# Renewable Energy Integration – SWIS Update

September 2021

# Important notice

## PURPOSE

AEMO has prepared this report to provide information and recommendations to the Western Australian Public Utilities Office about the security of the South West Interconnected System (SWIS), using information available to AEMO as at the date of publication.

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# Executive summary

Two years of strong industry collaboration, WA Government reforms and industry actions have delivered material improvements in the resilience of Western Australia's major power system, the South West Interconnected System (SWIS), and enhanced the system's ability to manage technical challenges associated with the transformation of the generation supply mix. As the physical characteristics of the power system continue to transform, further action will be required to efficiently and effectively manage existing and emerging challenges in both the short and medium term. Undertaking these actions will continue to support consumer choice and affordable, reliable electricity supply as more renewable generation is connected to the SWIS into the future.

In March 2019, AEMO published *Integrating Utility-scale Renewables and Distributed Energy Resources in the South West Interconnected System*[1] (the March 2019 Report), which examined the challenges and opportunities that came with integrating utility-scale and small-scale renewables. The report made seven key recommendations for keeping the power system secure based on the expected outlook of the drivers of power system security risk.

A lot has changed in the SWIS since early 2019. This Renewable Energy Integration – SWIS Update (Report) reviews the status and drivers of system security risks, considers the actions taken since early 2019, and makes 13 recommendations for enabling affordable, reliable energy as the transformation of the power system accelerates. Three of these recommendations are prioritised for implementation as soon as practicably possible.

### Key findings

- Since the March 2019 report, the early implementation of some of the WA Government's Energy Transformation Strategy (ETS) program actions are providing AEMO with better operational capability. AEMO has also developed better tools and insights to manage system security and both Western Power and generators have made improvements to their assets.
- Some of the emerging system conditions identified as potential challenges for managing system security in the March 2019 Report have become more common, particularly as the change in energy supply mix to more renewable generation continues at record pace. Low load conditions are now a permanent feature of the SWIS; AEMO, Western Power and Energy Policy WA (EPWA) have commenced a program of work for immediate and longer-term remedial action.
- The SWIS is on a clear trajectory towards being able to meet up to 100% of demand from renewable energy sources, including particular time intervals where 100% of demand is able to be met from residential and commercial solar systems.
- The implementation of various initiatives, investments, and WA Government-led reforms has enhanced the capability to manage the system to reasonably accommodate the persistence of lower operational demand. This has deferred to 2024 the point where power system operational conditions

[1] At https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf.

are likely to become insecure in the absence of additional measures, noting the system will for periods of time enter into a 'zone of heightened threat' due to diminished secure dispatch options prior to 2024.

- Whilst these positive changes have improved the outlook, AEMO has identified priority actions to improve resiliency in the short term noting further work and reform is required to manage the power system in the new paradigm. Ongoing reform is a necessity – the WA Government has already announced ETS Stage 2 reforms which will be critical for ensuring that essential system services (ESS) continue to support the requirements of the power system and that existing providers and new entrants are appropriately incentivised.
- The Whole of System Plan (WoSP) will be integral to steering the transition to the future power system, by determining a future system design that puts consumers at its centre, identifies the roles responsibilities of parties, and informs the investments to be made and how they interact with the market.

### Power system security has improved

The SWIS is in a more robust position than two years ago care of the implementation of the WA Government's reforms and industry actions which have provided additional operational capabilities. This has further offset the power system challenges resulting from record installations of variable inverter-based generation. Further work is underway to ensure the power system can continue to operate securely and efficiently for all consumers in facilitating renewable energy connection in the SWIS.

### The drivers for change in the 2019 power system still persist

This Report confirms the March 2019 Report's identified drivers of change in power system conditions are persisting, including:

- Increased generation and load volatility due to increased penetration of variable supply sources.
- Continued decrease in the minimum level of low system load through record uptake of distribution-connected photovoltaic (DPV) systems.
- Impacts on the operation of protection systems due to reducing operational demand.
- The displacement of traditional generation sources, that have historically provided ESS, by DPV and utility-scale renewable generation.
- A greater spread of Wholesale Electricity Market (WEM) Balancing Prices that are reaching lower negative prices more frequently, generally reflecting periods where there is significant renewable generation output (low prices) and periods where generation is more scarce (higher prices).

While operational conditions have continued to become more challenging and often changing at a faster rate than forecast, the implementation of specific reforms, operational initiatives, tools, and investments as outlined in this Report have materially contributed to a net improvement in capability to manage system security outcomes within operational limits, deferring the immediacy of the power system security challenges identified in the March 2019 Report.

Analysis by AEMO indicates that the timeframe in which the power system operational conditions are likely to become insecure, in the absence of additional measures, has been deferred to 2024. The March 2019 Report forecast that this point might be reached some time between 2022 and 2024 with the breach of an indicative operational demand threshold of 700 MW. The implementation of recent measures has improved the power system's ability to be managed securely at levels of operational demand below the indicative 700 MW threshold.

The analysis identifies that as the minimum operational load continues to drop there are fewer combinations of facility dispatch which can provide the ESS needed to keep the power system secure. Between 700 MW and 600 MW of operational demand, those dispatch options are noticeably diminished, however AEMO has high confidence that secure dispatch options will be available. Below 600 MW, the dispatch options materially decrease, such that AEMO considers it a zone of 'heightened power system security threat'.

AEMO has determined this zone will likely be entered for periods of time before 2024, and while AEMO has identified there is a low risk of not having at least one dispatch option available, AEMO recommends priority actions be implemented to increase the resiliency of the SWIS prior to 2024. These priority actions are needed as soon as possible as emergency events can occur at any point and some of the options will take some time to be implemented, and then a longer duration to have a material affect.

This Report outlines the operational tools, new standards, investments, system services and revised regulatory arrangements that AEMO recommends implementing to further mitigate the risk of the power system becoming insecure after 2024.

## Mitigation of the 2019 Challenges

In terms of the challenges identified in the March 2019 Report, this Report finds that:

- The WEM is now characterised by negative growth in operational consumption as the consequence of high levels of DPV penetration, such that the SWIS is experiencing low operational demand (and consequently system load[2]) conditions in most months of the year. The recently updated forecasts of operational demand reveal levels that are well below the previously indicated 700 MW threshold.
- The power system operating environment has become more challenging, with inertia declining, volatility in load and generation increasing, and the potential for DPV tripping (in response to a power system disturbance) to exacerbate contingency sizes. Based on the drivers of change identified in the March 2019 Report, the impacts on power system and market outcomes are manifesting faster than forecast.
- The Western Australian Government's Energy Transformation Strategy (ETS) Reform[3] program, which was announced in May 2019, has now provided the critical platform to implement the changes necessary to transition the power system from traditional sources of generation and passive consumers.
- The declining level of operational demand is contributing to an increasing proportion of negatively (or zero) priced trading intervals, in line with increasing participation of utility-scale non-synchronous renewable generation and higher levels of DPV output. In parallel, there is an increasingly high proportion of high-priced intervals. This is evidence that power system challenges are having a significant impact on outcomes in the market.
- Declining levels of operational demand are contributing to the displacement of synchronous generation that is presently critical for the provision of services essential for supporting system security. The prevalence of negatively priced trading intervals will erode the incentive of this generation to be available and online providing these services, unless otherwise compensated by the ESS framework.
- The changing generation mix and greater dynamism of the power system necessitates the continuation of the ETS Stage 1 WEM Reforms to scheduling and dispatch, and the Reserve Capacity Mechanism (RCM), to preserve their efficacy. Further reform to the services necessary for managing frequency and voltage may be required to ensure that technologies with the requisite capability are incentivised to enter, or remain in, the market. The ongoing programs of work under the ETS, which also includes the WoSP and Western Australian Distributed Energy Resources (DER) Roadmap, the Low Load Working Group led by EPWA and the further Stage 2 of ETS Reforms recently announced by the Western Australian Government[4], will continue to develop an energy ecosystem more prepared and capable of managing the prevailing system security challenges.

