On the other hand, there are clear costs and complexities involved in establishing distribution-level market arrangements. To go down that path, the benefits would need to outweigh the costs. While assessing the costs may be relatively straightforward (if the market design is sufficiently detailed) assessing the benefits will rely heavily on assumptions.

Through its market design assumptions CEPA gives a sense of the conditions under which the benefits from distribution-level market arrangements would be greatest. These include where:

- There is high penetration of CER at the distribution level that is responding to market prices.
- Some of these resources are actively participating in wholesale markets as part of a VSR, however a material number choose not to participate and remain unscheduled.





- There are material forecasting errors arising from unscheduled price responsive behaviour that justify a change to how unscheduled demand forecasts are developed.
- Constraints are frequently binding on the distribution network, at least where flows from the CER to the network are concerned, and off-market mechanisms are used frequently to manage system security and reliability. Unscheduled peak load may also cause congestion on the distribution network.
- DNOs have a sophisticated understanding and visibility of the distribution network.

CEPA also notes that the absence of a clear tipping point does not mean that a decision can't be made to pursue market arrangements at the distribution level. Delaying the decision could risk locking in path dependencies that make more efficient outcomes harder to reach later on, such as DNSPs or jurisdictions deciding different, and possibly opposing, pathways.

A view on when these conditions may arise, weighed up against the risk of delaying a decision may help guide stakeholders in providing their response to the consultation questions on whether, under what conditions and at what time distribution-level market arrangements may be the appropriate solution to integrate CER into the power system and market. We will use stakeholder feedback to inform our recommendations to Ministers on the path forward.

## 4.7. Consultation questions

Referring to the discussion of distribution-level market designs in chapter 4:

8. Do you think off-market mechanisms, along with other actions to improve visibility and predictability, support effective orchestration and embed CER in system security frameworks will, over time, be able to capture most (if not all) of the benefits of market orchestration of CER?
9. Do you think the long term benefits of distribution-level market arrangements would outweigh the cost and complexity of implementation?
10. What triggers/conditions in the future might indicate a need for more fundamental reform to more comprehensively integrate CER into the NEM wholesale market?
11. Which of the models described in the chapter are most appropriate to integrate CER into the NEM wholesale market? Are there any other market designs that you think should be considered, compared to Designs A-C in this paper?
12. What complementary measures would be necessary, for example in retail markets, to support effective implementation of the models described in the chapter?



## 5. Distribution system operators must deliver positive consumer outcomes in a high CER world

In chapter 3 we outlined near-term actions that we consider to be necessary first steps to support any future. They are the actions that are not yet being progressed, or progressed to the extent necessary, to enable us to consider how well CER can be integrated within current arrangements.

This chapter assumes the actions from chapter 3 have been implemented and asks stakeholders to consider whether further changes – in this case structural changes to governance arrangements - are necessary to support CER integration and deliver desired consumer outcomes.

The question explored in this chapter is whether we need different arrangements to govern how (and by whom) decisions about distribution system operations are made.

Whoever undertakes distribution system operations activities will need the right incentives, tools and governance arrangements to deliver positive consumer outcomes in a high CER future.

The **DSO** role (described in Chapter 3, Box 3) includes decision making for the real-time operation of the distribution network as well as the necessary planning and analysis functions to inform these decisions. DSO roles include generating load and CER demand forecasts, calculating and communicating network capacity and operating envelopes, and monitoring real-time network conditions on the distribution network.

DNSPs currently perform DSO responsibilities and are the natural entity to undertake them going forward, absent of substantive institutional reform. A key consideration for this work program and the CER Roadmap more broadly is whether DNSPs are best placed to undertake the DSO role and whether better consumer outcomes could be achieved under different institutional arrangements. Possible concerns with DNSPs performing the DSO role are discussed below, as well as an assessment of the options to address the potential issues identified.

Governance reform options could include:

1. functional and/or accounting separation (ring-fencing) of DSO functions within a DNSP
2. moving DSO functions from DNSPs to a new independent organisation
3. creating a new entity responsible for consistency and coordination of systems and processes across DNSPs (a 'coordination and facilitation body')
4. pursuing regulatory reform within the existing framework to address or mitigate the potential issues.

Any of these reform options could be pursued in the absence of a real-time distribution level market arrangements (as explored in chapter 4) but the introduction of real time markets at the distribution level would require governance reform.



CEPA's analysis primarily focused on the roles required within each market design option, rather than the actors that perform these roles. For the purposes of understanding links between CEPA's market design options and the governance options explored in this chapter, we have listed the possible combinations in Table 5 below.

**Table 5: Description of DSO/DMO roles and governance arrangements under each market design**

Potential governance arrangements under each market design	Description of DSO/DMO roles
<b>Current market design: Existing governance arrangements and all four governance reform options could support the current market design.</b>	Under current arrangements the TSO and TMO are the same entity (AEMO), and Transmission Network Operators (TNO) are separate entities (TNSPs). At the distribution level, the role of DSO is performed by the DNOs (DNSPs). DNSPs address and manage constraints on the distribution network. There is no DMO. TMO accepts bids from CER (including Voluntary Scheduled Resources) in line with the 'Integrating price-responsive resources into the NEM' rule. But many CER assets are expected to be 'outside' the market.
<b>CEPA design A: Existing governance arrangements and all four governance reform options could support CEPA design A.</b>	As for current market design, except that retailers also provide forecasts of the price-response behaviour of customers, including unscheduled price responsive CER, to the TMO. One variant of design A includes retailers being responsible for their proportional contribution to additional FCAS charges resulting from poor forecasts.
<b>CEPA design B: Existing governance arrangements and all four governance reform options could support CEPA design option B, noting that the new role of DMO must be established.</b>	Under CEPA design B, the TSO and TMO are the same entity (AEMO). This design introduces DMOs, which may or may not be integrated with the DSOs (currently performed by DNSPs). Under this model: <ul style="list-style-type: none"> <li>• Scheduled CER at distribution level submit offers to DMO.</li> <li>• The DMO applies DSO constraints before running optimisation.</li> <li>• Bids/offers are provided by DMO to the TMO, with pre-settlement iteration between the TMO and DMO until optimised.</li> </ul>
<b>CEPA design C: Existing governance arrangements and all four governance reform options could support CEPA design C. However, the new role of DMO must be combined with the TMO role and this may or may not involve establishing a new entity.</b>	Under CEPA design C there is a combined TMO/DMO that could, but does not have to, be the same entity as the TSO (e.g. AEMO) and/or DSO, removing the need for iteration. The role of the DSO in managing constraints is less material given all, or nearly all, constraints are built into the dispatch engine.



