Government of Western Australia
Energy Policy WA

# DER Roadmap: DER Orchestration Roles & Responsibilities Information Paper

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Working together for a brighter energy future.

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# Contents


**Glossary** iv

**1. Executive summary** ....1
- 1.1 DER orchestration roles and responsibilities – our approach ....2
- 1.2 Key policy positions ....3
  - 1.2.1 Optimise distribution network access ....3
  - 1.2.2 Build required technology and market infrastructure ....3
  - 1.2.3 Align customer incentives and protect rights ....5
  - 1.2.4 Integrate and phase implementation ....5
- 1.3 Where next? The future evolution of DER participation ....6
- 1.4 Timeframes ....7

**2. Introduction** ....8
- 2.1 Background – the Distributed Energy Resources Roadmap ....8
- 2.2 Approach to issue identification and analysis ....9
  - 2.2.1 Stakeholder views ....10

**3. Background and context for Western Austalia** ....11
- 3.1 Trends ....11
- 3.2 Wholesale Electricity Market reform ....12
- 3.3 Review of the Reserve Capacity Mechanism ....14
- 3.4 Project Symphony ....14
- 3.5 DER value opportunities ....16

**4. Scenario analysis** ....17
- 4.1 Scenario analysis ....17
  - 4.1.1 Scenario 1: Low operational load ....17
  - 4.1.2 Scenario 2: Electric vehicle charging ....20
  - 4.1.3 Scenario 3: Grid resilience ....24
- 4.2 DER Orchestration ....25
- 4.3 Key issues ....27
  - 4.3.1 Optimise distribution network access ....27
  - 4.3.2 Build required technology and market infrastructure ....27
  - 4.3.3 Align customer incentives and protect rights ....30
  - 4.3.4 Integrate and phase implementation ....30

**5. DER orchestration roles and responsibilities issues** ....32
- 5.1 Optimise distribution network access ....32
  - 5.1.1 Distribution network visibility ....32
  - 5.1.2 Dynamic operating envelopes ....38
- 5.2 Build market and technology structure ....41
  - 5.2.1 Facility visibility ....41
  - 5.2.2 NSS procurement framework ....43
  - 5.2.3 Facilitate aggregator entry ....49
  - 5.2.4 Facilitation of WEM participation ....54
  - 5.2.5 Standardised protocols ....70

5.3 Align customer incentives and protect rights ....73
5.3.1 Tariffs....73
5.3.2 Customer protections ....75
5.4 Integrate and phase implementation....76
5.4.1 Coordination of WEM and NSS dispatch....76
5.4.2 Extending complexity as technology and knowledge evolves ....79
5.4.3 Timeframes ....81
**Appendix A. Issue summary....83**
**Appendix B. DSO and DMO functions....102**

## Tables

Table 1: Timeframes for DER Aggregation....7
Table 2: Visibility requirement by use case....36
Table 3: Facility class summary ....56
Table 4: FCESS summary ....61
Table 5: Examples of more complex approaches to NSS procurement and integrated dispatch...79
Table 6: Current actions for DER participation ....81
Table 7: Issue summary ....84

## Figures

Figure 1: Hybrid (DSO/DMO) model for the SWIS....5
Figure 2: Potential phases in the evolution of opportunities for DER participation ....6
Figure 3: BTM PV Capacity 2019/20 - 2030/31 ....11
Figure 4: BTM Battery Storage Capacity 2019/20 - 2030/31....12
Figure 5: EV uptake 2020/21 - 2030/21....12
Figure 6: New WEM ....13
Figure 7: New WEM services....13
Figure 8: Project Symphony Test Scenarios....15
Figure 9: Potential future evolution of opportunities for aggregated DER ....16
Figure 10: Incidence of coincident peak charging with 12% EV uptake....21
Figure 11: Incidence of coincident peak charging with 40% EV uptake....22
Figure 12: Orchestration issues ....26
Figure 13: Hybrid (DSO/DMO) model for the SWIS....31
Figure 14: Overview of existing Western Power low voltage network visibility....34

# Glossary

| Term | Definition |
|---|---|
| Active DER | DER that can be externally controlled by a third party to provide a response, often coordinated with other DER as part of a Virtual Power Plant (VPP). |
| AMI | Advanced Metering Infrastructure<br><br>AMI typically includes ‘smart meters’ (that measure bi-directional energy flows at a higher level of granularity than conventional meters), upgraded communications networks (to transmit large volumes of data), and requisite data management systems. |
| Behind the Meter (BTM) | Any technology located on the customer’s side of the customer-network meter. |
| Connection Point | Is defined in accordance with the *Electricity Networks Access Code 2004* as:<br><br>a point on a *covered network* identified in, or to be identified in, a contract for services as an *entry point* or *exit point*.<br><br>In effect, the connection point is where electricity is delivered to or sent out from a point on the network. Metering infrastructure is located at the connection point and identified via a National Meter Identifier (NMI). |
| Contestable Customer | Customers in the South West Interconnected System that consume greater than 50MWh of electricity per annum, who can choose their electricity retailer. |
| Demand Side Programme (DSP) | Under the WEM Rules, DSPs can register in the Reserve Capacity Mechanism (RCM) to provide demand-side management (reducing load) in peak periods to support the objectives of the RCM. |
| Distributed energy resources (DER) | DER are smaller–scale devices that can either use, generate, or store electricity and form a part of the local distribution system, which primarily serve homes and businesses. DER can include renewable generation, energy storage, electric vehicles (EVs), and technology to flexibly manage loads (such as water heaters or pool pumps) at the premises.<br><br>Generation or storage DER operate for the purpose of supplying all or a portion of the customer’s electrical load and may also be capable of supplying power into the system or alternatively providing a load management service for customers.<br><br>DER can also include front-of-meter small generation or storage located in lower-voltage parts of the network, below the |

| Term | Definition |
| --- | --- |
| | Transmission Node Identifier (TNI), that operate for commercial purposes. |
| Distribution Market Operator (DMO) | A market operator that is equipped to operate a market that includes small-scale devices aggregated and able to be dispatched at appropriate scale.<br>The DMO functions represent an expansion of AEMO's existing role as market operator of the Wholesale Electricity Market (WEM).<br>In this report the terms DMO and AEMO (in its role as market operator) are used interchangeably. |
| Distribution System Operator (DSO) | A Distribution System Operator (DSO) enables access to the network, securely operates and develops an active distribution system comprising networks, demand, and other flexible distributed energy resources (DER).<br>In this report the terms DSO, Western Power and Network Operator are used interchangeably as the functions of the DSO represent an expansion of Western Power's existing role as Network Operator. |
| Electrical Location | The zone substation at which the Transmission Loss Factor for a Registered Facility is defined. The zone substation is identified by a unique code called a TNI. |
| Emergency Solar Management (ESM) | Policy implemented to manage the low load problem via restrictions to BTM PV generation |
| Facility | Defined in the post-amended WEM Rules as:<br>• a transmission network;<br>• a distribution network;<br>• all Facility Technology Types[1] behind a network connection point or two or more such Facilities aggregated under clause 2.30 of the WEM Rules;<br>• Interruptible Load;<br>    • Demand Side Programme; or<br>    • Small Aggregation (see below). |
| Financially Responsible Market Participant (FRMP) | The WEM-registered Market Participant that is responsible for settling the energy at a connection point. |

[1] Non-Intermittent Generating Systems, Intermittent Generating Systems, Electric Storage Resources (storage), Loads, and in some cases embedded networks.

| Term | Definition |
| --- | --- |
| | In the WEM, retailers associated with the connection points of Contestable Customers are the FRMP for those connection points, while Synergy is the FRMP associated with the Notional Wholesale Meter and non-contestable customers. Some very large customers may be a FRMP in their own right |
| Frequency Co-optimised Essential System Services (FCESS) | Means an Essential System Service that is co-optimised with energy and is used to maintain power system frequency in accordance with the Frequency Operating Standards prescribed in the WEM Rules. It includes contingency, regulation, and rate-of-change of frequency (RoCoF) control services. |
| Front of the Meter (FTM) | Any infrastructure located on the distribution network side of the customer meter (i.e. not behind a customer meter, or BTM). FTM infrastructure is still metered, but it is not part of a customer site. |
| Hosting Capacity | DER hosting capacity is defined as the maximum amount of DER that can be connected to a distribution network (and the electricity system as a whole) without breaching technical limits. |
| Large Customer | A customer whose annual electricity consumption equals or exceeds 160MWh per annum. All Large Customers are Contestable Customers. |
| National Meter Identifier (NMI) | A unique 10- or 11-digit number used to identify a connection point (as defined in the Metering Code). |
| Network Support Service (NSS) | Service provided to the network operator to assist in maintaining stable and safe network operations.<br>In the context of this report, the term is used to refer to services provided by “non-poles and wires” or non-traditional assets to operate the distribution network as an alternative to standard planning and operational responses used by Western Power to operate its network to the safety, security, and reliability standards that it is subject to. |
| Non-Contestable Customer | Non-Contestable Customers are those customers on the SWIS who consume 50 MWh or less of electricity per annum. This group includes most households and small businesses in Western Australia. Synergy is the only electricity Retailer able to supply Non-Contestable Customers directly connected to the Western Power network. |
| Non-co-optimised Essential System Services (NCESS) | Means an Essential System Service that is not a Frequency Co-optimised Essential System Service. The WEM Rules provide for a flexible framework with appropriate governance and oversight from EPWA that enables AEMO and Western Power to procure ad-hoc Essential System Services as required under |

| Term | Definition |
| --- | --- |
| | defined trigger conditions. These services are not co-optimised with energy in dispatch. |
| Passive DER | Any DER that is not an Active DER (i.e. cannot be externally controlled by a third-party to provide a response). Passive DER may still change its behaviour autonomously in response to network conditions (such as a change in electrical frequency). |
| Post-amended WEM Rules | Amended rules that are to apply from New WEM Commencement Date (1 October 2023). |
| Power System Security and Reliability (PSSR) | Means the safe scheduling, operation, and control of the SWIS in accordance with the Power System Reliability Principles as set out in clause 3.3.3 of the WEM Rules. |
| Project Eagle | The Power System Security and Reliability legislative reform project initiated by Energy Policy WA to reform legislation governing the energy sector. This will provide legislative heads of power to bring the WEM Rules, Western Power's Technical Rules, and the *Electricity Networks Access Code 2004* (among other pieces of subsidiary legislation) into a single instrument. |
| Project Symphony | The DER orchestration pilot delivering Actions 22 and 23 of the DER Roadmap, scheduled to complete in July 2023. |
| Reserve Capacity Mechanism (RCM) | The mechanism set out in Chapter 4 of the WEM Rules to ensure the South-West Interconnected System (SWIS) has sufficient capacity available from supply and demand side resources to meet peak load and reliability requirements. |
| Site | A location at which one or more Distributed Energy Resources are located and which is delineated by one or more Connection Points. Multiple Sites can be aggregated into a Small Aggregation. |
| Small Aggregation | Defined in the post-amended WEM Rules as a group of Facilities that are distribution connected and located at the same Electrical Location.<br>This definition contemplates aggregated DER. |
| Small Use Customer | A customer whose annual electricity consumption is less than 160MWh per annum. Small Use Customers whose annual consumption is between 50MWh and 160MWh are Contestable Customers.<br>Small Use Customers whose annual consumption is below 50MWh are Non-Contestable Customers. |

| Term | Definition |
|---|---|
| SCADA | Supervisory Control and Data Acquisition, defined in the Technical Rules as equipment which enables the power system operator (AEMO) or the network service provider (Western Power) to monitor continuously and remotely, and to a limited extent control, the import or export of electricity from or to the power system. |
| SWIS | South West Interconnected System. The integrated power system in the south-west of Western Australia, extending from Kalbarri to the north, Albany to the south and Kalgoorlie to the east. |
| Virtual Power Plant (VPP) | VPPs are notional entities comprised of aggregated and managed DER components, which can provide generation, managed load (up or down), and system support functions and can participate in energy markets (like traditional generators).<br><br>Note, a VPP denotes a set of combined DER and capability across one or more Sites whereas a Small Aggregation is the registered WEM object that represents the aggregated Connection Points at those Sites. In effect, a registered Small Aggregation would comprise a VPP which in turn would comprise DER located at one or more Sites which are delineated by one or more Connection Points. |
| Volt-Watt response | Volt-Watt response mode reduces inverter power output when voltage levels rise above 250V. |
| Volt-Var response | Volt-Var response mode smooths grid voltages by using the customer’s inverter to absorb reactive power from the grid when voltage levels rise above 235V. When voltages fall below 220V, the Volt-Var mode will cause the customer’s inverter to produce reactive power to support the grid voltage. |
| Wholesale Energy Market (WEM) Rules | The WEM Rules detail the roles and functions of the Australian Energy Market Operator (AEMO) and other governance bodies, and guide the operation of the market including the trading and dispatch of energy, the Reserve Capacity Mechanism and settlement. |

Capitalised terms used in this report not included in the glossary above are as defined in the WEM Rules.

# 1. Executive summary

## The Distributed Energy Resources (DER) Roadmap

The Distributed Energy Resources (DER) Roadmap was released in April 2020 as a key part of the Western Australian Government's over-arching Energy Transformation Strategy. The Roadmap outlines a set of specific, time-bound actions to reach a future where DER owned by households and businesses, such as rooftop solar, energy storage, and controllable devices (such as water heaters, pool pumps, air-conditioners, and Electric Vehicles (EVs)) participate in the power system, for the benefit of all users.

Fundamental to the vision outlined in the DER Roadmap is that Virtual Power Plants (VPPs), comprised of household DER devices, can provide value to both customers and the power system. The DER Roadmap noted that enhanced DER participation in the power system was essential to enable households to continue to invest in rooftop solar, avoid or reduce expenditure on networks and other infrastructure, and maintain power system security and reliability.

## DER participation – Roadmap Actions 24 & 25

The 2019 Roadmap contained the following actions to develop the initial capability for DER participation in the power system:

| | |
|---|---|
| **Action 24** | By December 2020, develop a plan for the establishment of a DSO [Distribution System Operator] and DMO [Distribution Market Operator] in the SWIS [South West Interconnected System], including the identification of roles, functions, costs, and practical operations. This plan should include an assessment of the costs and benefits to the system for the establishment of these functions. |
| **Action 25** | By December 2020, identify legislation and regulatory framework requirements including timeframes for development and implementation to establish DSO and DMO functions. |

The roles of the Distribution System Operator (DSO) and Distribution Market Operator (DMO) are critical to enabling the secure and efficient orchestration and participation of aggregated DER in the power system. The functions of the DSO – as an extension of Western Power's current role – will require improved visibility and alternative methods for ensuring the secure management of a lower-voltage distribution system hosting increasing amounts of DER. The DMO – as an extension of the Australian Energy Market Operator's (AEMO) current role – will facilitate the formal participation of DER in the provision of system-wide services in the Wholesale Electricity Market (WEM).

## The energy transformation is evolving rapidly

The Energy Transformation Taskforce released an Issues Paper in August 2020 outlining provisional policy positions and key matters to be considered in progressing DER orchestration and participation, including Actions 24 and 25. However, the deferral of the new WEM commencement date (from 1 October 2022 to 1 October 2023) and delays in the commencement of Project Symphony (the State Government's flagship Virtual Power Plant [VPP) pilot), has prompted a review of timelines for multiple DER Roadmap actions focused on DER participation in the WEM, including Actions 24 and 25.

In the meantime, accelerated uptake of rooftop solar has necessitated the introduction of Emergency Solar Management (ESM) and export limits for larger rooftop solar systems to manage emerging risks to power system security. ESM and export limits will manage risks while the development of policy settings and frameworks for DER participation continues and implementation of facilitating WEM Rules and regulation changes as part of a phased approach.

This phased approach will reflect the costs and benefits of different modes of aggregated DER participation in the power system.

## 1.1 DER orchestration roles and responsibilities – our approach

Since the release of the August 2020 Issues Paper, Energy Policy WA (EPWA) has worked extensively with Western Power and AEMO to identify the key requirements and implementation pathways for the DSO and DMO functions in the South West Interconnected System (SWIS). This work, which confirms the policy positions and answers questions contained in the August 2020 Issues Paper, completes Actions 24 and 25 of the DER Roadmap and specifies many of the key policy positions required to support the future aggregation and participation of DER, thereby also progressing related DER Roadmap Actions 26-30.

Consistent with the August 2020 Issues Paper, matters considered in determining policy positions included that policy positions should:

- improve visibility of DER and the lower-voltage network;
- 'start off simple' in their implementation to obtain benefits at least cost; and
- recognise opportunities for ongoing evolution in technology and the energy sector.

### Key themes

Noting the key elements identified in the August 2020 Issues Paper and related stakeholder consultation, policy positions and discussion have been categorised into four key themes:

1. ***Optimise distribution network access***: including how DER participation can be facilitated through improved network visibility and DOEs;
2. ***Build required technology and market infrastructure***: including how new technology, market infrastructure, and WEM Rules development is required to facilitate improved DER participation;
3. ***Align customer incentives and protect rights***: including how end-consumer incentives and regulatory protections are required for improved DER participation in the power system; and
4. ***Integrate and phase implementation***: how aggregated DER can be coordinated and dispatched in various markets.

The policy positions and responses to questions contained in the Information Paper have been grouped into each of these themes, for ease of navigation.

### Approach to determining policy positions

Policy positions and questions relevant to DER orchestration roles and responsibilities have been categorised as being either 'settled or 'deferred'. Settled positions and questions are those where the Minister for Energy has adopted a policy position. Those that have been deferred have not yet been endorsed and are likely to require further information, such as through the Government flagship VPP pilot Project Symphony or the evolution of the market, prior to becoming settled.

Most of the policy matters contained in this Information Paper are those that were raised in the August 2020 Issues Paper. Policy positions and questions (both settled and deferred) are a function of current and anticipated technological maturity; visibility required within the DSO and DMO to facilitate orchestration; the legislative and market frameworks present and anticipated in the SWIS; and a pragmatic approach to seeking the best value for customers and the power system from DER aggregation.

Providing clarity regarding settled positions will enable the network and market operators, as well as energy market participants, potential new entrants, and prosumers to plan investment decisions. Policy positions will be reflected in the progressive implementation of changes to regulation and other instruments, such as the WEM Rules, and are expected to remain unchanged following the commencement of new WEM arrangements on 1 October 2023. However, there may be opportunities to revisit policy positions in the medium- to longer-term as technology and the market evolve.

## 1.2 Key policy positions

Key settled and deferred policy positions described in the Information Paper are briefly outlined below. A more detailed summary of policy positions is provided in the *DER Orchestration Roles and Responsibilities Information Paper: Summary*, with each issue, policy position, or question being provided an identifier for ease of stakeholder reference. Where appropriate, the relation of policy positions to DER Roadmap actions has been noted. Key policy issues grouped by theme, are described below.

### 1.2.1 Optimise distribution network access

#### Network visibility

Western Power requires a 'digitalised' distribution network in which low- and medium-voltage data is readily available to provide it with a more accurate understanding of hosting capacity and network capacity and inform network planning and operational responses.

Without digitalisation and the resulting improvements in network visibility, Western Power will be unable to identify distribution constraints at a granular level, and hence be unable to clearly specify network support requirements. Additionally, Western Power will need to make conservative assumptions about hosting and network capacity, which will result in DOEs that may not optimise DER access to the network (including for the purposes of WEM participation and reducing emissions in the electricity sector).

Western Power will develop, as a matter of priority, a forward-looking strategy and plan for investment in monitoring and communication capability to enable further digitalisation of the electricity network, focusing on the lower-voltage network. This was outlined under Action 14 in the DER Roadmap and is still being progressed by Western Power.

#### Dynamic Operating Envelopes

Dynamic limits to exports and imports in the lower-voltage network ('Dynamic Operating Envelopes' or DOEs) are critical to enabling the optimised use of network. In the absence of these dynamic limits, the ability of the grid to accommodate more rooftop solar will be reduced and the uptake of EVs will result in the need for costly network augmentation. Informed by the outcomes of Project Symphony and elsewhere, Western Power will develop a transparent methodology for setting and applying DOEs. DOEs will only be available to 'active' DER that is under the control of an Aggregator.

### 1.2.2 Build required technology and market infrastructure

#### Network Support Services

Network Support Services (NSS) are services provided by non-traditional assets (such as controllable generation and storage) to operate the distribution network. These services are an alternative to standard operational responses used by Western Power to operate its network to applicable safety, security, and reliability standards. NSS can be used by Western Power to defer and potentially avoid costly network augmentation, which is ultimately paid for by customers.

Western Power procurement of location specific NSS is incorporated into the new Non-Co-optimised Essential System Services (NCESS) framework in the WEM Rules, effectively harmonizing NSS procurement with the intent of the Alternative Investment Options process contained in the Electricity Networks Access Code 2004 (ENAC). Adjustments will be made to the ENAC to reflect the focus of procurement and NSS dispatch through the NCESS framework. To ensure the integrity of the procurement process for NSS, Western Power will not directly invest in energy storage to provide its own NSS and will not compete with aggregators for Small Use Customers (customers consuming less than 160 megawatt hours (MWh) per year). However, Western Power will be able to engage directly with larger customers at a single site (>160MWh per year).

## Aggregation

The policy settings for aggregation reflect the State Government's current electricity retail contestability policy, existing metering arrangements, and practical cost and technical limits to implementing multiple trading relationships.[2] They also reflect technical barriers to offering multiple services from a single customer connection point with existing infrastructure.

Synergy (the state-owned retailer) will be the sole aggregator for non-contestable customers (customers consuming less than 50MWh per year). Retailers of contestable customers will be able to aggregate DER across their customer base. This is consistent with the State Government's policy on electricity retail contestability and obligations on Synergy to provide ESM. However, Synergy may engage with third parties in a variety of ways to deliver services. This position will be reviewed in the longer-term as technical capability matures and bespoke customer protection frameworks are developed for aggregation services, such as through the State Government's planned Alternative Energy Services framework.

## WEM participation and Essential System Services

The technical standards and testing requirements specified in the WEM Rules and WEM Procedures regarding DER aggregation capability mean that, in practice, DER is not currently able to participate in the WEM in the provision of most services, despite there currently being no explicit regulatory barriers from them doing so.

Project Symphony will provide information on the current capability and cost of aggregated DER to provide Frequency Co-optimised Essential System Services (FCESS) in the WEM. As such, any changes to FCESS technical standards and accreditation required to leverage aggregated DER capability will be deferred until the capability of DER is established via the pilot. In the interim, VPPs may still form an Interruptible Load (to provide Contingency Reserve Raise under FCESS) and the RCM (noting that the RCM is currently under review by the Coordinator of Energy). AEMO may procure services from VPPs through the NCESS framework, including (but not limited to) services to maintain minimum load, address intermittent and DER volatility, and provide ramping.

Standardised protocols for communication and coordination of VPPs by AEMO and Western Power will be developed through Project Symphony.

2 The SWIS currently has a 'linear contracting relationship' model, whereby most end-use customers do not have a direct contractual relationship with Western Power. Instead, the end-use customer is contracted with their retailer, who is contracted with Western Power for their use of the network (including legal liabilities for damage). Most models for facilitating 'multiple trading relationships', where more than one WEM participant is responsible for energy flows at a connection point, would require a direct contracting relationship between the end-use customer and Western Power, introducing substantial additional regulatory complexity and additional risk born by customers.

### 1.2.3 Align customer incentives and protect rights

#### Tariffs and customer protections

Consideration of retail tariffs and other retail VPP/aggregation products (by which customers may be paid for providing services from their DER) is outside scope of the Information Paper. EPWA is separately progressing work on tariffs (network and retail) appropriate for a future with high levels of DER and DER aggregation. Appropriately designed retail electricity tariffs create the platform on which aggregation products may be designed.

Lessons learnt from Synergy's 'Midday Saver' time-of-use tariff pilot (which offers a low daytime rate coinciding with periods of high rooftop solar output), undertaken as part of DER Roadmap Actions 17 – 19, will inform new opt-in products for consumers.

The Alternative Electricity Services framework is currently under development, with protections to be provided through industry- and service-specific codes of conduct, including for Aggregators. Access to the Energy Ombudsman will also be facilitated for customers in VPPs.

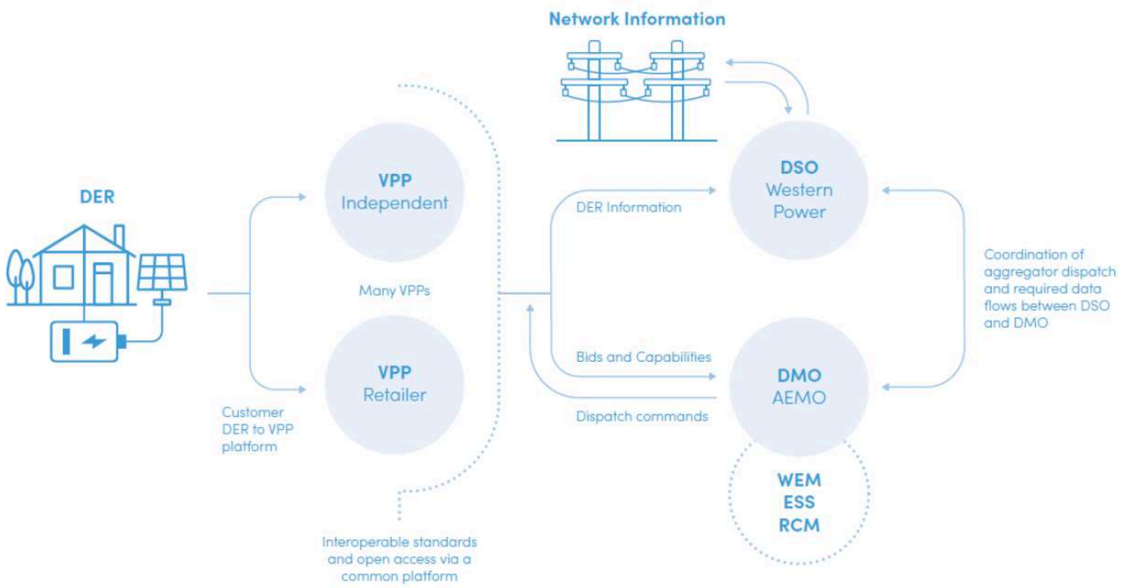
### 1.2.4 Integrate and phase implementation

#### Coordination of WEM and NSS dispatch

In future, orchestration of DER will see aggregators coordinating DER to value stack services such as energy, capacity, ESS and NSS (procured via the NCESS framework). Service provision across WEM and network services requires coordination between Western Power and AEMO to ensure all services are delivered while maintaining security and reliability requirements across the power system and the distribution network.

The 'Hybrid Model' for DSO and DMO functions, as outlined in the 2019 DER Roadmap, provides the most appropriate framework for coordinating functions in the SWIS and is outlined in Figure 1 below. Under the Hybrid Model, Western Power's role is extended to become the DSO, extending network management capability and visibility within the distribution network. AEMO is the DMO, which extends markets to include VPPs.

Figure 1: Hybrid (DSO/DMO) model for the SWIS




*Source: Issues Paper – DER Roadmap, April 2019*

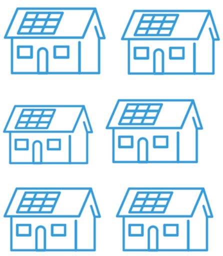
## 1.3 Where next? The future evolution of DER participation

Since the development of the DER Roadmap in 2019, there is now greater clarity about the likely evolution of DER participation. Based on lessons learned from local and national pilots and trials, it is not considered likely or desirable that DER orchestration and participation immediately commences with full integration with the WEM at new market start on 1 October 2023. Rather, there will be a glidepath over time commencing with highest value forms of participation, leveraging lower-risk technologies which can be implemented at lower costs. As such, there is a likely pathway for the development of full DER participation:

1. Aggregated DER will provide the highest net value services first, which includes high value services with less sophisticated (and expensive) orchestration requirements (which can be provided at a lower cost).
2. Services are expected to expand and evolve over time as control and measurement costs reduce and the WEM grows in depth and sophistication.
3. Services are likely to be 'stacked' as they develop, delivering value to customers, aggregators, and the power system as latent value in DER is realised.

Given the timing of the new market start, the review of the RCM and Project Symphony, as well as current value/aggregation cost trade-offs, it is likely that there will be a phased commencement of DER aggregation. This is uncertain but could follow the trajectory outlined in figure 2 below.

Figure 2: Potential phases in the evolution of opportunities for DER participation

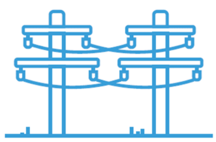


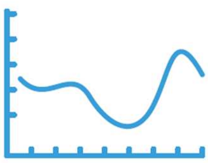
### 1: Retailer/Aggregator services

- 'Off market' services coordinated by retailer / aggregator to provide value to retailer, aggregator, or customer.
- e.g. managing DER to limit exposure to wholesale pricing extremes, allow commercial portfolio management, or customer energy optimisation.
- Does not require market registration.
- Some visibility needed by the system and network operators.

### 2: Network support & System support

- Non-Cooptimised Essential System Services (NCESS) provided to the:
  - network operator (Western Power/DSO); or
  - system operator (AEMO/DMO).
- Procurement under NCESS framework. e.g.:
- assist DSO manage local network peaks allowing network investment to be deferred or avoided, or;
- provide specific services related to power system security and reliability not current defined in the market.





### 3: WEM services

- Co-optimised WEM services (Wholesale energy, FCESS, Reserve Capacity).
- Will require DER to have higher levels of metering and telemetry capability to meet compliance and settlement obligations, dependent on the specific service provided.
- e.g. manage DER to offer demand response services or frequency support services alongside other market participants.

## 1.4 Timeframes

The timetable for implementing the DER participation actions within the DER Roadmap has been amended to reflect the dependencies for completing actions and status of work that will inform approaches to several issues. As discussed, above, two major dependencies include the implementation of new WEM arrangements on 1 October 2023 and the completion of relevant analysis from the outcomes of Project Symphony.

Table 1: Timeframes for DER Aggregation

| DER Roadmap Action | Date |
|---|---|
| **26.** By December 2023, finalise communications protocols, data, and technology requirements to accurately predict and publish operating constraints on the distribution network under a DSO, and requirements for coordination with the system operator. | December 2023 |
| **27a** By October 2023, implement initial changes to WEM Rules to enable development of DMO functionality and DER Aggregator participation in the WEM. | Oct 2023 – changes to basic participation model |
| **27b** By July 2025, commence implementation of changes to wholesale market arrangements necessary to enable the participation of DER in the wholesale market via a DER aggregator. | Jul 2025 – changes to wider participation model |
| **29** By July 2024, deliver a DSO / DMO legislative and regulatory framework, for transition to commencement by October 2025. | Jul 2024 – Oct 2025 |
| **30.** On 1 October 2025, DSO and DMO commencement with DER coordinated to provide services to the network and wholesale market and compensated appropriately. | Dec 2023 - Basic participation<br>Oct 2025 - Wider participation |

Updates on more detailed actions to develop and implement the settled policy positions, and progress on developing positions on deferred policy positions will be provided to external stakeholders via EPWA's DER Participation Stakeholder Forums.

Further work will be undertaken in consultation with stakeholders on the timeframes for developing these policy positions, with a detailed implementation plan to be released in mid-2022.

# 2. Introduction

## 2.1 Background – the Distributed Energy Resources Roadmap

The Distributed Energy Resources (DER) Roadmap, was endorsed by the Energy Transformation Taskforce in December 2019, providing a vision for the future role of DER in Western Australia's power systems. As part of this vision, the Roadmap set out high-level requirements to ensure:

- growing levels of DER can be safely and securely integrated into the SWIS, particularly within lower-voltage distribution networks; and
- households and businesses can continue to benefit from behind-the-meter (BTM) generation and other distributed technologies such as energy storage and Electric Vehicles (EV).

Particularly, the DER Roadmap recognised that DER integration requires:

- evolution of Western Power's and the AEMO's roles;
- the development and entry of aggregators to support orchestration of DER; and
- updates to regulatory and policy settings.

DER Roadmap Actions 24 and 25 intend to achieve the outcomes described above:

**Action 24:** Develop a plan for the establishment of a Distribution System Operator (DSO) and Distribution Market Operator (DMO) in the SWIS, including the identification of roles, functions, costs, and practical operations.

**Action 25:** Identify legislation and regulatory framework requirements including timeframes for development and implementation to establish DSO and DMO functions.

In August 2020, EPWA published an Issues Paper[3] (referred to hereafter as the August 2020 Issues Paper) that set-out a series of high-level policy issues and questions requiring confirmation and resolution to establish the roles and responsibilities of the DSO, DMO, and aggregators. The August 2020 Issues Paper also noted the importance of the DER orchestration pilot Project Symphony (Actions 22 and 23, DER Roadmap) in informing policy decisions pertaining to these roles.

Since August 2020, there have been several developments that affect how and when DER can participate in the provision of market and network services and consequentially the implementation of DSO, DMO and aggregator roles, including:

- the deferral of new WEM arrangements for 12 months, from 1 October 2022 to 1 October 2023;
- a 12-month extension to the completion for Project Symphony (now July 2023), pushing-back the time at which pilot outputs can inform policy, new WEM Rules, and changes to regulation;
- interim measures to manage short- to medium-term power system security risks have been introduced via new inverter standards and Emergency Solar Management (ESM) requirements, creating new capabilities for equipment and Synergy; and
- the Coordinator of Energy is conducting a review of the Reserve Capacity Mechanism (RCM) to ensure it is fit for purpose with respect to the broader energy transition.