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[2] System load is operational load plus generator auxiliary loads (loads required to operate the generators such as mills, fans and pumps for coal generators). Depending on the combination of generators online, and the intervals over which load is measured, the difference between operational (or 'market') demand and system load is approximately 200 MW, where system load is the higher value. However, under conditions of low system load, the MW difference may be much reduced.

[3] At https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/05/McGowan-Government-creates-Energy-Transformation-Taskforce.aspx.

[4] At https://www.wa.gov.au/government/publications/leading-western-australias-brighter-energy-future.

## Recommended actions and priorities

This report identifies power system security challenges, including new risks that have emerged since 2019, and the specific operational conditions driving these, as well as providing an overview of ongoing and further mitigation measures that will be required. These measures include actions being implemented as part of the WA Government's ETS reforms and some additional actions that have been identified.

Table 1 lists AEMO's 13 recommendations:

- Recommendations 1, 2 and 5 are priority actions, because they offer the greatest benefit in terms of mitigating the impacts of the power system transforming at a much more rapid rate than forecast, as well as providing resilience against emergency events.
- Other recommendations are already part of the Western Australian Government's ETS activities, or could be considered for inclusion as an extension of the published reform scope.

**Table 1 Recommendations**

| List of recommended actions by category and priority | |
|---|---|
| **Recommendations category 1: Technical standards, services and mechanisms** | |
| **1.** | **Fast Frequency Response (FFR) – PRIORITY**<br>• AEMO to explore contractual options with new providers or technologies to maximise the capability to deliver FFR, where faster frequency services are needed prior to the commencement of new Essential System Services (ESS) arrangements via ETS Stage 1. |
| **2.** | **Under-Frequency Load Shedding (UFLS) – PRIORITY**<br>• The changing conditions require an increase in more dynamic monitoring and resultant actions. This includes the real-time monitoring of UFLS loads, shifting of customers between bands and management of contingency sizes in periods where UFLS is compromised.<br>• Commence action to implement medium-term solutions, including dynamic disarming (or blocking arming) of UFLS relays when circuits are measured to be in reverse flows and adaptive arming (adjusting the frequency trip settings of relays in an adaptive manner based on real time parameters).<br>• Commence development of arrangements for longer-term solutions, including more granular load shedding at the individual customer level (potentially using AMI) capabilities, and a framework for the provision of FFR services by utility-scale Battery Energy Storage Systems (BESS) and solar farms.<br>• As the owner of the UFLS, as an extension of the DER Roadmap Western Power should undertake this recommendation with the support of AEMO and EPWA. |
| **3.** | **Ramping service**<br>• Investigate the utility of a ramping service as part of Energy Transformation Strategy (ETS) Stage 2 – Keeping the Lights On; that is, a mechanism to ensure that controllable facilities capable of responding to a dispatch instruction can remain online to meet intra-day or intra-week peak periods ahead of the dispatch interval.<br>• Prior to the implementation of ETS Stage 2, AEMO to explore potential contractual arrangements to procure ramping service where AEMO determines there is a need (including outside of peak periods). |
| **4.** | **Ongoing inverter monitoring and compliance**<br>• As part of DER Roadmap, from December 2021 all new (and upgraded) DPV installations will have to comply with AS/NZ 4777.2:2020 - it is important that inverters stay compliant with the whole of the Australian Standard. This may require revision of Western Power's Network Integration Guidelines (NIG).<br>• Consider mandating ongoing compliance with capabilities required by AS/NZ 4777.2:2020 and the NIG as part of the eligibility criteria for market participation and the Distributed Energy Buy Back Scheme (DEBS). |
| **Recommendations category 2: Distribution system related** | |

| List of recommended actions by category and priority | |
|---|---|
| **5.** | **Management of distribution-connected photovoltaic (DPV) systems – PRIORITY**<br>• As soon as practically possible, enable the capability to manage newly installed and upgraded DPV (i.e., for output reduction and/or curtailment) on instruction from AEMO to a third party to assist in managing power system security and reliability in all emergency operational conditions, including during extreme low system load conditions and black start, as a measure of last resort (i.e., backstop capability). This may require the development of separate methodologies for managing DPV output, depending on the operational condition of the power system. |
| **6.** | **Market and incentive frameworks for Distributed Energy Resource (DER) participation**<br>• As an extension to ETS Reforms (specifically the DER Roadmap and Wholesale Electricity Market (WEM) Reforms), incentivise aggregated DER responses to market signals, including during low-load conditions, and develop alternative arrangements and mechanisms, if required. This will likely necessitate the determination of role responsibilities and coordination between participants, of enabling systems and of effective participation models.<br>• Consider policy arrangements for the coordinated delivery of services from DER via market and non-market mechanisms and identify the role that new and legacy incentives that apply to DER (i.e., Renewable Energy Buy Back Scheme, DEBS, retail tariffs and network charges) could play in determining the scope and prospect for market-based solutions to manage minimum demand.<br>• Consider policy arrangements that promote customer enrolment with DER aggregators to maximise the effectiveness of reforms from the 'go live' date. |
| **7.** | **Flexible loads**<br>• As part of ETS Stage 2, develop options for increasing the visibility of loads and for incentivising load behaviour to release the value of flexible load to the power system through multiple participation pathways, including through:<br>– Tariff reform to incentivise alignment with the availability of renewable sources of energy.<br>– Mechanisms to mitigate network limits.<br>– Improved market participation framework to enable the provision of ESS by industrial customers and DER aggregators. |
| **Recommendations category 3: Wholesale related** | |
| **8.** | **Changing the approach to hybrid facilities**<br>• As an extension of ETS Stage 2, investigate WEM Rules which would provide the option for unit level market submission and dispatch of components forming part of a hybrid facility, to allow components (based on their technology type and technical capability) to provide those services of most value to the power system. |
| **9.** | **Improving market incentives to address system variability**<br>• As part of ETS Stage 2, develop WEM Rules to incentivise facilities (including utility-scale non-synchronous generation) to:<br>– Accurately forecast their energy quantities.<br>– Bid their generation to a degree of certainty and accuracy (and to ramp to a pre-defined level, upwards and downwards).<br>These Rules to include 'causer pays' mechanisms that mitigate behaviours which increase requirements for essential system service provision. |
| **Recommendations category 4: Regulatory architecture and functionality** | |
| **10.** | **Prioritise the development of a centralised SWIS reliability standard and supporting frameworks**<br>• As part of ETS Stage 2, commence work immediately on the design of a centralised reliability standard that explicitly defines the role of distribution network in meeting the efficient, secure, and reliable supply of energy.<br>• Frameworks supporting the reliability standard should require the standard is used as an input to:<br>– Methodologies for the WoSP, Western Power's Annual Planning Reports and the Network Opportunity Map.<br>– Investment decisions, including any WoSP 'priority projects and the procurement (where applicable) of Alternative Options Strategy and NCESS (Non-Co-optimised Essential System Service).<br>– Facilitate operational planning processes for the power system and the network over the various planning horizons. |