## 5.1. There is no ‘one-size-fits all’ solution

Many international jurisdictions are grappling with similar institutional reform questions as their own systems integrate increasing levels of CER (see Table 6 below). Many jurisdictions that have examined the suitability of their distribution-level institutional arrangements in recent years have established an independent DSO. However, not all have taken this step.

Key considerations from these jurisdictions in favour of moving to an independent DSO have included potential conflicts of interest with utilities managing both network investment and market facilitation functions, and the need for new capabilities. Note that in the international context the DSO and DMO functions are generally considered together.

Considerations against change have included cost efficiency, potential duplication of roles, regulatory barriers and technical capabilities (e.g. data and information).

Review of these jurisdictions demonstrates that there is a range of institutional responses to the increasing complexity of the DSO function. There is no one-size-fits-all solution, and the response depends on context-specific factors.



Table 6: DSO governance considerations in international jurisdictions

Jurisdiction	Decision on independent DSO entity	Rationale and consideration
<b>New York</b>	Separate independent DSO for each distribution utility.	Assessed to be most practical, given each distribution utility operates within its own service area. <b>Considerations:</b> conflicts of interest in utilities managing both grid operations and CER procurement, market transparency and jurisdictional clarity (DSOs under state regulation, ISOs federal).
<b>Hawai'i</b>	Separate independent DSO for each distribution utility	Assessed to be most practical given each utility operates within its own service area, given local grid structure and renewable goals. <b>Considerations:</b> the need for advanced DER integration and real-time system management, resilience given unique challenges in an island context.
<b>California</b>	Continuing to explore hybrid models, narrowing down on enhanced role for existing DSOs.	Reviewing DSO models and implications for roles, balancing utility control against enhanced neutrality and potential value of streamlined coordination with fewer independent DSOs. <b>Considerations:</b> conflicts of interest across utility grid and market facilitation functions.
<b>Maine</b>	Not pursuing formal DSO creation. Investigating the feasibility of a single statewide DSO and using their DSO feasibility study to inform future priority areas of analysis.	Prioritising broader grid management strategies. Key considerations include cost implications, reliability and climate goals. <b>Considerations:</b> Feasibility study into a single DSO managing CER and interacting with ISO, with the rationale being to simplify coordination and reduce administrative complexity given it's a smaller state.
<b>Germany</b>	Most DSOs are publicly owned and quite small, with 70 per cent having fewer than 30,000 connections. Only ten per cent of German DSOs have more than 100,000 connections.	Focus on regional flexibility markets managed by existing distribution utilities, given a strong regional focus in grid management. <b>Considerations:</b> Regulatory barriers preventing full unbundling of DSO functions from utilities, investments in smart meters, and automation technologies within current structures.
<b>UK</b>	Enhance the capability of existing distribution utilities without creating fully independent DSO entities.	Transitioned 14 existing distribution utilities into DSOs. Ofgem assessed five models for DSOs, focusing on efficient dispatch of flexibility services, stakeholder satisfaction, and performance metrics. <b>Considerations:</b> Cost efficiency, leveraging existing infrastructure to avoid duplication, and coordination with ISO for system reliability and flexibility markets.
<b>Ireland</b>	Single distribution utility assigned as the single DSO.	Single distribution utility operates across Ireland, making it a single independent DSO sufficient for national coordination. <b>Considerations:</b> Governance independence to act as a neutral market facilitator, independence in decision-making for IT projects and collaboration with third parties, enhanced ring-fencing arrangements.
<b>France</b>	Single national DSO	Single DSO entity managing distribution networks across the country without creating multiple independent entities, simplifying operations and ensuring consistency across regions. <b>Considerations:</b> National-level coordination for grid modernisation and renewable integration, cost efficiency in managing one centralised operator, alignment with European Union (EU) directives on enhanced DSO functionality.
<b>Spain</b>	Favouring independent DSOs for each distribution utility.	<b>Considerations:</b> the need for market neutrality in resolving grid congestion issues, the integration of renewables and flexibility mechanisms, and alignment with EU directives.



## 5.2. DNSPs are pursuing CER integration, but barriers remain

DNSPs are regulated under an incentive-based framework in the NEM. The regulatory framework aims to incentivise specific behaviours and outcomes from DNSPs, particularly with regard to efficiency improvements over time. New mechanisms have been introduced to further strengthen incentives for specific outcomes, including the Efficiency Benefits Sharing Scheme (EBSS),<sup>69</sup> the Capital Efficiency Sharing Scheme (CESS)<sup>70</sup> and the Service Target Performance Incentive Scheme (STPIS).<sup>71</sup>

A number of changes have been made to the regulatory framework in recent years to increase DNSPs' incentives and cost recovery certainty for CER solutions. These include:

- The Demand Management Incentive Scheme (DMIS), introduced in 2017, which provides an incentive of 50% of the cost of a non-network solution (which can include CER-based solutions), capped at the project's expected net benefit.<sup>72</sup>
- The Demand Management Incentive Allowance (DMIA), updated in 2017, which makes funding available to DNSPs for research and development of non-network solutions with the potential to reduce long term network costs.<sup>73</sup>
- The AEMC's *Access, pricing and incentive arrangements for distributed energy resources* rule change (2021) which added to DNSPs' core functions the provision of export services to CER, among other changes to support CER integration.
- The AER's *DER integration expenditure guidance note* which sets out how DNSPs should justify expenditure related to CER integration, and clarifies that broader system benefits such as wholesale market benefits are a relevant class of benefits.
- The AER's *Export service incentive scheme* which enables DNSPs to set CER export service performance targets based on the priorities and preferences of DNSPs' customers.

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<sup>69</sup> The EBSS was introduced in its current form in 2013 and is designed to equalise DNSPs' incentives throughout the regulatory control period to achieve opex efficiencies by allowing DNSPs to retain opex savings for six years ([AER 2023](#)).

<sup>70</sup> The CESS was introduced in its current form in 2013 and is designed to equalise NSP's incentives throughout the regulatory control period to achieve capex efficiencies by enabling DNSPs to retain 30% of capex savings ([AER 2023](#)).

<sup>71</sup> The STPIS incentivises NSPs to outperform service targets (i.e. network reliability) in line with the value customers place on increased reliability. This balances the incentives in the EBSS and CESS to reduce expenditure ([AER 2023](#)).