[2] Issues Paper – DER Roadmap: Distributed Energy Resources Orchestration Roles and Responsibilities.

https://www.wa.gov.au/system/files/2020-08/Issues%20Paper%20-%20DER%20Roadmap%20%20Distributed%20Energy%20Resources%20Orchestration%20Roles%20and%20Responsibilities.pdf

Given the above developments, a re-examination of the policy issues and timing relating to DER orchestration and the roles of the DSO, DMO and aggregator is timely. EPWA engaged consultant (Robinson Bowmaker Paul) to assist it with progressing Actions 24 and 25 of the DER Roadmap by:

1. identifying policy issues that require resolution for Actions 24 and 25 to be implemented (considering the developments above);
2. recommending a preferred policy position for those issues identified above which require resolution; and
3. developing an action plan to implement resolved policy positions and to address deferred policy positions.

This Information Paper describes the Government's policy positions on a range of matters relevant to DER orchestration and provides a high-level action plan to implement Actions 24 and 25 of the DER Roadmap. It has also informed updates to the timing of actions 26 to 30 in the DER Roadmap. These updated timings will be reflected in the forthcoming *DER Roadmap Two-year Progress Report*.

As part of the implementation of these policy positions, EPWA will progress regulatory and legislative amendments required to effect policy positions that have been settled. Detail on those policy positions and their implementation will be consulted-on with feedback sought from stakeholders through public forums, similar to the approach used in the development of the WEM reforms progressed under the Energy Transformation Taskforce.[4] One of the first stages will be developing a timeline for the activities required to implement the regulatory and legislative amendments, and trigger points at which deferred issues should be revisited (with a view to resolving them).

## 2.2 Approach to issue identification and analysis

This Information Paper sets-out policy, technology and implementation issues related to orchestrating DER. The Information Paper also identifies issues that need to be addressed to orchestrate DER in the SWIS and establish the roles of the DSO, DMO and aggregator.

This paper builds on the August 2020 Issues Paper, which provided information, outlined provisional Government policy positions, and asked detailed questions on the following themes:

- Distribution NSS specification and procurement
- WEM participation
- Role of the aggregator
- Regulatory issues (network asset management, customer protections and tariffs)
- Market and technology integration

EPWA discussed issues under these themes in an extensive series of workshops with AEMO as the market operator and emerging DMO, and Western Power as the network operator and emerging DSO. The outcomes of these workshops are reflected in the policy positions contained within this Information Paper, as well as the identification of policy positions on which decisions need to be deferred, pending the outcome of related dependencies or other reform activities.

These policy positions (including where decisions needed to be deferred) were presented to stakeholders at a stakeholder session on 29 March 2022. The Information Paper reflects the feedback received from stakeholders prior to submission to the Minister for Energy for approval.

[4] WEM reforms under the Energy Transformation taskforce were consulted-on through the Transformation Design and Operation Working Group, a public forum which held nearly 30 meetings over the life of the Taskforce.

The confirmation of policy positions creates a foundation upon which more detailed policy development and implementation can occur over the next few years. It also enables the network and market operator, as well as energy market participants, potential new market entrants and prosumers, to plan and will help guide investment decisions.

These positions are considered finalised for the purposes of informing planning and implementation activities to be undertaken prior to the commencement of new WEM arrangements on 1 October 2023 and in the period immediately following market start.  However, positions may be revisited later as the market and technology evolves.

Many deferred positions will be informed by ongoing DER Roadmap implementation activities, such as Project Symphony, or will be informed by national programs of work, for example on standards. An action plan for developing positions on these issues will be developed and released in coming months.

### 2.2.1 Stakeholder views

Extensive workshops were held with Western Power and AEMO in the development of these policy positions. There is broad support between the parties for the positions outlined within this paper, although some differing views still exist on the timing of actions, particularly around network visibility and the establishment of DOEs.

A stakeholder session held on 29 March 2022 was attended by around 140 stakeholders. Participant response to the settled and deferred policy positions was positive. Most questions raised by stakeholders were of a technical nature, covering topics such as the future implementation of five-minute settlement, cyber security, and market fee allocation.

EPWA thanks the contribution of stakeholders to both this Information Paper and the preceding August 2020 Issues Paper. This input has assisted the development of positions which will remain both robust and flexible as the market and technology evolves.

# 3. Background and context for Western Austalia

The development of policy settings for DER aggregation (primarily through VPPs) is occurring at the same time DER installations and capability continues to trend upwards. The WEM is also undergoing the most significant reform since its creation, with a security-constrained economic dispatch design and new Essential System Services (ESS) being implemented from 1 October 2023. In parallel with the work in this Information Paper, Project Symphony (delivering actions 22 and 23 of the DER Roadmap) is piloting and testing aggregation services and will deliver significant insights and information to inform changes that are needed to embrace the potential of aggregated DER and to appropriately manage risks.

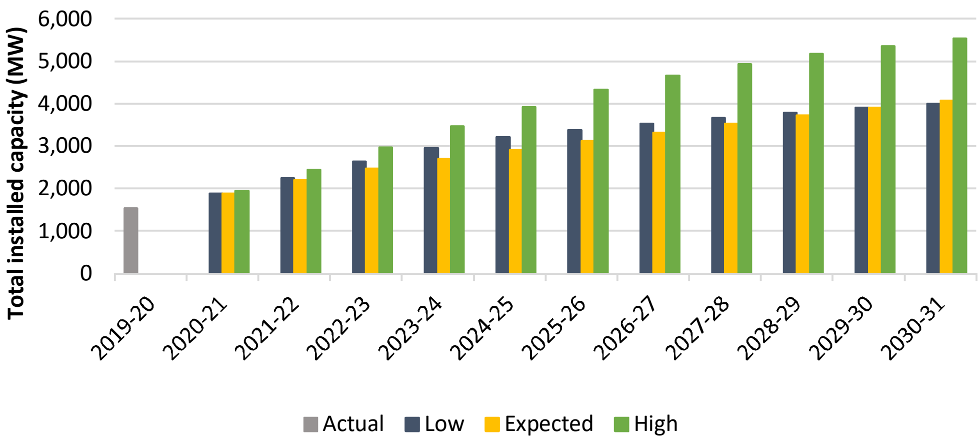
This chapter provides context on the interdependencies and external drivers for developing policy settings for DER participation explored in this report.

## 3.1 Trends

The Energy Transition underway in Western Australia is seeing an increasing number of prosumers installing DER devices. This includes both behind-the-meter generation devices such as rooftop solar and battery storage systems. Increasingly, it is expected that customers will also purchase EVs and install EV charging equipment, creating further opportunities and challenges for DER participation.

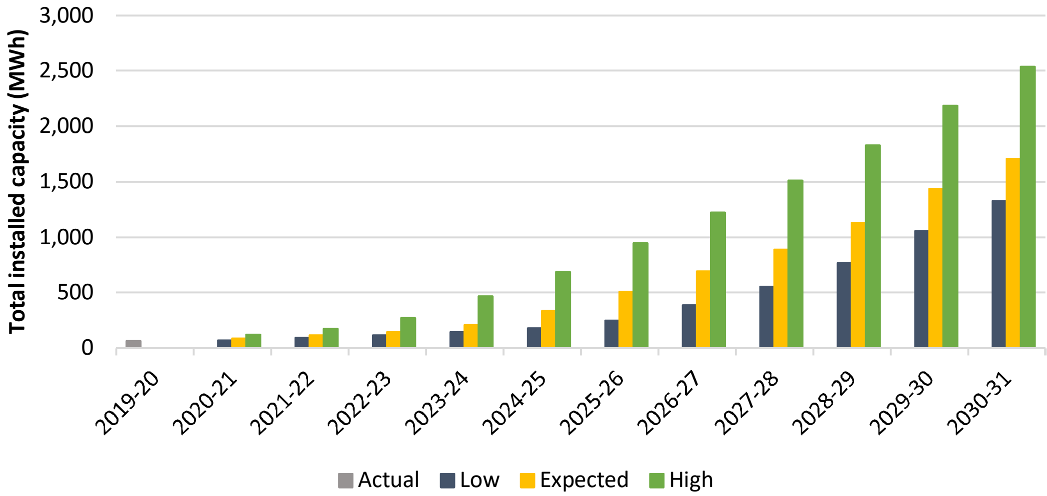
The uptake of DER is expected to continue to increase as technology prices fall. Figure 3, Figure 4 and Figure 5 respectively depict AEMO's projections of behind-the-meter rooftop solar, battery storage capacity, and EVs (respectively) over the next decade and are underlying assumptions informing the policy positions contained within this paper.

Figure 3: BTM PV Capacity 2019/20 - 2030/31



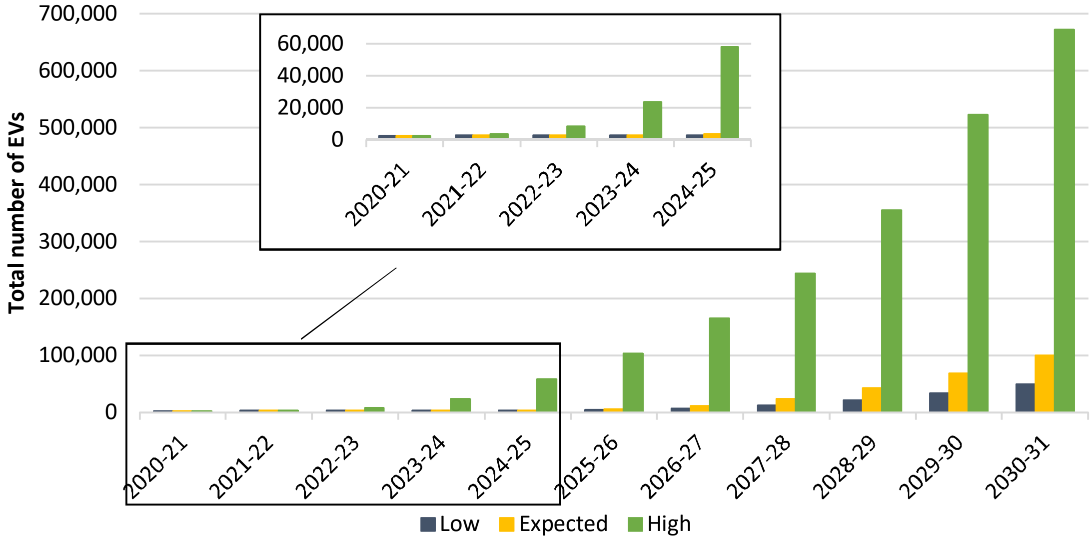

*Source: AEMO, 2021 WEM Electricity Statement of Opportunities*

Figure 4: BTM Battery Storage Capacity 2019/20 - 2030/31




*Source: AEMO, 2021 WEM Electricity Statement of Opportunities*

Figure 5: EV uptake 2020/21 - 2030/21




## 3.2 Wholesale Electricity Market reform

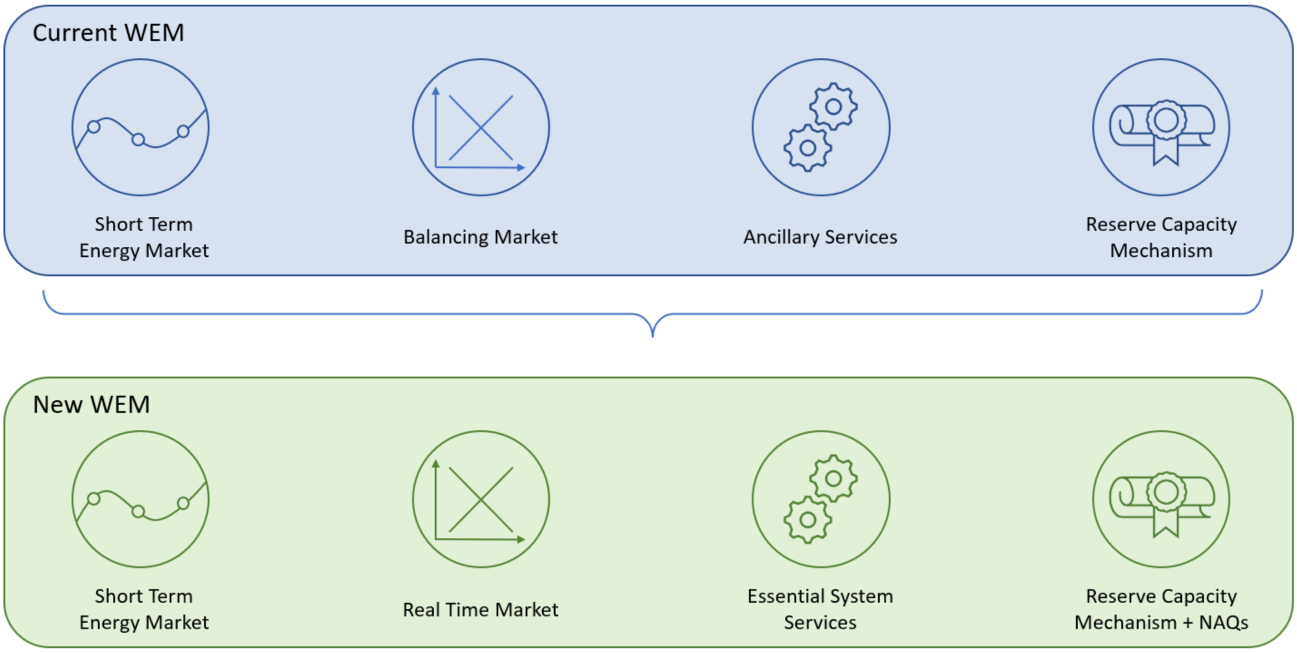
A new WEM design is being implemented in the SWIS as part of the State Government's Energy Transformation Strategy.

When the DER Roadmap was originally developed, new market arrangements were scheduled to commence on 1 October 2022. The date has since been revised to 1 October 2023 to reduce implementation risk, with consequential impact on the timing for some DER participation actions outlined in the DER Roadmap, including those relating to the provision of all WEM services by aggregated DER. To address challenges as they emerge and maintain power system security and reliability, the State Government will progressively implement greater DER participation in a phased manner to ensure that opportunities are unlocked as they become available. Section 5.4.3 provides more detail on amendments to timeframes for DER integration actions contained in the DER Roadmap.

Other items of note as part of the new market arrangements are:

- Synergy will no longer bid into the market as a portfolio. Each of its facilities will be bid and dispatched separately, like other independent power providers. This will include VPPs registering as facilities.
- Security-constrained economic dispatch (SCED) will be implemented which determines the most economic combination of generators to service demand while considering power system operation constraints.
- Co-optimisation between energy and ESS.

### Figure 6: New WEM




The new ESS framework being implemented on 1 October 2023 supports the integration of higher levels of non-synchronous renewable generation and other technologies in the power system. Over time, this will facilitate the decarbonisation of the power system as it transitions to the greater prevalence of renewable generation and storage.

### Figure 7: New WEM services

| Category | Current Ancillary Service | New Essential System Service | Procurement method |
|---|---|---|---|
| Frequency Control Services | Load Following Ancillary Service (LFAS) Up and Down | Regulation Raise and Lower | Markets |
| | Spinning Reserve Service (SR)<br>Load Rejection Reserve (LRR) | Contingency Reserve Raise<br>Contingency Reserve Lower | Markets |
| | | RoCoF Control Service | Markets |
| Locational and other services | Dispatch Support Service | Non-Co-optimised ESS | Contracts (off-market procurement) |
| | Network Control Service | | |

| | | | |
|---|---|---|---|
| | System Restart Service | System Restart Service | Contracts (off-market procurement) |
| Emergency Response | System management has powers to direct operations in emergency conditions (including dispatching ancillary services) | AEMO will retain powers to direct operations in emergency conditions | Emergency Directions |
| Scarcity Response | AEMO can procure additional Spinning Reserve Services | AEMO can trigger the Supplementary ESS Mechanism in case of shortfalls | Market/Contract |

## 3.3 Review of the Reserve Capacity Mechanism

The objective of the RCM is to assure the reliability of energy supply to the SWIS. In practice, this means ensuring that there is sufficient generation to meet peak electricity demand during warmer months.

Key features of the RCM in the post-amended WEM Rules include the following:

- Capacity is procured to meet the Reserve Capacity Requirement which is set using the Planning Criterion prescribed in the WEM Rules. This effectively requires AEMO to procure enough capacity to meet the larger of:
    - a one-in-ten-year peak demand forecast including a reserve margin plus an allowance for Regulation ESS and Intermittent Loads, and
    - sufficient capacity to limit expected unserved energy to 0.002% of annual demand.

The allocation of Certified Reserve Capacity depends on a resource's capability to generate during peak load intervals.

A review of the RCM is currently underway by the Coordinator of Energy to ensure that it remains fit for purpose given the transition to intermittent generation. The objective of the review is to develop an RCM that:

- achieves the system reliability at the most efficient cost for consumers for the current and the anticipated future system demand profiles;
- addresses the issues associated with the transformation of the energy sector (including the increase in DER in the SWIS); and
- accounts for any transitional issues associated with any changes to the RCM.

This review could have material changes to the participation of DER in the RCM (other than as a Demand Side Program [DSP]). Therefore, some decisions regarding DER participation will need to be deferred pending the results of the review.

## 3.4 Project Symphony

Project Symphony is the State Government's flagship DER orchestration pilot delivering actions 22 and 23 of the DER Roadmap. It has comprehensive technology and market interaction elements that will demonstrate end-to-end capability of aggregated DER in the SWIS, including its ability to respond in a coordinated manner under central dispatch instruction.

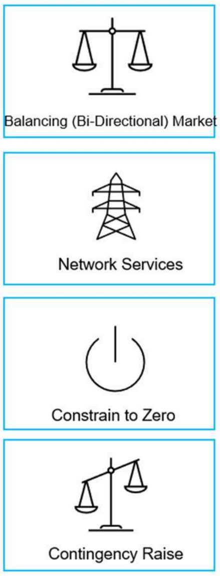
The pilot is focused in a small area of the Western Power network that has existing high levels of rooftop solar uptake and will also test the ability of VPPs to deliver NSS to Western Power.

Project Symphony is distinct from other VPP trials in that it will test DSO, DMO and aggregator platforms and the interaction between them. This includes the use of DOEs to simulate distribution network constraints that need to be applied by the aggregator. In turn, the aggregator will make market offers to the DMO within the bounds of the DOE. While market testing aspects are within a virtual ‘sandbox’ (that is, they are not part of a formal market process), the physical dispatch of customer DER is real to test visibility, control, and NSS delivery.

This will inform regulatory, technical compliance, and market rule changes that may be needed to facilitate greater levels of DER participation via virtual power plants.

The four main test scenarios within Project Symphony are outlined in the Figure below:

Figure 8: Project Symphony Test Scenarios




**Energy Services - Bi-Directional - Balancing Market Offer (BMO):** Offering (Sell) or bidding (Buy) energy into the balancing market, issuing, receiving & responding to dispatch instructions and settlement to determine the most economically efficient dispatch of generation to meet system electricity demand at a given time.

**Network Support Services:** a contracted service provided by a DER aggregator to help manage network constraints such as distribution level peak demand or reverse power flow and/or voltage issues as identified by the Distribution System Operator (DSO).

**Constrain to Zero:** AEMO dispatches an instruction to the Aggregator to constrain energy output from DER to zero export (net) or zero output (gross). This could be offered as a market service, or incorporated into normal dispatch arrangements if customers are remunerated appropriately.

**Essential System Services (ESS) Contingency Raise:** Market provision of a response to a locally detected frequency deviation to help restore frequency to an acceptable level in case of a contingency event (such as the loss of a large generator or load).

Learnings from Project Symphony provide numerous insights into the future development of DER aggregation and there are therefore several dependencies for the issues outlined in this paper. Outcomes from Project Symphony will be used to provide practical insights and inform specific future policy settings including:

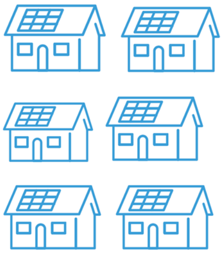
- the nature and extent of network visibility requirements;
- potential technological solutions to enable Facility visibility;
- visibility requirements sufficient for dispatch compliance monitoring purposes and for forecasting the generation of Non-Scheduled Facilities;
- the ability of aggregated DER to provide Contingency Reserve services;
- the nature and extent of network visibility requirements;
- the framework for DOEs including development and implementation, trade-offs, reporting, incentives, and regulatory requirements;
- the need for any changes to technical specifications to the post-amended WEM Rules or Procedures pertaining to Frequency Co-optimised ESS (FCESS) provision;
- default behaviour and redundancy requirements; and
- the most appropriate party to allocate NSS dispatch responsibility.

Delays in negotiating completing a funding agreement with ARENA meant that the Project Symphony was not able to kick off in earnest until early 2021. To ensure sufficient time is given for testing the project end date has been extended until Mid-2023. A decision on several policy settings will be delayed pending an evaluation of Project Symphony findings.

## 3.5 DER value opportunities

A vision for the full participation of DER in the power system, including in wholesale markets and services, is outlined in the DER Roadmap. Rather than an immediate transition, reaching this end state will require evolution over time. Figure 9, below, presents a likely pathway to full participation in the SWIS by aggregated DER and the likely order in which that value will be realised as technical capability, regulation and scale improve and evolve over time.

Figure 9: Potential future evolution of opportunities for aggregated DER

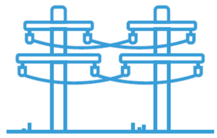


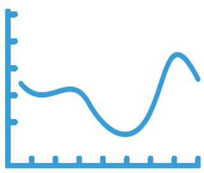
**1: Retailer/Aggregator services**

- 'Off market' services coordinated by retailer / aggregator to provide value to retailer, aggregator, or customer.
- e.g. managing DER to limit exposure to wholesale pricing extremes, allow commercial portfolio management, or customer energy optimisation.
- Does not require market registration.
- Some visibility needed by the system and network operators.

**2: Network support & System support**

- Non-Cooptimised Essential System Services (NCESS) provided to the:
  - network operator (Western Power/DSO); or
  - system operator (AEMO/DMO).
- Procurement under NCESS framework. e.g.:
- assist DSO manage local network peaks allowing network investment to be deferred or avoided, or;
- provide specific services related to power system security and reliability not current defined in the market.





**3: WEM services**

- Co-optimised WEM services (Wholesale energy, FCESS, Reserve Capacity).
- Will require DER have higher levels of metering and telemetry capability to meet compliance and settlement obligations, dependent on the specific service provided.
- e.g. manage DER to offer demand response services or frequency support services alongside other market participants.

# 4. Scenario analysis

This section details some example cases for the SWIS that highlight the benefits of DER orchestration and the risks of continuing under the status quo where DER is passive and not able to respond to the needs of the broader power system.

## 4.1 Scenario analysis

The use cases for DER orchestration and participation are compelling. If implemented, they will enable the continued integration of intermittent renewable energy within the power system at least cost. Scenarios around low load, EV integration, and grid resilience are presented below. The requirements for effective DER aggregation and participation are outlined in each scenario.

### 4.1.1 Scenario 1: Low operational load

More than 400,000 Western Australian homes and business (or around one third of customers) have rooftop solar connected to the SWIS network. In 2021 alone, over 350MW[5] of distributed rooftop solar was added, bringing total capacity in the SWIS to around 1,800MW. This means that the total capacity of rooftop solar is now more than double the capacity of Western Australia's largest power station - Synergy's coal-fired 854MW Muja Power Station.

The high level of rooftop solar penetration has led to the 'low load' problem on mild sunny days when air-conditioning load is low and solar output is high. In some instances, the operational load on the SWIS drops to a level where AEMO considers the power system to be at a heightened risk. AEMO currently considers this level of minimum load to be around 600MW[6], depending on power system conditions and generator availability.

ESM, introduced in February 2022, provides a 'last resort' tool to address the risk posed by low load conditions by enabling AEMO to direct Western Power to maintain the operational load at a secure level. Western Power can then direct Synergy to provide an ESM response from its portfolio of distributed rooftop solar systems that can be controlled via ESM capability. Initially, ESM applies only to Synergy's residential customers with systems smaller than 5kW in capacity. Consideration will be given in future to extending ESM to other groups of customers. Such consideration will only be taken following appropriate stakeholder consultation.

The cost-effective technology solutions available at the commencement of ESM result in rooftop solar systems being prevented from generating. In future, improvements in technology are likely to enable customers to still be able generate from their rooftop solar systems to meet their own behind-the-meter loads, while exports are effectively reduced to zero (sometimes referred-to as 'net zero export'). This functionality will depend on the availability of cost-effective technical capability, adequate availability of ESM-enabled rooftop solar capacity, and minimum demand threshold requirements identified by AEMO when ESM is called upon.

With the uptake of rooftop solar expected to continue at current rates, the frequency of low load events placing the power system at heightened risk is forecast to increase, and the level of operational demand is forecast to continue to fall. The more frequent these low load events, and the lower the level of power system demand, the more often and the greater the volume of

[5] https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en

[6] Operational demand below these levels can lead to adverse outcomes such as (but not limited to) insufficient ESS facilities committed to prevent an Under Frequency Load Shedding event and issues with transmission network voltage management. See also AEMO's September 2021 paper *Renewable Energy Integration Report – SWIS Update* (https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf?la=en).

distributed rooftop solar that will need to be curtailed via the ESM to maintain operational load at a secure level.

The mandatory requirement on new and upgraded residential rooftop solar systems smaller than 5kW in capacity to cease generation or export is a relatively blunt instrument and is considered among last resort measures to keep the system from blackouts. EPWA, in collaboration with AEMO and Western Power, is leading a project focused on the challenge of low load to identify and implement other measures in the short- and medium-term to reduce the frequency and extent to which ESM will be required in future.

The DER Roadmap identified low load as a risk and outlines the vision for a longer-term future where DER can be controlled and coordinated, allowing access to a wider variety of options both addressing the low load problem and providing value to customers and others:

- In periods of low operational demand and negative prices, controllable DER (especially batteries) will be enabled to provide load in the WEM, responding to price signals by increasing demand (e.g. charging or increasing charging rate). Demand-side resources such as storage and devices such as air conditioning, water heating, pool pumps, and EVs will respond to negative or lower-priced trading intervals in the WEM, increasing the net benefits of the market.
- If sufficient demand is forecast to not be available to respond and maintain operational demand at a secure level, AEMO may trigger procurement of services through the NCESS mechanism to activate a demand response. An aggregator could provide such services by control of DER such as pool pumps, air conditioners and EVs to increase load or decrease energy output from distributed rooftop solar.
- If price signals and available NCESS contracts are insufficient to restore operational demand to a secure level, ESM will remain in place as a last resort measure.

As a result of building opt-in market services and enabling price signals to better reflect underlying wholesale energy costs:

- fewer customers who prefer not to participate actively will likely be adversely affected as often through mandatory curtailment;
- customers choosing to opt-in to provide a demand response can be better off financially through:
  - limiting the amount of uncompensated rooftop solar curtailment and being able to continue to self-supply when exports are limited; and
  - optimising electricity usage by maximising self-consumption and shifting charging of EVs and other devices to low load times, which are generally coincident with low, or even negative, wholesale prices; and
- retailer/aggregators, including Synergy for non-contestable customers, will have more tools to manage solar exports, manage load and minimise exposure to negative prices in the Real Time Market in the WEM that result from oversupply of energy in the system.

These outcomes will be achieved via the implementation of varying actions over multiple time scales:

- ***In the short term***, pending full participation of DER in the WEM, the NCESS mechanism (which commenced on 1 February 2022) enables AEMO to undertake procurement where a demonstrated power system security or reliability risk exists that is not able to be met from FCESS. In addition, it enables AEMO to tailor registration, participation, and visibility requirements through NCESS contract conditions. This can enable DER to participate in the short term (although NCESS procurement would be technologically agnostic) and provide required services without requiring complex (and in the short-term, unnecessary) changes to existing WEM registration, monitoring, and compliance frameworks. This is not intended to force DER into the market, to bypass or disadvantage providers of existing or planned WEM services, but to facilitate appropriate and cost-effective use of DER resources during a time of rapid technology evolution.
- ***In the medium- to longer-term***, appropriate communications, control and metering infrastructure will be required to ensure DER can register in the WEM to provide more dispatchable energy and respond to low and negative price signals, thereby potentially reducing the need to procure a low load product via NCESS. DER capability is also anticipated to improve, mitigating, or removing the need to adjust FCESS registration and compliance requirements.

Further work is required to better understand costs and benefits for all parties of achieving higher levels of visibility deep in the lower-voltage distribution network so that an appropriate level of investment can be made. Project Symphony will inform visibility and capability requirements to some extent. Additionally, changes implemented by Western Power to improve operational visibility of the low voltage network to facilitate NSS deployment (see Scenario 2 below) can be leveraged to provide the Facility-level visibility and five-minute metering requirements required for WEM participation; the latter will be to facilitate five-minute settlement.

Allowing increasing distributed rooftop solar uptake with no changes to the frameworks under which they operate or requirements for aggregation and participation in the power system means that, over time, more and more households will experience emergency curtailment more often. The ability to coordinate DER and activate demand response to consume excess rooftop solar generation will drive fewer mandatory curtailment events and incentivise efficient resource allocation. A prerequisite to such coordination will be investment in improving network visibility, as this will enable optimised allocation of network capacity to DER (including via the use of DOEs), facilitate participation of VPPs, and, in the future, allow aggregators to dispatch energy and demand in response to price signals – enabling pool pumps, stationary battery EV (vehicle-to-load and vehicle-to-grid) and charging and discharging, etc to flatten the operational load curve.

## 4.1.2 Scenario 2: Electric vehicle charging

The share of EVs within the Western Australian vehicle fleet is expected to grow significantly over the next 10-20 years. Most major car manufacturers have announced carbon neutrality targets and ambitious EV targets. This includes manufacturers General Motors and Volvo targeting to sell only EVs in some countries by 2035 and 2030 respectively. Toyota plans to have 70 electrified models available by 2025, 15 of them being battery EVs (as opposed to hybrid vehicles).[7] Further, AEMO forecasts 99,435 EVs (5% of all cars) in Western Australia by 2030 under its 'expected' scenario and 672,230 (35% of cars) under its high scenario.[8] The 'Techtopia' scenario in the 2020 Whole of System Plan (WOSP) assumes that 12% of vehicles will be EVs by 2030, equating to 231,000 EVs. The variation is estimate highlights the significant uncertainty around uptake rates for the SWIS.

The lower-voltage distribution network has been built based on historical assumptions about load profiles and patterns of usage. Specifically, network capacity is delivered to the low voltage network based on a notional import/export limit of 4.7 kilovolt amps (kVA) for single phase connections, reflecting the 'After Diversity Maximum Demand' (ADMD);[9] this is based on the following three assumptions:

1. The daily representative profile of customer load will remain somewhat predictable over time (based on historical usage patterns). Historically, this was true due to one-way power flow, low levels of embedded generation, and negligible electrification of transport. Hence, visibility of the state of the low voltage network (e.g. active/reactive power, voltage, current, etc.) was not required to predict network needs or manage the network in the same way as the medium and high voltage networks.
2. The actual physical capacity of each connection is rarely used. This assumption does not consider large-scale electrification of transport, water heating, and cooking.
3. Peak network use of individual connections is not simultaneous. As above, this assumption does not consider large-scale electrification.

The projected uptake of EVs, even using conservative assumptions, will render the above assumptions obsolete, resulting in overloaded network assets if not addressed.

The below analysis is based on Western Power's EV modelling using the WOSP 2020 Techtopia scenario and illustrates the potential impact of EV uptake on low voltage feeders.

In this example, there are 10 metered connections with 17 vehicles,[10] of which 2 are EVs (based on an assumption that 12% of cars will be EV by 2030); 20% of the connections have EV, and there is a 20% chance that connections will be charging using 'Level 2' charging equipment[11] coincidentally at peak times.

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[7] Forbes Magazine, *Every Auto-makers EV Plans Through 2035 and Beyond*, available at: https://www.forbes.com/wheels/news/automaker-ev-plans/

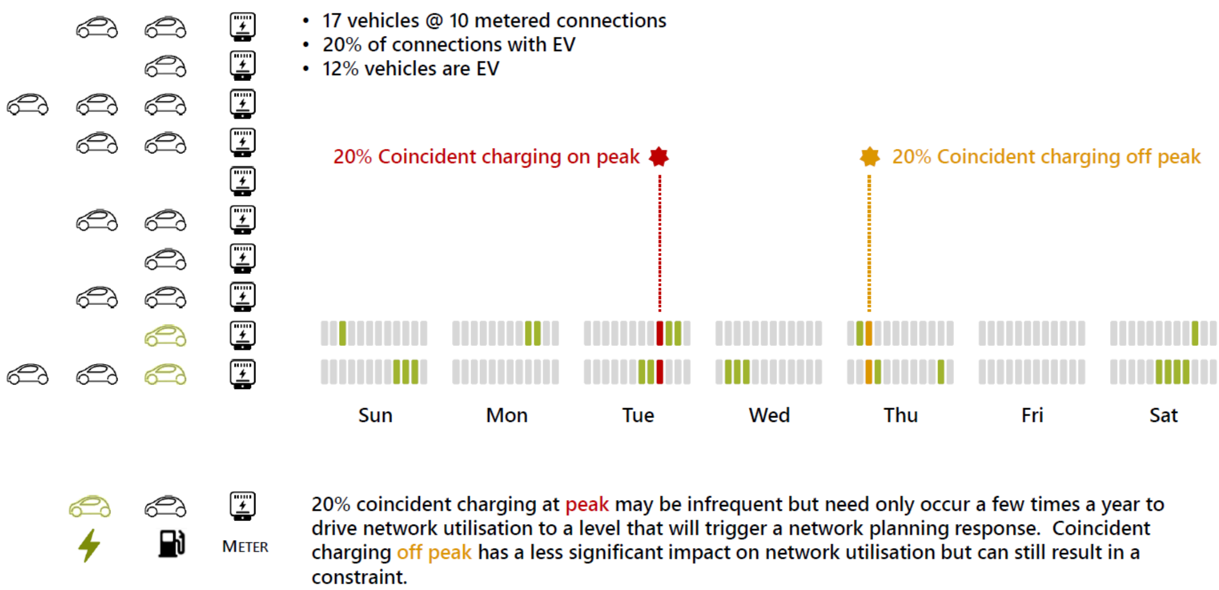
[8] AEMO, *2021 WEM Electricity Statement of Opportunities*, p. 45, available at: https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2021/2021-wholesale-electricity-market-electricity-statement-of-opportunities.pdf

[9] ADMD is a calculation used in the design of electricity distribution networks where forecast demand is aggregated over many customers. ADMD accounts for the coincident peak load a network (or part of a network) is likely to experience over its lifetime.