| List of recommended actions by category and priority | |
|---|---|
| **11.** | **Framework for contingency planning and management for power system resilience**<br>• As part of ETS Stage 2, develop arrangements that focus on short- to medium-term planning activities to address high impact/low probability events, system strength shortages, and other stability related issues, and facilitate the making of a case for investment. This will require:<br>– Co-ordinated action between EPWA, Western Power and AEMO.<br>– An investment mechanism, based on an assessment of reasonable risk, reasonable costs, and ongoing suitability of potential solutions.<br>– A cost-recovery mechanism that potentially identifies where there are clear 'causers' of an underlying issue and that allocates and recovers costs accordingly.<br>– A governance framework for the investment mechanism that coordinates with other planning processes (such as the WoSP and SWIS reliability planning). |
| **12.** | **Build on the utility of the inaugural Whole of System Plan (WoSP)**<br>Build on the achievements of the inaugural WoSP through the consideration of a centralised approach to system planning in which WoSP processes guide investment decisions and opportunities for market participation. This may specifically require the second iteration of the WoSP to look at how power system operability outcomes can be achieved with the least cost supply mix and market outcomes (across all markets and services), including under a carbon emissions policy as outlined in other WA Government documentation. |
| **13.** | **Embed requirements for interoperability and cybersecurity**<br>For EPWA, via the DER Roadmap and broader ETS Reforms, to consider policy arrangements that will support, across all ETS reform initiatives, the improved capability of all relevant supply chain participants to actively engage and coordinate activities focused on embedding interoperability and cybersecurity for DER integration, with the objective of keeping the power system secure. |

# Contents

# Tables



# Figures

# 1. Introduction

## 1.1 Purpose and structure of this report

This report:

- Reviews the status of drivers of system security risks.
- Provides an overview of the impact of the broad ranging work recently undertaken by AEMO, Western Power and Market Participants, and the reforms implemented under the Energy Transformation Strategy (ETS) led by Energy Policy Western Australia (EPWA).
- Highlights further actions that will be required to maintain power system security in the short and longer terms as the power system continues to transition to distributed and renewable energy sources.

Chapter 2 briefly revisits the main themes of the March 2019 Report, as context for Chapter 3, which updates the status and criticality of the drivers of system security risk in terms of the impacts on power system and market operation. Table 2 (in Section 1.2) summarises the updated status of drivers identified in March 2019.

This report highlights that while operational conditions have continued to become more challenging, the implementation of specific reforms, operational initiatives, tools and investments, outlined in Chapter 4, have deferred the immediacy of system security challenges identified in the March 2019 report. Table 3 (in Section 1.2) summarises the operational, policy and investment responses that are providing AEMO with improved capability to keep the South West Interconnected System (SWIS) within its operational limits as part of managing power system security challenges in the short term.

Chapter 5 looks at the current challenges to power system operation and managing power system risk. These include new challenges such as distribution-connected photovoltaic systems (DPV) tripping and transmission faults that were not (and could not) have been anticipated at the time of the March 2019 Report, and, perhaps more saliently, the ongoing challenge of keeping the power system secure under conditions of declining levels of minimum system load.

The key technical limits and standards that apply in the SWIS are:

- **Voltage standards** – voltage must be kept within normal operating bands and must be recovered appropriately following a fault
- **Stability limits** – power system operating limits to ensure that, following a disturbance or event, the power system recovers to within normal limits within an appropriate timeframe and remains controllable within those limits (with no undamped oscillations). The power system must remain synchronised and is not in a position where it can collapse
- **Equipment limits** – cover different types of equipment and include line ratings, generator ratings, transformer ratings, and fault levels (that is, voltage withstand and power quality immunity limits)
- **Inertia limits** – ensure power system frequency does not change at a rate that would prevent the operation of automated protection systems (UFLS relays) or cause generators to trip, and that frequency does not decay below key frequency limits following a credible contingency event
- **System strength limits** – ensure that voltage step change limits are not breached, generators remain stable following a credible contingency event and power system protection devices operate correctly. This is typically represented by a minimum fault current limit in a particular part of the power system
- **Frequency Operating Standards** – specify the frequency levels for the operation of the SWIS power system

At extremely low levels of operational demand, the power system becomes vulnerable to the breach of system operating limits. The extent of the vulnerability is dependent on:

- The combination of available synchronous generators that are online to provide the essential system services necessary for power system security and reliability.

- In advance of the installation of sufficient utility-scale Battery Energy Storage Systems (BESS), the implementation of enhanced Under-Frequency Load Shedding (ULFS) schemes and other technologies.
- The leveraging of additional engineering studies, investigations and large-scale trials to determine whether the secure operating envelopes of the SWIS can be further expanded by de-risking operation near to current assumed bounds.
- The effective and timely investment in, and operation of, market and control mechanisms, and network and facility infrastructure, including protection systems and energy storage solutions.
- The continuing operational capabilities of AEMO, Western Power and other Market Participants to forecast and respond to volatile power system conditions. This will require ongoing investment in power system models, engineering studies, investigations and potentially large-scale system trials to safely expand the secure operating envelopes of the SWIS.
- AEMO's access to timely and targeted solutions or 'last resort' measures.

Accordingly, Chapter 6 provides an overview of the ongoing and further actions required to mitigate power system security risk specifically in response to low load conditions, and more generally, as the SWIS continues its transformation. Table 4 (in Section 1.2) maps each of the actions identified in Chapter 6, which includes actions being implemented in ETS Stage 1 and ETS Stage 2, plus some extra required actions, against the drivers of power system security risk highlighted in Chapter 3.

## 1.2 Background

The *2021 Electricity Statement of Opportunities: A Report for the Wholesale Electricity Market*[5] (2021 WEM ESOO) forecast that minimum operational demand in the SWIS could decline to below 250 megawatts (MW) by 2025-26 (expected demand growth scenario), predominantly due to growth in DPV installations. Should the uptake of DPV potentially exceed this forecast, the loss of a major load would bring the level of operation demand experienced on the SWIS very close to 0 MW.