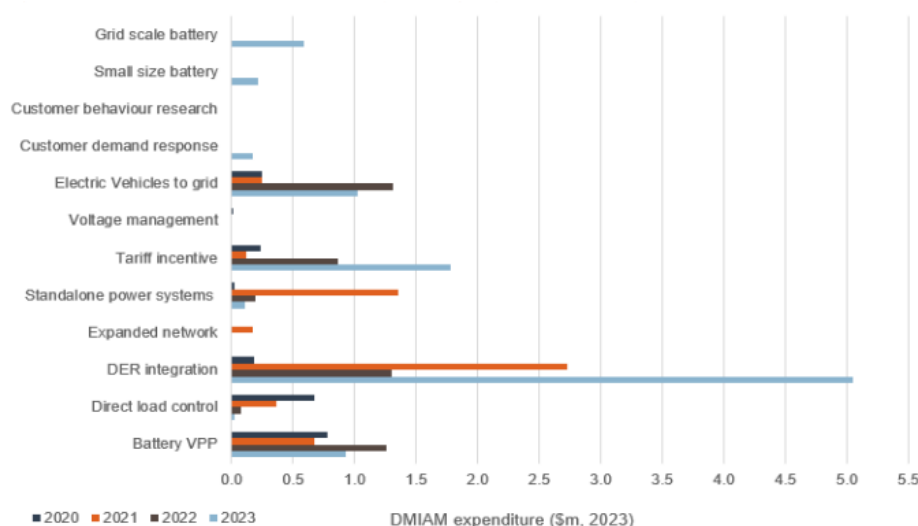
<sup>72</sup> AER, [Final decision: Demand management incentive scheme and innovation allowance](#), December 2017.

<sup>73</sup> AER, [Final decision: Demand management incentive scheme and innovation allowance](#), December 2017.



- The AER's *Export limit guidance note* (2024) which sets expectations as to how DNSPs should set flexible export limits, as well as static export limits.

Under these arrangements, DNSPs have an incentive to pursue non-network options (including services provided by CER) through the DMIS, to use CER to reduce capital or operational expenditure (through the CESS and EBSS), to use CER to improve service standards (through the STPIS), and trial innovative solutions related to CER through the DMIA. In 2023 the DMIA mechanism funded around \$11 million in CER-related research and development activities for distribution businesses, across a range of research areas (see Figure 8).<sup>74</sup>



**Figure 8: DMIA expenditure by category, 2020-2023. Source, [AER](#).**

DNSPs also have clarity that they are required to facilitate CER export and that certain costs associated with CER integration will be recoverable.<sup>75</sup> Furthermore, DNSPs have an apparent incentive to use mechanisms like FELs, DOEs and DNP to improve orchestration of CER as this presents opportunities for savings in operational and capital expenditure. These savings are incentivised under the EBSS and CESS incentive schemes. Examples of these mechanisms already being deployed or trialled are discussed in Chapter 3 and appendix E, and include SAPN's deployment of flexible export limits (FELs) for customers with solar PV and Ausgrid's Project Edith which is trialling DOEs and DNPs.<sup>76</sup>

However, the use of coordinated CER to provide network services such as managing network congestion or provision of other system services has been relatively limited to date. Only two projects with a combined value of \$834,287 were eligible for the DMIS incentive in FY2022 (latest

<sup>74</sup> AER, [2024 Electricity and gas networks performance report](#), September 2024

<sup>75</sup> The AER's export limits guidance note provides providing guidance to DNSPs to support the efficient implementation of flexible export limits. The guidance note can be accessed [here](#).

<sup>76</sup> More information about SAPN's FELs can be found [here](#). More information about Ausgrid's project Edith can be found [here](#).





reporting available), both being CER-based solutions.<sup>77</sup> CER-based options to meet distribution network requirements are still predominantly at the trial phase, often with financial support from ARENA or other government entities.

Experience across various trials indicates there are significant technical barriers to using CER for network services.<sup>78</sup> These barriers include:

- engaging enough participation for a viable solution
- integration complexity with DNSPs' operational systems
- level of 'firmness' and reliability of the solution considered and the extent to which it can address the identified need
- a lack of market depth (that is, sufficient number of potential participants to provide CER) to ensure competitive pressures are revealing efficient costs
- cost competitiveness of CER-based solutions.

Lack of uptake of CER-based solutions does not necessarily indicate that DNSPs are opposed to CER-based solutions, but it does suggest there are barriers to these solutions being utilised at this point in time.

### 5.3. DNSPs may not unlock CER value as soon as possible under current settings

DNSPs have taken action to address the technical challenges created by increases in CER on their network, particularly responding to voltage issues or network congestion arising from high uptake of rooftop solar PV. DNSPs are also trialling and implementing new systems to better integrate CER. Nonetheless, a requirement of this workstream is to assess which entity is best placed to perform DSO (and potentially DMO) functions into the future. A review of international arrangements demonstrates that some jurisdictions have moved to independent DSO governance arrangements in the context of increasing CER penetration. Governance arrangements in the Australian context therefore require careful consideration.

We set out below three potential concerns with DNSPs assuming the DSO role in the future, which could limit the pace at which the value of CER integration is realised in the Australian context.

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<sup>77</sup> These were United Energy's Summer Saver Program which was a behavioural demand response program, and AusNet's West Gippsland Non-network solution which was a 3 MW/6MWh distribution-connected battery owned by a third party provider. AER, [Decision: Demand management incentive scheme \(DMIS\) payments for 2020-2021 and 2021-22](#), May 2023

<sup>78</sup> Including, for example, the evolve DER project (2019 to 2023), Project EDGE (2020 to 2025), Project Converge (2021 to 2024) and Project Symphony (2021 to 2024). Knowledge sharing reports are available on the ARENA website, at <https://arena.gov.au/knowledge-bank/>



### 5.3.1. Lack of consistency across DNSPs

A primary consideration is the current lack of consistency in systems, processes, service offerings and pricing between DNSPs. Inconsistency increases the transaction costs and technical challenge for entities to engage with different DNSPs. There are 13 different DNSPs in the NEM, one in WA and one in the NT. Each defines its own operating protocols, procedures and practices and there is further variation in State- and Territory- based regulations and licensing conditions that apply.

Integrating CER into the distribution system will require a greater number of organisations to interact, including DNSPs, TNSPs, retailers/aggregators, AEMO, and regulators. From an operational perspective, the interactions between these entities will need to be efficient to make the necessary data exchange and computational requirements tractable. From an economic perspective, improving the ease of interactions will reduce transaction costs and by extension reduce overall costs to consumers.