[10] Assuming 1.7 cars per household, consistent with the 2016 Australian Census.

[11] 'Level 2' charging equipment has both higher Amp and Watt ratings and can charge an EV up to ten times faster than connecting the EV to a 10 Amp walls socket.

Figure 10: Incidence of coincident peak charging with 12% EV uptake




*Source: Western Power analysis*

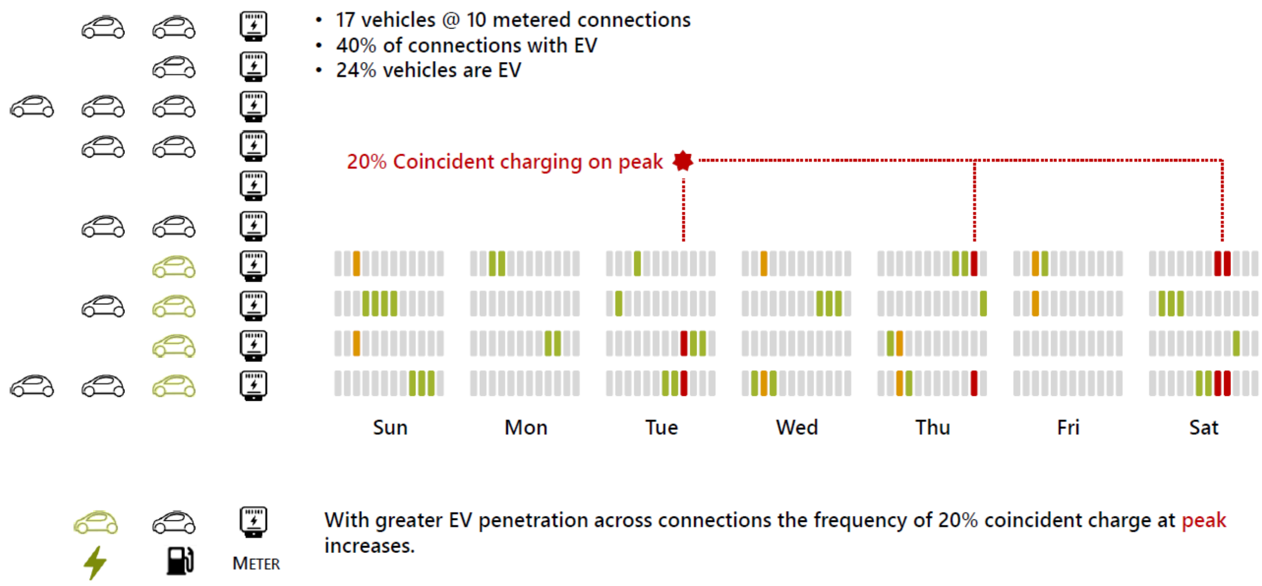
Western Power's analysis[12] indicates that 20% coincident charging at peak may be infrequent, but only needs to occur a few times a year to trigger a potentially costly network planning response (i.e. network augmentation or an alternative option). In fact, Western Power estimates that 10% of households charging an EV at peak times in geographically small areas would be required before these issues could reach a severity requiring widespread network augmentation.[13]

Unsurprisingly, with greater EV penetration, the frequency of 20% coincident charging at peak also increases.

[12] This analysis is preliminary and further understanding of the scale of impact due to coincident peak charging will be better understood on completion of Action 1 of the Western Australian *EV Action Plan*.

[13] *Electric Vehicle Action Plan: Preparing Western Australia's Electricity System for EVs*, August 2021. Available at: https://www.wa.gov.au/government/publications/electric-vehicle-action-plan-preparing-was-electricity-system-evs

Figure 11: Incidence of coincident peak charging with 40% EV uptake




*Source: Western Power analysis*

The above analysis assumes that EV uptake is uniform across feeders and low voltage networks with no geographic concentration due to economic factors. However, data shows that older suburbs currently have the highest numbers of EVs and are likely to continue to lead uptake due to higher-than-average incomes and observed customer preferences.[14] This means that thermal constraint breaches on the network may manifest earlier than 2030 in some suburbs due to geographically varying EV uptake rates. Of particular concern are those suburbs that are served by medium voltage (11kV or 22kV) overhead network feeders. Western Power notes that at sufficient EV uptake level, network constraints would also present challenges on other types of medium-voltage feeder.

Without the ability to actively adjust the charging behaviour of EVs via control and coordination of external or onboard charging, the options available are:

- Invest in a more robust electricity network. Preliminary modelling has indicated that under an EV uptake scenario of 15% customer base with 1 EV per household charging during peak period, more than $1 billion worth of network investment would be required in the SWIS to facilitate unmanaged charging; or
- Restrict consumption related to EV charging passively by:
  - Encouraging off-peak charging through time of use retail tariffs; and/or
  - Placing limits on the size and type of chargers that people can install in houses[15].

Restrictions on consumption are likely to deter the uptake of EVs, drive unwanted consumption patterns, and impact adversely on the utility of customers with EVs.

In a future where DER can be actively managed and coordinated, DER participation can be used to shift charging to periods of low demand or relying on local resources to prevent overloading of low voltage feeders. Western Power (as the DSO) would procure localised NSS (via the NCESS

[14] Electric Vehicle Action Plan: Preparing Western Australia's Electricity System for EVs. August 2021. https://www.wa.gov.au/government/publications/electric-vehicle-action-plan-preparing-was-electricity-system-evs

[15] Such restrictions may be made harder to police and relatively simple for customers to get around by using three-phase 15amp sockets and portable charging devices. Caution needs to be taken in the approach used to prevent this outcome.

framework) from aggregators who coordinate DER to manage behind-the-meter resources in congested areas of the low voltage network.

To enable the capability required to reduce augmentation costs:

- The DSO would have to develop DOEs as a means of allocating available network capacity. DOEs would need to be developed for both import and export at a connection point. To do this properly, the DSO will require adequate visibility in the low voltage network to understand what the hosting capacity is (in as near to real-time as is practical and cost-effective), and to be able to allocate spare capacity in the most optimal manner that is practicably possible.
- Clear specifications for constraint management services (procured under the NCESS framework) need to be in place to facilitate efficient procurement. This will require planning-level visibility in the lower-voltage network so that constraints can be identified ahead of time within planning timeframes (as opposed to operational timeframes, which are much shorter), with clear signalling to aggregators on what services will be required.
- Real or near real-time monitoring capability would have to exist to enable the DSO to determine when to trigger an NSS (i.e. operational timescales) and whether the service has been delivered in accordance with the relevant NCESS contract. This will require operational visibility in the lower-voltage network, so that large quantities of data that can be transmitted at frequent intervals, managed by the DSO's back-office data management systems, and made available for network operation.

The key dependency identified above is that adequate visibility (or access to usage and other data) exists in the low voltage network. Without appropriate investment in visibility, Western Power will not have access to the data it needs to accurately identify the constraints it needs to manage at the lower-voltage network. Consequently, while it may be able to identify the nature of an NSS that is needed on a planning timescale, it will not be able to identify when it is required on an operational timescale, to defer material network augmentation.

While the new meters being installed as part of Western Power's Advanced Metering Infrastructure (AMI) rollout can read five-minute usage and power quality data (and are potentially configurable to gather more granular data), it is currently unclear:

- whether Western Power's end-to-end communications network can transport the large quantity of data required to its head-end systems;
- whether Western Power's back-office systems can process the increasing volumes of data above; and
- what the costs associated with any improvements are to bring this capability at scale.

Without action now, EVs could, by 2030, pose a threat to the security of the power system similar in scale to that now being addressed because of the rapid uptake of rooftop solar systems since 2012. The key action required to address this problem is further 'digitalisation' of the distribution network to obtain and use the massive volumes of data about network use and performance that is available. Appropriate investment in digitalisation to record, transmit, and use data is a key enabler to allowing more EVs to connect to the network while avoiding significant network augmentation by 2030.

### 4.1.3 Scenario 3: Grid resilience

In extreme weather scenarios, power can be lost to low voltage networks because of equipment damage due to fires, damage to network infrastructure, or protection mechanisms tripping due to heat.

A recent example of extreme weather conditions impacting on electricity supply in the distribution network was the recent Christmas 2021 outages, when thousands of homes were left without power during a heatwave which saw five consecutive days of temperatures above 40 degrees.[16]

The resulting loss of supply can result in material economic loss as well as loss of customer utility and wellbeing. For some customers interruption of power supply can even be life-threatening.

A resilient and smart distribution network is characterised by:

- *Operational visibility* (availability of usage and power quality data) in the lower-voltage network so that potential failures can be forecast in advance and acted on. Improved visibility also facilitates faster repair and recovery after extreme weather events have occurred by enabling network operators to detect where faults have occurred. As noted in Scenario 2, there is limited operational visibility in the SWIS low voltage network.
- *Control and coordination capability* of local DER to provide supply while networks are repaired and restored (the UK flexibility market, for example, includes this type of service). To attract a deep pool of providers with DER in diverse locations, aggregators will require information on potential opportunities so that they can make the relevant investments. To facilitate this, the DSO would need planning visibility of the distribution network to identify the potential for network restoration services.

Extreme weather events are forecast to become more frequent in future[17], with more bushfires and storms increasing the risk of damage to networks and power supply interruptions. The increasing importance of electricity to day-to-day household and business activities, particularly transport, makes a resilient power supply even more important.

As with Scenario 2, the precedent condition and key action required to ensure a smart and resilient network as described above is investment in the digitalisation of the distribution network to improve network visibility.

[16] https://www.wa.gov.au/government/publications/independent-review-of-christmas-2021-power-outages-final-report.

[17] http://www.bom.gov.au/state-of-the-climate/documents/State-of-the-Climate-2020.pdf

## 4.2 DER Orchestration

The underlying theme demonstrated in the scenarios above is that there are two potential futures:

1. A future without change in which threats to power system and network security will have to be increasingly managed via restrictive measures such as connection restrictions, curtailment of network use and wholesale market interventions; and where additional traditional network investment will be required to respond to electrification and uptake of DER, thereby increasing network and customer costs; or
2. A future in which DER is actively managed and coordinated to alleviate the threats to power system and network security by optimising the behaviour of DER to deliver benefits to the system and network, and ultimately the end-consumer. This coordination of DER (in particular, exploiting the flexibility of these resources) to optimise system and market outcomes is referred to as orchestration.

A future with orchestration of DER requires a multi-faceted approach, including optimising access to the distribution network to ensure network capacity is allocated as efficiently and equitably as possible, so that:

- more DER can connect (noting that the extent of orchestration will depend on the pool of capable DER in the right location that aggregators can access); and
- customer utility is maximised as flexible DER is used to:
  - facilitate access to cheaper, low emission energy (e.g. Scenario 1);
  - facilitate access to the network (e.g. charge EVs, see Scenario 2); and
  - ensure reliable supply even during periods of system stress (see Scenario 3).

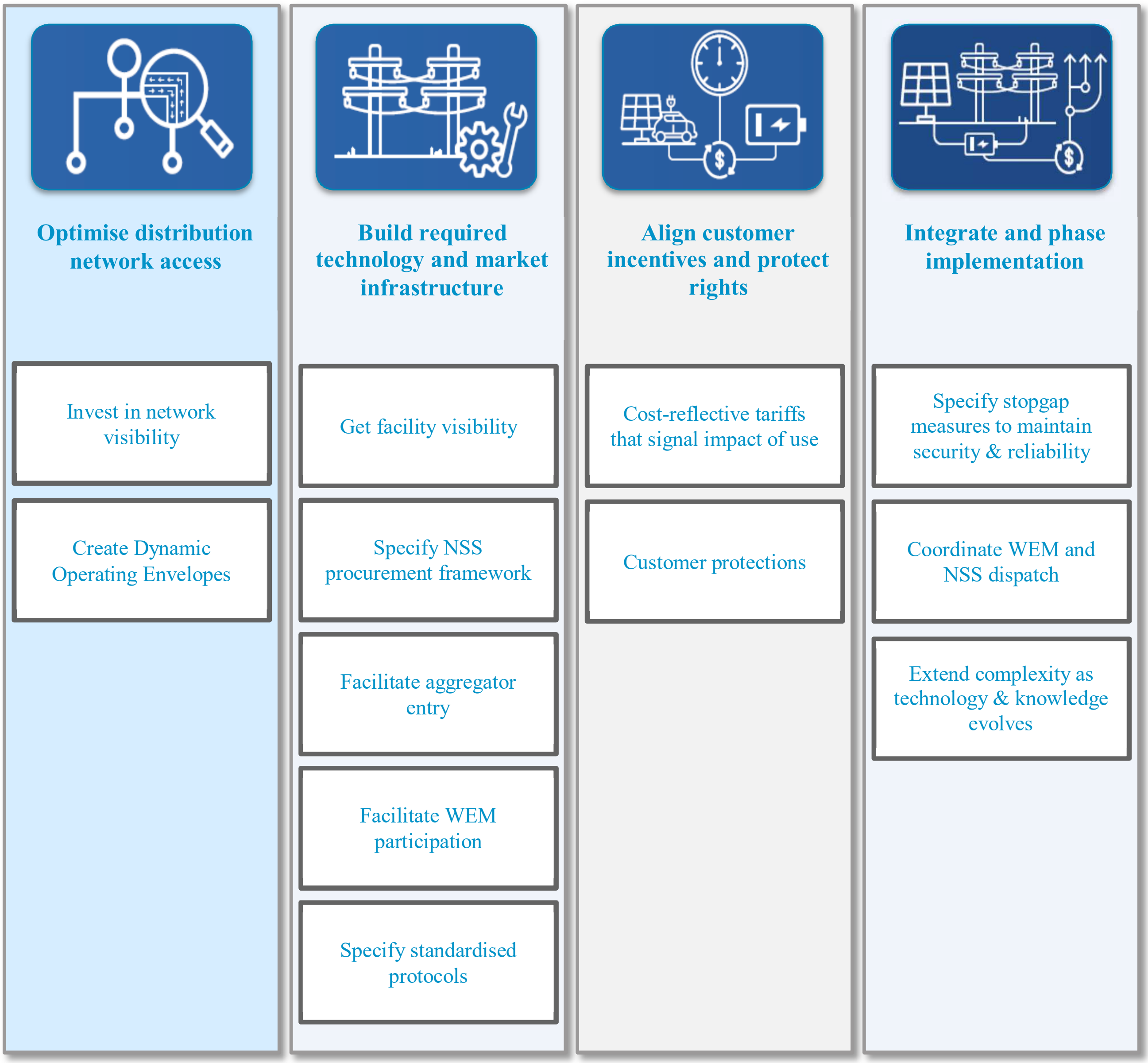
Critical to optimisation of network use is digitalisation – or rather appropriately utilising data available in the low and medium voltage networks to obtain a more accurate understanding of hosting capacity (i.e. the amount of DER that can be connected and used at any point in time). This requires access to usage and power quality data, the communications systems to transport very large quantities of data (at varying measurement granularities and update rates), and the back-office systems (or databases) to store and use the data. This will require:

- building technology and market infrastructure that enables DER to participate in existing and new markets, including:
  - robust procurement mechanisms to enable DER to provide non-traditional services such as distribution NSS and minimum load services (see Scenario 1);
  - reviewing existing WEM arrangements to ensure they can facilitate the participation of DER;
  - specification of communications standards and protocols to integrate DER technologies into the market in a manner that does not compromise market or power system outcomes; and
  - Building appropriate IT and communications systems to transport large quantities of data, and the back-office systems to store and use the data; and
- Regulations that:
  - align customer incentives with the incentives of the aggregator, network operator and power system operator; and
  - ensure customer rights are protected as new business models emerge that are not captured under existing licensing and other protective regulations;
- an implementation approach that addresses immediate needs while allowing for extended complexity as technology and knowledge evolves (e.g. via Project Symphony); and
- an implementation approach that prioritises the security and stability of the power system to ensure ongoing reliable supply of electricity to customers.

Underpinning the approach above is the implementation of the DSO, DMO and aggregator roles which will facilitate the delivery of the policy above.

The policy areas that must be addressed, resolved, and implemented to enable the establishment of the DSO, DMO and aggregator roles are summarised in the figure below.

Figure 12: Orchestration issues




The August 2020 Issues Paper noted specific issues pertaining to the areas above.

In the following section, key issues from each of the policy areas above are summarised briefly. Issues are described in more detail in the following chapter.

## 4.3 Key issues

### 4.3.1 Optimise distribution network access

Optimisation of distribution network access means access that maximises the economic benefit accruing to the users of the network while ensuring network security, reliability, and safety requirements are met. Such optimisation will require first and foremost a digitalised distribution network in which low and medium voltage data is readily available to:

- provide Western Power with a more accurate understanding of hosting capacity and network capacity; and
- inform network planning and operational responses.

Without digitalisation and the resulting improvements in network visibility, Western Power will be unable to identify distribution constraints at a granular level, and hence be unable to clearly specify network support requirements. Additionally, Western Power will need to make more conservative assumptions about hosting and network capacity, which will result in static and dynamic operating envelopes that do not optimise DER access to the network (including for the purposes of WEM participation).

Western Power's AMI program will result in a metering fleet that can read current, active and reactive power, and voltage data at five-minute intervals (and potentially configurable to higher granularities). As such, the data required for operational visibility will exist at individual connection points. The uncertainty lies in the capacity of Western Power's radio frequency mesh communications network to transport the data at the required measurement granularity and update rates, and in Western Power's back-office systems to store and process the same data.

Any investment would therefore be focussed on upgrading the capability of the communications network and back-office systems. The existing regulatory framework (i.e. the ENAC) enables investment in network visibility (see information on NSS procurement, below). Consideration needs to be given as to whether real-time data is required in the longer-term for settlement purposes, or if granular data can be supplied later following services being provided.

The immediate requirement is a forward-looking strategy and plan for Western Power's investment in monitoring and communication capability to enable further digitalisation of the electricity network, focusing on the low voltage network. Although Project Symphony will provide practical insights into the nature and extent of network visibility requirements, these insights will not be available in full until the pilot concludes in mid-2023. The first step is to obtain an objective understanding of the current and future requirements for digitalisation and control capabilities and technologies. To support this, Western Power should complete Action 14 of the DER Roadmap by June 2023 (see Section 5.1.1 for the recommended scope of such a review).

### 4.3.2 Build required technology and market infrastructure

#### Facility visibility

Facilities providing NSS and WEM services require measurement and communications systems so that that they can be monitored for performance and to inform AEMO's operational decisions. Traditional Supervisory Control and Data Acquisition (SCADA) is not practicable for Small Aggregations comprising DER due to cost. Project Symphony will yield lessons on potential technological solutions to cost-effectively enable Facility visibility, while Western Power's future investments in improving network visibility can also be leveraged to this end.

## Aggregators

Key policy decisions pertaining to aggregators include the following:

- In the absence of multiple-trading-relationships at the meter, only the Financially Responsible Market Participant (FRMP) at a connection point will be allowed to aggregate connection points for the purposes of providing energy or any ESS that requires the energy output to be controlled (i.e. any FCESS other than Contingency Reserve Raise provided by Interruptible Loads).
- Contestable customer connection points can be aggregated by anyone, noting limits outlined in the previous point.
- Synergy will be the sole aggregator for non-contestable customers, including for demand response services.

While aggregation is a developing service, it is desirable to preserve the current linear legal and contracting relationships between customers and retailers, in line with the State Government's existing policy positions on electricity retail contestability. This will ensure that customers retain adequate protections, as the existing licensing framework has certain gaps with respect to energy service providers who are not retailers. EPWA is progressing work to review the current licensing framework with a view to developing a new framework for alternative electricity service providers. As such:

- Contestable Customer connection points can be aggregated by anyone; and
- access to historical meter data (to inform aggregator business cases) will be facilitated through the existing regulatory framework by the retailer, or on request (with customer consent) from Western Power.
- The implementation of the Consumer Data Right (CDR) in the Western Australian energy sector will be reviewed in the near-term, which may provide for more efficient and extensive access to data.

## NSS procurement

NSS will be procured through the new NCESS framework. This framework provides for a robust procurement process which allows for market testing (through Expression of Interest process) and enables smaller Facilities that do not wish to register to participate. The framework also enables enhanced governance and oversight, as the Coordinator of Energy can trigger procurement and must be consulted in the specification of an NSS.

Acknowledging that recent amendments to the ENAC (the Alternative Options framework under Chapter 6A) were introduced to provide greater certainty around Western Power's procurement of alternative options to operate its networks, maintaining two parallel procurement regimes (i.e. Western Power procuring NSS via NCESS and AOS) is not efficient. As such, EPWA will consider amendments necessary to rectify any uncertainty or conflict and provide advice to the Minister for Energy.

To support efficient procurement of NSS, Western Power will only be able to directly procure NSS directly from larger customers (those with annual consumption greater than 160MWh per year). The intention is that this threshold applies to each connection point. However, EPWA will progress further work in consultation with Western Power to consider situations where the same customer may have DER on adjacent sites where consumption is less than 160MWh per year.

This restriction will ensure Western Power, as the sole procurer of NSS, does not compete with aggregators for DER services from Small Use Customers. Allowing Western Power to compete with aggregators is likely to lead to confusion among customers and erode the ability for aggregators to value stack across multiple orchestration services. It could also result in Western Power duplicating aggregation platform capability unnecessarily.

The Economic Regulation Authority (ERA) has signalled it expects to see an uplift in Capex in the coming years to build the capability to manage higher levels of DER, including investment in monitoring and communication equipment and information systems. Consideration could be given to whether more locationally granular service standard benchmarks would enable Western Power to better quantify net benefits associated with NSS procurement. A material barrier to efficient future NSS procurement is the absence of digitalisation of network data (and hence lack of visibility). This may impede Western Power's identification of low voltage network constraints and NSS requirements, and from deploying NSS as an operational response.

## WEM participation

While the WEM Rules giving effect to the new arrangements from 1 October 2023 do not explicitly prevent the participation of aggregated DER, the technical standards specified in the WEM Rules and WEM Procedures[18] mean that, in practice, DER will not be able to participate directly in the WEM, except as:

- Demand Side Programmes (in the RCM);
- Interruptible Loads providing Contingency Reserve Raise; or
- Unregistered Facilities providing services procured through the NCESS framework (e.g. to provide a minimum load product to address the low load issue).

Moreover, as the measurement point for FCESS is the connection point, aggregators wanting to provide Contingency Reserve (other than Contingency Reserve Raise as an Interruptible Load), will need to be able to control the behind-the-meter load to be able to provide the service, or at least manage the effects of uncontrolled elements such that the service is delivered as requested at the connection point. Particularly, such aggregations may struggle to meet the Dispatch Target for energy that is issued to a provider of Contingency Reserve.

Project Symphony will provide lessons on the ability of aggregated DER to provide Contingency Reserve services. Specifically, Symphony will test DER against current standards to assess the gap between capability and requirements. Until capability is better understood relative to local conditions, it is prudent to defer any changes to FCESS technical standards for the purposes of facilitating the participation of aggregated DER.

Additionally, a review of the RCM is currently underway by the Coordinator of Energy that may result in changes to the Planning Criterion, as well as how Certified Reserve Capacity is allocated to different technologies. As such, decisions pertaining to facilitating DER participation in the RCM (other than as a DSP) will be deferred pending the results of the review.

Western Power's AMI rollout program will mean all meters at Non-Contestable Customer connection points will be 30 minutes or five-minutes configurable. While Western Power can facilitate the provision of data for settlement at 30-minute granularity, Western Power's and AEMO's communications infrastructure and back-office systems have not been designed to accommodate five-minute settlement of Non-Contestable Customer connection points. This includes those that are part of registered Small Aggregations. In the absence of five-minute meter data, AEMO would need to profile 30-minute data into five-minute intervals for settlement purposes.

Any profiling methodology used for settlement would need to be reasonably accurate to ensure that the price signals DER are responding to are accurately reflected in what they are ultimately paid. Profiling may also result in unintended incentives which may result in inefficient market operation.

Project Symphony will yield lessons on the type of data that may be available from aggregator platforms to facilitate such profiling, if appropriate, while the completion of Action 14 of the DER Roadmap (including the visibility recommendations above) will make clear what changes are

[18] Requirements to have SCADA for monitoring purposes, sub-metering for RCM purposes, high speed data recorders for FCESS purposes and the requirement to be AGC-enabled for Regulation ESS.

required to implement five-minute metering for Small Aggregations comprising Non-Contestable Customer connection points. As such, policy decisions on metering requirements for Small Aggregations are deferred.

### Standardised protocols

Decisions surrounding standards and protocols governing communications between the aggregator and the devices in a VPP, as well as redundancy requirements to cover the loss of communications will be deferred pending completion of work in under the Distributed Energy Integration Program (DEIP) and Project Symphony.

## 4.3.3 Align customer incentives and protect rights

### Tariff policy

Orchestration of DER will ideally be underpinned by cost-reflective pricing structures reflecting the ‘input’ costs to deliver electricity services. These structures, including appropriately designed retail electricity tariffs, create the platform on which customer aggregation products may be designed. However, consideration of the types and design of network tariffs, retail tariffs, and customer aggregation products (through which customers get paid to provide services) is not in scope for this paper.

EPWA is separately progressing work around future tariff directions in consultation with Western Power, Synergy, Horizon Power, and consumer groups. Notable is Synergy’s ‘Midday Saver’ pilot time-of-use tariff. This tariff features a low rate during daylight hours, reflecting the relative over-supply of generation during this period, and a higher peak rate. Adoption of retail tariff structures comparable to the Midday Saver will become increasingly important as EV uptake increases.

### Consumer protections

EPWA is currently progressing legislative reforms to enable a licensing framework for alternative electricity service providers such as aggregators who are not traditional retailers.  The framework will include protection mechanisms for consumers including access to the Energy Ombudsman. As outlined earlier, until this work is completed the policy position is for Synergy to be the sole aggregator for Small Use Customers.

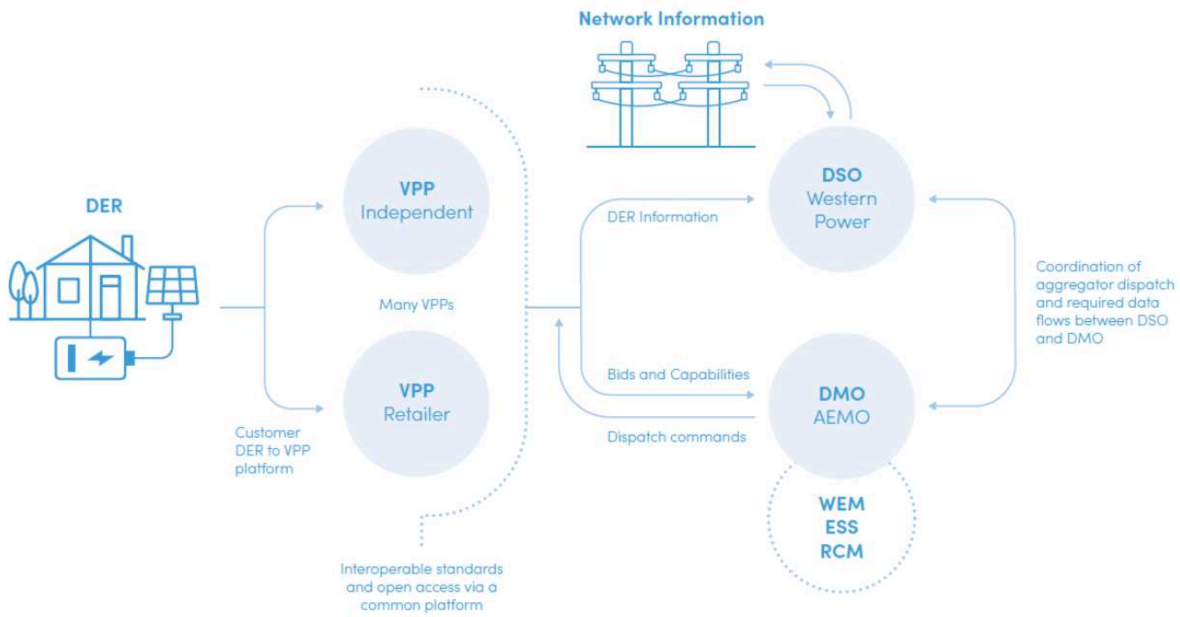
## 4.3.4 Integrate and phase implementation

Consistent with the vision set out in the DER Roadmap, the hybrid model,[19] illustrated below, remains the basis of the implementation approach adopted in the SWIS for aggregated DER participation in the power system. Western Power and AEMO will perform the DSO and DMO functions respectively, extending existing capability, without resulting in separate or distinct entities being created.

The DSO role reflects an expansion in Western Power’s role as Network Operator in a high DER future, while the DMO role reflects an expansion AEMO’s role as market operator to integrate DER into the WEM.

[19] The hybrid model is based on work done as part of the Open Energy Network Project. https://www.energynetworks.com.au/projects/open-energy-networks/

Figure 13: Hybrid (DSO/DMO) model for the SWIS




*Source: Issues Paper – DER Roadmap April 2019*

The hybrid model will require coordination of dispatch of NSS and WEM services. The historical scale of NSS use has been negligible and has not affected AEMO’s decision making as power system operator. Additionally, providers of NSS have not concurrently provided WEM services. Hence central co-ordination of dispatch has not been necessary.

As market participation by DER increases, central co-ordination by a single party such as AEMO may be more efficient than co-ordination by multiple parties. However, adding a “middle-man” deploying instructions on behalf of Western Power may create inefficiencies due to latency issues. Project Symphony will yield practical experience in NSS dispatch that can be used to determine the most appropriate party to allocate NSS dispatch responsibility. The decision on allocating NSS dispatch responsibility will therefore be deferred pending lessons from Project Symphony.

Note, whatever decision is made with respect to this issue, it is important that AEMO has visibility of NSS dispatch decisions that impact on power system security. Procuring NSS through the NCESS framework (see issue **NSS1**) will ensure obligations exist on Western Power to provide relevant information to AEMO in this respect.

In terms of a dispatch hierarchy, NSS will be dispatched ahead WEM services (consistent with the approach adopted for services procured through the NCESS framework). The precise way NSS dispatch would be implemented will depend on who is responsible for dispatch.

# 5. DER orchestration roles and responsibilities issues

This section provides greater detail on identified issues related DER orchestration in the WEM in more detail:

- Issues relating to distribution network access are covered in Section 5.1.
- Issues relating to market and technology infrastructure are covered in Section 5.2
- Customer related issues are addressed in Section 5.3.
- Implementation issues are addressed in Section 5.4.

Issues are marked as:

- ***Settled***, where a policy position has been reached.
- ***Deferred***, where policy resolution is not yet possible or desirable due to dependencies with other reform activities.

The appendices further summarise these issues in a tabular format as follows:

- *Appendix A* summarises the detailed issues in this chapter in a concise format, for ease of reference.
- *Appendix B* maps the DSO and DMO roles and responsibilities set out in the August 2020 Issues Paper against the policy issues.

## 5.1 Optimise distribution network access

### 5.1.1 Distribution network visibility

#### Current approach

Historically, distribution networks have been designed around static ADMD limits, with safety margins included for anticipated loading level and power flows. Western Power's planning cycle allowed for monitoring, assessment, and planning for network investments to address forecast changes in demand and non-compliances. Visibility of lower-voltage networks was not required to inform this approach to planning as largely predictable one-way usage patterns made it possible to rely on proactive and responsive programs to adequately manage the risk. The cost of delivering widespread lower-voltage network visibility is also a factor that needs to be considered against the benefits.

Increasing DER adoption by customers has created a range of challenges to network planning and operations including power quality and power system operations issues.[20] Addressing these challenges in a manner that reduces long-term costs for customers will require digitalisation to enable orchestration, i.e. more granular coordination of network use which optimises supply and demand within available network capacity.

Such optimisation is already occurring for transmission and high- to medium-voltage distribution networks. This optimisation is possible due to the network visibility enabled by digitalisation. Network operators monitor and respond to network conditions on timescales down to milliseconds using various measurement and monitoring devices. There has not been equivalent visibility of lower-voltage networks due to the reasons noted above. That is, data such as active and reactive

[20] Challenges in the energy market include the low load issue.

power, and voltage and current data have not been traditionally monitored, or needed, to evaluate the state of the low voltage network.