The findings of the 2021 WEM ESOO are consistent with those of the March 2019 Report. The report highlighted the imperative for taking immediate action to accommodate increasing volumes of variable renewable energy from DER to address the commensurate decline in the level of minimum operational demand, and from increasing utility-scale renewable resources displacing dispatchable synchronous generation. AEMO's studies at the time had indicated that:

**Operational conditions** are the conditions experienced on the power system that arise from the combination of network configuration, the generation mix, the level of instantaneous generation and loading on the network

Operational limits are prescribed for each SWIS operating state; once those limits are breached, the SWIS enters into a state of higher (and potentially unacceptable) risk.

- Power system security in the SWIS would become increasingly challenging to maintain as the minimum operational demand and synchronous generation level reached the indicative 700 MW threshold level and below if no changes were made in respect to reforms and investments.
- Challenges to system security were most likely to manifest in Autumn (March, April and May) and Spring (September, October and November) when weather was mild and sunny, where demand was moderate but DPV generation was high.
- The frequency and extent of AEMO intervention to maintain power system security, by constraining off non-synchronous generation and constraining on synchronous generation, would increase.
- Voltage control was likely the first challenge to manage in the SWIS, to avoid unsecure operation and a high likelihood of cascading failures in the system.
- Investment in network solutions would be needed, as well as reform of the ancillary services framework.

[5] At https://aemo.com.au/newsroom/media-release/2021-wem-esoo.

Without investment in alternative technology resources that can provide services essential to system operation, or changes to system and market arrangements:

- By the early 2020s, the market and system would no longer be able to operate in an acceptable cost-effective, secure, and reliable manner.
- The level of minimum operational demand will potentially breach the indicative threshold of 700 MW between 2022 to 2024.
- The market would reach the wholesale market floor cap by 2023, and this was anticipated to occur more frequently resulting in distorted market and financial outcomes when facilities offering at the floor price are directed by AEMO to 'stay on' to ensure system security.
- From 2022 to 2024, AEMO may be required to employ rotational load shedding to disconnect excess DER generation as a last resort measure, where constraining off non-synchronous renewable generation and constraining on synchronous generation was insufficient to preserve system security.

The configuration of UFLS may need modification to discriminate between feeders that are net loads versus net generators (exporting to the grid) due to high DER generation output relative to demand[6].

On 6 March 2019, the Western Australian Minister for Energy announced the ETS, to respond to the system security concerns raised by AEMO. Since this time, the Government has published the first Whole of System Plan (WoSP) and DER Roadmap to guide the integration of DER, particularly DPV systems, battery storage and technologies such as electric vehicles (EVs). These new ETS initiatives were designed to be developed alongside the prevailing WEM Reform program to modernise market arrangements, enhance power system security, and improve access to Western Power's network for all generation types, including large renewable generators and energy storage. To support this, Western Power's commercial, regulatory, and technical framework were also in scope to be reformed. Several priority initiatives under the DER Roadmap and WEM Reforms have already been implemented or are in the process of implementation.

The Minister for Energy announced further reforms as part of ETS Stage 2 on 14 July 2021. The work program shown in Figure 1 below complements other initiatives identified in this Report to underpin longer-term system security and reliability outcomes in the SWIS.

ETS Stage 2 is expected to be the vehicle for addressing some of the recommendations made in this report that are aimed at meeting the evolving needs of the power system.

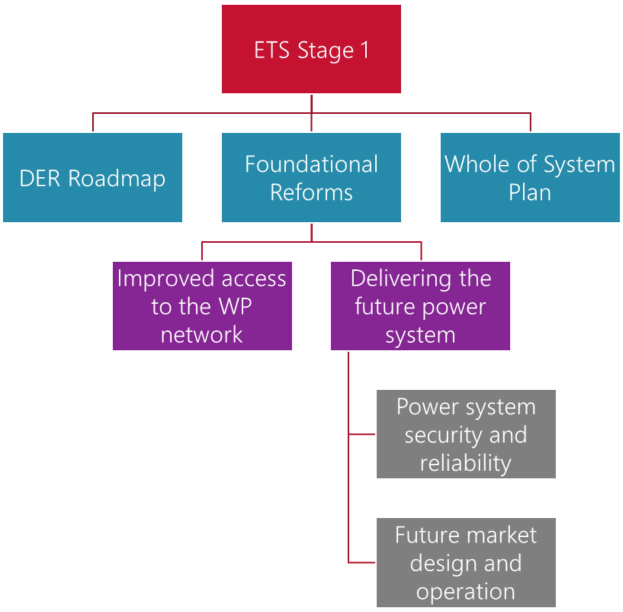
Prior to the full implementation of ETS Stage 1 reforms, and with the changes implemented since 2019, the WEM Rules provide AEMO with sufficient remit under the current power system and market operation frameworks to take remedial real-time and pre-emptive actions, where necessary, to manage prevailing system security challenges. This includes (but is not limited to):

- Real-time actions:
  - Authorisations under the SWIS Operating States framework.
  - Out of Balancing Merit Order dispatch (including constraining on / off generation).
  - Directions to Western Power and other Rule Participants.
- Pre-emptive actions:
  - Reduce either synchronous or non-synchronous generation (as relevant) to avoid thermal constraints or ensure the remaining generating units online have additional headroom to move up and down to manage system load.
  - Revised ancillary services requirements.
  - Market-based contracts.

[6] UFLS schemes needed immediate review, prior to the connection of new renewable generation to ensure the risk to system security is not exacerbated where high DER output and/or net generator distribution feeders are disconnected in the event of a loss of generation contingency event.

**Figure 1 Energy Transformation Strategy – Stage 1 and Stage 2**

**ETS Stage 1**




**ETS Stage 2**


The immediacy of these requirements and the necessity of future reform is based on the ongoing trajectory of the drivers impacting system security. Table 2 identifies the movement of system security and reliability drivers outlined in the March 2019 Report as these materially determine the challenges facing the SWIS in respect of system security and reliability. Table 2 serves as the basis to determine the degree to which these drivers contribute in net terms to the ongoing challenges in the SWIS and a basis to assess the necessary mitigations to be put in place.

Currently available options to undertake real-time and pre-emptive remedial action to maintain power system security requires intervention by AEMO in the market and/or requires AEMO to act pro-actively in a way that may compromise market efficiency. Where intervention is required with some frequency, the consequences are poor price signals, a lack of market transparency and uncertainty for market participants, and potentially higher cost outcomes for consumers. Further, in last resort circumstances, remedial measures may involve the shedding of whole distribution feeders that are exporting power to the grid, and therefore the customers that are connected (that is, their load and DPV).