An example is CER customer agents such as retailers or aggregators operating at a national level. These entities can potentially provide aggregated CER-based network services to DNSPs. But currently there is diversity in approaches across DNSPs, and this diversity increases the complexity and cost for customer agents engaging with multiple DNSPs. This diversity increases transaction costs for customer agents working across multiple distribution zones which is likely to reduce entry for new players and to slow the speed at which existing customer agents can scale to a national level. Barriers to scaling are likely to increase the cost of service that customer agents are able to offer (all else being equal), which ultimately makes CER-based solutions less competitive and reduces the value CER can provide and capture.

### 5.3.2. Lack of whole of system perspective

Secondly, the institutional framework under which DNSPs are established and regulated may not support the necessary system design perspective needed to integrate CER as quickly and efficiently as possible, nor in ways which maximise benefits across the whole system. Creating incentives that support the necessary innovation and ongoing improvement in coordination and data exchange between a range of entities (such as retailers, aggregators or CER owners) may be challenging. Incentivising whole of system design considerations may not be a natural fit within the existing regulatory framework and may be challenging to achieve in practice.

Furthermore, even where DNSPs are motivated to achieve such outcomes, the propose-respond cost recovery framework under which DNSPs are regulated may not support DNSPs recovering the costs of expenditure that has a system focus but may not stack up from the perspective of the individual DSNP. New approaches that are innovative and unproven may struggle to pass a cost-benefit analysis in isolation and therefore may not be approved by the AER for cost recovery. Furthermore, DNSPs would be disincentivised from identifying options which might generate better outcomes for the whole system but create less manageable or profitable outcomes for their business. Sandboxing<sup>79</sup> and the DMIS/DMIA schemes are intended to overcome these barriers to an extent, but these

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<sup>79</sup> For information on sandboxing arrangements see the AER's [website](#).



schemes may not support the changes to ongoing business as usual approaches that are likely to be required. An entity with a broader whole of system perspective that is subject to a different set of objectives and form of expenditure scrutiny may be able to more freely trial new approaches.<sup>80</sup>

### 5.3.3. Possible preference for network solutions

As noted above, the existing regulatory framework provides relatively strong financial incentives that support expenditure by DNSPs on CER integration (e.g. through the DMIS and DMIA). However, DNSPs may have countervailing financial incentives relating to different types of expenditure, that lead to a preference for network options (i.e. ‘poles and wires’ solutions) over non-network options (i.e. the provision of network services by storage or other CER-based solutions).

The potential preference for network options (capital expenditure (capex) based) over CER or other non-network options (operating expenditure (opex) based) is because capex is capitalised into a network’s regulatory asset base (RAB) on which they earn a regulated return.

In theory, if the return on capex is appropriately set then a network should be indifferent to growing its RAB.<sup>81</sup> However, even when this is the case, there may still be a bias for RAB growth for two reasons:

- i) attracting investment – network investors are likely to prefer long-term cash flows which arise from growing RABs.<sup>82</sup>
- ii) large RABs offer greater potential rewards to equity owners from increasing opportunities for financial engineering efficiencies.<sup>83</sup>

A preference, or perceptions of such, for network solutions over non-network options (including CER-based options) could delay the rate at which CER is deployed and utilised in the distribution system. This is a specific case and may not apply to broader questions of CER integration and coordination, for example using network pricing.

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<sup>80</sup> For an expanded consideration of importance of a whole-system perspective, refer to Power Systems Architecture, Report 3: Systemic Issues & Transformation Risks, 2025, CSIRO (Sections 4.2.1)

<sup>81</sup> CEPA, [Expenditure incentives faced by network service providers – Final report](#), 25 May 2018, p. 21.

<sup>82</sup> CEPA, [Expenditure incentives faced by network service providers – Final report](#), 25 May 2018, p. 12.

<sup>83</sup> KMPG, [Distribution Market Models – Assessment of supporting frameworks](#), June 2017, p. 70.



## **5.4. We considered four reform options to address the identified issues**

To address these potential challenges we have considered four reform options:

1. regulatory and/or accounting separation of DSO functions within a DNSP
2. move DSO functions to a new independent organisation (I-DSO)
3. create a new entity responsible for consistency and coordination of systems and processes across DNSPs (a 'coordination and facilitation body')
4. pursue regulatory reform within the existing framework to address or mitigate the identified issues.

No one solution can address all issues identified. It is also important to carefully consider the implementation challenges, complexities and costs of each reform option, as these are likely to be material. The options are discussed in detail below, with a summary of the assessment at Table 7 .



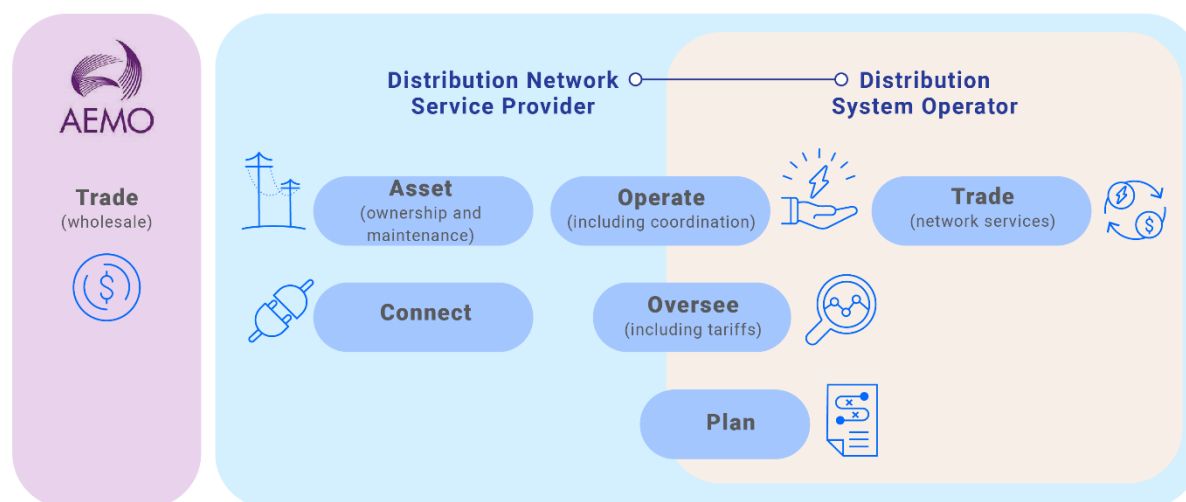
**Table 7: Assessment of governance reform options**