As part of Western Power's AMI project:

- Non-Contestable Customer connection points will have AMI meters capable of recording the following information at 30 minute and five-minute intervals (with the functionality for more frequent intervals, e.g. 60 seconds):
  - Active power data including kWh import, export, and net-metered usage.
  - Reactive power use (kVar) at three phased connections.
  - Power quality (voltage and current) data at selected connections.
- Active and reactive power data is polled every four hours for transmission to Western Power's tariff metering database.
- Power quality data is recorded at five-minute intervals and polled every four hours for single phase connections and every two hours for three-phase connections for transmission to Western Power's power quality database.
- The data above is transmitted via Western Power's radio frequency mesh network to an access point, typically at the nearby substation. From there, the data is transmitted via optical fibre or microwave radio or cellular network to Western Power's head end system before being passed to its back-office systems to the relevant databases.[21]

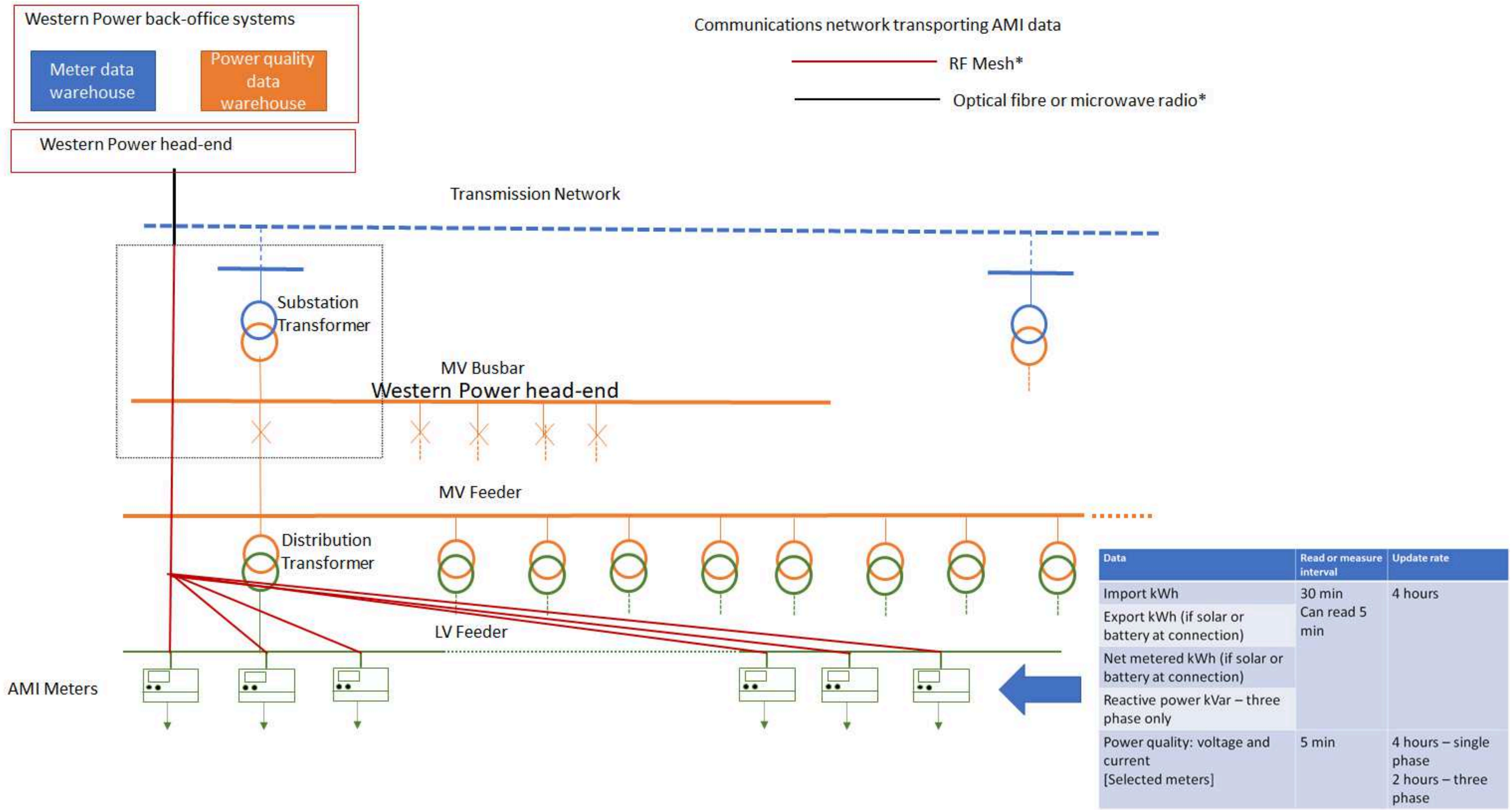
While the AMI metering hardware is capable of recording data at both 30 minute and five-minute intervals, the following is unclear:

- The ability of Western Power's end-to-end communications network to:
  - Poll five-minute data at Non-Contestable Customer connection points every four hours. This would be required if Small Aggregations comprising Non-Contestable Customer connection points are to be settled using five-minute meter data (see also Section 5.2.4, Issue **WEM_METER2**). It is unclear how many Non-Contestable Customer connection points could be accommodated before the bandwidth of the meter to access point section of the communications network is exhausted.
  - Poll five-minute data at more frequent intervals for operational purposes (e.g. every few minutes, or seconds).
- The capability of Western Power's back-office systems to store and process the increasing volumes of data.

Note also that only distribution transformers that are rated at 300kVA or more have local visibility of actual and peak loading (provided via a non-telemetered ammeter). Western Power is currently seeking changes to the Technical Rules to enable it to remotely monitor power flows and voltage on new ground mounted distribution transformers as a minimum.

[21] Where there are no access points, Western Power relies on third party cellular networks to transport data from connection point to its head end.

Figure 14: Overview of existing Western Power low voltage network visibility




| Data | Read or measure interval | Update rate |
|---|---|---|
| Import kWh | 30 min<br>Can read 5 min | 4 hours |
| Export kWh (if solar or battery at connection) | | |
| Net metered kWh (if solar or battery at connection) | | |
| Reactive power kVar – three phase only | | |
| Power quality: voltage and current [Selected meters] | 5 min | 4 hours – single phase<br>2 hours – three phase |

**Where no access point (substation) exists, data is transported to Western Power's head end via third party cellular networks.*

## Future state

Visibility is a critical pre-requisite to DER orchestration and active participation. There are two aspects to visibility:

1. Planning visibility:

- Planning visibility is required to identify adverse network conditions ahead of time and to plan and signal any operational or investment response, including signalling the extent and timing of NSS requirements. The latter is a critical component of ensuring NSS providers are present when needed.
- In future, Western Power should signal NSS opportunities to aggregators through clearly defined service specifications and projected distribution system constraints. Service specification and granular identification of opportunities within planning timeframes will require improved visibility of the lower-voltage network.

2. Operational visibility:

- Operational visibility is required to understand the hosting capacity of the network to implement methods which optimise the allocation of available network capacity (i.e. using DOEs), rather than using static limits (see also Section 5.1.2). To date, emerging network challenges associated with unmanaged DER have been addressed via restrictions on the allowable size of rooftop solar systems connecting to the network. These limits are placed to prevent physical limits of the lower-voltage network being breached and causing network and equipment damage and endangering safety.
- Real-time limits (or hosting capacity) are, theoretically, calculable. However, for the most part they are unknown due to the lack of visibility in the lower-voltage network. This causes network operators to act more conservatively than they would if they had greater visibility of actual constraints on the distribution network closer to real time. The result is sub-optimal utilisation of the network infrastructure and greater costs, which are ultimately borne by end-use customers, as well as reduced opportunities for low emission generation by customers.
- Communications infrastructure is required to support operational responses, including coordination of network use in real or near-real time so that DER resources can be dispatched to provide NSS and WEM services and have the performance measured for compliance and settlement purposes.

Visibility requirements will depend on the use case; but in all cases there are four dimensions to visibility requiring consideration:

1. What data is being collected and where?
2. What is the granularity at which data is to be measured?
3. How frequently is the data required (update rate)?
4. What coverage is required or what is the sampling density (e.g. is the data required from all connection points or is sampling sufficient?)?

The Australian Energy Market Commission (AEMC) notes the following operational visibility requirements (in the context of the four dimensions above) for seven use cases in the DER Monitoring and Visibility Best Practice Guide.

Table 2: Visibility requirement by use case

| Use Case | Data required (at NMI) | Measurement granularity | Update rate | Sampling density |
|---|---|---|---|---|
| Network state estimation and performance | Voltage (assumes voltage and current available at substation) | 5-10 min | Real-time (could be Monthly) | >2% of premises, greater fidelity at higher density, ideally 75% of "nodes". 20% required for MV. |
| Fault identification | Voltage and current | 1-5 min | Real-time | >2% of premises. Note millisecond likely required for broken neutral |
| DER hosting capacity | Voltage, Active/Reactive Power generated and consumed | 5 min | Monthly | 2 sites per feeder, with greater certainty/ redundancy from greater coverage |
| DER compliance | Voltage, Active/Reactive Power generated | 5-10 min | Monthly | >20% DER, with greater accuracy and compliance near 100% coverage |
| Constraint management | Capacity, Voltage, Active/Reactive Power generated and consumed | 10s –5 min | Real-time | Participating DER |
| Constraint reporting | Capacity, Voltage, Active/Reactive Power generated and consumed | 10 min | Weekly/Monthly | At least 1 customer per LV feeder, more increases accuracy |
| Orchestration (dispatch[22]) | Capacity, Voltage, Active/Reactive Power generated and consumed | 10s-5 min | Real-time | Participating DER. Note that full orchestration will require 1 min or better |

*Source: AEMC, DER Monitoring and Visibility Best Practice Guide May 2020.*[23]

As noted in the previous subsection, following the completion of its AMI program, Western Power's lower-voltage meters will all be capable of reading active and reactive power and voltage data at five-minute intervals. Hence, the data required for operational visibility will exist at connection points. The uncertainty lies in the capability of Western Power's radio frequency mesh communications network to transport the data at the required measurement granularity and update rates, and in Western Power's back-office systems to store and process the same data.

Any investment would therefore be focussed on upgrading the capability of the communications network and back-office systems (see Section 5.1.1 for a discussion on whether the existing

[22] For market settlement in the WEM (post five-minute settlement), a measurement granularity of five-minutes and an update rate of a few hours to a day would be sufficient.

[23] https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0301_-_solar_analytics_updated_-_20210114.pdf

regulatory regime enables such investment). To ensure that investment is targeted and fit for purpose, Western Power will need to:

- evaluate the capability of each part of its end-to-end communications network to transport five-minute data, plus more granular data required for distribution automation, at varying update rates for varying sampling rates (e.g. for 1% of low voltage connections vs 5% vs 10%, etc.);
- evaluate the capability of its back-office systems to store and process data collected at varying update rates for varying sampling rates;
- form a view on the measurement granularity and update and sampling rates required given likely use cases around network planning, network maintenance, network operations, and WEM participation; and
- identify what changes are required over what timeframe to upgrade its communications infrastructure and back-office systems to meet the visibility requirements for the identified use cases.

Note that DER Roadmap Action 14 has a similar scope[24] and is yet to be completed. As such, it is prudent for Western Power to include the above evaluation in the scope of Action 14.

## Policy Issue - Visibility

**VIS1** (Settled): Western Power will develop a plan for delivering the appropriate level of network visibility to facilitate orchestration of DER. It is not clear that additional incentives or obligations are required for Western Power to facilitate this investment. The ENAC already says Western Power must be able to earn a target revenue equivalent to the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

The ERA guidance on factors that will be considering in new facilities test determination notes that:

"*Higher levels of distributed energy resources have cost implications for the network … [including] ... Managing increased distributed energy resources may require increased monitoring and management of the network at a more granular level which may require investment in monitoring and communication equipment and associated information systems.*"[25]

To support future investment by Western Power, the immediate requirement is a forward-looking strategy and plan for investment in monitoring and communication capability to enable further digitalisation of the electricity network, focusing on the lower-voltage network.

Although Project Symphony (and other pilots such as project EDGE) will provide practical insights into the nature and extent of network visibility requirements, these insights will not be available until mid-2023.

The first step is to obtain an objective understanding of the current and future state requirements for digitalisation and control capabilities and technologies. To support this, Western Power should complete Action 14 by June 2023. Western Power's plan should include:

[24] *By June 2020, undertake an assessment of distribution network visibility capability and develop an investment plan for deploying technology to improve that visibility, both static and dynamic, to support DSO and system/market operator requirements. The scope should include a review of the coverage of network visibility investments under the regulatory framework, including the Electricity Networks Access Code 2004 and Technical Rules.*

[25] ERA, *Guideline on factors that will be considered in new facilities investment test determinations and methods to value net benefits*, December 2021, available at: https://www.erawa.com.au/cproot/22365/2/Guideline.PDF

- consultation with AEMO, assessment of communication and control capability in place (e.g. functionality of existing metering fleet, plus communication and control capability ‘in the market’) and an assessment of future state capability scenarios describing communication and control functionality required to deliver specified outcomes, including orchestration and aggregation;
- a survey of technology options, describing the purpose of the solution (e.g. network operation, market coordination, etc.), the owner (e.g. Western Power, DER owners, aggregators etc.) and the operator(s) (e.g. DSO, AEMO, Western Power, aggregator etc.);
- a review of the adequacy of the coverage of network visibility investments under the current regulatory framework, including the ENAC and Technical Rules; and
- a preferred communication and control technology investment pathway which aligns with the timeframes for introducing DSO and DMO functions.

### 5.1.2 Dynamic operating envelopes

#### Current approach

Access to the network for customer connections has historically been subject to physical limits, with a typical domestic connection rated to 63 A (approx. 15 kVA) for single phase and 32 A (approx. 22 kVA) for three phase connections (import or export). Network capacity has been delivered based on a notional import/export limit of 4.7kVA, reflecting assumptions about ADMD.

The ADMD reflects an assumption, based on the representative typical daily profile of customer load, that the actual physical capacity of each connection is rarely used, and peak network use of individual connections is not simultaneous.

Residential customer connections with rooftop solar have been subject to a physical capacity export limit of 5kVA (lower than the connection rating of 15kVA) via equipment installation restrictions. This acknowledges that there is generally little to no diversity associated with distributed rooftop solar generation output.

#### Future state

Electrification and uptake of DER (currently rooftop solar, and in the future EVs) is causing network use to diverge from the representative typical daily profile, resulting in increased coincident demand (both import and export) for network capacity by individual connections which can exceed the physical and operational limits of the distribution feeder (or in the medium-voltage network).

The three options available for responding to increased electrification and uptake of DER, particularly on lower-voltage networks, are:

1. augment the lower-voltage network;
2. impose restrictions on access to network capacity using static or dynamic limits; and/or
3. optimise network capacity by providing relevant price and non-price signals and enabling market integration.

These options are not mutually exclusive and may be implemented alongside one another.

DOEs are a method of allocating access to network capacity; they define the limits that an electricity customer can import and export to the electricity grid, with these limits varying by time and location. The August 2020 Issues Paper noted that:

> *“Operating envelopes indicate to customers the export and/or import limits that they must operate within for the safe and secure operation of the network. To update the envelopes, data needs to be collected in near real time. Algorithms are then executed to define the network state, based on the data. Constraints determined by these algorithms would then be communicated, based on standard protocols.”*

Dynamic limits are preferred to static limits (for example the existing 5kVA per phase limit on rooftop solar system installations) because they optimise use of hosting capacity and enable increased access to the network. This is important, because as DER uptake increases, relying on static limits will reduce the total amount of low emission solar energy exported to the grid. Static limits prevent exports at times when the network can't accommodate them, but also at times when it could.

Similarly, dynamic limits support optimisation of power imported from the grid through placing limits on household load. DOEs have the potential, in conjunction with smart charging capability, to support the integration of EVs at lower cost by managing charging rates during periods of peak network use. Placing limits on imports may prove contentious and significant community engagement would be required prior to introduction to gain social licence and guide implementation.

Dynamic limits based on actual or expected network conditions provide upper and lower bounds for the export and import of power that can be accommodated by the network element before physical or operational limits of a distribution network are breached.

DOEs allocate the network capacity available to each connection based on forecast or actual network capacity in that location, e.g. a specific feeder. However, solely relying on DOEs removes the potential to use orchestration to match supply and demand for network capacity on the lower-voltage (feeder) network. That is, aggregators should have capability to modify or tailor the operation of DER within the bounds of the DOE to deliver services.

Project Symphony is demonstrating that DOEs can be calculated and published at any point in the day to support network operations by allocating generation and consumption limits to participating connections (DOE allocation at the NMI).[26] Broadly speaking, DOE calculation:

- results are made available at agreed intervals, with Project Symphony initially calculating and publishing DOEs for participating connections every 24 hours for a three-day interval and DOEs being set with 5-minute intervals;
- accounts for the latest network load information.
- will ensure that Aggregators can access DOE allocation information relating to their customers; and
- outputs will be accessible by the DMO to understand distribution network constraints that may have implications above the TNI level.

Calculation of DOEs relies on access to a range of data, including:

- Network Model Data, including facility and NMI registration information;
- Historic Load Data, including MV/Feeder load history, connection consumption history and distribution transformer (DSTR) load history (from PQ data loggers);
- power-quality transformer data; and
- weather and solar irradiance forecast data.

The data requires network visibility sufficient to provide up to date (i.e. for the prior day based on a 24-hour publication schedule) load and power quality data, at 5-minute intervals, for the medium-voltage network/feeder, distribution transformer, and up-to-date load data for the connection point.

The process for setting DOEs to allocate access to the network requires consideration of the impacts on network use, for example, whether the DOE precludes a customer from maximising economic benefit of using the network by preventing dispatch of near zero marginal cost electricity

[26] Further information on the approach to under Project Symphony can be found in the DOE knowledge sharing report. https://arena.gov.au/knowledge-bank/project-symphony-distribution-constraints-optimisation-algorithm-report/

(with the benefit of dispatching the energy is greater than the cost of augmenting the network for this to occur).

Explicit criteria are required to ensure DOEs are set to maximise customer value across all connections. In particular, the criteria should ensure there is a clear link between the level of the DOE and network capacity to avoid misuse of restrictions on network access. For example, restricting network access to export electricity when there is no localised network congestion represents an unnecessary and inefficient restriction on network use, even if such a restriction 'solves' an energy-related problem elsewhere in the power system. That is, DOEs should reflect local network constraints, not power system or market issues that can be resolved by other means.

Given the application of DOEs will place limits on the operation of customer equipment and aggregated DER (albeit in a way that maximises their ability to participate), further stakeholder engagement will precede the application of DOEs.

## Policy Issues – Dynamic operating envelopes

1. **DOE1** (Settled): Explicit criteria will be used to decide how to use and set DOEs and, as importantly, when not to use DOEs. A framework will be developed to identify (but not limited to) the following:

- development and implementation of DOEs for export and import, including calculation of DOEs with reference to market impacts;
- how the trade-offs associated with restricting use of the network will be measured and considered against using augmentation or orchestration;
- the reporting requirements to be placed on Western Power to ensure their decision making with respect to the trade-offs above is transparent; and
- whether incentives or regulatory requirements will work to ensure DOEs are set based on maximising economic benefit from using the network.

Project Symphony will be an important learning tool to inform this framework. The criteria should also be informed by and aligned with national practice, such as the outputs of the DOE workstream of the DEIP,[27] where appropriate for the Western Australian context.

2. **DOE2** (Settled): DOEs will only be available to connections with active DER which can respond to an external signal and can provide the data inputs needed to calculate the DOE.[28]

- 'Active DER' is any DER that can be controlled to provide an appropriate response.
- However, the definition of active DER should not result in unreasonable restrictions on its operation which prevent the owner and the wider power system from realising potential net benefits. Similarly, DER that is not active should not face unreasonable restrictions to access to the network. These matters should be included in the explicit criteria to be developed to document how to use and set DOEs.

3. **DOE3** (Settled): The following two operating envelope parameters adopted for Project Symphony will be implemented for broader application, subject to the outcomes of Project Symphony:

- Operating envelopes will be calculated for each NMI.
- Operating envelopes will be published for each 5-minute interval but may be calculated at a coarser granularity (so that multiple adjacent intervals may have the same value).

[27] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

[28] Connections must meet certain technological requirements (e.g. equipment capability and AMI) to be assigned a DOE. As such, not all connection points can be assigned be a DOE (at least in the short-term).

**DOE4** (Settled): The following approach will be adopted to DOE compliance:

- For export limits, the FRMP for the NMI will be responsible for applying the DOE (noting **AGG1**).
- For import limits the Aggregator will be responsible for applying the DOE, noting **AGG1**, **AGG2** and **AGG3** limits, and that import limits are not anticipated to be applied in the short term.
- Where no Aggregator is present, a DOE will not be applied.[29]
- The DSO is responsible for monitoring and enforcing compliance with the DOE.
- While the DMO may check that NMIs within a VPP offering a market service do not exceed the published DOEs as part of operational processes, it is not responsible for policing compliance with the DOE.

In March 2022 the DEIP DOE workstream released its Outcomes Report. While this report was not available in time to be considered while developing this Information Paper, EPWA considers the recommendations are broadly aligned with the approach to be adopted in Western Australia and the positions outlined in this section.

## 5.2 Build market and technology structure

### 5.2.1 Facility visibility

#### Current approach

The WEM Rules place real-time monitoring requirements on facilities to verify compliance with dispatch obligations. For example, facilities which must comply with dispatch instructions[30] require SCADA monitoring equipment and high-speed recorders if they provide ESS to manage frequency.

Additionally, self-scheduling facilities are also required to have SCADA monitoring. While these smaller facilities do not have dispatch compliance obligations,[31] AEMO uses real-time monitoring to inform its load forecasts (e.g. using persistence forecasts, where it is assumed that the monitored conditions at the time of the forecast – such as temperature - will not materially change over long periods of time). The use of persistence forecasts has the effect of increasing the accuracy of AEMO's forecasting.

While the WEM Rules are silent on the type of technology that should be employed to facilitate visibility, the relevant WEM Procedure prescribes SCADA monitoring and places identical visibility requirements on all energy producing Facility Classes, dependant on the services provided; this reduces incentives for Market Participants to register multiple smaller Facilities to avoid more onerous requirements.[32]

[29] The DEIP Dynamic Operating Envelope Working Group Outcomes Report considers that direct DSO/DNSP application of DOE's at the device is likely an early path for implementation. However, in Western Australia the DNSP does not have the same direct contractual relationship with the end user that is in place in the NEM; rather, the access contract is usually held by the customer's retailer (referred-to as a 'linear contractual relationship'). As per the approach taken in the implementation of ESM in the SWIS, this means that it is unlikely that the DNSP would have the authority to 'reach in' to modify the behaviour of end-user equipment.

[30] Under the new WEM arrangements to be implemented on 1 October 2023, Scheduled Facilities and Semi-Scheduled Facilities will be required to comply with Dispatch Instructions from AEMO; the latter only need comply with a Dispatch Cap, unless they are also enabled for Frequency Co-optimised Essential System Services (FCESS).

[31] Unless they are directed by AEMO in an emergency. In such a case, ex-post checks may suffice.

[32] Under the new WEM arrangements to be implemented on 1 October 2023, AEMO is empowered to transition Facilities from the Non-Scheduled Facility Class to the Scheduled Facility or Semi-Scheduled Facility Class if it can demonstrate risks to Power System Security and Power System Reliability.

## Future state

Increasingly, AEMO will require visibility of VPPs providing WEM services:[33]

- Large VPPs (System Size greater than or equal to 10MW) will be required to comply with dispatch instructions and will therefore need to provide real-time visibility of the aggregated facility so AEMO can monitor compliance.
- Smaller VPPs (System Size less than 10MW) require some form of visibility to ensure AEMO can incorporate their output into its forecasting processes (thereby ensuring more accurate dispatch) and to facilitate monitoring of compliance with emergency directions. For the latter, ex-post checks using meter data may suffice but further assessment will be required.

Specific obligations on Aggregators are likely to correspond to the requirements of the services being offered. This will reduce any incentives to construct several smaller VPPs to avoid visibility requirements.

Under current arrangements, VPPs would be required to have SCADA monitoring to participate directly in the WEM. SCADA monitoring under the current SCADA requirements of individual devices within a VPP is not practical (due to relatively high costs and complexity) and will prevent VPP entry in the WEM.

VPPs wanting to provide NSS to Western Power may also need to have real or near real-time monitoring in place so that Western Power can determine whether services have been delivered.

The challenges associated with real-time or near-real-time visibility of VPPs pertain to technology, cybersecurity and assuring consumer consent. Overcoming technological barriers may require use of the 5G network and 5G-network-capable measuring equipment (amongst other options). Very high levels of visibility will come at a cost that may outweigh additional benefits derived. Visibility need only be sufficiently accurate to support operational decision making.

Project Symphony will test how real-time visibility (via a gateway device) of facilities providing WEM services and NSS can be facilitated at least cost.

The issue of Facility visibility is linked to that of network visibility (see Section 5.1.1, Issue **VIS1**). Particularly, the functionality of Western Power's metering fleet and the capability of its communications network will directly impact on the extent to which Small Aggregations comprising connection points can be monitored for the purposes of real-time dispatch.

## Policy Issues - Visibility

1. **VIS2** (Deferred): What real-time or near-real-time visibility requirements will be placed on Small Aggregations registering in the WEM?

- As noted above, visibility requirements serve different purposes for Non-Scheduled Facilities vis a vis Scheduled Facilities and Semi-Scheduled Facilities.
- In the short-term, entry of smaller VPPs is more likely than larger VPPs. If a technological solution cannot be found to monitor Facilities for dispatch compliance, immediate to short-term effort could be expended on facilitating the entry of VPPs registering in the Non-Scheduled Facility class, which could potentially have less onerous requirements than larger VPPs subject to dispatch compliance.
- Visibility requirements sufficient for dispatch compliance monitoring purposes, and for forecasting the generation of Non-Scheduled Facilities, will be informed by Project Symphony and by Western Power's evaluation of network visibility under Action 14 of the DER Roadmap (see Section 5.1.1, Issue **VIS1**).

[33] Small Aggregations that do not meet the monitoring requirements to provide energy and FCESS may still be able to provide NCESS, as the visibility requirements for such a service can be stipulated in the NCESS contract and may be less onerous than the standard requirements.

- This issue is deferred pending lessons from Project Symphony and Action 14 of the DER Roadmap.

### 5.2.2 NSS procurement framework

#### Current approach

NSS are services provided by "non-poles and wires" or non-traditional assets to operate the lower-voltage distribution network within required standards. These services are an alternative to standard operational responses used by Western Power to operate its network to the safety, security, and reliability standards that it is subject to. NSS can be used by Western Power to defer and potentially avoid costly network augmentation.

Historically, Western Power's use of NSS has been limited and there is no 'standard' definition or specification of NSS to assist in the development and commercialisation of the service(s). Recent changes to the ENAC require Western Power to publish an annual Network Opportunities Map and develop an Alternative Options Strategy to engage with potential providers and consider alternative options to network augmentation.

Notwithstanding the changes to the ENAC, Western Power currently has reduced financial incentives to use NSS or support orchestration due to: regulatory settings governing investment favouring capital expenditure (Capex) over operating expenditure (Opex) and the relative technological and commercial immaturity of NSS means costs have been higher than traditional solutions.

#### Future state

The ability of orchestrated DER to offer NSS services requires Western Power to support the commercialisation of NSS.

An efficient approach to procuring NSS requires:

- transparent sharing of network information about the prospect, timing and scale of network constraints which could be managed by deploying NSS; this will enable aggregators to confidently invest in aggregating DER;
- clear NSS specification;
- transparent procurement mechanisms, including market testing and equity of treatment; this is important as lower-cost providers of alternative options may choose not to enter the market if there is a perception that Western Power is likely to prefer investment in its own non-traditional assets (e.g. battery storage); and
- providers able to meet the NSS requirements in the area where the NSS is needed.

Acknowledging the relatively limited incentives present to do so, the current regulatory framework forms a sound basis to facilitate the procurement of alternative options, or non-network services, (including investment to facilitate the ability to procure), including the use of DER for NSS purposes.

#### Non-cooptimised essential systems services framework

The new NCESS framework in the WEM Rules is flexible enough to incorporate distribution NSS and already includes a procurement mechanism that supports commercialisation through market testing and provides for appropriate regulatory oversight and governance.

In particular:

- The NCESS framework enables AEMO, Western Power and the Coordinator of Energy to initiate procurement (the former two require approval from the Coordinator of Energy); including the power system operator and policy agency in the procurement process, in addition to the network operator, ensures a wider view is taken when deciding where alternative options should be exercised:

- Clause 3.11A.2(c) of the amended WEM Rules enables Western Power (or AEMO) to request NCESS procurement be triggered to enable alternative options such as DER to provide distribution network services.[34]
- Clause 3.11A.4(c)[35] of the amended WEM Rules enables the Coordinator of Energy to trigger procurement if the WOSP indicates alternative options may be suitable to meet a network need. The scope of the WOSP is broad enough to include consideration of the lower-voltage distribution network. Again, this provides a second opinion to sense-check Western Power's NOM modelling (see below).

- The NCESS framework requires Western Power to issue an Expression of Interest with a clear service specification to gauge whether service providers can meet its requirements. This process will help establish the capability that exists in the market at that point of time, and whether service specifications can be amended to match that capability (while also ensuring the network requirements are met).
- Clause 3.11B.11 of the amended WEM Rules enables Western Power to use the New Facility Investment Test (NFIT) process to conduct the cost-benefit analysis on which combination of NCESS submissions to select (if any). Clause 3.11B.11 also requires Western Power to consider wider market costs (beyond just network costs); this is consistent with a whole-of-system approach.

Recent changes to the ENAC (the NOM and AOS) were introduced to explicitly clarify Western Powers ability to procure alternative options to operate its networks. Maintaining two parallel procurement regimes (i.e. Western Power procuring NSS via NCESS and AOS) has the potential to be inefficient and confusing for prospective service providers and Western Power. Therefore, consideration must be given to how the NOM and AOS interacts with the NCESS framework. For example:

- the NOM and AOS could be completely removed from the ENAC and brought into the NCESS framework in the WEM Rules; or
- the NOM could remain in the ENAC while the AOS is removed, with procurement being handled exclusively through the NCESS framework:

While the reporting requirements are broadly like those imposed on network operators in the NEM and the United Kingdom, the key difference is the availability of granular information at lower-voltage levels. For example:

- In the NEM, the NOM includes spatial data from all electricity network businesses on network constraints, planned investment and the potential value of DER to provide network services across the NEM. Electricity networks have reported this data in their Distribution and Transmission Annual Planning Reports, and more recently on each network business' website in digital format. The NOM brings this data together in a consistent format across jurisdictions, to make it more visible and meaningful for those seeking to understand areas of opportunity to provide network services or connecting new sources of renewable generation.[36]
- In the United Kingdom, an opportunities map is published which indicates demand for flexibility services (by named service) and region.[37] The lack of granular lower-voltage network information limits Western Power's ability to publish readily usable information to aggregators and/or investors (see Section 5.1.1. on network visibility).

[34] Note that interim NCESS arrangements do not have combined trigger clauses.

[35] This is clause 3.11A.2(b) of the old WEM Rules.

[36] See NationalMap

[37] See Dashboard - Piclo Flex

Changes may be required to the NCESS framework to ensure it is fit for purpose procuring distribution NSS. For example, the current WEM Rules:

- Prevent Energy Uplift Payments[38] to any Facility injecting power when the constraint equation associated with their NCESS contract binds;
  - This provision was added to ensure that where a Facility is providing a network congestion management service to Western Power, it is not also compensated via an Energy Uplift Payment relating to the same network constraint.
  - In future, Small Aggregations may concurrently provide NSS while injecting active power behind a binding network constraint such that they are negatively mispriced. In such a scenario, it is not prudent to withhold the Energy Uplift Payment as the NSS may be unrelated to transmission congestion; and
- Require a Market Participant entering an NCESS contract to apply for Capacity Credits (where its Facility would ordinarily be eligible to apply for capacity); the NCESS payment is reduced by the amount of Capacity Credits that Facility would receive over the relevant Reserve Capacity Cycle.
  - The intent of this rule is to prevent a participant recouping its capital costs twice. Subtracting capacity payments from aggregations providing demand management through NCESS to address the minimum load problem may not be prudent (unless they are attempting to recoup capital costs through both the RCM and the relevant NCESS contract).
  - As such, minor amendments may be required to the NCESS rules to ensure the “double-dipping” provisions are fit for purpose for DER providing market services. NSS specific amendments cannot be drafted until further information is available on the types of NSS DER are likely to provide – see, for example, deferred issue **AGG8** (Section 5.2.3).

## The Energy Networks Access Code (ENAC)

The ENAC, in particular the changes introduced in 2020 to facilitate procurement of network solutions, provides a sound regulatory basis to ensure Western Power is able to procure NSS from DER to defer or substitute network augmentation costs.

Furthermore:

- The gain sharing mechanism approved in the ERA’s Framework and Approach for Western Power Fifth Access Arrangement[39] enables Western Power to retain savings from Opex on alternative options for a period of five years (and not recover overspending).
- The amended clause 6.52 of the ENAC notes the NFIT is satisfied if:

> *“...the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard to …**whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period** may require the installation of a new facility with capacity sufficient to meet the forecast sales”.*

This provision enables Western Power to consider potential benefits over the long-term (i.e. a “reasonable period”).

The ERA has also indicated in its document *Guideline on factors that will be considered in NFIT determinations and methods to value net benefits* that:

[38] Make whole payments to Facilities that have been negatively mispriced such that they have been cleared at an offer price that is greater than the Regional Reference Price at Southern Terminal.

[39] https://www.erawa.com.au/cproot/22112/2/Western-Power-AA5-Review---Framework-and-approach---Final-decision.PDF

- it expects to see identification and evaluation of non-network options; and

> *"Advances in technology are leading to greater opportunities for non-network options to be used to support network services. .... To meet the efficiency test, Western Power will need to demonstrate that it has properly identified and evaluated non-network options before proceeding with a new facilities investment.* ***This includes allowing adequate time for third parties to develop feasible alternatives****." Section 3.1*

- it expects an uplift in Capex in the coming years to build the capability to manage higher levels of DER, including investment in monitoring and communication equipment and information systems; and
- it expects an uplift in Capex in the coming years to build the capability to manage higher levels of DER, including investment in monitoring and communication equipment and information systems.