**However, as the level of operational demand continues to decline, some level of minimum low system load will be reached at which the operational initiatives and remedial actions will be insufficient to keep the system secure, irrespective of the extent of intervention taken and the attendant costs to the market.**

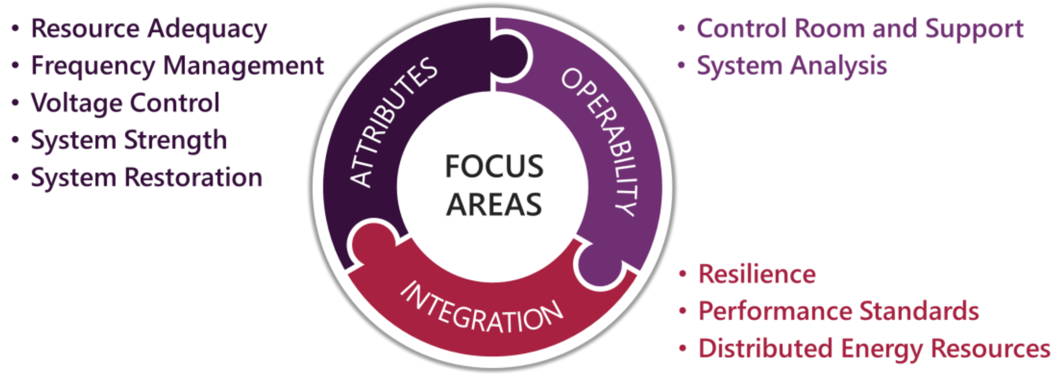
AEMO has therefore implemented new operational initiatives to enhance its system management functionality that are providing it with greater visibility of system dynamics, thereby deferring the need for intervention that would otherwise have been required. Western Power has also progressed a range of actions to improve network voltage control since the publication of the March 2019 Report. These will be instrumental in managing network voltage and system stability issues and are likely to defer the immediate risk of voltage issues causing security issues by several years.

The WEM Reforms, the DER Roadmap and other tailored actions, many of which will be delivered in ETS Stage 2, will provide longer-term solutions for managing system security. For example, on implementation of the full suite of DER Roadmap initiatives, AEMO will be able to leverage active and controllable DER via market arrangements to address minimum system load conditions.

In undertaking the significantly broad range of initiatives in the SWIS that are necessary to inform the future requirements for sustaining power system security, AEMO will draw on learnings from the National Electricity Market (NEM) Engineering Framework[7].

In developing the NEM Engineering Framework, AEMO identified 10 focus areas, identified in Figure 2, to frame ongoing and additional work required to support the transition towards future operating conditions.

**Figure 2 AEMO's complementary work program to underpin system security and reliability**




The required further mitigations described in this paper for the SWIS align with these focus areas, which are spread across three themes:

- **Attributes** are the fundamental technical elements of power system operation needed to ensure reliability and security.
- **Operability** is the ability to manage the power system within security and reliability standards and includes the data, tools, training, analytical capability, and market mechanisms to support operation.
- **Integration** is the adaptation of both the existing system and the innovative ways in which parties are interacting with the power system, so the system will continue to meet consumer expectations.

[7] At https://www.aemo.com.au/initiatives/major-programs/engineering-framework.

**Table 2 Observations on power system and market outcomes based on drivers identified in the March 2019 Report**

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Operational consumption**[8] | As per the 2018 ESOO:<br>• Level of operational consumption forecast for FY 2018-19 was:<br>– 18,320 GWh (high scenario)<br>– 18,296 GWh (expected)<br>– 18,271 GWh (low)<br>• Operational consumption was forecast to increase over the 5-year and the 10-year average annual growth outlooks:<br>– High (0.8% and 1.4%)<br>– Expected (0.5% and 0.9%)<br>– Low (0.2% and 0.4%) | As per the 2021 ESOO:<br>• Level of operational consumption forecast for FY 2021-22 is:<br>– 17,963 GWh (high scenario)<br>– 17,127 GWh (expected)<br>– 15,987 GWh (low)<br>• In general, operational consumption is forecast to decline over the 5-year and the 10-year average annual growth outlooks:<br>– High scenario (-1.1% and 0.3%)<br>– Expected scenario (-0.9% and -0.8%)<br>– Low scenario (-3.8% and -2.6%) | Within three years of the 2018 ESOO, the trend in forecast operational consumption for the following financial year went from annual increase to one of decline. The longer term 5-year and 10-year forecasts for average annual growth also showed this trend. The reason for the reversal in the forecast direction of the forecast has been the significant increase in the forecast installation of DPV relative to historical installation rates. | Deteriorated |
| **Minimum system load and minimum operational demand** | • Modelled trajectories identified the SWIS will breach the indicative 700 MW minimum level of operational demand required for system security between 2022 and 2024<br>• Period between September and December consistently pose significant operational challenge | Ever lower record levels of minimum system load achieved:<br>• 1,157 MW reached on Sunday 13 September 2020<br>• 1,144 MW on Saturday 28 November 2020<br>• 1,074 MW on Sunday 14 March 2021<br>• 984MW on Sunday 5 September 2021 | September to December in 2019 and 2020 continued to exhibit low minimum system load (and commensurately, low minimum operational load). Record lows recorded in September and November 2020, suggest declining levels of low system load in this period, and a record low in March 2021 suggest low system load conditions are starting to present outside of this period. AEMO forecasts have been adjusted to reflect the new dynamic arising from the significant increase in the installation of DPV relative to historical installation rates. | Deteriorated |

[8] Operational demand (and operational consumption) refers to electricity demand (and consumption) that is met by all utility-scale generation and excludes the impacts of behind-the-meter PV generation and battery storage. Operational consumption includes demand (and consumption) from EVs.

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Installed behind the meter (BTM) DPV capacity** | As per the 2018 ESOO:<br>• 913 MW of installed BTM DPV capacity forecast in FY 2017-18 (high forecast). This matched the 'actual' for 2017-18 (as per the 2019 ESOO).<br>• 1,249 MW forecast for FY 2019-20 (high forecast) and 1,231 MW (expected)<br>• 2,419 MW forecast for FY 2027-28 (high forecast) and 2,273 MW (expected) | As per the 2021 ESOO:<br>• 1,536 MW of installed BTM DPV capacity forecast in FY 2019-20 (actual)<br>• As of April 2021 there was 1,740 MW of installed BTM DPV capacity (actual)<br>• 4,935 MW forecasted for FY 2027-28 (high forecast) and 3.527 MW (expected) | The 2021 ESOO's high forecast for installed BTM DPV capacity by 2027-28 will be more than double that of the 2018 ESOO and the expected forecast is one-and-a-half times higher. | Deteriorated |
| **Non-Scheduled Generation (NSG) fraction**[9] | • SWIS experiencing periods of >40% NSG fraction i.e., monthly average of the weekly maximum NSG fraction in March 2019 was 40.1%<br>• Maximum NSG fraction predicted to reach almost 60% by October 2020 and 65% before 2023 | • SWIS consistently experiencing periods of >50% NSG fraction i.e., monthly average of the weekly maximum NSG faction in March 2021 was 55.8%<br>• Maximum NSG fraction first exceeded 60% on 3 October 2020 (61.5%) and was 69.9% on 7 September 2021 at 12:10 PM | The March 2019 Report flagged spring as the most challenging season to manage system security risks (with October being the most challenging month). Low system loads coincident with a high NSG fraction are still more likely to occur in spring/autumn as the precursor weather conditions are more likely to occur; however, the timing of the connection of new utility-scale renewable generation and ongoing DPV installations means that a mild day (usually a Saturday or Sunday) could result in a new record, as it did in September 21). | Deteriorated |