Potential Issue	1. Regulatory/accounting separation	2. Independent-DSO (I-DSO)	3. Coordination facilitation body (CFB)	4. Regulatory solutions
<b>Consistency in systems and processes across distribution regions</b>	<p>✓✗</p> <p>Some diversity across DNSPs/DSOs would likely remain. However, the process of regulatory separation provides an opportunity to develop consistent expectations for DSO functions across the NEM.</p>	<p>✓✗</p> <p>Consistency could not be achieved by one I-DSO that operates across all distribution regions as this is not currently considered operationally feasible. However, the process of establishing I-DSOs could provide an opportunity to mandate consistency across I-DSOs.</p>	<p>✓</p> <p>A CFB could be mandated to define consistent processes and protocols across DNSPs.</p>	<p>✓</p> <p>Standardisation mandates embedded within the regulatory framework for platforms, protocols and market access to reduce transaction costs and level the playing field for third parties.</p>
<b>Whole of system perspective</b>	<p>✓</p> <p>Separated DSOs could be regulated against differentiated objectives from the DNSP, including those which incorporate whole system outcomes. There are difficulties where DNSP and DSO objectives and accountabilities are not appropriately aligned.</p>	<p>✓</p> <p>An I-DSO could be mandated to consider and enable access to information, interoperability etc. from a whole of system perspective.</p>	<p>✓</p> <p>A CFB could be mandated to define appropriate access, data exchange protocols etc to ensure and interoperability</p>	<p>✓✗</p> <p>Incentive-based regulation may be able to target CER enablement or flexibility procurement to an extent, but may have limits.</p>
<b>Impartiality between network and non-network solutions</b>	<p>✓✗</p> <p>An internally separated DSO could have some involvement in network investment decisions which could have some influence over network vs non-network decisions. A closer internal relationship may enable barriers to be overcome more quickly.</p>	<p>✗</p> <p>An I-DSO would not influence network investment decisions under the models considered and so would not influence DNSPs' consideration of network vs non-network options.</p>	<p>✓✗</p> <p>A CFB would not directly influence network investment decisions but could be mandated to provide clear guidance as to how such investment decisions are made, how potential CER providers are to be engaged, and the requisite evidence to be provided.</p>	<p>✓</p> <p>Regulatory reform could better balance incentives between network and non-network options, such as move to a total expenditure (totex) framework or other non-network option incentive mechanisms.</p>



### 5.4.1. Option 1: Internally separated DSO

Accounting and/or regulatory separation of DSO activities from DNSPs would see separated governance arrangements that seek to remove potential conflicts of interest and improve transparency in decision making by DNSPs. This could involve accounting separation between traditional distribution activities and DSO activities, which would enable transparent allocation of roles and responsibilities as well as financial reporting between the two entities. The potential separation of responsibilities under this option is shown in Figure 9.



**Figure 9: Operational responsibilities under accounting and regulatory separation**

Importantly, separation could also allow different regulatory and potentially cost recovery regimes to apply to the entities. This could improve transparency and the ability to set bespoke objectives or incentives for DSO activities.

An international example is UK Power Networks (UKPN is the DNSP servicing London and surrounding areas). UKPN has established a DSO as a separate legal entity, with its own independent supervisory board, executive management level representation within UKPN and clear regulatory incentives.

#### **Benefits**

**Whole of system perspective:** Internally separated DSOs could be established with different objectives and regulatory (including cost recovery) arrangements to DNSPs. These arrangements could better support the DSO to act with a whole of system perspective and ongoing improvement towards targeted outcomes.

**Preference for network solutions:** An internally separated entity might be able to partially address any internal preferences for network solutions by being involved in the development and procurement of CER-based non-network options. Retaining the DSO function within the same organisation as other DNSP activities may allow for a greater involvement of the DSO in network investment decisions than I-DSO models. Closer involvement may also support the DSO understanding barriers to increased use of CER-based solutions in the network better, which could support these barriers being overcome more quickly.



**Consistency:** This approach would see separate DSO entities operate within existing DNSP organisations. There would therefore likely be divergence in approach between the various DSO entities. However, the process of regulatory or accounting separation would provide an opportunity to set nationally consistent expectations for these new entities. This consistency could be guided by a collaborative forum or external third party.

### **Challenges**

**Regulatory:** A key challenge with any separation of DSO functions is to maintain a link between decision making and accountability. DSOs would likely take on at least some degree of operational decision making while DNSPs would remain accountable for the outcomes of those decisions through reliability standards and service targets. This split in decision making and accountability could weaken current regulatory mechanisms that support service reliability and lead to poor consumer outcomes. This issue could potentially be mitigated to an extent by robust performance criteria for CER and considered allocations of responsibilities and accountabilities.

**Consistency:** Despite the regulator being able to set national expectations of DSOs, there would still be the potential for divergence in approach between different DSOs. Even slight differences between DSO functions could create additional costs for entities engaging across multiple distribution zones.

## **5.4.2. Option 2: Independent DSO (I-DSO)**

Another option is to move DSO responsibilities to an independent entity, an ‘I-DSO’. As noted above, this approach has been pursued in some international jurisdictions to address their own concerns with incumbent utility organisations taking on DSO functions.

An I-DSO would mean separating DSO functions from DNSPs and assigning them to an independent entity. Potential models include:<sup>84</sup>

- New entity I-DSO for each distribution region
- New entity I-DSO for each NEM region, WA and NT
- New entity I-DSO for the entire NEM, separate I-DSOs for WA and NT
- AEMO to incorporate I-DSO functions NEM-wide and in WA and NT

In practice, a single entity undertaking DSO functions for multiple distribution regions is expected to be extremely challenging. This is because each distribution network has different systems and operating contexts, including license conditions, operational policies, network topologies and management practices.