> *"Distributed energy resources can also provide lower cost options to network investment, so it is important that they be considered in the application of the new facilities investment test…*
>
> *Managing increased distributed energy resources may require increased monitoring and management of the network at a more granular level* ***which may require investment in monitoring and communication equipment and associated information systems****…*
>
> ***Western Power will need to clearly demonstrate that it has adopted a coherent and coordinated approach on investment required to integrate, manage and utilise distributed energy resources that incorporates expenditure, pricing and demand management....***
>
> *Investment that is not required for safety and reliability will need to be justified based on the benefits it will provide. When making its assessment, the ERA will take into consideration whether the proposed network investment is aligned with the strategies set out in the Distributed Energy Resource Roadmap and ongoing reforms to provide future power system security."*

Hence, there is no obvious barrier to Western Power including DER-related Capex (or Opex) in its forecasts for the upcoming access period subject to demonstrating the proposed investment meets the NFIT and/or is aligned with the actions in the DER Roadmap.

EPWA considers that a prudent network operator with a reasonable expectation of significant DER uptake would investigate the potential to use the capability of DER to support provision of NSS and would invest in capability building and communications and control infrastructure. In fact, distributors in the UK, eastern Australia, New Zealand and throughout the United States have been incurring costs associated with 'product development' and industry capability building, noting that each jurisdiction uses differing cost recovery approaches:

The leading example of forward-looking investment in digitalisation is the UK distribution businesses. One of these, UK Power Networks (UKPN), in 2017 outlined five investment principles for its DSO transition.

1. Make sure our planned investments are consistent with the emergent DSO role and can support the full DSO role if this can be done for minimal additional cost.
2. Identify no regret investments that make sense whatever the future DSO model looks like, where the benefits accrue in the current price control period.
3. Identify innovation projects that can move our understanding forward, particularly where the benefit is uncertain or is expected to materialise in a future price control period.
4. Use business as usual funds to embed DSO capabilities if a business case can be made

5. Apply for Innovation Roll-out Mechanism funding for cases where there is clear customer benefit, but the current incentive regime cannot justify investment within the current price control.” [40]

In 2019, UKPN invested £15 million in Active Network Management (ANM), including a new intelligent software platform from Smarter Grid Solutions that will be integrated into the heart of its control system.[41] The platform was described as,

> *“It’s going to function a bit like your smart phone and apps. Once we have the core platform ready, we’ll be able to add a vast number of smart applications to it without having to build and maintain individual platforms for individual projects. The fact it acts as a platform, as opposed to a solution to a specific problem, means it will be able to take advantage of emerging technologies around big data, machine learning and artificial intelligence.”*

The investments in network visibility to support the transition to providing DSO functions underpin the uptake of flexibility services (i.e. NSS) and helped make procurement of flexibility a tool for balancing supply with demand by turning supply up or demand down, depending on what is happening on the network.[42]

Across the UK, the flexibility services market has grown rapidly from 116MW of flexibility contract in 2018 to 1.6GW contracted in 2021.[43]

A necessary pre-requisite to properly implement the intent of the ENAC changes is a coherent investment plan on how visibility in the low voltage network will be improved – see Section 5.1.1.

## Policy Issues – NSS

1. **NSS1** (Settled): *Procurement of NSS will be incorporated into the NCESS framework to ensure that there is a single unified and consistent framework for procuring all system services (be they transmission or distribution network-related).*

- EPWA will review the NOM and AOS framework in the ENAC to determine how best to consolidate with the NCESS rules in the WEM Rules.
- Changes will be required to NCESS framework or ENAC (as relevant) to ensure the content of the NOM better facilitates the development of flexibility or distribution NSS; e.g. by requiring the publication of information that provides aggregators a clearer view of what opportunities are present.
- Changes may be required to the NCESS framework to ensure the procurement rules are fit for purpose for distribution NSS.

2. **NSS2** (Settled): *Acknowledging that it may not have adequate incentives to do so, the current regulatory framework adequately enables Western Power to procure alternative options (including making necessary investment to facilitate procurement). The ERA has signalled it expects to see an uplift in Capex in the coming years to build the capability to manage higher levels of DER, including investment in monitoring and communication equipment and information systems.*

- Consideration could be given to whether more locationally granular service standard benchmarks would enable Western Power to better quantify net benefits associated with NSS procurement, noting that there are challenges with complexity and cost of this approach.

[40] FutureSmart-Consultation-Report.pdf (ukpowernetworks.co.uk)

[41] UK Power Networks - Plans unveiled for world’s most advanced electricity network control system

[42] Flexibility Hub - UKPN Smart Grid (ukpowernetworks.co.uk)

[43] https://www.energynetworks.org/assets/images/Resource%20library/ON21-WS1A-Flexibility%20Figures%202021%20Full%20Update%20(30%20Jul%202021).zip

- The key barrier to NSS procurement at this stage is the lack of digitalisation of network data (and hence lack of visibility, discussed in detail above) which will impede Western Power from identifying lower voltage network constraints and NSS requirements, from deploying NSS as an operational response, and incentivising investment by VPP operators in the right areas.

3. **NSS3 (Settled):** T*o ensure the integrity of the procurement process for NSS, Western Power will continue to assess the cost-effectiveness and technical suitability of third party offers to provide a service prior to directly investing in network solutions, including energy storage. noting that:*

- In the absence of any cost-effective third party offers[44] to provide NSS to Western Power, Western Power may make appropriate investment (including alternatives such as storage) to defer network augmentation
- Where there are third-party offers to provide NSS, Western Power should assess these for cost effectiveness vs network owned solutions (including storage).

4. **NSS4** (Settled): *Western Power must only procure NSS through aggregators for DER associated with Small Use Customers (<160MWh per year). For non-contestable customers (<50MWh per year), the aggregator will be Synergy.*
5. **NSS5** (Settled): *Western Power may directly procure NSS from larger customers with DER under the conditions below:*[45]

- Western Power can directly procure from customers with DER whose annual consumption is greater than the Small Use Customer threshold of 160MWh per year, at a single site.
- The customer associated with the site above may elect to provide NSS to Western Power from adjacent sites that consume below 160MWh per year (as long as there is at least one site consuming above 160MWh per annum that Western Power is directly procuring from). EPWA will work with stakeholders to further clarify how adjacency will be defined.
- Western Power's procurement as described above precludes it from aggregating the sites or devices at those sites. That is, Western Power will not act as an Aggregator; rather, where aggregation is required as indicated above, the relevant customer will be responsible for ensuring they can provide the services required from the devices at their sites; the customer may either act as its own Aggregator or engage a third-party for this purpose.
- If Western Power procures NSS directly from a larger customer whose connection point is part of a VPP registered to an Aggregator, then the Aggregator must ensure that any WEM bids and offers related to the VPP accurately reflect availability considering the relevant connection point's NSS obligations to Western Power; this will require either Western Power or the customer to notify the aggregator of NSS deployment plans.[46,47]

Underpinning the positions outlined in **NSS5** is the view that Western Power's core business (even considering its emerging DSO capabilities) is and will be the construction and operation of its networks. As such, it is undesirable for Western Power to compete with Aggregators for either

[44] See NSS4 and NSS5 for third parties that Western Power can procure NSS from.

[45] This does not preclude Western Power from procuring NSS directly from providers who own small generators with no behind the meter load, or front of meter storage facilities.

[46] This will be the case for all VPPs that are providing NSS. Project Symphony is including consideration of this requirement during its scenario testing.

[47] Note that it is unlikely that a contract between a large customer and Western Power would lead to an aggregator unable to meet its WEM obligations. This is because the aggregator's contract with the customer would presumably put availability requirements on the customer to ensure the aggregator can meet its WEM obligations.

customers (and their devices) or the provision of services, including NSS. Furthermore, allowing Western Power to aggregate sites would require it to invest in aggregation capability. Having invested in such capability, Western Power would have less incentive to procure from other aggregators. It is desirable, therefore, to restrict Western Power procurement to single sites with the limited exception indicated above.

### 5.2.3 Facilitate aggregator entry

## Aggregator choice

#### Current approach

The August 2020 Issues Paper noted an Aggregator was:

> *A party which facilitates the grouping of DER to act as a single entity when engaging in markets (both wholesale and retail) or selling services to the DSO (network operator).*

In effect, an Aggregator is an entity which provides electricity related services to AEMO or to Western Power, or provides direct benefits to themselves or their customers by aggregating DER. An aggregator may do so by:

- aggregating devices located behind-the-meter at either contestable or non-contestable customer sites; devices may include DER such as rooftop solar, battery storage, EVs, heat-pumps, pool-pumps. Devices are located at sites where there is a customer who has energy consumption requirements (i.e. service providing devices are co-located with a load); and
- aggregating devices that are directly connected (‘front-of-meter’) to Western Power’s low- or medium-voltage networks, with limited or no co-located load. e.g. directly connected battery storage in the distribution network owned by Synergy or other parties.

While certain forms of demand-side aggregations currently exist in the WEM (e.g. Demand Side Programmes and Interruptible Loads), complex aggregations comprising behind-the-meter devices co-located with loads providing a variety of services do not currently exist in the SWIS. As such, there are currently no Aggregators operating in the SWIS in the manner contemplated in this Information Paper.

#### Future state

Orchestration of DER requires aggregators with the required technological infrastructure to enter the market and provide WEM services, NSS, or retailer services from aggregated DER under their control.

Western Australia’s regulatory framework for electricity services has certain features which affect the ability of non-retailers to provide services as an Aggregator. Specifically, competition for retail electricity services in the SWIS is restricted to customers with an annual consumption greater than or equal to 50MWh per year. Customers below this threshold must receive retail electricity services from Synergy. In terms of WEM services, this restricts Synergy to being the FRMP at any connection point serving a non-contestable customer.

This restriction means that even if multiple meters or multiple-trading-relationships[48] at a single meter were viable, no entity other than Synergy would be allowed to settle the energy at any connection point at which a Non-Contestable Customer was supplied. However, this restriction does not prevent parties other than Synergy from providing ‘non-energy’ services such as ESS or

[48] Multiple trading relationships at a meter refer to arrangements where multiple parties providing different services may be associated with a single connection point and meter. For example, a single connection point might be served by a retailer settling the energy. consumption (using import channel of the meter for settlement) and an aggregator who settles the DER generation (using the export channel of the meter for settlement).

Interruptible Load services, demand-side management (e.g. via Demand Side Programmes in the WEM), NSS, etc. to non-contestable customers.

The State Government has no near-term plans to make the retailing of electricity for residential customers contestable. Further, the existing licensing framework for energy services does not contemplate the provision of aggregation services to customers. As such, there is no customer protection mechanism covering customers aggregated by third parties. EPWA is currently progressing changes to primary legislation and the licensing framework to facilitate appropriate levels of consumer protection for new business models (including aggregation services) so that customers are fully protected. This work is in progress.

While Aggregation is still a relatively immature service in an emerging market, the policy preference is to extend the existing linear relationship between the customer and retailer[49] to aggregation arrangements to align with existing contractual relationships. This will ensure the customer only contracts with one party and that existing consumer protections are maintained. In the medium- to longer-term, alternative contractual structures may emerge with the evolution of technology and consumer preferences.

## Policy Issues - Aggregation

1. **AGG1** (Settled): *Only the FRMP at a connection point (NMI) can aggregate that NMI into a Small Aggregation for the purpose of offering energy into the WEM. This means:*

- if the FRMP has created an aggregation for the purposes of offering energy into the WEM, no other Market Participant can aggregate any of the relevant NMIs for the purposes of providing ESS only (including Interruptible Load) or a DSP - this is because the latter participant cannot control the flexibility at the relevant NMIs while another participant is controlling the energy; and
- the unit of aggregation for providing energy will be the connection point.

2. **AGG2** (Settled): *Non-contestable customers can only be aggregated by Synergy (or an intermediary acting through Synergy[50]). This restriction applies to all services (WEM and NSS).*

This position allows aggregator choice in the medium to long-term if the contestability threshold shifts and has been adopted to ensure Non-Contestable Customers maintain adequate protections until such time as protections specific to the provision of aggregation services are developed. The position also reflects policy preference to retain the linear relationship between customer and retailer.

Third parties can provide aggregation services but must do so as an intermediary, on behalf of Synergy. For example, an intermediary wanting to provide energy and ESS by aggregating DER can do so if Synergy is the Market Participant to whom the aggregation is registered. Likewise, third parties can provide NSS; however, Synergy would hold the contractual relationship with Western Power.[51]

[49] That is, the retailer holds the supply contract with the customer and the access contract with the network operator (Western Power). By contrast, in the NEM the retailer only holds the supply contract with the customer, while the customer directly holds the contract with their network operator.

[50] The FRMP at a connection point for a non-contestable customer is Synergy. This means that only Synergy can offer energy in respect from Small Aggregations comprising connection points of Non-Contestable Customers. However, intermediaries can act through Synergy to provide aggregator services, with Synergy remaining the responsible Market Participant.

[51] Project Symphony is exploring how these relationships may work.

3. **AGG3** (Settled): *Contestable customers can be aggregated by anyone - subject to **AGG1**, **NSS4** and discussion in **NSS5** above.*
4. **AGG4** (Settled): *As a consequence of **AGG2** and **AGG3**, the following will apply to aggregations registered as Demand Side Programme or Interruptible Loads in the WEM:*

- Existing WEM Rules around participation will be retained for contestable customers. That is, any Market Participant can associate contestable customer NMIs to a Demand Side Programme or Interruptible Load.[52]
- Non-contestable customers' NMIs can only be associated to a Demand Side Programme or Interruptible Load by Synergy or an intermediary acting through Synergy. The registration framework in the WEM Rules will require amendment to reflect this restriction.

5. ***AGG5** (Deferred): Can aggregators aggregate NMIs to provide FCESS where those NMIs are associated with a different FRMP but are otherwise a non-dispatchable load? The service would be analogous to an Interruptible Load but would have more flexibility, i.e. able to increase and decrease injection or withdrawal, and (subject to resolution of technological issues) able to provide raise and lower services for both contingency and regulation ESS). **AGG1** notes that the unit of aggregation will be the connection point. An FCESS only product will not be possible if service provision is at the connection point (and not at the device level)[53]; this is because the aggregator would need to control all elements behind the meter including the load as a Dispatch Instruction for FCESS would include a Dispatch Target for energy. This cannot be done prudently with a separate party acting as retailer for energy.*

   As noted in **WEM_ESS1**, existing FCESS specifications will be retained (including connection point delivery) and changes to technical requirements may be considered in the future when DER's ability to meet existing FCESS requirements are better understood. It is therefore prudent to defer this decision until DER's capability to provide FCESS is better understood.

6. **AGG6** (Settled): *As a result of **NSS1** (NSS to be procured through the NCESS framework), aggregators or service providers providing NSS may need to register in the WEM in accordance with the WEM registration and NCESS rules. Where the WEM Rules require an NSS provider and their Facility to register, they must do so. Practically, this means that this means that service providers providing NSS from small Facilities (less than 10MW) may not need to register themselves or their Facilities.*

## Access to historical meter data

### Current approach

The current SWIS licensing regime has the following energy data provision regulations:

- The Electricity Industry (Metering) Code 2012 (Metering Code):
    - requires Western Power as Meter Data Agent to provide historical meter data to retailers and anyone with whom Western Power has an access contract;
    - enables a customer (usually a retailer) to direct Western Power to provide historical data to a nominated individual;

52 Under the post-amended WEM Rules, a connection point can be associated with up to three parties: the retailer, the Demand Side Programme provider, and the Interruptible Load provider. Hence, a Contestable Customer that is part of an aggregation may have relationships with up to three parties where their connection point is aggregated to both a Demand Side Programme and an Interruptible Load.

53 See Section 5.2.4, for a discussion on issues associated with FCESS provision and measurement at the device level

- requires electricity retailers to provide consumption and standing data to customers for billing purposes and for the provision of metering services;
- requires Western Power to confirm that customer details and associated NMIs are accurate (clause 5.17A(2)(a) of the Metering Code, which requires Western Power to confirm verifiable consent);[54]
- requires signatures and names must be provided of the customer associated to the metering point; and
- depending on the volume of data requested, allows up to 10 business days for data to be provided to customers.

- The Code of Conduct for the Supply of Electricity to Small Use Customers 2018 (Code of Conduct) requires:
  - electricity retailers to provide historical billing data to non-contestable Small Use Customers within 10 business days; and
  - Western Power to supply Small Use Customers with historical consumption data within 10 business days.

Likewise, while the Code of Conduct enables customers to access historical billing and consumption information, customers would need to email that data to prospective Aggregators. This is not an efficient process and is not scalable.

### Future state

Effective orchestration requires Aggregators to have access to meter and other energy data (e.g. tariff and billing information) to inform product offers to customers. The framework and processes are not fit for purpose to facilitate data exchange with third parties at scale.

One option is to adopt the CDR data exchange mechanism (regulated by the Australian Competition and Consumer Commission). The CDR was introduced to provide consumers greater control over their data. It enables a consumer to direct a data holder to provide their CDR data to an accredited data recipient, in a CDR-compliant format that ensures privacy and information security protections are maintained. Proposed changes to the Consumer Data Right Rules to expand the CDR to the energy sector by late 2022 were published in August 2021.[55]

CDR datasets in the energy sector will include metering data (including NMI standing data), billing data, tariff data, customer details, and register of DER.

In the NEM, AEMO will operate the gateway that will enable the exchange of energy data between third parties (or data recipients) and data holders. The AEMO Gateway will provide benefits by automating authentication, facilitating data exchange between data holders and accredited data recipients, capturing customer consent, and coordinating with the ACCC accreditation register

In November 2020, EPWA assessed the applicability of the CDR to Western Australia under Action 33 of the DER Roadmap Action 33[56]:

*By September 2020, assess the applicability of the Consumer Data Right to Western Australian energy customers and commence assessment of an applicable customer data regulatory framework.*

54 The expectation set for verification through implementing the Consumer Data Right (CDR) for banking is for a digitalised and near instantaneous online process. See below for more details on the Consumer Data Right (CDR).

55 Refer to Consumer Data Right rules amendments (version 4) | Treasury.gov.au

56 Energy Consumer Data Right in Western Australia. Position Paper. 6 November 2020. https://www.wa.gov.au/system/files/2020-11/Energy%20Policy%20WA_Position%20Paper%20-%20Energy%20Consumer%20Data%20Right.pdf

EPWA concluded that the unique characteristics of the Western Australian energy sector would require a customised implementation model for CDR, citing the following reasons:

- AEMO (as gateway operator) does not have visibility of the metering database as Western Power is the Meter Data Agent in Western Australia (vis-a-vis AEMO in the NEM).
- The CDR framework requirements do not automatically apply to state-owned entities such as Western Power and Synergy. The Federal Treasurer is required to seek Western Australian Government agreement if the CDR requirements are to be applied to Western Australian state-owned electricity entities.
- There are several EPWA workstreams pertaining to the DER Roadmap and the review of the electricity retail licensing framework that may impact on how the CDR is implemented in Western Australia.

EPWA therefore proposed that the implementation of the CDR for the Western Australian energy sector be assessed in 2022. Until the CDR is re-assessed for Western Australia and implemented, the existing regulatory regime will need to be leveraged to facilitate low-cost meter data and other energy data exchange. While the level of aggregation in Western Australia remains low, and Synergy is the main aggregator (see **AGG2**[57]), the existing means of data exchange as outlined in the previous subsection may suffice (i.e. access of billing and meter data through the customer or directly from Western Power with permission of the client).

However, the current provisions for data exchange are not scalable and would not be able to accommodate large numbers of aggregators seeking meter and billing data for large numbers of customers. Additionally, the scope of available data under the current regulatory regime is not as wide as that available under the CDR energy datasets. As the implementation of the CDR is to be re-assessed soon, there is limited value in implementing large-scale changes to the existing data exchange provisions.

### Policy issues

1. **AGG7** (Deferred pending re-assessment of CDR implementation in Western Australia): *How will the efficient exchange of historical meter and other energy data be facilitated to enable third parties (aggregators) to access data for business development purposes?*

- EPWA will re-assess the implementation of CDR following implementation and evaluation of the relevant reform work programs currently underway. This may resolve this issue.
- If a customised implementation of the CDR is not adopted in Western Australia, consideration will need to be given to:
  - changes to Western Power’s existing (largely manual) process for meter data provision to third parties to facilitate low-cost data exchange at scale;
  - ability for third parties to request billing, tariff, and customer data directly from retailers with the customer’s permission; and
  - *efficient and effective means of capturing c*onsent, ensuring information security and dispute resolution (so customers can lodge complaints) for the above.

## Value stacking as double payment

### Current approach

As a general principle, Aggregators (or any service provider for that matter) should not be paid twice for the same service as this may unnecessarily increase costs to the end-consumer.

[57] Given AGG2, (allowing only Synergy to aggregate Non-Contestable Customers), the issue of data exchange will, in the short to medium-term, only affect parties able to aggregate Contestable Customers, or intermediaries wanting to enter the market through Synergy.

An example of double payment in the WEM is where a facility receives an Energy Uplift Payment for negative mispricing during congestion, while simultaneously being paid to provide an NCESS to relieve the local congestion. The NCESS already compensates that facility for negative mispricing; therefore, the facility has been paid twice for doing the same thing (relieve congestion and serve local load). For this reason, the NCESS framework will prevent the payment of Energy Uplift Payment to any facility providing an NCESS to relieve the relevant constraints.

### Future state

With respect to aggregated services, it is important to not mischaracterise the ability of flexible resources to simultaneously provide different services as "double-dipping". Flexible resources can value stack successfully precisely because they are able to provide different services simultaneously.

WEM energy, Capacity and FCESS services are designed to prevent double dipping. The potential for double dipping therefore exists where:

- DER provides WEM services above alongside NSS or other services procured via the NCESS framework; or
- DER provides multiple NSS simultaneously.

Without knowing the full range of NSS services that are likely to be procured from DER, it is challenging to determine whether double dipping is likely. However, considering the types of flexibility services procured by Distribution Network Service Providers in the UK (constraint management, system restoration and outage management), it can be noted that these services are distinct from traditional WEM services. For example, a DER facility providing a constraint management service to Western Power (by supplying local load during periods of distribution congestion) could simultaneously provide the following services when injecting active power into the network:

- a NSS to Western Power whose value is related to Western Power's network investment costs; and
- energy to SWIS consumers.

The DER facility above could provide Reserve Capacity at the same time as supporting network capacity. Such a situation should be described as value-stacking, rather than double dipping. The separate procurement decisions of AEMO and Western Power would be made independently and decisions to dispatch or deploy the services would also be made independently.

As noted above, without knowing the full range of NSS Western Power will procure, it is not possible to develop explicit criteria that reliably make the distinction between double dipping, rather than flexible value stacking. As such, this matter should be revisited in the future when service specifications for NSS become clearer.

The NCESS framework enables AEMO and Western Power to subtract Capacity Credit payments from the relevant NCESS contract payment; this is to ensure that providers do not attempt to recoup capital costs twice through the RCM and NCESS. As noted in issue **NSS1** (Section 5.2.2), these rules may need to be reviewed to ensure DER providers are not inadvertently penalised where their NCESS payments do not include capital costs.

### Policy issue

1. **AGG8** (Deferred): *What approach will be used where an aggregation provides similar services across the value stack to prevent "double-dipping"?*

## 5.2.4 Facilitation of WEM participation

## Registration and aggregation

### Current approach

All references to registration arrangements in this section pertain to the post-amended WEM Rules that will apply on or after new WEM Commencement Date (1 October 2023).

In the WEM Rules, parties wanting to provide WEM services are required to register as a Market Participant and in most cases are required to register the facility which will provide the service.[58]

The WEM Rules mandate Rule Participant and Facility registration based largely on the System Size of the relevant Facility:

- For the purposes of WEM service provision, a Facility is:
  - a set of Facility Technology Types[59] behind a network connection point. This definition contemplates traditional ("non-DER") Facilities. Two or more such Facilities can be aggregated into an Aggregated Facility under clause 2.30 of the WEM Rules, but the aggregation rules do not apply to Small Aggregations, Interruptible Loads or Demand Side Programmes. Aggregation criteria include that:
    i. the aggregation must not adversely impact on AEMO's ability to maintain Power System Security and Reliability;
    ii. the relevant participant can provide Standing Data for each individual Facility and the aggregation as whole;
    iii. appropriate control and monitoring equipment must exist for the aggregation;
    iv. facilities being aggregated must be at the same Electrical Location to facilitate the specification of network constraint equations for the purposes of SCED;
    v. where a Facility is providing ESS, the ESS capability can be accurately depicted for the aggregated Facility in its entirety;
    vi. to prevent the over-procurement of Contingency Reserve Raise costs, either the credible contingency associated with the aggregated Facility must represent the loss of the aggregated Facility in its entirety (as opposed to loss of individual components), or the aggregation must be small enough to not affect Contingency Reserve Raise costs; and
    vii. all individual Facilities comprising the aggregation must have the same Facility Reserve Capacity Price, and none of the individual Facilities must be under a Network Control Service contract which prevents them from being aggregated.
  - a Small Aggregation. A Small Aggregation is a group of Facilities that are distribution connected and located at the same Electrical Location (or substation with the same Transmission Network Identifier (TNI)). This definition contemplates aggregated DER. For example, a VPP comprising BTM DER falls under this definition, as does an aggregation of FTM storage connected directly to the distribution network;
  - a Demand Side Programme; or
  - An Interruptible Load.

[58] Parties wanting to provide NCESS only from a facility must register as a Market Participant. However, Facility registration is not required for Facilities with a System Size less than 5MW, or where the service is provided by equipment like synchronous condensers.

[59] Non-Intermittent Generating Systems, Intermittent Generating Systems, Electric Storage Resources (storage), or Loads.

- Participant and Facility registration is mandatory if the relevant Facility has a System Size greater than or equal to 10MW. Smaller Facilities are usually exempt from registration requirements; however, AEMO can enforce registration requirements on such Facilities if the exemption compromises AEMO's ability to maintain PSSR.
- The System Size of a Facility is a function of its maximum potential injection (lesser of its technical capability to inject and its network access or Declared Sent-out Capacity (DSOC)) and its single cycle change capability as measured by maximum potential withdrawal by Electric Storage Resources (lesser of the technical capability to charge and its network access or Contract Maximum Demand (CMD)).

Registered Facilities are assigned a Facility class. The purpose of a Facility class is to enable placing obligations on Facilities which share characteristics, and therefore share similar obligations (e.g. obligations relating to dispatch compliance).

Facilities can register in the following Facility classes:

Table 3: Facility class summary

| Facility class | Registration Requirements |
|---|---|
| Scheduled Facility | Must be fully controllable such that it can comply with a Dispatch Target to maintain its Injection or Withdrawal for a specified period (e.g. Facilities comprising Electric Storage Resources only, Non-Intermittent Generating Systems such as thermal plants, or hybrid systems comprising Non-Intermittent Generating Systems and Electric Storage Resources). |
| Semi-Scheduled Facility | Must be partially controllable so that it can curtail upon request from AEMO, i.e. it can comply with a Dispatch Cap by reducing the absolute value of its Injection or Withdrawal (e.g. Facilities comprising Intermittent Generating Systems such as wind or solar, or hybrid systems comprising Intermittent Generating Systems and Electric Storage Resources). |
| Non-Scheduled Facility | Not required to comply with Dispatch Targets or Dispatch Caps but must respond to Directions during system emergencies.<br>Only Facilities with a System Size below 10MW can be registered in this category.<br>Under certain circumstances (relating to Power System Security and Reliability), AEMO may enforce registration in the Scheduled Facility or Semi-Scheduled Facility Classes or sub 10MW Facilities which could otherwise have registered as a Non-Scheduled Facility. |
| Interruptible Load | Interruptible Load Facility comprising one or more Non-Dispatchable Loads that can be interrupted in response to a frequency signal to provide Contingency Reserve Raise ESS.<br>Interruptible Loads are compensated solely via ESS payments,<br>Energy consumed by the associated Non-Dispatchable Loads is settled by the participant for that Non-Dispatchable Load. |
| Demand Side Programme | Demand Side Programme Facility comprising one or more Non-Dispatchable Loads that can be curtailed on request by AEMO.<br>Demand Side Programmes are solely compensated via Reserve Capacity payments.<br>Energy consumed by the associated Non-Dispatchable Loads is settled by the participant for that Non-Dispatchable Load. |

## Future state

Aggregators wanting to provide WEM services from their aggregated DER (or Small Aggregations) will need to meet technical requirements that are specific to the service being provided. Technical requirements pertaining to ESS and RCM are discussed in more detail in the sections below. The requirements for providing energy mostly depend on an aggregation's size and consequently

Facility class.[60] Particularly, for aggregations registering as a Scheduled Facility or a Semi-Scheduled Facility (whether voluntarily or compulsorily by AEMO), AEMO must undertake a controllability assessment to determine whether the aggregation is fully or partially controllable, as set out in a WEM Procedure.

As such, no amendments are required to the WEM Rules to facilitate a controllability assessment for Small Aggregations registering as a Scheduled Facility or a Semi-Scheduled Facility. Changes would be required to the relevant WEM Procedure. It is worth reiterating that until a solution is found to facilitate Facility level visibility (see Section 5.2.1), it will not be possible for any Small Aggregations comprising BTM DER to enter the market irrespective of Facility class. Additionally, capability improvements are likely required by AEMO.

In addition to meeting technical requirements, Small Aggregations must be incorporated into the registration framework so that:

- there is an aggregation process that specifically caters to Small Aggregations, which must cover:
  - initial registration of the aggregation;
  - ongoing changes that facilitate the addition and removal of connection points to reflect the fact that VPPs are more dynamic in nature than traditional facilities, including the extent to which the addition and removal of individual households is tracked by AEMO;
  - how aggregations will be treated with respect to their contribution to the Contingency Reserve Raise requirement;
    - » As noted above, clause 2.30 does not allow the aggregation of traditional facilities where the credible contingency is the loss of individual components as opposed to the entire Aggregated Facility. This restriction is to prevent the over-procurement of Contingency Reserve Raise costs.
    - » Small Aggregations will comprise multiple connection points or Facilities where the credible contingency will not be the loss of the entire aggregation. As such, this restriction cannot be applied to Small Aggregations in its current form as it would prevent larger aggregations[61] that do not pose the same risk as traditional grid-connected aggregated facilities from registering.
  - how aggregations will be treated in ESS cost recovery;
    - » The cost of Contingency Reserve Raise ESS is recovered from causers who contribute to the Contingency Reserve Raise requirement; i.e. energy producing resources cleared for energy and Regulation raise services above 10MW in a given Dispatch Interval.
    - » The requirement is set by the Largest Credible Supply Contingency; the runway method allocates costs to causers of contingencies, commensurate with the extent to which they have contributed to the additional procurement of Contingency Reserve Raise Requirement. The rationale for this approach is that the credible contingency associated with traditional Facilities is the loss of Facility in its entirety.
    - » The credible contingency associated with an aggregation would not be the loss of the whole aggregation. Hence changes to Contingency Reserve Raise cost recovery should be considered to ensure the causer contribution of Small Aggregations is modelled appropriately.

[60] However, smaller Facilities can optionally register in the Scheduled Facility and Semi-Scheduled Facility classes. In doing so, they would be subject to the relevant dispatch obligations.

[61] Small Aggregations that are small so as not to affect the amount of Contingency Reserve Raise procured would be unaffected by this restriction.

- the registration process considers any specialised arrangements for DER. For example, The System Size definition which affects Facility Class assignment should be fit for purpose to apply to VPPs. Particularly, the System Size definition in the WEM Rules specifically references Declared Sent-out Capacity (DSOC) and CMD.
  - These parameters do not apply to residential connections that may be part of a Small Aggregation. Consideration should be given to what values should be used for Small Aggregations. Options include using:

1. the maximum physical connection limit (e.g. 15kVA import/export for single phase residential customers); or
2. the installation limit for DER systems such as solar PV and batteries (e.g. 5kVA per phase for standard residential connections[62]); there are currently no such limitations on load devices (e.g. EV chargers); or
3. forecast maximum DOEs for export; using a forecast DOE (which may have accuracy issues) is not appropriate for the purposes of determining System Size.

Option 1 and Option 2, above, are equivalent as the maximum physical connection will always be greater than or equal to installation limit, which will be greater than or equal to the maximum injection capability of the DER behind the meter. Options 1 and 2 are more consistent with the concept of Declared Sent Out Capacity (DSOC) and Contracted Maximum Demand (CMD) as it reflects the connection points' unconstrained access (ignoring any distribution or transmission constraints). Option 1 is more closely related to the concept of DSOC and CMD and is therefore preferred for definitional consistency purposes. In other words, for small aggregations the DSOC equivalent would be the minimum of the maximum physical connection limit and the installation limit.

Small Aggregations comprising behind the meter load will use some of their generation to meet the requirements of that load. Hence, System Size for Small Aggregations could consider the maximum injection capability of Energy Producing Systems and maximum withdrawal capability of Electric Storage Resources net of expected load behaviour. For example, a Small Aggregation comprising 7.5MW of storage across multiple connection points would have a System Size of 15MW (7.5 (injection) + 7.5 (offtake)) under the post-amended WEM Rules as currently drafted. However, the load at these connection points might be such that realistically, only 4MW of storage capacity is available. An alternative System Size calculation would be 8MW (4+4). This approach is undesirable for two reasons:

1. It does not reflect the gross capability of the battery to modify the net response at the connection point (e.g. the battery in this example can modify the Facility's Injection or Withdrawal by up to 15MW (e.g. if it is providing an ESS raise service while charging).
2. It is inconsistent with how the System Size of Facilities with Intermittent Loads is calculated for the purposes of assigning a Facility class.

High-level registration principles should, insofar as is possible, be consistent across different technology types. As such, it is preferable to retain the same principles for System Size calculation for Small Aggregations.

[62] Currently, there are restrictions placed by the network operator on the size of DER systems that can be installed at residential connections. The installation limit is 5kVA per phase and does not reflect the size of the actual network connection. In the future this limit may be increased for systems that are subject to a DOEs.