[9] NSG fraction = (total wind + total solar PV) / (system load + total rooftop PV + embedded generation)

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Peak DPV generation (estimated)** | Monthly average of weekly maximum (estimated) DPV generation for March 2019 was 663 MW (calculated using now superseded methodology) | • August 2020 first saw record >1 GW weekly averages of maximum (estimated) DPV generation<br>• Since late August 2020, weekly averages of maximum (estimated) DPV generation consistently exceeded 1GW in every week of every month until late April 2020<br>• The month average of weekly maximum (estimated) DPV generation for February 2021 was 1,250 MW<br>• 1,046 MW was achieved on 11 July 2021. It was the first time Peak DPV generation exceeded 1 GW in July<br>• The record for total maximum DPV generation of 1,517 MW was achieved on 12 September 2021 at 11:50pm. | With the forecast rates of DPV take-up, it is expected that the monthly average of weekly maximum (estimated) DPV generation will soon regularly exceed 1 GW, even in the coldest months (May through July). | Deteriorated |
| **Volatility** | Weather conditions causing high volatility of wind and/or fluctuations in DPV generation is challenging available supply of Ancillary Services and is expected to have wide-ranging implications for both private sector and government-owned market participants | Significant intra-interval and intra-day load swings are increasingly requiring significant re-dispatch of dispatchable generators and regularly requires AEMO to procure additional ancillary services, where ramping absorbs available Load Following Ancillary Services (LFAS). These events are typically resulting from weather patterns that cause rapid changes to DPV output in suburbs with large quantities of installed DPV. Examples of this impact include:<br>• Three occasions of 250 MW swings over ½ hour 18 October 2020<br>• 750 MW over ½ hour 10 August 2021 | While geographic diversity of the SWIS provides some smoothing of total contribution from DPV, high levels of installed DPV capacity in Perth suburbs contributes to significant volatility in total generation where fast moving cloud fronts either reduce or increase DPV output. The inability to predict these cloud movements accurately impacts AEMO's ability to predict locational volatility in DPV output and their contribution to operational demand. | Deteriorated |
| **System load swing (difference in max vs min system load of the week)** | Weather conditions were causing volatility of wind and/or fluctuations in DPV generation, impacting on LFAS quantities | Weekly load swing >2,500 MW was experienced:<br>• 2,614 MW over 8-15 March 2021<br>• 2,506 MW over 4-11 January 2021<br>• 2,673 MW over 21 – 28 December 2020<br>Over the same period in the previous year December 2019 to January 2020, the weekly load swing was in the vicinity of 1,900 MW to 2,200 MW | In a system the size of the WEM/SWIS a load swing of 2,500 MW represents a movement that is more than 60% of the maximum system load experienced in any day in December through March. Weekly load swings in the Summer months are increasing in magnitude. | Deteriorated |

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Inertia** | Inertia in the order of 8,000 MWs, which can be provided by a level of synchronous generation output that is slightly lower than the 700 MW needed for voltage control, would be sufficient to maintain the power system at a minimum level of frequency necessary to avoid triggering UFLS | • Record low minimum inertia of 7,841 MWs reached on 14 March 2021 between 9:15 AM and 1:55 PM.<br>• There were days between late November and late-December 2020 where inertia levels ranged between 8,485 to 9,697 MWs | The power system is experiencing a trend to lower levels of inertia since 2019 as a function of the ratio of non-synchronous to synchronous generation in the SWIS. | Stable |
| **New generation connections** | A total of 1,267 MW was projected to be installed between 2017-18 and 2020-21 | • A total of 1,552 MW installed between 2017-18 and 2020-21, all from renewable sources | Uptake of renewables has exceeded AEMO's forecasts of the March 2019 Report, highlighting the imperative for action prior to 'go live' of the reformed market and the need for additional measures to ensure AEMO's ongoing capability to maintain power system security and reliability. | Stable |
| **Voltages and reactive power** | On 28 October 2018, combined with high levels of DER generation (766 MW) and low operational demand (1,324 MW) meant synchronous generators online were absorbing reactive power at levels close to their thermal limits | • Easter weekend 2019 saw several scheduled synchronous generators operating above 70% of their reactive power capability limits<br>• Voltages and reactive power are now well managed due to the installation of 350 MVAr of shunt reactors by Western Power, and the 330 kV line (MU-NT 91) is taken out of service less frequently. | Voltages and reactive power were well managed in 2020 and 2021 (to date) without the frequent need to take lines out of service, even in low load conditions. The management of voltage was enhanced by the installation of shunt reactors by Western Power. However, AEMO's recent preliminary studies show that voltage control will become an issue again as system load declines below around 650 MW. | Improved |

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Load Following Ancillary Service (LFAS) and Backup LFAS requirements** | • Backup LFAS was used on three occasions on 18 October 2018 (the first time since LFAS market commencement in 2014[10]) for system security purposes, in response to cloudy weather conditions causing high volatility / fluctuations in DPV generation[11]<br>• March 2019 Report flagged that interim operational measures may be required in the lead up to the go live date of WEM reforms, including the procurement of backup ESS | • LFAS requirements for 2019-2020 were:<br>– 85 MW Upwards and Downwards 5:30 AM – 7:30 PM (peak)<br>– 50 MW Upwards and Downwards 7:30 PM – 5:30 AM (off-peak)<br>• Revised LFAS requirements approved by ERA in September 2020 applied for remainder 2020-21:<br>– 105 MW Upwards and Downwards 5:30 AM – 7:30 PM (peak)<br>– 80 MW Upwards and Downwards 7:30 PM – 5:30 AM (off-peak)<br>• AEMO determined the LFAS requirements (quantities and timings) for 2021-22 be amended to:<br>– 110 MW Upwards and Downwards 5:30 AM – 8:30 PM (peak)<br>– 65 MW Upwards and Downwards 8:30 PM – 5:30 AM (off-peak)<br>• Backup LFAS was utilised by AEMO due to volatility of NSG and BTM DPV:<br>– On 3 occasions in 2018-19<br>– On 10 occasions in 2019-20 in the range of 25-88 MW[12]<br>– On 6 occasions in 2020-21 in the rage of 25-50 MW[13] | LFAS requirements for the peak (daytime) have continue to increase since the March 2019 Report due to the expected connection of 520 MW of additional intermittent non-scheduled generation and continued uptake of DPV. However, LFAS requirements for the off-peak (night) are reduced on 2018-2019 quantities. Based on observed frequency performance over FY 2019-20 and FY 2020-21, the quantities of LFAS provided was adequate[14]. | Stable |

[10] AEMO (2019), Ancillary Services Report for the WEM 2019, June, p.9.

[11] AEMO (2019), Integrating Utility-scale Renewables and Distributed Energy Resources in the South West Interconnected System, March, p.13.