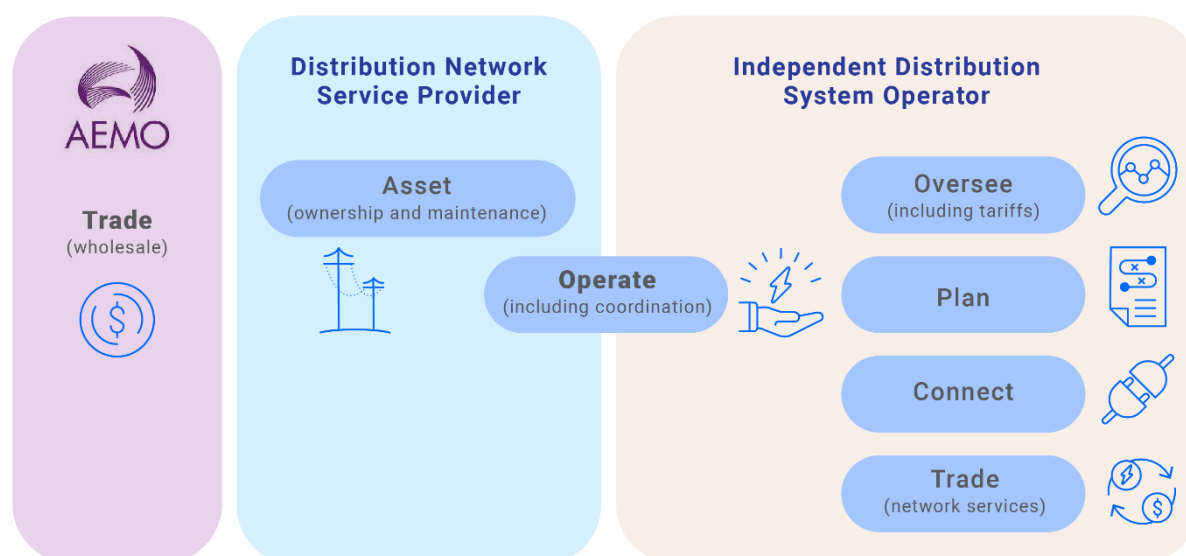
The most prospective I-DSO model for further consideration would involve a new I-DSO being established for each distribution region. This is shown in Figure 10 and discussed further below.

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<sup>84</sup> Consideration would need to be given to WA and NT.







**Figure 10: Operational responsibilities under I-DSO model**

### **Benefits**

**Whole of system perspective:** The primary benefit of moving to an I-DSO model would be to remove any perceived or actual conflict in objectives between the system operations functions and the interests of the DNSP as the network owner. An I-DSO could be assigned responsibility for ensuring systems and processes are sufficiently accessible and compatible between relevant entities such as CER customer agents, AEMO and TNSPs. Appointing this responsibility to an independent entity would support system integration between relevant parties.

**Consistency:** Establishing I-DSOs could improve consistency across distribution regions to an extent. Each region would likely require its own I-DSO, which could create scope for divergent approaches. However, this could be mitigated by including consistency requirements in the establishing governance documents of I-DSOs. This consistency could be guided by a collaborative forum or external third party.

### **Challenges**

There are significant challenges to separating DSO functions from DNSPs. These include regulatory, operational, legal and financial considerations. Addressing these factors would also have implications for implementation timeframes and may be disruptive to DNSPs' current CER integration work programs.

**Regulatory:** Separating DSO responsibilities from DNSPs would split decision making and accountability under the current framework. The I-DSO would likely be responsible for some degree of real-time operational decisions while the DNSP would be accountable for reliability outcomes, as in the internal separation option above. This issue could potentially be mitigated to an extent by robust performance criteria for CER and considered allocations of responsibilities and accountabilities.

**Operational:** The operational complexity of a split in decision making and network operation would also be very challenging at the distribution level. This split exists and is manageable at the



transmission level due to the relatively small number of large network assets that must be coordinated. At the distribution level, there are many more network assets that need to be controlled. A very high degree of integration in systems and processes would be required to enable real-time decision making by the DSO to be sufficiently coordinated with operation of network assets by the DNSP.

**Cost:** There would be an initial financial cost in setting up I-DSOs. Baringa Partners was engaged under the ENA/AEMO Open Energy Networks project to assess the cost of various distribution-level market designs. Baringa estimated that implementing a market design similar to Option B discussed in Chapter 4 would cost approximately \$500 million more under an independent DSO/DMO model than if the DSO/DMO were to be integrated within a DNSP over a 20 year period.<sup>85</sup>

Both initial investment costs and ongoing operational costs were estimated to be higher under an independent model due to the cost of splitting roles across multiple parties.<sup>86</sup>

**Legal:** DNSPs' functions are established under the National Electricity Law for NEM jurisdictions. Separation of DSO functions would require substantial legal changes and would have implications for subordinate instruments such as the National Electricity Rules (NER) and AER guidelines.

**Timeframes:** Due in particular to the operational and legal considerations, moving to I-DSO arrangements would require an estimated 2-5 years to implement, and would also depend on the regulatory determination cycle for each region.

**Disruption:** The separation of DSO responsibilities would likely impact CER integration work currently underway by DNSPs. This may negatively impact the rate at which CER value is unlocked.

### 5.4.3. Option 3: Coordination and facilitation body

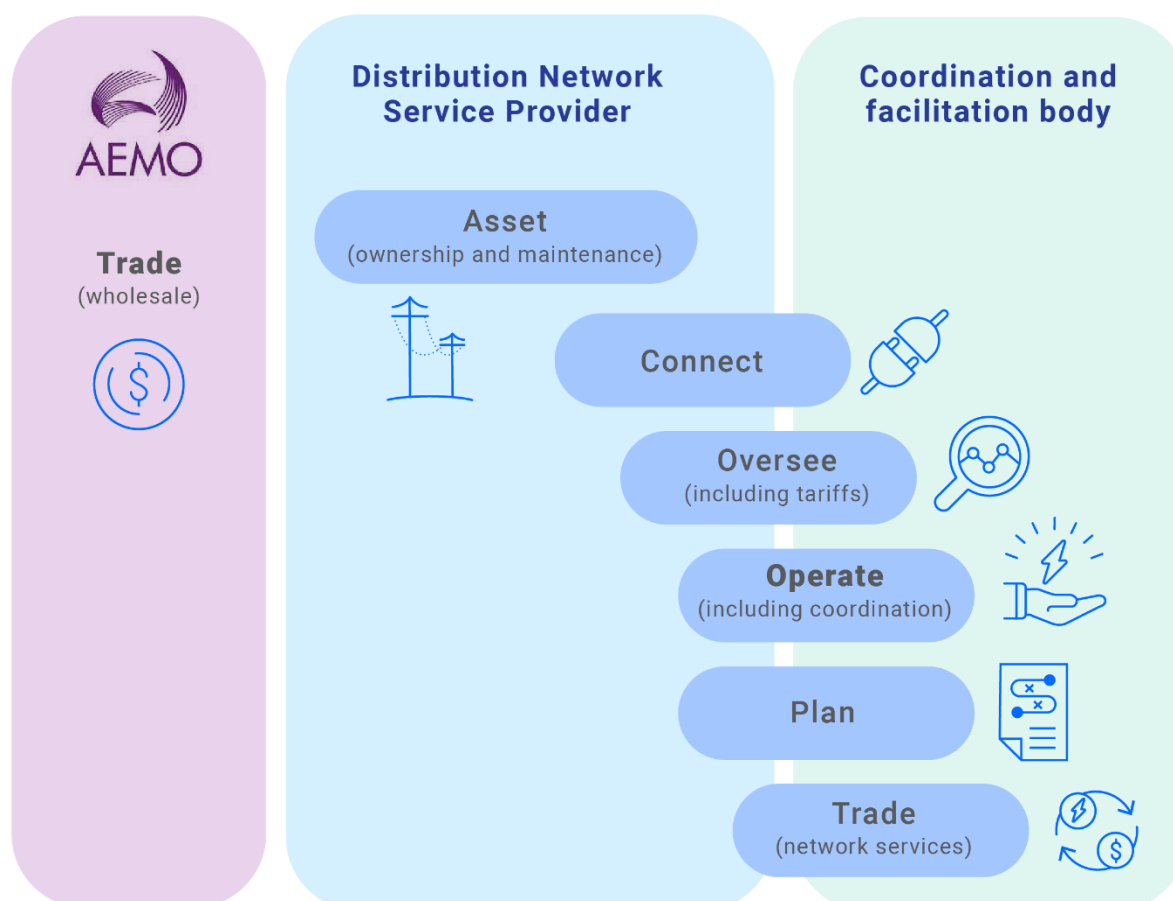
As an alternative to moving to an I-DSO model, a new 'coordination and facilitation body' (CFB) could be established with responsibility for systems integration and consistency in rules interpretation between DNSPs and other actors. Under this approach, DSO responsibilities would remain with DNSPs, and a new body would be established that is empowered to determine specific systems and processes that DNSPs must follow that are deemed necessary to meet the National Electricity Objective (NEO), particularly through the efficient integration of CER. The split in responsibilities is shown in Figure 11.