## Policy Issues – Registration and aggregation

1. **WEM_REG1** (Settled): *The high-level principles applied to aggregating conventional Facilities (in clause 2.30 of the WEM Rules, see above) will also apply to Small Aggregations.*[63] *In particular (but not limiting):*

- Small Aggregations will not be permitted to aggregate connection points across diverse Electrical Locations. This restriction applies irrespective of the System Size of the aggregation. AEMO has advised there is scope to streamline registration processes for smaller aggregations (e.g. with a total System Size less than 10MW) to reduce transaction costs; this would depend on the flexibility of the aggregation process (see **WEM_REG3**).
- AEMO can only deny aggregation of DER, if it can demonstrably prove an impact on power system security and reliability. AEMO's process for determining power system security and reliability impacts of a Small Aggregation will vary relative to traditional Facilities aggregated under clause 2.30 of the WEM Rules. The details of such a process could be devolved to a WEM Procedure; however, the WEM Rules will require clauses to enable AEMO to consult with Western Power to deem power system security and reliability impacts and to oblige Western Power to provide information as required by AEMO.
- Further consideration will be needed to ensure that aggregators do not break-up DER aggregations into smaller facilities to avoid WEM Rule obligations.

2. **WEM_REG2** (Deferred): *What approach will be taken to determining the contribution of Small Aggregations to the Contingency Reserve Raise requirements when:*

- modelling the Contingency Reserve Raise contribution of Small Aggregations for the purposes of dispatch (e.g. for traditional Aggregated Facilities the contribution equals the total energy and Regulation raise cleared from the Aggregated Facility in its entirety?
  - this is not appropriate for Small Aggregations as the credible contingency will not be the loss of the entire aggregation).
- evaluating aggregation requests?
  - This will depend on how the contribution of Small Aggregations are modelled in dispatch.
- calculating the cost contribution of Small Aggregations via the runway method?

This issue is deferred as it applies only to larger aggregations that would be cleared for 10MW or more of energy and Regulation Raise. Such Facilities cannot enter the market until the issue of Facility visibility is resolved (see VIS2).

3. **WEM_REG3** (Settled): *The DER aggregation process (for aggregating connection points for a Small Aggregation) should follow a model like the Non-Dispatchable Load to Demand Side Programme/Interruptible Load association process set out in clause 2.29 of the WEM Rules.*

- The aggregation process must recognise the more dynamic nature of Small Aggregations so that aggregators can add and remove connection points with ease.
- While Small Aggregations will have more dynamic aggregation needs than traditional facilities, the extent of this dynamism will not extend to real-time or near real-time changes to aggregation configuration. See Section 5.4.1, issue IMP6 for details on how real-time or near real-time network changes affecting the availability of Small Aggregations should be handled.

4. **WEM_REG4** (Settled): *The Facility class transition principles applied to traditional Facilities with respect to Facility will apply to Small Aggregations. That is, AEMO can transition Facilities*

[63] As noted above, however, a separate section will be required in the WEM Rules (over and above clause 2.30) addressing how DER will be aggregated.

*to different classes if configurational changes require it, or where PSSR concerns require the Small Aggregation to appear in network constraint equations.*

5. **WEM_REG5** (Settled): *System Size for Small Aggregations will follow the same principles as that of other Facilities:*

- System Size will not consider behaviour of any behind-the-meter loads to ensure consistency with how other Facilities with co-located loads are treated (e.g. Intermittent Loads) and to ensure the calculation considers the gross capability of DER storage to modify the net response at a connection point.
- For Small Aggregations comprising residential or other connection points at which DSOC and CMD does not apply under the ENAC, the following will be adopted:
  - The DSOC equivalent of a Small Aggregation will be the aggregate physical connection limit (MW equivalent) for export.
  - The CMD equivalent will be the aggregate physical connection limit (MW equivalent) for import.
  - This change will need to be reflected by modifying the WEM Rules, either directly in the System Size definition, or in the definition of DSOC and CMD. The former is preferred, as DSOC and CMD are ENAC defined terms and should be defined consistently in the WEM Rules.

It is worth noting that given the unique characteristic of Small Aggregations (particularly comprising behind-the-meter DER), tailored WEM Rules may be required governing Facility class assignment and transitions (and possibly registration rules more broadly). However, it is not possible to pre-empt such amendments until further experience has been gained as DER enters the WEM. Hence, registration is likely to be an evolving process. AEMO and EPWA will continue to evaluate the appropriateness of existing minimum facility limits in the face of aggregated DER participation.

## Essential system services

### Current approach

ESS are dispatched by AEMO to maintain system security, restore power, and address locational issues. The post-amended WEM Rules contemplate two categories of ESS:

1. **FCESS**, which includes Contingency (raise, lower), Regulation (raise, lower), and RoCoF Control Service. FCESS are AEMO's key tools to meet the Frequency Operating Standards (FOS) specified in Chapter 3B of the WEM Rules – see Table .

- Contingency Reserve and RoCoF Control Service performance is measured using high-speed data recorders. Response is autonomous; the facility control system monitors local frequency and responds when the frequency goes outside a defined range, or, in the case of RoCoF Control Service, delivered automatically according to the inertia of that Facility.
- Regulation is centrally managed via Automatic Generation Control (AGC). The size of AGC movements is based on SCADA measurements of system frequency, which are used to calculate a required response from each Facility enabled for Regulation, every four seconds. The AGC signal can take up to 30 seconds to reach a facility; upon receiving the signal the facility must respond within five seconds. AEMO is exploring limits for lag time in concert with other thresholds and requirements for FCESS services to ensure the efficacy of these services.

Table 4: FCESS summary

| FCESS | Description |
|---|---|
| Contingency ESS | • Arrests, stabilises, and restores the SWIS Frequency after a Contingency Event occurs.<br>• Provided by Facilities able to rapidly adjust output or consumption in response to significant changes in their local frequency.<br>• Facilities can provide Contingency Reserve Raise or Lower or both.<br>• Contingency Reserve Raise service operates to address under-frequency excursion. Cost is recovered from generators using runway method.<br>• Contingency Reserve Lower service operates to address over-frequency excursion. Cost is recovered from consuming participants in proportion to their consumption. |
| Regulation ESS | • Keeps SWIS Frequency close to 50 Hz by offsetting minor mismatches between electricity supply and demand.<br>• Provided by Facilities capable of receiving Automatic Generator Control (AGC) signals from AEMO.<br>• Facilities can provide Regulation Raise service, Regulation Lower service, or both.<br>• When the SWIS Frequency is below 50 Hz, AEMO will send AGC signals to increase output (or reduce consumption) (Raise).<br>• When the SWIS Frequency is above 50 Hz, AEMO will send AGC signals to reduce output (or increase consumption) (Lower).<br>• Cost recovered from loads, Non-Scheduled Facilities and Semi-Scheduled Facilities in proportion to the absolute value of their Metered Schedules. |
| RoCoF Control Service | • Slows the Rate of Change of Frequency (RoCoF) to within the RoCoF Safe Limit.<br>• Provided by Facilities which contribute inertia when synchronised to the power system.<br>• Cost recovered from causers who cannot demonstrate ride-through capability. Additional RoCoF (substitute for Contingency Reserve Raise) requirement recovered via runway method. |

- Facilities providing both FCESS and energy must meet AEMO's Dispatch Target for energy (specified in clause 7.6.11 of the post-amended WEM Rules). This Rule effectively limits provision of energy and FCESS to resources that can control their energy output to meet a Dispatch Target. DER and grid-connected hybrids (with an uncontrollable load or generation component) may not currently be able to meet this requirement.
- Accreditation thresholds define the minimum amount a Facility can be accredited for. Facilities seeking Contingency Reserve ESS must accredit a minimum of 5MW; Facilities seeking Regulation ESS accreditation must accredit a minimum of 10MW. AEMO has indicated that intends to review the appropriateness of these minimums for a high DER environment.

1. **NCESS**, which can be procured by AEMO or Western Power (triggered by Coordinator):

- NCESS can be procured by Western Power as a "network control service" to defer network investment or otherwise relieve network constraints. The NCESS framework is flexible enough to interpret this type of service to apply to any part of the Western Power network (high, medium, or low voltage).

- AEMO can also procure NCESS for system restart services and to meet ad-hoc “dispatch support services” (e.g. ramping).

### Future state

The flexibility inherent in DER devices makes them a good candidate for the future provision of ESS. However, there are challenges associated with technology integration that must be resolved to facilitate the provision of contingency and regulation ESS from DER aggregations.

#### *Contingency reserve ESS provision from DER*

Challenges associated with contingency reserve ESS provision from DER include:

- *Defining an appropriate measurement resolution to measure Contingency Reserve response from aggregated DER*: As noted above, high-speed recorders measure contingency reserve response. These record service provision at 40 millisecond (ms) intervals. Some DER aggregations may not currently be able to be measured to this level of granularity. The AEMO Market Service Ancillary Services Specification (MASS) trials in the NEM used one second granularity to measure Contingency Reserve response.[64]
  - Measurement at this granularity can lead to material over-estimation of service delivery (i.e. the measurement exceeds actual service delivery). Additionally, unexpected responses due to oscillatory behaviour because of voltage or frequency disturbance cannot be detected at coarser measurement granularity.
  - AEMO is investigating alternative measurement granularity for DER and has noted the potential to increase the granularity to 200ms in the NEM with consequential changes to AEMO’s verification methodology. It is however recognised that the WEM and the NEM are different environments, and any future changes will need to be appropriate for local conditions.
- *Defining the measurement point for the service*: The WEM Rule definition of ’Facility’ (see Registration section, above) means that the point of service provision and the point at which the service will be measured is the connection point (i.e. at the relevant NMIs of a DER aggregation). An alternative is to measure the service at the inverter level. However, this approach has been rejected in AEMO’s recent Market Ancillary Service Specification (MASS) review in the NEM, as AEMO is unable to verify actual service delivery from the inverter alone (e.g. the measurement at the inverter may under-estimate actual delivery because of a related change in consumption by the load at the NMI).
- Potential power system security and reliability issues due to inverter behaviour, including:
  - Unexpected disconnections: The AS 4777.2:2020 inverter standards should mitigate this risk for new connections due to the ride-through requirements in the standard. Risk mitigation is subject to inverter settings remaining compliant, for example not being reset inadvertently by a manufacturer firmware update or intentionally by the DER owner.
  - Under-delivery of service because of autonomous (Volt-Watt, Volt-Var) inverter response or DOE limits, noting that the aggregator should have visibly of the current performance of DER and any network constraints, and build this into their ESS offer.
- *Adverse interactions with Under-Frequency Load Shedding (UFLS) schemes*: For example, if the aggregation contains connection points behind a feeder that is disconnected during an UFLS event, then the aggregation will be unable to respond to the contingency event, potentially exacerbating the power system risk further.

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[64] Some participants in the pilot noted that they were able to meet the 50ms measurement requirement. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/mass/third-stage/amendment-of-the-mass-der-general-consultation-second-draft-determination.pdf?la=en

The 5MW accreditation threshold for Small Aggregations able to provide Contingency Reserve Raise may prove a barrier to entry as such Facilities are likely to be much smaller in size than traditional Facilities. As with other facility size thresholds, further consideration needs to be given to applicability in a high DER environment following further learning and experience.

### *RoCoF Control Service provision from DER*

The post-amended WEM rules explicitly require actual inertia or a spinning mass for the purposes of providing RoCoF Control Service. Hence, inverter-based technologies cannot provide RoCoF Control Service. However, Fast Frequency Response (FFR)[65] is possible through the use of performance factors in the Contingency Reserve service specification (i.e. faster-responding resources can provide fewer MW to provide the same level of service and are effectively paid more per MW of service delivered than a slower resource); additionally, Contingency Reserve Raise ESS can also be used as substitute for RoCoF Control Service (as co-optimised with the Additional RoCoF Control Requirement) where this reduces overall cost.

DER could provide FFR once the challenges noted above have been resolved; this includes the emerging capability of inverter-based battery storage systems to provide synthetic inertia. AEMO has recommended this as a priority area for testing at scale to support the transition from large synchronous generators to inverter-based power resources.[66]

### *Regulation ESS provision from DER*

As noted above, Regulation ESS is managed centrally via AGC. Research is still required to understand whether this model can be applied to DER aggregations. Regulation ESS has not been tested in any NEM VPP pilots. Further learning is required to understand the potential for larger front-of-meter storage to provide these services.

Note that an alternative to AGC is autonomous response. For example, in New Zealand regulation (or frequency-keeping) is provided through autonomous generator response.

Like other services, the current accreditation threshold (10MW) for Regulation ESS may prove a barrier to Small Aggregations that are likely to be smaller in size than traditional Facilities. EPWA and AEMO will give further consideration of what accreditation thresholds are appropriate for DER in the future following consultation with the sector.

### *NCESS provision from DER*

The NCESS framework in the WEM Rules provide a generic and flexible framework for AEMO or Western Power to procure ESS that will not be co-optimised with energy in dispatch. The flexible nature of the framework means that AEMO or Western Power can detail requirements for DER providing a specific service (performance, monitoring, etc.) in the contract with the Aggregator (as opposed to being restricted by service specifications in the WEM Rules).

AEMO noted in its renewable integration study update[67] that – in the short-term – there is potential to procure non-standard ESS from Small Aggregations, including services to:

- maintain minimum load by increasing imports or decreasing exports;
    - This product could operate in prior to ESM. ESM would be invoked to prevent an emergency operating state if AEMO is unable to resolve the situation through other measures that include this product;

65 Fast Frequency Response (FFR) refers to the delivery of rapid active power increase or decrease by generation or load in a timeframe of two seconds or less to correct a supply-demand imbalance and assist in managing power system frequency.

66 https://aemo.com.au/newsroom/news-updates/application-of-advanced-inverters

67 AEMO, *Renewable Energy Integration – SWIS Update*, September 2021, available at: https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf?la=en

- manage volatility caused by variability of roof-top PV and other forms of intermittent generation; and
- provide a ramping service to flatten the morning and evening ramps caused by PV ramping up and down respectively.

The NCESS framework can be used to procure the above services from DER; however, AEMO must first demonstrate that the requirements above cannot be procured through the FCESS framework.

## Policy Issues – Essential System Services

1. **WEM_ESS1** (Settled): *No changes will be made to the post-amended WEM Rules or Procedures pertaining to FCESS provision in the short-term. There is not enough information available to address the challenges to FCESS provision by aggregated DER as currently assessed. Existing technical specifications will be retained in the short-term and be revised to incorporate DER as lessons are learned from VPP pilots including Project Symphony.*

The approach to amending technical specifications and alternative standards will be to test whether DER can meet existing service standards/specifications (e.g. via VPP pilots and trials), and only specify an alternative when it is confirmed DER cannot meet the existing specification and where the alternative is assessed as appropriate for the WEM. Hence, while regulation ESS could be provided through autonomous response, such a specification would not be explored until it is confirmed that AGC cannot be used for DER.

The post-amended WEM Rules do not prevent Small Aggregation seeking ESS accreditation. However, in practice, most Small Aggregations will not be able to meet the current technical requirements. Updates to AEMO processes and procedures are also still required to apply for DER aggregation. This means DER will be unable to provide any FCESS other than an Interruptible Load seeking accreditation for Contingency Reserve Raise – see **WEM_ESS2**.

Alternative standards may be specified in the future depending on the above. A review should be conducted in the future to perform a stock-take on whether the technical issues pertaining to ESS provision from DER have been resolved, and whether it is timely and appropriate to consider alternative standards for ESS. In the interim (as per issue **WEM_ESS3**, below), AEMO may use the NCESS framework to procure alternative ESS from aggregated DER if required.

2. **WEM_ESS2** (Settled): *DER can be aggregated into Interruptible Loads; all connection points that are part of the aggregation must be at the same Electrical Location (see **WEM_REG1**).*
3. **WEM_ESS3** (Settled): *AEMO may use the NCESS framework to procure NCESS from DER as required from either existing and intending Market Participants and service providers who may be exempt from registration requirements. This may include (but is not limited to) services to maintain minimum load, address intermittent and DER volatility, and providing ramping (as set out in AEMO's renewable integration study update).*

AEMO must first demonstrate the relevant ESS needs cannot be met through the FCESS framework.[68] Alternatively, the Coordinator may identify that more economic procurement could be achieved through a bespoke service (as opposed to over-procurement of FCESS).

The NCESS framework allows AEMO to specify visibility requirements in the contract with the aggregator. No further policy decisions are required to give effect to this position.

4. **WEM_ESS4** (Deferred): *Will the requirement to meet a Dispatch Target (clause 7.6.11) be amended to enable energy and FCESS provision from hybrids and DER if such facilities cannot control their energy output to meet a Dispatch Target? This issue is broader than*

[68] Or the Ancillary Services framework prior to New WEM Commencement Day.

*facilitating DER participation in the WEM. As such this issue is deferred to be addressed through a more appropriate work stream.*

5. **WEM_ESS5** (Deferred): *Will FCESS accreditation thresholds be reduced to facilitate DER participation? This issue cannot be addressed until the technical issues relating to FCESS provision by DER is resolved (see issue WEM_ESS1). Moreover, a review of thresholds is better handled via a future review of ESS arrangements.*

## Reserve Capacity Mechanism

### Current approach

The RCM's objective is to assure the reliability of energy supply within the SWIS.

Key features of the RCM in the post-amended WEM Rules include the following:

- Capacity is procured to meet the Reserve Capacity Requirement which is set using the Planning Criterion prescribed in the WEM Rules. This effectively requires AEMO to procure enough capacity to meet the larger of:
    - A one-in-ten-year peak demand forecast including a reserve margin plus an allowance for Regulation ESS and Intermittent Loads, and
    - Sufficient capacity to limit expected unserved energy to 0.002% of annual demand.
- The allocation of Certified Reserve Capacity depends on a resource's capability to generate during peak load intervals. For example:
    - Non-intermittent generating systems are certified based on their sent-out at generation at 41 degrees centigrade.
    - Intermittent generating systems (and Non-Scheduled Facilities) are certified using the Relevant Level Methodology which allocates capacity based on historical output during Trading Intervals when surplus capacity was the lowest, and therefore the system was under greatest stress (known as the Existing Facility Load for Scheduled Generation (EFLSG) intervals).
    - Electric Storage Resources are certified using the linear de-rated method which allocates capacity based the ability of storage to sustain output during eight consecutive Trading Intervals during a Trading Day (Electric Storage Resource Obligation Intervals), given their storage (MWh) capability and capacity (MW).
    - Demand Side Programmes are certified based on the amount of load they can curtail relative to their Relevant Demand, which is indicative of the consumption of its Associated Loads during peak Trading Intervals.[69]
    - Ability to curtail relative to Relevant Demand for DSPs
- Certified Reserve Capacity cannot exceed a Facility's DSOC which is the maximum access granted to the Facility under its access contract with Western Power.
- Capacity credits are assigned based on Certified Reserve Capacity adjusted for network congestion. This is achieved by calculating NAQs which considers the delivery capability of Facilities during peak demand intervals under a variety of dispatch scenarios in the presence of network constraints. Briefly:
    - Capacity Credits are assigned based on a Facility's NAQ.

[69] The Relevant Demand of a DSP represents the larger of its historical 5% POE consumption during peak Trading Intervals, and the aggregate Individual Reserve Capacity Requirements (IRCR) of its Associated Loads.

  - The NAQ framework facilitates access to Capacity Credits for incumbents, where this access is usually only affected by the retirement of a Facility, by changing network constraints, or if there are severe performance issues such as prolonged outages or where changes to the network impact that Facility.
  - New entrants can only access residual capacity unless they fund network augmentation.
  - Only Scheduled Facilities and Semi-Scheduled Facilities are constrained in the NAQ calculation. Non-Scheduled Facilities are treated as unconstrained and assigned Capacity Credits based on the Certified Reserve Capacity that they have been allocated based on the Relevant Level Methodology.
- The Reserve Capacity Price is based on an administered Benchmark Reserve Capacity Price (BRCP), which reflects the Long Run Marginal Cost (LRMC) of a 40MW Open Cycle Gas Turbine (OCGT) and is derated depending on the amount of excess capacity procured.
- Facilities assigned Capacity Credits have obligations:
  - The Reserve Capacity Obligation Quantity (RCOQ) reflects the amount that a facility must offer into the STEM and real-time energy markets; RCOQ is zero for intermittent systems and Non-Scheduled Facilities.
  - Market Participants must pay refunds if they fail to meet the must-offer obligation above with respect to Facilities with non-zero RCOQ.
- Some Facilities subject to Reserve Capacity Tests (intermittent systems and Non-Scheduled Facilities are not tested). AEMO can reduce Capacity Credits for Facilities that fail a second test.
- Scheduled Facilities and Semi-Scheduled Facilities must have sub-metering for each Separately Certified Component comprising the Facility where that Facility contains multiple Separately Certified Components, or a single Separately Certified Component and an uncertified Energy Producing System. For example, a Facility comprising an Electric Storage Resource and solar PV generator must have sub-metering for the storage and the generator. The sub-metering is used only for certification and reserve capacity testing purposes.

Note that a review of the RCM by the Coordinator of Energy has commenced, the outcomes of which may impact on how the Reserve Capacity Requirement is set and how Certified Reserve Capacity is allocated.

### Future state

The characteristics of DER or Small Aggregations pose challenges when it comes to RCM participation:

- The sub-metering requirements applied to Scheduled Facilities and Semi-Scheduled Facilities are specified in a way that means every single behind-the-meter device being certified would require a sub-meter or appropriate SCADA. This is unlikely to be commercially viable, and as such alternative means (such as testing based on sampling) will need to be developed to test and certify Small Aggregations intending to register in the above Facility Classes.
- As noted previously, it is unlikely that Small Aggregations will register in these categories in the short-term (given the barrier to meeting the controllability requirements pertaining to these classes, and the absence of tailored visibility for monitoring purposes (see issue **VIS2**)). Longer-term fit-for-purpose metering arrangements or aggregated telemetry could be suitable for RCM purposes.
- Certification of Small Aggregations (irrespective of Facility class) will require AEMO to form a view on the likely consumption of 'parasitic' or embedded loads. This assessment will be challenging for connection points containing unpredictable customer loads. The WEM Rules are silent on the approach that AEMO must adopt when considering the effect of parasitic or embedded loads; as such this assessment could be devolved to procedure but must be addressed to facilitate certification.

- Small Aggregations seeking certification under the Relevant Level Methodology may be adversely affected by the requirement to provide an Independent Expert Report; reviewing and assessing the output profile of multiple connection points (including the complexity of modelling the effects of the uncontrollable behind-the-meter load) may be a financial barrier. However, this issue could be addressed by specifying tailored requirements for Small Aggregations via a WEM Procedure.
- The calculation of NAQ for Small Aggregations of scheduled and semi-scheduled facilities will require the formulation of distribution-network level constraints; this would require changes to the NAQ rules unless an alternative approach is adopted (see below). This is unlikely to be possible without distribution network visibility (see unsettled issue **VIS1**).[70]
- AEMO advises that the NAQ methodology as currently drafted has limited scope to be amended to include distribution-level constraints. If the NAQ methodology cannot be applied to Small Aggregations (either due to an absence of visibility, or because distribution-level constraints cannot be incorporated into the NAQ method), then an alternative approach may be required, e.g. modelling the NAQ of a Small Aggregation at its Electrical Location and distribution network constraints modelled by proxy by using DOE values during peak periods to set the Facility DSOC for certification purposes; this is not an ideal approach and in the first instance incorporating distribution-level constraints into the NAQ method would be preferable.

Notwithstanding the challenges above, the post-amended Rules as drafted do facilitate some participation of DER or Small Aggregation:

- Small Aggregations can be certified to provide Demand Side Programme services.
- Small Aggregations (with a System Size below 10MW) intending to register as a Non-Scheduled Facility could be certified under the Relevant Level Methodology. Non-Scheduled Facilities are treated as unconstrained in the NAQ calculation; hence the NAQ issue noted above would not require resolution to enable Non-Scheduled Facilities to gain certification. The main challenge preventing Non-Scheduled Facilities participating relates to issue **VIS2** pertaining to Facility visibility.

### Policy issues

1. **WEM_RCM1** (Settled): *Small Aggregations can seek certification as Demand Side Programmes. No further policy decisions or WEM Rule amendments are required to give effect this.*
2. **WEM_RCM 2** (Deferred pending RCM review): *How will Small Aggregations seek certification as Non-Scheduled Facilities under the Relevant Level Method? As indicated above, the WEM Rules already allow for such aggregations to seek certification under the Relevant Level Method. However, DER participation in the Non-Scheduled Facility category will not be possible until the issue of Facility visibility is resolved (see **VIS2**). Moreover, given the upcoming RCM review, this issue would be revisited once the review is complete.*

   Notwithstanding the deferral of this issue, note that the following applies with respect to certifying Small Aggregations registering in the Non-Scheduled Facility class under the post-amended WEM Rules:

- AEMO will require WEM Procedures to determine the impact of parasitic and embedded loads on the sent-out capability of the Small Aggregation.

[70] As NAQ calculations focus exclusively on periods of peak operational demand, congestion in the distribution network is likely to be in the direction of withdrawals (as opposed to injection). It may be possible for Western Power, therefore, to specify a limit set of distribution constraints focussed limitations on injecting into the distribution network during peak intervals.

- The DSOC of a Small Aggregation intending to register as a Non-Scheduled Facility would be its physical connection limit (e.g. 15 kVA for a residential (single phase) connection limit). Note that a DOE here is not appropriate as the DSOC reflects the unconstrained contracted access of a Facility (noting that Non-Scheduled Facilities are treated as unconstrained for the purposes of the NAQ).
- Going forward, it is important to not incentivise the proliferation of large numbers of Non-Scheduled Facilities in the distribution network – especially as they are treated as unconstrained for the purposes of the NAQ. Such Facilities are not controllable for the purposes of dispatch and have limited obligations under the RCM. Note, however, that AEMO has powers to transition Non-Scheduled Facilities to a different class where PSSR is compromised.

3. **WEM_RCM3** (Deferred pending RCM review): *What approach will be taken to facilitate the participation in the RCM of larger DER aggregations intending to register in the Scheduled Facility or Semi-Scheduled Facility classes?*

- What changes will be required to sub-metering requirements and subsequently certification and reserve capacity testing requirements?
- What approach will be taken to model the impact of network congestion on the aggregation's contribution to reliability? That is:
  - *i. Will distribution network constraints be modelled via the NAQ method? If so, what changes might be required to the methodology facilitate this? Or*
  - *ii. Will Small Aggregations have NAQ calculations based on constraints modelled at their Electrical Location with distribution constraints modelled by proxy by setting the Facility DSOC to reflect the DOE at peak times or other time of system stress? If this approach is adopted, Western Power would need to provide DOE forecasts at the time of certification (two years before reserve capacity obligations apply). Western Power has indicated that such forecasts will be uncertain. In effect, this would mean that aggregators would be subject to refunds if in real-time their actual DOEs diverge from the DOEs used to allocate Certified Reserve Capacity.*[71]

The resolution of this issue is deferred as:

- The entry of larger VPPs registering in the Scheduled Facility and Semi-Scheduled Facility classes are unlikely until Facility visibility issues are resolved (see issue **VIS2**). Even if the visibility issue were resolved, it is unclear how such VPPs would meet the dispatch compliance obligations associated with these classes given the uncontrollable load component behind the meter. Ideally, Project Symphony needs to, and is considering the controllability and visibility aspects of aggregations that would be subject to dispatch compliance obligations.
- The upcoming RCM review may change the way reliability is measured and how Certified Reserve Capacity is allocated. As such, **WEM_RCM2** and **WEM_RCM3** are deferred pending the RCM review.

## Access to meter data to facilitate market settlement

### Current approach

In the reformed WEM, the settlement interval or Trading Interval will initially be 30 minutes. This Trading Interval will eventually move five-minute granularity; by this time registered (traditional) facilities and Contestable Customers will have been upgraded to five-minute meters.

[71] Noting that refunds would not apply to Non-Scheduled Facilities, or Intermittent Generating Systems comprising other Registered Facilities.

Meter data at Trading Interval granularity will be used in almost all settlement calculations including (but not limited to) energy settlement, RCM settlement, Market Fees recovery and many ESS cost recovery calculations. Additionally, AEMO must calculate Energy Uplift Payments (to compensate affected facilities for negative mispricing due to locational price separation) at Dispatch Interval granularity. The post-amended WEM rules (with 30-minute settlement) require AEMO to use SCADA data to profile 30-minute meter data into five-minute intervals to support this calculation.

### Future state

The following will be required with respect to Small Aggregations (comprising BTM DER at Non-Contestable Customer sites) for the purposes of market settlement:

- Under 30-minute settlement:
  - AEMO will require actual 30-minute meter data.
  - AEMO will require a head of power to profile 30-minute meter data into five-minute quantities for the purposes of the Energy Uplift Payment calculation.
- Under five-minute settlement:
  - As above, AEMO will require meter data at the appropriate Trading Interval granularity.

Small Aggregations comprising Non-Contestable Customer sites will be captured by Western Power's AMI roll-out. This means that by 30 June 2027, all Non-Contestable Customer meters are expected to have 30-minute granularity. While the meters being rolled out can be upgraded to read five-minute data, Western Power does not currently have the systems or the infrastructure to facilitate the provision of five-minute data from non-contestable meters (see also Section 5.1.1, Issue **VIS1**).

The transmission of five-minute meter data from significant numbers of connection points to aggregators and corresponding Meter Data Submissions to AEMO would require upgrades to the Western Power's network, head-end systems, and back-office systems. In the short-term, it is unlikely that there will be significant penetration of Small Aggregations in the WEM. As such, the number of connection points for which Western Power may need to transmit five-minute meter data may be modest; as noted in Section 5.1.1, it is unclear how many such connection points Western Power existing systems could accommodate without material upgrades (noting that Western Power's AA4 submission assumed five-minute settlement would only require five-minute data for traditional generators and Contestable Customer connection points). AEMO may also require upgrades to manage the volumes across all non-contestable customers.

An alternative to using five-minute meter data to settle Small Aggregations in the WEM, would be to profile 30-minute meter data to create estimates for five-minute settlement intervals. However, unless the profiling method is reasonably accurate at capturing variations within the 30-minute interval, there will be a misalignment (analogous to the 5/30 anomaly) between the price signals a Small Aggregation is responding to and what it is ultimately paid. For example, a Small Aggregation responding to a very high negative price in a five-minute interval by temporarily increasing its consumption to a high level will end up getting paid less if the profiling method is based on a straightforward average that under-estimates consumption in that five-minute period. If AEMO has access to five-minute connection point information from the aggregator (e.g. through the aggregator's platform), then the profiled estimates could be highly accurate (depending on what information is available).

There is also an issue of equity associated with preventing aggregators from accessing five-minute meter data when grid-connected and traditional embedded Facilities can access this data for the purposes of settlement.

## Policy Issues – Access to meter data to facilitate settlement

1. **WEM_METER1** (Settled): *For the purposes of 30-minute settlement AEMO will have access to 30-minute meter data through Western Power's AMI project.*[72] *While this rollout will not be complete until 30 June 2027, it is likely that only new DER meeting the new AS4777.2:2020 standard will be controllable for the purposes of aggregation; such DER will have AMI meters at their connection points.*

As such, the 2027 date for the AMI rollout completion should not affect the entry of VPPs. In any case, until the issue facility visibility is resolved (see Section 5.2.1: Issue **VIS2**), no VPPs will be able to enter the WEM to provide energy and FCESS.

- AEMO will require a head of power to profile 30-minute meter data into five-minute quantities for the purposes of the Energy Uplift Payment calculation. This will require an amendment to the relevant clause indicating profiled quantities (as opposed to SCADA profiled quantities) will be used for Small Aggregations. The profiling methodology could be devolved to a WEM Procedure.

2. **WEM_METER2** (Deferred): *Once five-minute settlement is implemented, will Small Aggregations comprising Non-Contestable Customer connection points be required to submit five-minute meter data or will profiling be used? (This issue is deferred pending further consideration and understanding of the costs involved).*

Completion of Action 14 of the DER Roadmap included Western Power's evaluation of the capability of its communications network and back-office systems (see Section 5.1.1, Issue **VIS1**). Lessons from Project Symphony will also provide insights on the type of information AEMO may be able to access from the aggregator for profiling purposes.

### 5.2.5 Standardised protocols

## Current approach

The WEM Rules place obligations on Rule Participants to have communication and control infrastructure in place to ensure:

- facilities providing WEM services are controllable for the purposes of dispatch (where required) by the relevant participant or by AEMO (depending on the service being provided);
- AEMO can communicate Dispatch Instructions to Facilities; and
- AEMO can remotely monitor Facility performance.

The details of the communications and control system requirements (including backup requirements) is devolved to WEM Procedures. The detailed requirements are based on traditional facilities and do not contemplate the participation of VPPs.

## Future state

#### Common standards and protocols

The orchestration of DER requires communication and control infrastructure between the aggregator and the devices they control to provide WEM services and NSS. These requirements will need to be standardised to:

- Provide AEMO and Western Power assurance that the devices which comprise the VPP are controllable by the VPP and can provide services safely, securely, and reliably.

[72] AEMO is likely to also require capability improvements to deal with increased volumes of data and communications related to expanding to a very large number meters across non-contestable customers.

- Ensure customers are not locked into a specific aggregator’s platform due to inconsistent standards.

Potential standards governing communications between devices and the aggregator include IEEE 2030.5 and IEC 61850. While a standard has not yet been selected for Western Australia, AEMO and Western Power advise that nationally there is a preference to move toward the IEEE standard. Standards associated with EV charging equipment are also becoming increasingly urgent to resolve given the potential impact of EV charging on network infrastructure. South Australia is currently leading a national approach in this area and has indicated a preference for OCPP1.6 or equivalent, which will be considered for implementation in Western Australia.

In terms of a standardised protocol, the CSIP-AUS protocol (which encompasses IEEE 2030.5) is being considered by the (DEIP Working Group, including how cybersecurity protocols could be applied under this protocol. Western Power has advised that if the CSIP-AUS protocol is adopted for Project Symphony, the project will test whether there are any gaps in terms of cybersecurity coverage.