[12] AEMO (2020), Ancillary Services Report for the WEM 2020, June, p.8.

[13] AEMO (2021), Ancillary Services Report for the WEM 2021, June, p.8.

[14] AEMO (2021), Ancillary Services Report for the WEM 2021, June, p.9.

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **LFAS costs** | • The quantity of Ancillary Services, and the frequency of their deployment, is expected to increase significantly. A parallel increase in cost for their provision was therefore expected.<br>• Despite LFAS quantities for FY2018-19 being unchanged from FY 2017-18, LFAS costs:<br>– Increased by 33.7% for LFAS Upwards<br>– Increased by 0.7% for LFAS Downward | • In FY 2019-20, there was an overall net reduction in total LFAS availability costs of approximately $7.72 million compared to FY 2018-19, due to increased participation in the LFAS Market and the introduction of more efficiently sculpted LFAS requirements[15]<br>• In FY 2020-21, despite an increase in the average LFAS requirement, there was an overall net reduction in total LFAS availability costs of $6.2 million compared to 2019-20 | Although the average LFAS requirement increased in FY 2020-21 compared to FY 2019-20, the drivers for lower LFAS cost were changes in prices offered by Market Participants (likely driven by increased competition and other external factors[16]) and more efficiently sculpted LFAS requirements. Future LFAS prices are subject to market behaviour and are therefore difficult to predict. | Improved |

[15] For FY2019-20, L FAS costs: increased by $4.23M for LFAS Upwards primarily due to an increase in the LFAS Up requirement during the peak periods when the LFAS Up prices are typically higher; and decreased by $11.95M for LFAS Downward primarily due to a decrease in LFAS Down quantities during the off-peak periods when the LFAS Downward prices are typically higher. See AEMO (2020), *Ancillary Services Report for the WEM 2020*, June, p.14.

[16] AEMO (2021), Ancillary Services Report for the WEM 2021, June, p.15.

| Issue / Impact | From studies informing the March 2019 Report | Observations to September 2021 | Comments | Security Impact |
|---|---|---|---|---|
| **Negative Balancing Price and the Market Floor** | • Based on modelling, the number of trading Intervals with a negative balancing price in Q3 2018 was modelled to be:<br>– 101 (On-Peak)<br>– 22 (Off-peak)<br>• The modelling suggested the WEM would expect an increasing number of trading intervals with negative balancing prices, increasing exponentially to approx. 40% in October 2021 | • The number of trading intervals with a negative balancing price has increased significantly over recent years (285 in 2018-19 and 471 in 2019-20 to 1,282 in 2020-21<br>• In Q3 2021 (June, July and August) there were 251 trading intervals (or 5.8% of intervals) with a negative balancing price.<br>• The actual proportion of intervals with zero or negative prices increased from 2.5% in October 2018 to 10.7% in October 2020. This is forecast to increase to 32% in October 2022.<br>• In 2019, the balancing price reached the market floor price (-$1,000/MWh) for the first time over the weekend:<br>– Saturday 12 October 2019 (13:00)<br>– Sunday 13 October 2019 in 2 intervals (12:00, 13:00)<br>• In 2020, the balancing price reached the market floor price:<br>– Saturday 15 August 2020 for 3 intervals (10:00, 11:30; 12:00)<br>Saturday 12 September 2020 in 3 intervals. The (then) maximum (estimated) DPV generation of 1,189.12 MW was recorded on the same day (12:10 PM).<br>• AEMO's Quarterly Energy Dynamics (QED) reports also highlight a trend over 2020 and 2021 to a high proportion of high-priced trading intervals. | The trend is one of increasing frequency of zero and negative balancing prices and a high proportion of high-priced intervals, reflecting an increasing spread and volatility of the balancing price. This indicates that system challenges are impacting market outcomes. While the proportion of negative price intervals has increased significantly in recent years, the stepwise increase to the level forecast in the March 2019 Report has been moderated due to the updated supply curve which captures more recent bidding behaviour relative to that used in analysis for the March 2019 Report. | Stable |

Table 3 identifies measures that are currently in operation (or partially operational) and providing AEMO with enhanced capability to manage risk, or otherwise contributing to the mitigation of that risk, in the short term. Also included are measures that, in the short term, are available for deployment or are in the process of being implemented to provide AEMO with enhanced capability. The end column indicates the longer-term outlook for the measure, that is, whether it will remain in operation to complement (or be further enhanced by) ETS Reforms or will be replaced by (or operationalised through) ETS Reforms, to facilitate improved capability to manage risk in the longer-term.

**Table 3 Power system risk mitigation measures and their status**

● Indicates the measure is currently in operation*

● Indicates the measure is partially operational*

● Indicates the measure is undergoing implementation*

● Indicates the measure is available for deployment in the short-term but not deployed*

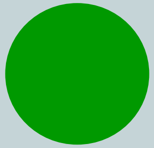
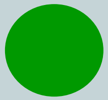
★ Indicates the measure will be replaced by, or operationalised through, ETS Reform activities

✓ Indicates the measure will remain operational in the longer-term and complement, or be further enhanced by, ETS Reform activities

*Size of coloured circle indicates the magnitude of the contribution (or potential contribution) to the mitigation of power system security risk

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| **AEMO's empowerments under the WEM Rules** | The WEM Rules empower AEMO (as part of its System Management functionality) to take actions over various operational planning timeframes, as well as in real time and pre-emptively, to ensure the power system is operated in a secure and reliable manner | These empowerments allow AEMO to take actions to ensure sufficient generation of the right capabilities are online to keep the power system operating within technical limits, to reduce the size of the largest risk to system security, to procure services that support power system operation via the market or contract, and to direct Rule Participants to operate in specified ways | AEMO provides the System Management, for the SWIS, undertaking all necessary actions that the WEM Rules empower it to take to maintain power system security. The empowerments will endure under the revised WEM Rules with the full implementation of the WEM Reforms | ● | ✓ |
| **Real Time Frequency Stability (RTFS) tool** | The RTFS tool used by AEMO Controllers and System Planners to assess actual Spinning Reserve requirements to avoid hitting Stage-1 Under-Frequency Load Shedding (UFLS) for loss of the largest generation contingency | The RFTS tool enables AEMO to better understand system conditions and how the system will respond to a disturbance. This is crucial to determining whether and how the system will remain in a Normal Operating State | The RFTS tool has been operational since late 2019 | ● | ✓ |
| **Dynamic Load Rejection Reserve (LRR) requirement** | The dynamic LRR is used by AEMO Controllers and System Planners to determine what quantity of LRR service is needed at any given time. A trial undertaken in 2019 showed it was possible to practically manage a dynamic | A dynamic LRR incorporates physical aspects of the power system and includes the setting of the upper limit of the LRR requirement based on the largest credible contingency in real time | Following the successful trial of dynamic LRR, from April 2019 AEMO adopted a dynamic LRR for 2020-21. The LRR requirement approved was up to a maximum of 90 MW[17]. Dynamic LRR is a short-term solution and the | ● | ★ |

[17] AEMO (2021), Ancillary Services Report for the WEM 2021, June, p.11.