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<sup>85</sup> Baringa, [Assessment of Open Energy Networks Frameworks](#), May 2020, p. 8.

<sup>86</sup> Baringa, [Assessment of Open Energy Networks Frameworks](#), May 2020, p. 28.





**Figure 11: Allocation of responsibilities under CFB model**

It is envisaged that a CFB entity could determine system and operational processes that DNSPs would be obligated to comply with across areas such as:

- connections and access standards
- pricing
- dynamic operating envelope design
- platform design
- data exchange protocols.

### **Benefits**

**Whole of system perspective:** The CFB could be mandated with setting system and operational processes in a way that maximises access and coordination between distribution system participants including CER customer representatives, AEMO and TNSPs.

**Consistency:** DNSPs could be required to comply with the procedures issued by the CFB, for example through minor NER or AER guideline amendments. This would ensure consistency across DNSPs and would reduce transaction costs for other system participants.



**Timeframe:** The CFB could be established more quickly than an I-DSO. Indicatively it could be established within 12-18 months. Such a body could also have a time-limited mandate and the ongoing need for such a body could be reviewed at a pre-determined point in the future.

### **Challenges**

**Cost:** The CFB would have implementation and ongoing operational costs, although these would likely be much lower than an I-DSO model, as only one body would be required and it would have a regulatory rather than operational function.

**Regulatory:** There would be potential for overlapping regulatory functions between the CFB, the AER and the CER technical regulator. Clear delineation of responsibilities would require careful consideration.

**Accountability:** If DNSPs were required to implement processes determined by the CFB, these could potentially have operational implications. This could split accountability for any negative operational (or other) outcomes between DNSPs and the CFB.

## **5.4.4. Option 4: Regulatory reform**

A final option is for DNSPs to retain DSO responsibilities, with identified issues addressed through targeted regulatory reform within the existing framework.

Regulatory reform to address the identified challenges could include:

### **Whole of system perspective:**

- Clarify in regulatory instruments (i.e. NER, WEM Rules, AER guidelines) that DNSPs have an obligation to design systems in a way that maximises access to relevant parties – including platforms, data, interoperability, and connections.
- Clarify in the AER's *DER integration expenditure guidance note* that expenditure can be made on systems integration and other necessary system design activities. Consideration would need to be given to how benefits could be quantified and assessed by the AER.

### **Consistency**

- Mandate a consistent approach to areas where there is currently divergence such as platform and system design and information/data sharing protocols. This could be implemented in regulatory instruments with processes and platforms set by AEMO and AER, in consultation with relevant stakeholders. This process would need genuine co-design with appropriate resourcing and expertise in order to be successful.

### **Preference for network options**

- Regulatory mechanisms to strengthen incentives for DNSPs to undertake CER-based non-network options (in addition to the existing DMIS/DMIA schemes) such as:
  - Strengthen and/or adapt the DMIS to enhance incentives
  - Consider total expenditure (totex) regulatory regimes that better balance incentives between capex and opex



- Exemptions from penalties or loss of incentives for when trialling CER-based solutions (e.g. 'STPIS holiday')

### ***Benefits***

This approach would enable targeted actions that seek to address the specific issues identified. It would likely be faster and cheaper to implement and would leverage existing processes and regulatory frameworks.