### Scope of devices covered by common standards and protocols

The scope of devices covered by common standards and protocols must be able to facilitate a wide range of devices including electric vehicles.

Regarding direct procurement of services from large customers by Western Power (see **NSS5**), consideration also needs to be given to the extent to which standards will apply to different types of Facilities or aggregations. Connections that are 1MVA or greater already have SCADA monitoring and communication systems in place (through the customer’s connection agreement with Western Power). Whether or not additional communication standards (e.g. via CSIP-AUS) are required will depend on whether Western Power is procuring from single sites only or has access to nearby related sites and the nature of control required by Western Power (which will depend on the nature of the NSS being procured).

Western Power has advised that it currently does not have enough information to advise on the above. As such, it is not possible at this stage to determine what standards and protocols would apply governing communications between Western Power and customers it directly procures from.

### Standards governing reliability of communications and redundancy

VPPs have a different risk profile to traditional resources when it comes to risks related to communication loss and availability. This is due to the different technological and configurational characteristics of VPPs. Tailored requirements governing loss of communications and redundancy are therefore required for VPPs.

If an aggregator loses control of devices that are part of its VPP, its ability to provide WEM services or NSS may be compromised. As such AEMO and Western Power (as procurer of these services) may need standardised requirements around:

- *Default behaviour that is likely from the devices that comprise the VPP when there is a loss of communications between the aggregator and its devices:* This will govern rules around how VPP dispatch would be handled if there is a transient vs more prolonged loss of communications. It is possible that there is scope in CSIP-AUS to require an autonomous loss-of communications response to be embedded in inverters or other DER.
- *Redundancy requirements to mitigate against the loss of service provision*: For example, aggregators may be required to recruit an additional “reserve margin” of DER to ensure that in the event of communications loss, other devices or connection points in the VPP can provide redundancy. It is important to assess the actual reliability risks associated with DER (in terms of likelihood, consequence, and materiality) to ensure that overly restrictive redundancy requirements are not specified.

- *Overly restrictive requirements may lead to unnecessary costs imposed on aggregators*: Restrictive requirements may limit the extent of active DER participation. An alternative to specifying redundancy requirements, is to rely on performance requirements and liability provisions to ensure aggregators provide the service as required (as it is incumbent upon them to ensure delivery – how they choose to do so is at their discretion and may involve recruitment of additional connection points to cover communications loss or other unforeseen events).

Project Symphony will inform how standardised requirements regarding default behaviour from devices and redundancy requirement should be set.

### Governance of standards

Consideration must also be given to which regulatory instrument common standards and protocols would be enforced through. Options could include enforcing standards through the:

- connection agreement; and/or
- WEM Rules. For example, the rules could require that an aggregator must ensure that their Small Aggregation is compliant with CSIP-AUS, or that rule participants must only procure DER services from aggregators who comply with the standard.

Note that standards pertaining to reliability of communications and redundancy requirements should sit in the WEM Rules for aggregations providing standard WEM services and in the relevant contract for aggregations providing NCESS/NSS.

## Policy Issues – Standardised protocols

1. **COMMS1** (Deferred): *What standards and protocols will be adopted to govern communications between the aggregator and the devices in a VPP? This is the subject of on-going work by DEIP, which will be monitored by EPWA, Western Power, and AEMO.*

2. **COMMS2** (Settled): *The standards and protocols adopted under **COMMS1** must include electric vehicle charging equipment and may include electric vehicles.*

3. **COMMS3** (Deferred): *What standard and protocol will apply to communications between Western Power and customers that it directly procures from? As noted above, Western Power does not have enough information to advise what its communication requirements may be. As such, this issue is deferred until it is clearer how direct procurement of NSS by Western Power would work. See related issues **NSS3** and **NSS4**.*

4. **COMMS4** (Deferred): *What requirements and rules will be placed on VPPs to mitigate against loss of communications by way of standardised default behaviour and redundancy requirements?[73] This issue is deferred pending the outcomes of Project Symphony which will inform default behaviour and redundancy requirements, and lessons from NEM pilots.*

5. **COMMS5** (Deferred): *Which regulatory instrument should common standards and protocols be enforced through? This issue does not need to be resolved until **COMMS1** is settled. Furthermore, the work being undertaken by EPWA regarding the legislative framework for energy sector governance that will consolidate and rationalise regulatory instruments.*

Standards additional to Western Power connection requirements pertaining to reliability of communications and redundancy requirements should sit in the WEM Rules for aggregations

[73] Note, the CSIP-AUS standard includes a requirement to reduce export to 1.5kW when there is loss of communications. Adopting the CSIP-AUS standard may therefore address this issue.

providing standard WEM services and in the relevant contract for aggregations providing NCESS/NSS.

## 5.3 Align customer incentives and protect rights

### 5.3.1 Tariffs

#### Current approach

Electricity retail contestability is currently restricted to customers consuming 50MWh and above per year. Retail tariffs charged by Synergy to non-contestable customers are regulated by the State Government and usually determined as part of the State Budget process.

Network tariffs charged by Western Power are regulated by the ERA under the ENAC.

The DER Roadmap Regulatory Settings Summary paper identified the following issues with retail and network pricing.[74]

- Network tariffs provide little signal of the costs being imposed on the network.
- Discounted network tariff for efficient connections (using DER) are provided for in the ENAC, but are rarely, if ever, used.
- Retail tariffs deliver limited signalling of the value of DER/load shifting at different times of day.
- The Uniform Tariff Policy (as applied to both retail and network tariffs) limits signalling of value of DER at different locations.
- For rooftop solar systems, the Renewable Energy Buyback Scheme (REBS) rate is unlikely to reflect value of rooftop solar output to the broader system, including at different times of day. REBS has since been replaced with the Distributed Energy Buyback Scheme – DEBS, which partly addresses this problem.[75]
- The existing retail consumption tariff and REBS framework does not provide a strong incentive for installing batteries due to current battery prices, the over-compensation of exports, lack of time of use signals relating to network congestion, and the absence of effective arbitrage opportunities.
- Most customers – both with and without DER – are currently on a flat retail tariff and, as such, have no incentive to shift their consumption to times that would lower overall costs.

The conclusion outlined in the Regulatory Settings Summary Paper was that, given circumstances in late 2019:

*'Without appropriate price signals, household customers have no incentive to use or export DER generation in ways that are valuable to the system. The flat A1 tariff (and REBS) may even encourage customers to exacerbate system issues by overinvesting in solar PV and facing their PV panels north (maximising total generation) rather than west (which would better support the system at peak times).'*

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[74] DER Roadmap Regulatory Settings Summary, page 4, Table A. Note the issues reflect circumstances in late 2019.

[75] While DEBS does not precisely reflect the value of rooftop solar generation to the power system (it reflects an approximation of the balancing market value of the energy), the buy-back rate is lower than the REBS rate and features varying time-of-export rates, with rates being lower during periods of higher solar output. Non-contestable customers will gradually be transferred from REBS to DEBS as systems are upgraded or replaced. It is expected that in approximately four to five years, there should be very few customers on REBS.

## Future state

Orchestration of DER will require more cost-reflective wholesale, transmission, and distribution pricing – the 'input' costs to the delivered electricity service – to provide actionable information about the costs and benefits of using energy services and the network by time and, for contestable customers potentially location.

More cost-reflective pricing provides customers, including DER owners, retailers, Aggregators, Western Power, and AEMO with the information required to make efficient decisions about the use of electricity, the use of the distribution network for import or export, and efficient decisions about coordinating the use of the distribution service.

Consequently, cost-reflective, and ideally locational (reflecting network conditions and costs at the feeder or substation level), pricing is preferred as it may better support successful DER orchestration by communicating information about the costs and benefits of consuming or producing electricity and of using network capacity by time and location. Effective DER orchestration will be difficult to achieve without cost-reflective pricing of input costs.

There are no regulatory barriers to Western Power developing cost-reflective pricing (albeit not by location for almost all customers); however, the ability to pass through cost-reflective retail pricing structures is limited by the regulatory settings for retail tariffs, the rate of AMI roll-out, and Western Australian's uniform tariff policy.

Changes to the ENAC mean Western Power must engage with customers on a tariff structure statement which describes how its proposed pricing structures meet regulatory requirements, or why they do not.

Successful orchestration requires a distribution pricing structure which includes a signal of the impacts of using the network by time and location, by using a charge which discourages activity which causes congestion (i.e. breaching thermal limits either from export during the day or import during early evening summer peaks) and provide revenue to fund costs of NSS used to alleviate the issue (with the costs reflecting the value of not augmenting the local network).

Without cost-reflective pricing which customers respond to, coordination of network use will rely more heavily on command-and-control mechanisms which take less account of customer preferences and whole-of-system costs and benefits. Additionally, without cost-reflective tariffs, investment in battery storage is likely to be stilted until battery prices drop significantly. While a potential substitute to orchestrating storage is capitalising on the Vehicle to Grid (V2G) capability of Electric Vehicles, regulatory interventions promoting technology integration (e.g. smart charging) alone will not be sufficient for orchestration purposes. For example, the UK's Office of Gas and Electricity Markets' (OFGEM) strategy[76] includes an approach to technology integration which encompasses both technology interventions (e.g. requiring new homes to have smart charging capability, developing enablers such as data and communications for smart charging) and pricing interventions through time-of-use tariffs.

Retail pricing should reflect customer preferences regarding exposure to price and quantity risks. Direct pass through of input costs to end-consumers is not a requirement for successful orchestration. However, the commercial feasibility of aggregators does require the aggregator to be exposed to input costs to develop its aggregation proposition.

However, this needs to be traded off against other policy considerations that are in place to reduce cost pressures on rural and regional households and other customers below 1MVA that are put into effect using a 'postage stamp' approach to network pricing and the uniform tariff policy. These policies recognise a characteristic of the SWIS where a significant proportion of the Western Power

[76] https://www.ofgem.gov.uk/sites/default/files/2021-09/Enabling%20the%20transition%20to%20electric%20vehicles%20-%20the%20regulators%20priorities%20for%20a%20green%20fair%20future.pdf

distribution network (over 50%) exists to serve a small number of customers in these areas (around 3% of total customer base).

Energy Policy WA, Western Power and Horizon Power are progressing work on stand-alone power systems and regional microgrids that use DER to reduce costs in high cost-to-serve areas outside the scope of this project.

### Policy Issue - Tariffs

1. **CUST1** (Settled): Postage stamp pricing will be retained for network tariffs for customers below 1MVA. While the regulatory requirement for uniform pricing does not preclude locational signalling using demand charges, the current tariff structures do not include such charges. This position could be revisited once the AMI project has been fully rolled out.

## 5.3.2 Customer protections

### Current approach

Western Australia has a licensing framework that places regulatory obligations on electricity retailers and network owners. The licensing framework encompasses customer protection regulations. The licensing framework also enables providers to seek exemption from specific licensing obligations.

The framework was developed at a time when electricity supplies were for the most part centrally generated and supplied to consumers via the transmission and distribution networks under supply contracts with retailers.

The energy transition has seen increasing number of alternative electricity suppliers entering the market to provide services such as “solar as a service” that includes the supply of assets and financing. Such suppliers are increasingly seeking exemptions from licensing obligations compromising the ability of the framework to deliver adequate customer protections.

### Future state

Given the appropriate market and regulatory conditions, orchestration of DER will result in increasing numbers of suppliers offering innovative new products that do not readily fit within the current licensing framework. Without changes to address the gaps in customer protection regulations, orchestration will bring with it increasing risks to the consumer.

Energy Policy WA is undertaking a project which will be address the gaps in the licensing framework with a view to developing a tailored framework covering alternative electricity suppliers such as aggregators.

### Policy issues

1. **CUST2** (Deferred to Energy Policy WA’s licencing framework reforms): *What changes are required to the retailer and network operator licensing framework to ensure customers are protected from risks associated with entering contracts with aggregators using devices at customer sites (e.g. residences) for orchestration purposes?*

## 5.4 Integrate and phase implementation

### 5.4.1 Coordination of WEM and NSS dispatch

#### Current state

There is currently no coordinated dispatch of NSS and WEM services, as DER is currently not orchestrated for either service. While Western Power does procure some NSS, it is from traditional generators, and the extent of NSS use does not require coordination with AEMO for the purposes of maintaining power system security and reliability.

#### Future state

Orchestration of DER will see aggregators coordinating distribution connected devices to value stack services such as energy, capacity, ESS and NSS. Service provision across WEM and network services requires co-ordination between Western Power and AEMO to ensure all services are delivered while maintaining security and reliability requirements across the power system and the distribution network. Even where aggregations are providing NSS only, large-scale orchestration of such aggregations requires coordination with AEMO as the power system operator to ensure AEMO has visibility of the impacts of NSS dispatch on system load and potential upstream impacts on transmission network congestion.

Coordination of dispatch requires the following issues to be addressed:

- *DMO/DSO roles and responsibilities for dispatch co-ordination*: The August 2020 Issues Paper proposed a hybrid model which implements a natural extension to AEMO's role as market operator (taking on the DMO role), and Western Power's role as distribution network operator (taking on the DSO role).
  - While Western Power currently deploys NSS, the historical scale of NSS use has had negligible impacts on AEMO's decision making as power system operator. Additionally, providers of NSS have not concurrently provided WEM services. Hence central co-ordination of dispatch has not been necessary.
  - As market participation by DER increases, central co-ordination by a single party such as AEMO may be more efficient than co-ordination by multiple parties. However, adding a "middle-man" deploying instructions on behalf of Western Power may create inefficiencies due to latency issues. Project Symphony will yield practical lessons on NSS dispatch that can be used to determine the most appropriate party to allocate NSS dispatch responsibility to.
- *AEMO's role in NSS dispatch*: If AEMO were to be the entity responsible for the dispatch NSS in future, this role may be nominal, where Western Power sends deployment instructions to dispatch aggregations to a set MW level (e.g. dispatch an aggregation to 10MW). In this case, AEMO would merely be a conduit implementing an instruction directly from Western Power before it dispatches WEM services (see discussion on dispatch hierarchy below). If, however, the instruction from Western Power comes in the form of a constraint (as it does for Generator Interim Access (GIA) Facilities which operate under a Network Control Service, e.g. a particular facility must generate no more than 100MW), then AEMO would need to incorporate that constraint into its dispatch engine and come up with an optimal dispatch solution. In this case, AEMO is still a conduit but is undertaking additional calculations to optimise overall outcomes given the NSS constraint deployed by Western Power.
- *Coordination of AEMO and Western Power in dispatch*: The detail of how AEMO performs NSS dispatch will depend on the nature of the NSS. Consideration would also need to be given to how NSS dispatch would be co-ordinated where Western Power directly procures from large customers (see also issue **NSS3**). Particularly, what information must Western Power provide to AEMO when it procures and dispatches NSS directly from customers?

- Determining a market interaction and dispatch hierarchy:
  - Energy and FCESS will be co-optimised in the reformed WEM, while NCESS services pertaining to network control would place limits on dispatch of energy and FCESS. A similar approach should be adopted for NSS, where NSS has priority ahead of WEM services. While it is theoretically possible to co-optimise NSS, energy and FCESS, the infrastructure to do so does not exist today and is not likely to exist in the medium-term. Even if it did, consideration must be given to the costs of such a complex co-optimisation relative to the benefits it delivers. See Issue **IMP7**, Section 5.4.2 for further discussion on extending the complexity of the dispatch hierarchy.
  - NSS are focused on a specific location. This means that only a subset of connection points registered in an aggregation with AEMO may be activated to provide NSS (as opposed to the aggregation in its entirety). Consideration needs to be given to how an NSS dispatch instruction pertaining to part of an aggregation would be implemented. One option is to allow only those connection points providing NSS in a single aggregation. However, this may be inefficient for an aggregator, who may have to register multiple aggregations behind an Electrical Location to provide WEM services instead of just one. This is an issue that requires further consideration once basic DER participation capability is established.
- *DSO provision of information to Aggregators*: Determining Western Power's obligations as DSO to provide distribution network information to aggregators, where such information affects their availability to provide NSS or WEM services. For example:
  - Network switching can affect an aggregator's NSS provision and WEM service provision; the latter would be affected if network switching results in part of an aggregation being mapped to a different Electrical Location (relative to the Electrical Location recorded in Standing Data for the aggregation). While it is uncommon for distribution network switching to affect the Electrical Location of an embedded Facility, it is not impossible.
  - As such, The DSO will need to notify aggregators where network switching means connection points that are part of an aggregation will be mapped to a different Electrical Location.[77] The aggregator can adjust its facility registration standing data to reflect the change and adjust its market offers appropriately. Further work is needed to fully understand the implications and approach to addressing the issue.
  - The DSO will require access to selected Standing Data pertaining to Small Aggregations including connection points in an aggregation and the Electrical Location.
  - Distribution network outages will affect an aggregator's bids and offers into the WEM. In the new WEM, transmission outages (forced and planned) will be represented as network constraints and will therefore be a part of the SCED clearing engine's inputs (expressed as constraint equations). The clearing engine will consider constraints caused by transmission network outages when clearing Facilities. Hence, Western Power has no obligation to provide information on transmission network outages directly to Market Participants. This approach is possible because:
    1. SCED has a network constraint library modelling the transmission network (based on limit advice from Western Power).
    2. Western Power is required to schedule planned outages of transmission network equipment. Hence, AEMO will have visibility of how such outages impact on network constraints.
    3. AEMO has visibility of the transmission network via its EMS which enables it to detect forced outages of network equipment, and update network constraints accordingly.

[77] The DER register should reflect such changes where a NMI changes association with a TNI with Western Power updating AEMO of such a change. Current processes are not likely to meet operational requirements.

The distribution network will not be modelled for the purposes of SCED, as dispatch occurs at the Electrical Location of a Facility. As such AEMO cannot model the impact of a distribution network outage (planned or forced) on dispatch. Instead, distribution network outages will be incorporated into the DSO's (Western Power) DOE calculation by reducing the available network capacity in the areas affected by the outage. This means the DSO will require the capability to update DOEs in near-real time where there are forced outages affecting the availability of DER aggregations providing market services.

In the case of a forced network outage, the aggregator may also have visibility (from the device telemetry) that export from that NMI is no longer available. In this case the aggregator will be able to adjust its service offers, even if the DSO has not issued an updated DOE. In effect the aggregator can see the 'forced outage' of some, or all, of its facility. Further consideration is needed of the interaction with RCOQ and refunds as there could be a differentiation between being unable to provide capacity due to behind the meter issues compared to distribution network constraints.

In the future, distribution outages may be addressed via the use of NSS; in such cases, the DOEs in the affected areas would not be reduced.

## Policy issues – Coordination of WEM and NSS dispatch

1. **IMP1** (Settled): *The hybrid model will be adopted with Western Power and AEMO performing the DSO and DMO functions respectively. These changes are expected to reflect extending existing capability, without resulting in new entities to deliver these functions.*
2. **IMP2** (Deferred): *Who will be responsible for dispatching NSS?*

   *As noted above, Project Symphony will yield practical lessons on NSS dispatch that can be used to determine the most appropriate party to allocate NSS dispatch responsibility. This issue is therefore deferred pending lessons from Project Symphony.*

Regardless of outcome, it is important that AEMO has visibility of NSS dispatch decisions that impact on power system security. Procuring NSS through the NCESS framework (see **NSS1**) will ensure obligations exist on Western Power to provide relevant information to AEMO in this respect.

3. **IMP3** (Settled): *The following dispatch hierarchy will be adopted:*

- NSS will be dispatched first.
- WEM services will be dispatched second
- The precise way NSS dispatch would be implemented will depend on who is responsible for dispatch (see **IMP2**).

4. **IMP4** (Deferred): *How will NSS dispatch be coordinated when Western Power procures NSS from larger customers directly? What information would Western Power need to provide AEMO?*

   *As noted above, AEMO must have visibility of any dispatch that impacts on its ability to dispatch WEM services and maintain power system security. This issue is deferred pending resolution of* ***IMP2*** *(NSS dispatch responsibility), as that is a precedent to finalising the details of dispatch coordination.*

An advantage of incorporating NSS into the NCESS framework is that it provides an established process for Western Power to provide this information relevant to the dispatch of the NSS to AEMO. A further advantage of using the NCESS framework is that AEMO will have visibility of NSS dispatch from larger customers; this will be particularly important where the customer's site is part of an aggregation providing WEM services (see also **NSS5**).

5. **IMP5** (Deferred): *Can NSS be provided by a subset of connection points within a registered aggregation also providing WEM services? If so, how will it be dispatched?*

*This issue is deferred pending the decision on **IMP2** and lessons from Project Symphony on whether a dynamic approach to managing the composition of aggregations is scalable.*

6. **IMP6** (Settled): *Distribution network outages and network switching affecting an aggregation's availability to provide market services will be managed as follows:*

- The DSO will provide information on network switching that affects the Electrical Location of connection points that are part of a Small Aggregation providing WEM services. To do this, the DSO will require access to selected Standing Data pertaining to Small Aggregations including connection points in an aggregation and the Electrical Location.
- Distribution network outages will be reflected through changes in DOEs in areas affected by the outage. This means the DSO will require the capability to update DOEs in near-real time where there are forced outages. In the future, distribution outages may be addressed via the use of NSS; in such cases, the DOEs in the affected areas would not necessarily be reduced.

### 5.4.2 Extending complexity as technology and knowledge evolves

Orchestration of DER is in its very early stages and there is still relatively little knowledge and experience on how DER can be integrated into existing markets and systems at the scale contemplated in the DER Roadmap. Given the pressing need to orchestrate DER to avoid inefficient outcomes and maintain power system security and reliability, waiting for technology and knowledge to evolve to facilitate orchestration at scale before acting is not prudent. As such, many of the policy positions adopted in the short- to medium-term will have to be simplified to enable implementation. However, as technology and knowledge does evolve it is important to revisit some of the simplified policy positions to assess whether more sophisticated arrangements can be instituted to optimise the use of DER and customer welfare further.

In particular:

1. **IMP7** (Deferred): *More complex arrangements for NSS procurement and dispatch may be contemplated in the future.*

The increase in complexity could vary significantly depending on the evolution of technology, investment in network visibility, knowledge, and aggregator entry. The table below provides examples (in order of least to most complex) of alternative approaches to NSS procurement and integrating dispatch of electricity related services.

Table 5: Examples of more complex approaches to NSS procurement and integrated dispatch

| Procurement approach | Comment |
|---|---|
| 1. Bilateral contracting between Western Power and providers (e.g. aggregators or customers) using merit order) | Competitive procurement process in which multiple providers offers are used to calculate a least cost clearing price.<br>This approach is used by Distribution Network Operators (DNOs) in the United Kingdom when procuring regional flexibility services where there is sufficient liquidity. |
| 2. Real-time NSS market (separate to WEM, but dispatch integrated with WEM with dispatch hierarchy dispatching NSS first) | DSO balances supply and demand for network capacity for each network element, (e.g. conceivably each feeder) by dispatching energy (solar/battery storage) on that element when load on the element is reaching technical limits, thereby reducing import from the medium voltage network. Conversely the DSO would dispatch load on the element (battery storage, pool pumps, EVs) when export is reaching technical limits, thereby reducing export to the medium voltage network. |

| Procurement approach | Comment |
|---|---|
| | Note that under this approach, NMI-level DOEs are effectively replaced by constraints defined at the network element level (e.g. the feeder) – i.e. logical node approach to setting DOEs.<br>The process can be done 'manually' by an algorithm which directs/controls the activity of the DER, or (preferably) be automated by using pricing visible to the aggregator to provide information about the value of importing/exporting. The latter approach is analogous to how the WEM uses Security Constrained Economic Dispatch (SCED) to dispatch energy to meet load given network conditions.<br>NSS dispatch or deployment is communicated to AEMO to incorporate into its WEM dispatch processes. |
| 3. Whole-of-system optimisation for energy, ESS and NSS | Under this approach a central party dispatches resources to meet energy, ESS and NSS. NSS may appear as distribution network constraints in the SCED algorithm – such that energy is dispatched subject to both transmission and distribution network constraints. Locational prices would be calculated at the distribution level and transmission level – hence providing price signalling at the low voltage level.<br>As above, this approach would see NMI level DOEs replaced with constraints defined at the network element (e.g. feeder) level.<br>While this concept has been investigated theoretically,[78] current technology and infrastructure would not support implementing an arrangement this complex without costs outweighing benefits. |

Moving to complex arrangements like the ones outlined above requires that certain pre-requisites be met, including:

- The development of clear product definitions;
- sufficient liquidity in the DER orchestration market so that there are multiple providers competing to provide services;
- technology capable of providing the services required by the power system; and
- network visibility adequate to facilitate:
  - planning activities, so that clear product definitions can be developed;
  - operational responses so NSS can be dispatched in real or near-real time; and
  - specification of distribution network constraints/DOEs at a logical node level.

In contemplating more complex arrangements, consideration must be given to whether the cost of increased complexity outweighs the benefit to the consumer in the long-term.

[78] See for example, https://www.srgexpert.com/wp-content/uploads/2019/01/An-exploration-of-locational-marginal-pricing-at-a-distribution-level-in-the-NZ-context.pdf

## 5.4.3 Timeframes

The DER roadmap included several actions directly related to DER participation.

Since the release of the Roadmap in 2019, there have been changes that will require updates to the timing of these actions. These changes include a move of the new WEM start from 1 October 2022 to 1 October 2023 and delays to the completion of Symphony to June 2023.

Actions 24 and 25 will be completed with the finalisation of this project.

Timeframes for the remainder of current DER participation actions are outlined in the table, below:

Table 6: Current actions for DER participation

| Action | Date | Comment |
|---|---|---|
| **26.** By December 2023, finalise communications protocols, data, and technology requirements to accurately predict and publish operating constraints on the distribution network under a DSO, and requirements for coordination with the system operator. | Dec 2023 | Key precedent conditions:<br>--VIS1 (Network visibility): digitalised distribution network will be required to calculate accurate Dx constraints that maximise hosting capacity. Western Power to complete visibility investment plan by June 2023.<br>--DOE specific issues – Design of 'minimum viable product' (MVP) for DOEs is targeted for July - September 2023 (contingent on understanding Western Power's comms network and systems capabilities). By this stage lessons will be available from both Project Symphony and NEM distribution network businesses implementing DOEs.<br>- Communication protocols - By Jul 2023, IEEE2030.5 is expected to be confirmed as the national standard for DOE communications, the standardisation of CSIP-AUS through Standards Australia should also be finalised as should lessons from Symphony required to inform the remaining COMMS issues |
| **27a.** By October 2023, implement initial changes to WEM Rules to enable development of DMO functionality and DER Aggregator participation in the WEM. | Dec 2023 – changes to basic participation model | - DSP, Interruptible Load and NCESS participation can be facilitated in the short-term following an update to the WEM Rules to reflect aggregator decisions relating to contestable vs non-contestable connection points - target date of October 2023. |
| **27b.** By July 2025, commence implementation of changes to wholesale market arrangements necessary to enable the participation of DER in the wholesale market via a DER aggregator. | Jul 2025 – changes to wider participation model | - Wider participation through standard registration framework will require lessons from Symphony and network visibility plan, the completion of the RCM Review and an approach for DOEs to be implemented.<br>MVP for WEM products is targeted for Dec 2023 - Mar 2024. |
| **29.** By July 2024, deliver a DSO / DMO legislative and regulatory framework, for transition to commencement by October 2025. | Jul 2024 - Oct 2025 | This will require:<br>- Action 27 to be completed<br>- MVP specifications developed for NSS and NCESS framework reviewed and amended as needed to incorporate NSS procurement. NSS dispatch coordination issues (including responsibility) to be confirmed including data/info exchange requirements |
| **30.** On 1 October 2025, DSO and DMO commencement with DER coordinated to provide services to the network and | Dec 2023 - Basic participation<br>Oct 2025 - | See Action 27 - basic participation can start once rules have been drafted for Demand Side Programmes, Interruptible Loads and NCESS participation via aggregators. |

| | | |
|---|---|---|
| wholesale market and compensated appropriately. | Wider participation | Wider participation start requires completion of Actions 26, 27 and 29, allowing around 12 months for implementation. |

# Appendix A. Issue summary

Table 7 summarises the issues covered in Chapter 5 and is structured as follows:

- Each issue is assigned a reference number the prefix of which denotes the policy area to which the issue belongs. For example, issues pertaining to network or facility visibility are suffixed with ‘VIS’_, while issues pertaining to WEM participation are prefixed with ‘WEM_’.
- The status of each issue indicates whether the issue is settled, unsettled, or deferred.

The issue is then briefly described in the ‘Issue’ column with additional commentary provided in the ‘Comment’ column.

### Table 7: Issue summary

| Issue Ref | Status | Issue | Comment |
| --- | --- | --- | --- |
| VIS1 | Settled | The immediate requirement is a forward-looking strategy and plan for investment in monitoring and communication capability to enable further digitalisation of the electricity network, focusing on the low voltage network. The first step is to obtain an objective understanding of the current and future state requirements for digitalisation and control capabilities and technologies. To support this, Western Power should complete Action 14 by June 2023 based on the following scope:<br>• Consultation with AEMO, assessment of communication and control capability in place (e.g. functionality of existing metering fleet, plus communication and control capability 'in the market')<br>• An assessment of future state capability scenarios describing communication and control functionality required to deliver specified outcomes, including orchestration and aggregation<br>• The future state assessment should include a survey of technology options, describing the purpose of the solution (e.g. network operation, market coordination, etc), the owner (e.g. Western Power, DER owners, aggregators etc) and the operator(s) (e.g. DSO, AEMO, Western Power, aggregator, etc)<br>• A review of the coverage of network visibility investments under the regulatory framework, including the Electricity Networks Access Code 2004 and Technical Rules | No additional obligations are needed to enable Western Power to invest in the appropriate level of network visibility to facilitate orchestration of DER.<br>The ENAC says Western Power must be able to earn a target revenue equivalent to the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.<br>The ERA guidance on factors that will be considering in new facilities test determination notes that "*Higher levels of distributed energy resources have cost implications for the network … [including] ... Managing increased distributed energy resources may require increased monitoring and management of the network at a more granular level which may require investment in monitoring and communication equipment and associated information systems.*"[79] |

[79] ERA, Guideline on factors that will be considered in new facilities investment test determinations and methods to value net benefits, at https://www.erawa.com.au/cproot/22365/2/Guideline.PDF

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | • A preferred communication and control technology investment pathway which aligns with the timeframes for introducing DSO and DMO functions. This is the strategy and plan. | |
| DOE1 | Settled | Explicit criteria will be used to decide how to use and set DOEs and, as importantly, when not to use DOEs. A framework will be developed to identify (but not limited to) the following:<br>• Development and implementation of DOEs for export and import, including calculation of DOEs with reference to market impacts<br>• How the trade-offs associated with restricting use of the network will be measured and considered against using augmentation or orchestration.<br>• The reporting requirements to be placed on Western Power to ensure their decision-making with respect to the trade-offs above is transparent<br>• Whether incentives or regulatory requirements will work to ensure DOEs are set based on maximising economic benefit from using the network. | Project Symphony will be an important learning tool to inform this framework. The criteria should be informed by and consistent with national practice, such as the outputs of the DOE workstream of the Distributed Energy Integration Program (DEIP).[80] The DEIP DOE workstream is supported by insights from ARENA-sponsored projects relating to DOEs.<br>The DEIP DOE workstream outcomes report will also be considered in the development of DOEs for the SWIS to align, where appropriate, with a national approach.[81] |
| DOE2 | Settled | DOEs will only be available to active DER which can respond to an external signal and can provide the data inputs needed to calculate the DOE. | 'Active DER' is any DER that can be controlled to provide an appropriate response. |

[80] Go to https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

[81] https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-outcomes-report/

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | | However, the definition of active DER should not result in unreasonable restrictions on its operation which prevent the owner and the wider power system from realising potential net benefits. Similarly, DER that is not active should not face unreasonable restrictions to access to the network. These matters should be included in the explicit criteria to be developed to document how to use and set DOEs. |
| DOE3 | Settled | The following two operating envelope parameters adopted for Project Symphony will be implemented for broader application, subject to the outcomes of Project Symphony:<br>• Operating envelopes will be calculated for each NMI<br>• Operating envelopes will be published for each 5-minute interval but may be calculated at a coarser granularity (so that some intervals have the same value). | |
| DOE4 | Settled | The following approach will be adopted to DOE compliance:<br>• For export limits, the FRMP for the NMI will be responsible for applying the DOE (noting AGG1).<br>• For import limits the Aggregator will be responsible for applying the DOE, noting AGG1, AGG2 and AGG3 limits, and that import limits are not anticipated to be applied in the short term.<br>• Where no Aggregator is present, a DOE will not be applied.[82] | |

[82] The DEIP Dynamic Operating Envelope Working Group Outcomes Report considers that direct DSO / DNSP application of DOE's at the device is likely an early path for implementation. However, in Western Australia the DNSP does not have the same direct contractual relationship with the end user that is in place in the NEM; rather, the access contract is usually held by the customer's retailer (referred-to as a 'linear contractual relationship'). As per the approach taken in the implementation of ESM in the SWIS, this means that it is unlikely that the DNSP would have the authority to 'reach in' to modify the behaviour of end-user equipment.

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | • The DSO is responsible for monitoring and enforcing compliance with the DOE.<br>• While the DMO may check that NMIs within a VPP offering a market service do not exceed the published DOEs as part of operational processes, it is not responsible policing compliance with the DOE. | |
| VIS2 | Deferred | What real-time or near-real-time visibility requirements will be placed on Small Aggregations registering in the WEM? | • Visibility requirements serve different purposes for Non-Scheduled Facilities vis a vis Scheduled Facilities and Semi-Scheduled Facilities.<br>• In the short-term, entry of smaller VPPs is more likely than larger VPPs. If a technological solution cannot be found to monitor Facilities for dispatch compliance, immediate to short-term effort could be expended on facilitating the entry of VPPs registering in the Non-Scheduled Facility class, which could potentially have less onerous requirements than larger VPPs subject to dispatch compliance.[83]<br>• Visibility requirements sufficient for dispatch compliance monitoring purposes and for forecasting the generation of Non-Scheduled Facilities will be informed by Project Symphony and by Western Power's evaluation of network visibility under Action 14 of the DER Roadmap (see Section 5.1.1, Issue VIS1).<br>• This issue is deferred pending lessons from Project Symphony and Action 14 of the DER Roadmap. |
| NSS1 | Settled | Procurement of NSS will be incorporated into the NCESS framework to ensure that there is a single unified and consistent framework for procuring all system services (be they transmission or distribution network related). | • The NOM and AOS framework in the ENAC will be reviewed to determine how best to consolidate with the NCESS rules in the WEM Rules. |

[83] Western Power is considering placing SCADA 'lite' requirements for DER installations above a certain threshold (e.g. 200kW or higher).

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | | • Changes will be required to NCESS framework or ENAC (as relevant) to ensure the content of the NOM better facilitates the development of flexibility or distribution NSS); e.g. by requiring the publication of information that provides aggregators a clearer view of what opportunities are present.<br>• Changes may be required to the NCESS framework to ensure the procurement rules are fit for purpose for distribution NSS. |
| NSS2 | Settled | The current regulatory framework adequately enables Western Power to procure of alternative options (including making the necessary investment to facilitate the ability to procure). | The ERA has signalled it expects to see an uplift in Capex in the coming years to build the capability to manage higher levels of DER, including investment in monitoring and communication equipment and information systems. Consideration could be given to whether more locationally granular service standard benchmarks would enable Western Power to better quantify net benefits associated with NSS procurement. The key barrier to NSS procurement at this stage is the lack of digitalisation of network data (and hence lack of visibility) which will impede Western Power from identify low voltage network constraints and NSS requirements, and from deploying NSS as an operational response. |
| NSS3 | Settled | To ensure the integrity of the procurement process for NSS, Western Power will continue to assess the cost-effectiveness and technical suitability of third party offers to provide a service prior to directly investing in network solutions, including energy storage”:<br>• In the absence of any cost-effective third party offers to provide NSS to Western Power, Western Power may make appropriate investment (including alternatives such storage) to defer network augmentation<br>• Where there are third-party offers to provide NSS, WP should assess these for cost effectiveness vs network owned solutions (including storage). | Further work is being progressed by EPWA and Western Power on the formation of microgrids as an alternative to replacing aged network infrastructure. A range of possible ownership, commercial, and operational models will be considered as part of this work. |

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| NSS4 | Settled | Western Power must only procure NSS through aggregators for DER associated with Small Use Customers. Western Power may procure NSS directly from larger customers. See related issue NSS5 below. | • See also settled issue AGG2 pertaining to Synergy being the sole aggregator for non-contestable customers to preserve the State Government's current retail contestability policy and ensure adequate customer protection coverage of smaller customers. This policy position is consistent with Synergy being the sole aggregator for smaller customers.<br>• Restricting Western Power to larger customers also reduces implementation complexity for Western Power. |
| NSS5 | Settled | Western Power can directly procure from customers with DER whose annual consumption is greater than the Small Use Customer threshold of 160MWh per annum at a single site.<br>• The customer associated with the site above may elect to provide NSS to Western Power from adjacent sites that consume below 160MWh per annum (if there is at least one site consuming above 160MWh per annum that Western Power is directly procuring from).<br>• If Western Power procures NSS directly (via the NCESS framework) from a large customer whose connection point is part of a VPP registered to an aggregator, then the aggregator must ensure that their WEM bids and offers accurately reflect availability considering the relevant connection point's NSS obligations to Western Power; this will require either Western Power or the customer to notify the aggregator of NSS deployment plans. | Western Power's procurement as described above precludes it from aggregating the sites or devices at those sites. That is, Western Power will not act as Aggregator; rather where aggregation is required as indicated above, the relevant customer will be responsible for ensuring they can provide the services required from the devices at their sites; the customer will be acting as its own aggregator.<br><br>It is unlikely that an NCESS contract between a large customer and Western Power would lead to an aggregator unable to meet its WEM obligations; this is because the aggregator's contract with the customer would presumably put availability requirements on the customer to ensure the aggregator can meet its WEM obligations. |
| AGG1 | Settled | Only the FRMP at a connection point (NMI) can aggregate that NMI into a Virtual Power Plant for the purpose of offering energy or energy system services into the WEM. | • This is a limitation resulting from metering and multiple trading relationship limits that will not be resolved in the short- to medium-term. |

| Issue Ref | Status | Issue | Comment |
| --- | --- | --- | --- |
| | | | • If the FRMP has created an aggregation for the purposes offering energy into the WEM, no other Market Participant can aggregate any of the relevant NMIs for the purposes of providing ESS or a DSP – this is because the latter participant cannot control the flexibility at the relevant NMIs while another participant is controlling the energy.<br>• The unit of aggregation for providing energy will be the connection point. |
| AGG2 | Settled | Non-Contestable Customers can only be aggregated by Synergy (or an intermediary acting through Synergy[84]). This restriction applies to all services (WEM and NSS). | This position allows aggregator choice in the medium to long-term if the contestability threshold shifts and has been adopted to ensure Non-Contestable Customers maintain adequate protections until such time as protections specific to the provision of aggregation services are developed. The position also reflects policy preference to retain the linear relationship between customer and retailer.<br><br>Third parties can provide aggregation services but must do so as an intermediary, on behalf of Synergy. For example, an intermediary wanting to provide energy and ESS by aggregating DER can do so if Synergy is the Market Participant to whom the aggregation is registered. Likewise, third parties can provide NSS; however, Synergy would hold the contractual relationship with Western Power. |
| AGG3 | Settled | Contestable Customers can be aggregated by anyone – subject to AGG1, NSS4 and NSS5. | See also NSS5 – while Western Power can directly procure NSS from Large Customers (with annual consumption greater than 160MWh), they must do so from single sites. That is, Western Power would not be involved in aggregation of customers. |

[84] The FRMP at a connection point for a Non-Contestable Customer is Synergy. This means that only Synergy can offer energy in respect from Small Aggregations comprising connection points of Non-Contestable Customers. However, intermediaries can act through Synergy to provide aggregator services, with Synergy remaining the responsible Market Participant.

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| AGG4 | Settled | As a consequence of AGG2 and AGG3, the following will apply to aggregations registered as Demand Side Programme or Interruptible Load services in the WEM:<br>• Existing WEM Rules around participation will be retained for Contestable Customers. That is, any Market Participant can associate Contestable Customer NMIs to a Demand Side Programme or Interruptible Load.<br>• Non-Contestable Customers NMIs can only be associated to a Demand Side Programme or Interruptible Load by Synergy or an intermediary acting through Synergy. The registration rules in the WEM will require amendment to reflect this restriction. | The WEM registration rules will require amendment to reflect the new restriction indicated in the second bullet point.<br>It may be appropriate to review this once EPWA's electricity retail licensing reform project is complete and the appropriate customer protections are in place for suppliers of alternative electricity services. |
| AGG5 | Deferred | Can aggregators aggregate connection points (NMIs) to provide Frequency-Co-optimised ESS (FCESS) where those NMIs are associated with a different FRMP but are otherwise a non-dispatchable load? The service would be analogous to an Interruptible Load but would have more flexibility, i.e. able to increase and decrease injection or withdrawal, and (subject to resolution of technological issues) able to provide raise and lower services for both contingency and regulation ESS). | AGG1 notes that the unit of aggregation will be the connection point. An FCESS-only product will not be possible if service provision is at the connection point (and not at the device level); this is because the aggregator would need to control all elements behind the meter including the load as a Dispatch Instruction for FCESS would include a Dispatch Target for energy. This cannot be done prudently with a separate party acting as retailer for energy. As noted in WEM_ESS1, existing FCESS specifications will be retained (including connection point delivery) and changes to technical requirements may be considered in the future when DER's ability to meet existing FCESS requirements are better understood. It is therefore prudent to defer this decision until DER's capability to provide FCESS is better understood. |
| AGG6 | Settled | As a result of NSS1 (NSS to be procured through the NCESS framework), aggregators or service providers providing NSS only may need to register in the WEM in accordance with the WEM registration and NCESS rules. | Where the WEM Rules require an NSS provider and their Facility to register, they must do so. Practically, this means that this means that service providers providing NSS from small Facilities (less than 10MW) may not need to register themselves or their Facilities. |
| AGG7 | Deferred pending re-assessm | How will the efficient exchange of historical meter and other energy data be facilitated to enable third parties (aggregators) to access data for business development purposes? | If a customised implementation of the CDR is not adopted in Western Australia, consideration will need to be given to the following: |

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | ent of CDR implementation in WA | EPWA will re-assess the implementation of CDR following implementation and evaluation of the relevant reform work programs currently underway. This may resolve this issue.<br>In the meantime, data access provisions exist under the current regulatory framework (i.e. access via the retailer or by request - with customer consent - from Western Power). | • Changes to Western Power's existing (largely manual) process for meter data provision to third parties to facilitate low-cost data exchange at scale.<br>• Ability for third parties to request billing, tariff and customer data directly from retailers with the customer's permission.<br>• Efficient and effective means of capturing consent, ensuring information security and dispute resolution (so customers can lodge complaints) for the above. |
| AGG8 | Deferred | What approach will be used where an aggregation provides similar services across the value stack to prevent "double-dipping"? | The potential for 'double dipping' (inefficient double payment) exists where:<br>• DER provides WEM services above alongside NSS or other services procured via the NCESS framework, or<br>• DER provides multiple NSS.<br>Without knowing what types of NSS are likely to be procured from DER, it is challenging to determine whether double dipping is likely. Hence, this issue should be revisited in the future when service specifications for NSS become clearer.<br>Note, the importance of not mischaracterising the ability of flexible resources to simultaneously provide different services as "double-dipping". Flexible resources can value stack successfully precisely because they are able to provide different services simultaneously. |
| WEM_ REG1 | Settled | The high-level principles applied to aggregating conventional Facilities (in clause 2.30 of the WEM Rules, see above) will also apply to Small Aggregations. In particular (but not limited to):<br>• Small Aggregations will not be allowed to aggregate connection points across diverse Electrical Locations (i.e. must be behind a single TNI). | • The Electrical Location restriction applies irrespective of the System Size of the aggregation. AEMO has advised that registration processes can be streamlined for smaller aggregations (e.g. with a total System Size less than 10MW) to reduce transaction costs.<br>• AEMO's process for determining PSSR impacts of a Small Aggregation will vary relative to traditional Facilities aggregated under clause 2.30 of the WEM Rules. The details of such a process could be devolved to procedure. |

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | • AEMO can only deny aggregation of DER, if it can demonstrably prove an impact on power system security and reliability. The WEM Rules will require clauses to enable AEMO to consult with Western Power to deem PSSR impacts and to oblige Western Power to provide information required by AEMO. | |
| WEM_ REG2 | Deferred | What approach will be taken to determining the contribution of Small Aggregations to the Contingency Reserve Raise requirements when:<br>• Modelling the Contingency Reserve Raise contribution of Small Aggregations for the purposes of dispatch.<br>• Evaluating aggregation requests (this will depend on how the contribution of Small Aggregations are modelled in dispatch).<br>• Calculating the cost contribution of Small Aggregations via the runway method? | For traditional Aggregated Facilities, contribution to Contingency Reserve Raise requirement is modelled as the total energy and Regulation raise cleared from the Aggregated Facility in its entirety; this is not appropriate for Small Aggregations as the credible contingency will not be the loss of the entire aggregation).<br><br>This issue is deferred as it applies only to larger aggregations that would be cleared for 10MW or more of energy and Regulation Raise. Such Facilities cannot enter the market until the issue of Facility visibility (see VIS2) and controllability is resolved. |
| WEM_ REG3 | Settled | The DER aggregation process (for aggregating connection points for a Small Aggregation) should follow a model like the Non-Dispatchable Load to Demand Side Programme/Interruptible Load association process set out in clause 2.29 of the WEM Rules. | The aggregation process must recognise the more dynamic nature of Small Aggregations so that aggregators can add and remove connection points with ease.<br>While Small Aggregations will have more dynamic aggregation needs than traditional facilities, the extent of this dynamism will not extend to real-time or near real-time changes to aggregation configuration. |
| WEM_ REG4 | Settled | The Facility class transition principles applied to traditional Facilities with respect to Facility will apply to Small Aggregations. That is, AEMO can transition Facilities to different classes if configurational changes require it, or where power system security and reliability concerns require the Small Aggregation to appear in network constraint equations (to the extent this is possible). | Given the unique characteristic of Small Aggregations (particularly comprising BTM DER), tailored WEM Rules may be required governing Facility class assignment and transitions (and possibly registration rules more broadly). However, it is not possible to pre-empt such amendments until further lessons become available as DER enters the WEM. Hence, registration is likely to be an evolving process as more lessons become available. |
| WEM_ REG5 | Settled | System Size for Small Aggregations will follow the same principles as that of other Facilities: | This change will need to be reflected by modifying the WEM Rules, either directly in the System Size definition, or in the definition of DSOC |

<table>
<tr><th>Issue Ref</th><th>Status</th><th>Issue</th><th>Comment</th></tr>
<tr><td></td><td></td><td><ul><li>System Size will not consider behaviour of any behind the meter loads to ensure consistency with how other Facilities with co-located loads are treated (e.g. Intermittent Loads) and to ensure the calculation considers the gross capability of DER storage to modify the net response at a connection point.,</li><li>For Small Aggregations comprising residential or other connection points at which DSOC and CMD does not apply under the ENAC, the following will be adopted:<ul><li>The DSOC equivalent of a Small Aggregation will be the aggregate physical connection limit (MW equivalent) for export.</li><li>The CMD equivalent will be the aggregate physical connection limit (MW equivalent) for import.</li></ul></li></ul></td><td>and CMD. The former is preferred, as DSOC and CMD are ENAC defined terms and should be defined consistently in the WEM Rules.</td></tr>
<tr><td>WEM_ ESS1</td><td>Settled</td><td>No changes will be made to the post-amended WEM Rules or Procedures pertaining to FCESS provision in the short-term. There is not enough information available to address the challenges to FCESS provision. Hence, existing technical specifications will be retained in the short-term and be revised to incorporate DER as lessons are learned from VPP pilots including Project Symphony.</td><td><ul><li>The general approach to amending technical specifications and alternative standards will be to test whether DER can meet existing service standards/specifications (e.g. via VPP pilots), and only specify an alternative when it is confirmed DER cannot meet the existing specification. Hence, while regulation ESS could be provided through autonomous response, such a specification would not be explored until it is confirmed that AGC cannot be used for DER.</li><li>The post-amended WEM Rules do not prevent Small Aggregation seeking ESS accreditation. However, in practice, most Small Aggregations will not be able to meet the current technical requirements. This means DER will be unable to provide any FCESS other than an Interruptible Load seeking accreditation for Contingency Reserve Raise – see WEM_ESS2.</li></ul></td></tr>
</table>

| Issue Ref | Status | Issue | Comment |
|---|---|---|---|
| | | | • Alternative standards may be specified in the future depending on the above. A review should be conducted in the future to perform a stock-take on whether the technical issues pertaining to ESS provision from DER have been resolved, and whether it is timely and appropriate to consider alternative standards for ESS.<br>• In the interim, per issue WEM_ESS3, AEMO can use the NCESS framework to procure alternative ESS from DER if required. |
| WEM_ ESS2 | Settled | DER can be aggregated into Interruptible Loads; all connection points that are part of the aggregation must be at the same Electrical Location (see WEM_REG1). | |
| WEM_ ESS3 | Settled | AEMO may use the NCESS framework to procure NCESS from DER as required, via a market participant. This may include (but is not limited to) services to maintain minimum load, address intermittent and DER volatility, and providing ramping (as set out in AEMO's renewable integration study update). | • AEMO must first demonstrate the relevant ESS needs cannot be met through the FCESS framework[85]. Alternatively, the Coordinator may identify that more economic procurement could be achieved through a bespoke service (as opposed to over-procurement of FCESS).<br>• The NCESS framework allows AEMO to specify visibility requirements in the contract with the aggregator.<br>• No further policy decisions are required to effect this position.<br>• The service specification should not be technology specific. That is, it may be developed in such a way that aggregated DER can meet it but should be able to be delivered by any capable technology. |
| WEM_ ESS4 | Deferred | Will the requirement to meet a Dispatch Target (clause 7.6.11) be amended to enable energy and FCESS provision from hybrids and DER if such facilities cannot control their energy output to meet a Dispatch Target? | This issue is broader than facilitating DER participation in the WEM. As such this issue is deferred to be addressed through another work stream. |

[85] Or the Ancillary Services framework prior to New WEM Commencement Day.

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| WEM_ ESS5 | Deferred | Will FCESS accreditation thresholds be reduced to facilitate DER participation? | This issue cannot be addressed until the technical issues relating to FCESS provision by DER is resolved (see WEM_ESS1). Moreover, a review of thresholds is better handled via a future review of ESS arrangements. |
| WEM_ RCM1 | Settled | Small Aggregations can seek certification as Demand Side Programmes. | No further policy decisions or WEM Rule amendments are required to give effect to this. |
| WEM_ RCM2 | Deferred pending VIS2 | How to certify as non-scheduled facilities? | Facility visibility is an issue that needs to be resolved first. |
| WEM_ RCM3 | Deferred pending RCM review | What approach will be taken to facilitate the participation in the RCM of larger DER aggregations intending to register in the Scheduled Facility or Semi-Scheduled Facility classes?<br>• What changes will be required to sub-metering requirements and subsequently certification and reserve capacity testing requirements?<br>• What approach will be taken to model the impact of network congestion on the aggregation's contribution to reliability? That is:<br>- Will distribution network constraints be modelled via the NAQ method? If so, what changes might be required to the methodology facilitate this? Or<br>- Will Small Aggregations have NAQ calculations based on constraints modelled at their Electrical Location with distribution constraints modelled by proxy by setting the Facility DSOC to reflect the DOE at peak times or other time of system stress? | If NAQ for Small Aggregations is modelled at the Electrical Location, Western Power would need to provide DOE forecasts at the time of certification (two years before reserve capacity obligations apply). Western Power has indicated that such forecasts will be uncertain. In effect, this would mean that aggregators would be subject to refunds if in real-time their actual DOEs diverge from the DOEs that were used to allocate Certified Reserve Capacity[86].<br>The resolution of this issue is deferred as:<br>• The entry of larger VPPs registering in the Scheduled Facility and Semi-Scheduled Facility classes are unlikely until Facility visibility issues are resolved (see issue VIS2). Even if the visibility issue were resolved, it is unclear how such VPPs would meet the dispatch compliance obligations associated with these classes given the uncontrollable load component behind the meter. Ideally, Project Symphony should consider both the controllability and visibility aspects of aggregations that would be subject to dispatch compliance obligations. |

[86] Noting that refunds would not apply to Non-Scheduled Facilities, or Intermittent Generating Systems comprising other Registered Facilities.

| Issue Ref | Status | Issue | Comment |
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| | | | • The RCM review currently being undertaken by the Coordinator of Energy may change the how reliability is measured and how Certified Reserve Capacity is allocated. As such, WEM_RCM2 and WEM_RCM3 are deferred pending the RCM review. |
| WEM_ METER1 | Settled | For the purposes of 30-minute settlement:<br>• AEMO will have access to 30-minute meter data through Western Power's AMI rollout.<br>• AEMO will require a head of power to profile 30-minute meter data into five-minute quantities for the purposes of the Energy Uplift Payment calculation. | • While the AMI rollout will not be complete until 30 June 2027, only new DER meeting the new AS 4777.2:2020 standard will be controllable for the purposes of aggregation; such DER will have AMI meters at their connection points. As such, the 2027 date for AMI rollout completion should not affect the entry of VPPs.<br>• Empowering AEMO to profile Small Aggregations for the purposes of the Energy Uplift Payment will require an amendment to the relevant clause indicating profiled quantities (as opposed to SCADA profiled quantities) will be used for VPPs. The profiling methodology could be devolved to a WEM Procedure. – QUESTION as to whether it is easier just to get 5-min data direct from meter. Profiling is inconsistent with this approach for the rarity of the event and possibly not legal for settlement. – See uplift payment paper. Possibly remove from the paper as too detailed an issue. |
| WEM_ METER2 | Deferred | Once five-minute settlement is implemented, will Small Aggregations comprising Non-Contestable Customer connection points be required to submit five-minute meter data or will profiling be used? | This issue is deferred pending<br>• Completion of Action 14 of the DER Roadmap including Western Power's evaluation of the capability of its communications network and back-office systems (see issue VIS1).<br>• Lessons from Project Symphony that will provide insights on the type of information AEMO may be able to access from the aggregator for profiling purposes. |
| COMMS1 | Deferred | What standard and protocol will be adopted to govern communications between the aggregator and the devices in a VPP? | This is the subject of on-going work in relation to DER Roadmap Action 3, 2030.5 and CSIP-AUS by DEIP and others at a national level. |
| COMMS2 | Settled | The standard and protocol adopted under COMMS1 must include Electric Vehicle supply equipment (EVSE). | Noting South Australia is leading work on establishing minimum communications standards for EVSE. Note that Western Power will |

| Issue Ref | Status | Issue | Comment |
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| | | | consider this as part of the EV Action Plan (Action 9) under the DER Roadmap (Action 16) |
| COMMS3 | Deferred | What standard and protocol will apply to communications between Western Power and customers that it directly procures from? | Western Power does not have enough information to advise what its communication requirements may be. As such, this issue is deferred until it is clearer how direct NSS procurement from customers by Western Power would work. See related issues NSS3 and NSS4. |
| COMMS4 | Deferred | What standards and rules will be placed on VPPs to mitigate against loss of communications by way of standardised default behaviour and redundancy requirements[87]? | • This issue is deferred pending lessons from Project Symphony, which will inform default behaviour and redundancy requirements, and lessons from NEM pilots<br>• It is important to assess the actual reliability risks associated with DER (in terms of likelihood, consequence and materiality) to ensure that overly restrictive redundancy requirements are not specified. Overly restrictive requirements may lead to unnecessary costs imposed on aggregators which will, in turn, limit the extent of orchestration.<br>• An alternative to specifying redundancy requirements, is to rely performance requirements and liability provisions to ensure aggregators provide the service as required (as it is incumbent upon them to ensure delivery – how they choose to do so is at their discretion and may involve recruitment of additional connection points to cover communications loss or other unforeseen events). |
| COMMS5 | Deferred | Which regulatory instrument should common standards and protocols be enforced through? | • This issue does not need to be resolved until COMMS1 is settled. |

[87] Note, the CSIP-AUS standard includes a requirement to reduce export to 1.5kW when there is loss of communications. Adopting the CSIP-AUS standard may therefore address this issue.

| Issue Ref | Status | Issue | Comment |
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| | | | • Standards pertaining to reliability of communications and redundancy requirements should sit in the WEM Rules for aggregations providing standard WEM services and in the relevant contract for aggregations providing NCESS / NSS. |
| CUST1 | Settled | Postage stamp pricing will be retained for network tariffs for customers below 1MVA. | While the regulatory requirement for uniform pricing does not preclude locational signalling using demand charges, the policy position is to not include such charges. This is being reflected in the pricing proposals being considered as part of Western Power's Fifth Access Arrangement process. |
| CUST2 | Deferred | What changes are required to the retailer and network operator licensing framework to ensure customers are protected from risks associated with entering contracts with aggregators using devices at customer sites (e.g. residences) for orchestration purposes? | Pending Alternative Electricity Services Framework. |
| IMP1 | Settled | The hybrid model will be adopted with Western Power and AEMO performing the DSO and DMO functions respectively. | These changes are expected to reflect extending existing capability, without resulting in separate or distinct business units. |
| IMP2 | Deferred | Who will be responsible for dispatching NSS? | Project Symphony will yield practical lessons on NSS dispatch that can be used to determine the most appropriate party to allocate NSS dispatch responsibility to. This issue is therefore deferred pending lessons from Project Symphony. Note, whatever decision is made with respect to this issue, it is important that AEMO has visibility of NSS dispatch decisions that impact on power system security. Procuring NSS through the NCESS framework (see NSS1) will ensure obligations exist on Western Power to provide relevant information to AEMO in this respect. |
| IMP3 | Settled | The following dispatch hierarchy will be adopted (for a facility):<br>• NSS will be dispatched first.<br>• WEM services will be dispatched second. | The precise manner that AEMO would implement the NSS dispatch based on Western Power's deployment instruction will depend on the nature of the NSS. |
| IMP4 | Deferred | How will NSS dispatch be coordinated when Western Power procures NSS from larger customers directly? In particular, | AEMO must have visibility of any dispatch that impacts on its ability to dispatch WEM services and maintain power system security. This issue |

| Issue Ref | Status | Issue | Comment |
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| | | what information would Western Power need to provide AEMO? | is deferred pending resolution of IMP2 (NSS dispatch responsibility), as that is a precedent to finalising the details of dispatch coordination. Note:<br>• An advantage of incorporating NSS into the NCESS framework is that it provides an established process for Western Power to provide this information relevant to the dispatch of the NSS to AEMO.<br>• A further advantage of using the NCESS framework is that AEMO will have visibility of NSS dispatch from larger customers; this will be particularly important where the customer's site is part of an aggregation providing WEM services (see also NSS5). |
| IMP5 | Deferred | How can NSS be provided by a subset of connection points within a registered aggregation also providing WEM services? If so, how will it be dispatched? | This issue is deferred pending the decision on IMP2 and lessons from Project Symphony on whether a dynamic approach to managing the composition of aggregations is scalable. |
| IMP6 | Settled | Distribution network outages and network switching affecting an aggregation's availability to provide market services will be managed as follows:<br>• The DSO will provide information on network switching that affects the Electrical Location of connection points that are part of a Small Aggregation providing WEM services. To do this, the DSO will require access to selected Standing Data pertaining to Small Aggregations including connection points in an aggregation and the Electrical Location.<br>• Distribution network outages will be reflected through changes in DOEs in areas affected by the outage. This means the DSO will require the capability to update DOEs in near-real time where there are forced outages. | |
| IMP7 | Deferred | More complex arrangements for NSS procurement and dispatch may be contemplated in the future. The increase in complexity could vary significantly depending on the evolution of technology, investment in network visibility, knowledge, and | Moving to complex arrangements like the ones outlined above require certain pre-requisites:<br>• Clear product definitions |

| Issue Ref | Status | Issue | Comment |
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| | | aggregator entry. Examples (from least to most complex) of increased complexity might include:<br>• Extension of bilateral contracting of NSS to include merit order approach to clearing and pricing offers<br>• Real-time NSS market (dispatched ahead of WEM) that matches supply and demand for network capacity in real or near-real time<br>• Whole of system optimisation where a central party dispatches resources to meet energy, ESS and NSS together. | • Sufficient liquidity so that there are multiple providers competing to provide services<br>• Capable technology<br>• Network visibility to facilitate planning and operational activities<br>In contemplating more complex arrangements, consideration must be given to whether the cost of increased complexity outweighs the benefit to the consumer in the long-term. |

# Appendix B. DSO and DMO functions

The August 2020 Issues Paper set out high level roles and responsibilities of the DSO and DMO roles. The issue identification and evaluation undertaken as part of this project indicates that the specification in the August 2020 Issues Paper was accurate and exhaustive (at a high level).

In this section we map each of the identified responsibilities against policy issues identified in this paper. The next stage of this project will develop the Action Plan required to implement settled decisions).

## a) DSO responsibilities

| | Responsibility | Policy issue | Comment |
|---|---|---|---|
| D1 | Determine technical arrangements for the connection of DER. | VIS1<br>DOE1<br>NSS2 | Western Power currently undertakes this role. In a future with a digitalised distribution network with access to granular network data, decisions around technical arrangements will be better informed due to the DSO having a better understanding of hosting capacity.<br>The use of DOEs and procurement of NSS will enable the DSO to optimise the DER access to the network. |
| D2 | Review and approve connection applications for DER assets. This includes assessment of network capacity and requirements within a given area. | | |
| D3 | Manage the commercial and technical control of DER connections, as allowed by the signed connection agreement and regulatory frameworks.<br>Note - currently the commercial contract for connection to the network is via retailer as per linear contracting relationship. | N/A | |
| D4 | Collate information on DER and provide it to AEMO for the purposes of establishing, maintaining and updating a DER register.<br>Note - the DER register will only gather static information when initially implemented. | N/A | This has been addressed through Action 18 of the DER Roadmap |
| D5 | Develop static and/or dynamic constraint equations at the distribution level that describe the transfer limits of the network. | VIS1<br>DOE1<br>DOE2<br>DOE3<br>DOE4 | A precedent condition for developing and disseminating DOEs that accurately reflect hosting capacity is digitalisation of the distribution network and adequate visibility of the low voltage network.<br>Principles for calculating DOEs should be informed by and consistent with national practice. |
| D6 | Provide a static and/or dynamic operating envelope to aggregators/retailers/AEMO for all active DER (at the connection point). | | |
| D7 | Plan, install and manage links to aggregators/retailers/AEMO to disseminate information about the static and/or dynamic operating envelopes at a specific location or interface. | | |
| D8 | Create and/or administer systems, such as a DSO Platform, to enable the visibility of power flow across the distribution network, and to provide visibility of, and means of managing, issues on its network in real time when they emerge.<br>This will also support the DSO where distribution network issues have emerged, and an aggregator has been engaged by the DSO to alleviate the issue.<br>The consequential actions must be addressed by the System Operator (AEMO) as part of whole-of-system operation. This will | N/A | This is a technology issue related to implementation of the Western Power's expanded role as DSO. |

| | Responsibility | Policy issue | Comment |
|---|---|---|---|
| | ensure the power system at all levels is securely and reliably operated and maintained. | | |
| D9 | Develop processes within the DSO platform that allow the network operator (DSO) to request NSS where needed and available to meet network support requirements. | NSS1<br>NSS2<br>NSS5 | This is an implementation activity that depends on NSS the nature of NSS procurement. NSS procurement will occur through the NCESS framework. |
| D10 | Provide information on the deployment of NSS to allow the Market Operator (DMO) to consider the impact of these services on the broader power system. | IMP2<br>IMP4 | The coordination of NSS with WEM services will depend on who dispatches NSS and the nature of the NSS. |
| D11 | Planning network investments that deliver economic benefit. | VIS1<br>DOE1<br>NSS1<br>NSS2 | The key to planning network investment that maximise economic benefit will be orchestrating DER to enable the deployment of NSS as network operational response. This will require network visibility and consequently the use of DOEs and identification of NSS requirements. A robust procurement mechanism (NCESS) that enables market testing and provides governance and oversight will also be required. |

## b) DMO responsibilities

| | Responsibility | Policy issue | Comment |
|---|---|---|---|
| M1 | Leverage and / or administer a market platform(s) to enable generators, customers, aggregators and other third parties to access value in the energy market, the Reserve Capacity Mechanism, Essential System Services (such as frequency control) and network control services that may be required in the future. | VIS2<br>WEM_ESS1:<br>WEM_ESS5<br>WEM_RCM1:<br>WEM_RCM3 | AEMO's ability to facilitate participation will be limited in the short-term as DER will not be able to meet visibility (monitoring) requirements and various technical standards to provide WEM services.<br>In the short-term, AEMO will facilitate participation of DER as Demand Side Programs and Interruptible Loads, or as unregistered Facilities through the NCESS procurement framework. |
| M2 | Register aggregators and aggregated facilities for the purposes of market participation and provision of services (such as network control services) under the WEM Rules. | WEM_REG1:<br>WEM_REG5 | While high level aggregation and registration principles will be consistent for DER and traditional Facilities, a tailored aggregation process will be required to accommodate the distributed and dynamic nature of DER. |
| M3 | Ensure that registered market participants meet participation requirements under the WEM rules; e.g. meet appropriate testing, prudential, and technical requirements. | See M1 and M2<br>COMMS1<br>COMMS2<br>COMMS4 | Decisions surrounding standards and protocols governing communications between the aggregator and the devices in a VPP, as well as redundancy requirements to cover the loss of communications will be deferred pending completion of working the Distributed Energy Integration Program (DEIP) and Project Symphony. |
| M4 | Coordinate with the DSO and aggregators to dispatch active DER in the market. | See D10 | |
| M5 | Operate and manage the wholesale electricity market platform(s) to enable settlement inclusive of services provided by aggregated DER in the WEM. | WEM_METER1<br>WEM_METER2 | Small Aggregations comprising Non-Contestable Customer connection points with controllable DER will have 30-minute AMI meters and able to meet metering requirements under 30-minute settlement. Whether Western Power can facilitate five-minute metering for five-minute settlement is yet to be determined. |
| M6 | If / when a centralised market for NSS is established, settlement of DER dispatched to provide NSS. | N/A – see NSS1 | NSS will be procured through the NCESS framework; hence NSS (which will be procured by Western Power as DSO) will be settled off-market |

| | Responsibility | Policy issue | Comment |
|---|---|---|---|
| M7 | Providing information to the DSO (Western Power) on opportunities for investments within the distribution network which would alleviate constraints that may deliver market benefit. | NSS1<br>IMP7 | The procurement of NSS through the NCESS framework enables AEMO to trigger procurement of NSS. However, in the short to medium term, it is unlikely that AEMO will have or require access to low voltage network data that enables them to form a meaningful view on the state of distribution network constraints (other than inferring based on the bidding behaviour of aggregators who will be constrained by their DOEs). In the longer term, if a more centralised whole-of-system-optimisation approach is adopted, then AEMO will have better visibility of distribution networks that will enable it to better form a view on the impact of potential constraints on market outcomes. |

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