### ***Challenges***

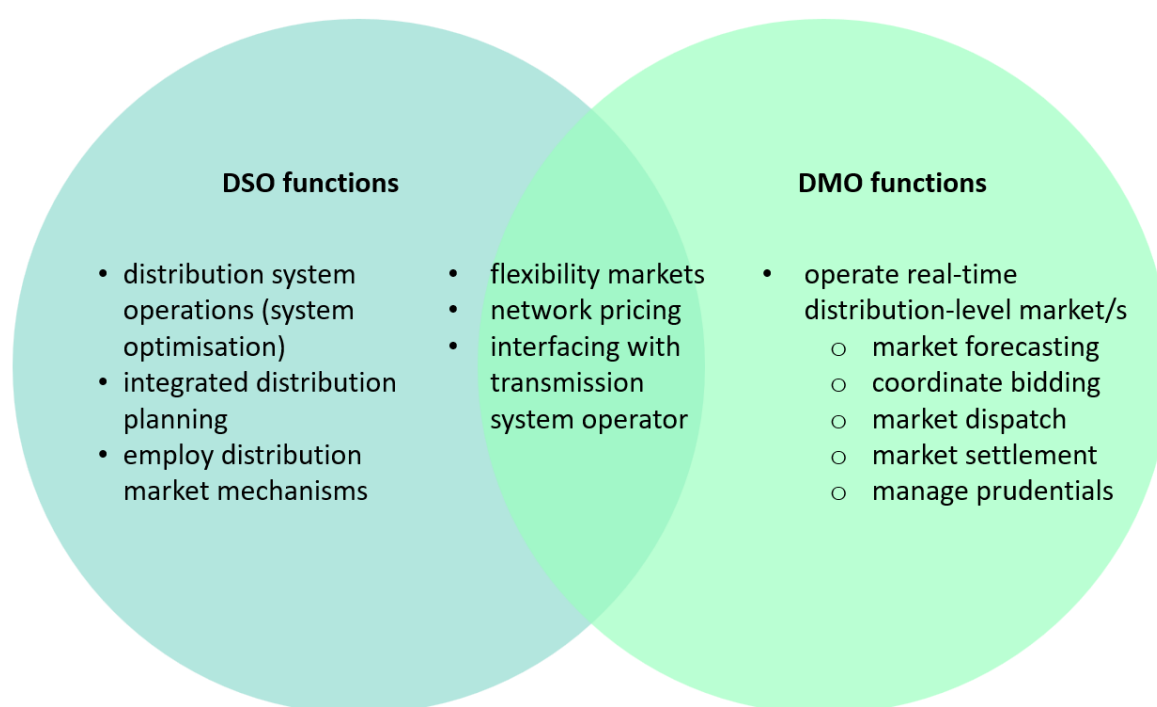
It is unclear the extent to which the issues identified can be fully addressed through the existing regulatory framework. It may be challenging achieve whole of system outcomes that require ongoing effort and adaptation through the existing regulatory framework. Regulatory requirements regarding standardisation may remain open to interpretation to an extent and difficult to enforce in practice.

There is also a risk that these reforms become 'set and forget' and do not drive ongoing improvement in the same way that could be achieved by establishing an entity with ongoing responsibility for these tasks.



## 5.5. A DMO is a distinct role from a DSO and their role depends on the market design

A DMO is a distinct role from a DSO. A DMO is responsible for market functions at the distribution level. This may primarily relate to operation of a real-time distribution level electricity market (if one were to be established), but could also extend to other market services such as flexibility markets or ancillary services at the distribution level. This includes the type of real-time energy market options discussed in Chapter 4, such as Options B and C. As there are no real-time markets at distribution level in the NEM, there is no DMO at this time. There is some overlap in the roles that a DMO and a DSO might perform as shown in Figure 12.



**Figure 12: Separation and overlap in DSO and DMO functions**

A DMO would undertake the functions involved in running a real-time market at the distribution level. These functions include:

- market forecasting and issuing notices and other information to participants
- receiving and processing bids from market participants
- scheduling and issuing dispatch instructions
- market settlement between market participants.

At the transmission level, AEMO is the TMO and operates the wholesale market which includes these functions.

In many international jurisdictions the DMO and DSO roles are undertaken by one entity, usually referred to as a 'DSO', but it is useful to consider the functions separately as they have different capability requirements and governance considerations. Separating the DMO and DSO functions is

consistent with the approach developed by ENA and AEMO under the Open Energy Networks project.<sup>87</sup>

### **5.5.1. Introduction of a real-time market would increase the need for an independent DSO/DMO**

A significant aspect of the DMO function relates to operating real-time, distribution-level energy markets. The need for the DMO function is therefore contingent on introduction of a real-time market such as Option B or C discussed in Chapter 4. While the DMO could also be responsible for managing other market platforms, such as for flexibility services, this function overlaps with DSO activities and could be undertaken by a DSO.

If a distribution-level real-time market were introduced, it would have a bearing on governance considerations. DMO activities are a substantive function, and the capabilities and systems required are largely distinct from DSO activities and functions currently undertaken by DNSPs.

If such a market were introduced an independent entity would likely be best placed to undertake DMO functions. The extent to which some or all DSO activities should be undertaken by this entity would need further consideration. In many of the international jurisdictions that have introduced independent DMO/DSO entities, the need for independent market functions has been a primary consideration in whether an independent entity is required.

## **5.6. The question is: what problem are we trying to solve? This will inform if and which governance arrangements are appropriate**

DNSPs currently perform DSO responsibilities alongside their DNO responsibilities. They are the natural entity to undertake them going forward, absent substantive institutional reform. A key consideration for this work program is whether DNSPs are best placed to undertake the DSO role into the future.

The actions proposed in chapter 3 would equip DNSPs and others with new information, tools and frameworks to improve how they perform their roles. If implemented, the actions set out in chapter 3 would lead to a world where DNSPs continue to play the role of DSO alongside their role of DNO, to organise unscheduled distribution-level resources through a range of off-market mechanisms (DOEs, DNPs, flexibility services) to achieve more effective distribution-level outcomes and deliver value to CER customers and customers more broadly. A range of participants would leverage DOEs, DNPs and flexibility service platforms to structure products and services to orchestrate CER and deliver value back to consumers.

The question explored in this chapter is whether we need different arrangements to govern how decisions about distribution system operations are made, would support better consumer outcomes than what the chapter 3 path offers. The options explored in this chapter are:

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<sup>87</sup> ENA, [Open Energy Networks Project, Energy Networks Australia Position Paper](#), 2020.





1. regulatory and/or accounting separation of DSO functions within a DNSP
2. move DSO functions to a new independent organisation
3. create a new entity responsible for consistency and coordination of systems and processes across DNSPs (a 'coordination and facilitation body')
4. pursue regulatory reform within the existing framework to address or mitigate the identified issues.

The answer depends on the problem that requires solving. The potential problems that have been identified with DNSPs playing the role of DSO are:

- lack of consistency in systems and processes across distribution regions
- lack of whole of system perspective
- preference for network solutions

No one solution can address all issues identified. It is also important to carefully consider the implementation challenges, complexities and costs of each reform option, as these are likely to be material.

We are seeking stakeholder views on both the problems considered to be most relevant when considering the institutional arrangements for DSOs in the NEM, and also views on the options explored.

## 5.7. Consultation questions

Referring to the discussion of governance options in chapter 5:

13. Do stakeholders agree with the potential issues we have identified when considering whether or not DNSPs can perform the role of DSO effectively? Which issues do you consider to be the highest priority to address?
14. When considering how best to integrate CER into the power system and market are the institutional arrangements that govern how decisions are made within a DSO a priority for you?
15. Noting the near-term, no-regrets actions identified in chapter 3 to improve the delivery of DSO functions under a high CER future, do you consider there is a need for an independent DSO in the future? If so, why?
16. Would you support further investigation of any of the other governance reform options, and if so, which one/s and why?
17. Are there governance reform options that we have not identified that should be considered?