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| | LRR requirement while still ensuring system security | | process will be replaced by the suite of WEM Reforms processes | | |
| **Sculpted LFAS requirements** | LFAS is the power system security ancillary service where assigned generators automatically and constantly change their output to compensate for load and unplanned generation fluctuations, including those from non-scheduled generation, to regulate power system frequency. Load following units respond to signals from AEMO's control systems when frequency is out of normal range (including generator trips and load rejection events) | Sculpted LFAS requirements are based on an assessment of volatility, quantities, and timeframes, as assessed through AEMO's operational experience the different requirements for daytime/ night-time periods reflect the need to respond to the increasing volatility in load commensurate with increasing DPV penetration | Revised 'sculpted' LFAS requirements were implemented on 15 July 2021.<br>The sculpting of LFAS requirements will compliment arrangements on co-optimised energy and ESS implemented under WEM Reforms |  | ✓ |
| **WEM Reforms on Frequency Co-Optimised Essential System Services (ESS)** | The new Frequency Co-Optimised ESS framework introduces market services for Regulation and Contingency Reserve to replace the existing Ancillary Services and introduces a new Rate of Change of Frequency (RoCoF) Control Service for the procurement of inertia in the WEM. These new services will be co-optimised with energy under security-constrained economic dispatch (SCED) and are supported by a new framework for Non-Co-optimised ESS to allow location services to be procured by both AEMO and Western Power. | The new framework allows services to be supplied through market mechanisms and expands the range of services that allow AEMO to manage frequency. Co-optimisation with energy will allow AEMO to constrain on facilities providing ESS through normal operation of SCED, minimising directions and market intervention. | WEM Reforms on ESS provide a long-term solution for the management of frequency, however there will be a continuing need for tools such as the RTFS (or similar) in real-time<br>Available from the 'go live' of WEM Reforms |  | ★ |
| **Western Power projects – voltages and reactive power** | Install 350 MVAr of reactive power compensation, and an assessment of network technology solutions for grid support to maintain network stability during low-demand. In addition, Western Power is undertaking other power support projects (in the context of system minimum load): | Defers risk of voltage issues causing security issues by several years when implemented | 350 MVAr of reactive power compensation has been installed. Western Power are currently undertaking additional studies to determine whether additional reactors are required to support further reducing operational demand. |  | ✓ |

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| | • Operational adjustments: Providing AEMO with up to date UFLS information / availability to facilitate secure dispatch; Sharing Secure Reactive Dispatch (SRD) tool with AEMO; Ongoing joint operational planning activities between Western Power and AEMO<br>• Enhanced tools: Joint development of Single Frequency Model (SFM) by Western Power and AEMO for the purposes of UFLS and frequency stability studies; Investigation into Wide Area Monitoring Protection and Control (WAMPAC) schemes.<br>• Additional MVAr Reactors: Mandatory volt-var functionality for inverter connected generation that has been installed / upgraded since August 2019 provide "natural" additional reactive power support. | | | | |
| **DER Register** | DER Roadmap Action item #15 – Register of static data on inverter-connected DER devices (including DPV and battery storage) | The register provides data on DER that is necessary to provide visibility of DER on the power system, this data supports real-time forecasting, long-term planning, and will facilitate the future participation of aggregated DER in the market | DER Register went 'live' on 1 March 2021. The DER Register will have longer-term applications | | ✓ |
| **Revised inverter standard AS/NZ 4777.2** | DER Roadmap Action items #1 – AEMO working with Western Power via Standards Australia review of AS/NZ 4777.2 for improved autonomous grid support capability (frequency and voltage ride-through) and regulation | The revised standard mandates improved disturbance ride-through capabilities for DER response to system disturbances (for those devices installed after December 2021 when the standard becomes mandatory), thereby supporting real time power system operation | New standard published 18 December 2020 (applies to new installs after December 2021, with some requirements commencing in WA in July 2021) | | ✓ |

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| **DER orchestration pilot** | DER Roadmap Action item #22 – Joint AEMO-Synergy-Western Power pilot to demonstrate the coordination and dispatch of an aggregated portfolio of DER, including DPV, battery storage and other devices – part funded by ARENA | The pilot will validate the technical capability required by aggregated DER for WEM participation and the communications and control requirements for coordinating power system management, network management and market dispatch. | Pilot scheduled for operation in early 2022 with project closure by June 2023. Learnings from the pilot will contribute to the development of market participation models for aggregations of DER | | ★ |
| **Generator Performance Standards (GPS)** | As part of WEM reforms, amendments to the WEM Rules provide for a suite of revised GPS for transmission-connected market facilities (including renewable generation) and a new compliance and monitoring framework | GPS are an essential component of maintaining stable network voltage and frequency for a secure and reliable power system, and for providing AEMO and the network operator with high quality information on a facility's expected performance as the generation mix changes | Amending WEM rules for new GPS obligations, and new GPS procedures commenced 1 February 2021. The GPS (updated as required) is a long-term solution | | ✓ |
| **Under Frequency Load Shedding (UFLS)** | DER Roadmap Action item #10 – Western Power to undertake a review of its feeder selections to UFLS stages and implement optimisation. AEMO to advise on the future implementation of UFLS | Ensures sufficient load on the UFLS stages to the extent possible (noting that ever-decreasing system load will eventually make this impractical) and ensure the ongoing suitability of UFLS in a high-DER environment (by preventing UFLS operation from exacerbating supply shortages) | Improvements completed as a short-term solution. Program to enable for improved telemetry is underway. A 'dynamic' UFLS scheme which adjusts feeder UFLS selection based on net load (and any further arrangement improvements) will provide a longer-term solution when implemented. | | ✓ |
| **System model update** | DER Roadmap Action item #13 – AEMO's system model updated to incorporate DER | Allows AEMO's system model to reflect distributed PV under steady state and dynamic conditions as well as load tripping behaviours. It augments AEMO's capability across several planning functions | Validation of steady state model has been completed. The dynamic model is undergoing validation studies and will be initially operationalised in October 2021, and then enhanced through to mid-2022. | | ✓ |
| **Revised System Restart arrangements** | DER Roadmap Action item #12 – Revised System Restart arrangements to consider DER in the short-term, with enhanced DER and Load Model information to be incorporated as part of longer-term System Restart arrangements | AEMO needs the ability to restart the power system in the rare event of a 'black' system. This presently involves the start-up of large synchronous units which require adequate stable load to meet their minimum loading requirements. Revised arrangements will consider the | Robust view of DER has been integrated into System Restart arrangements, based on minimum demand and power flows expected on restart. Enhanced System Restart arrangements will provide a longer-term solution when implemented. | | ✓ |

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| | | dynamic behaviour of DPV so that restart can be undertaken in consideration of the load that is available, including for the operating a small island during the System Restart process | | | |
| **Whole of System Plan (WoSP)** | Energy Transformation Strategy Action item – An EPWA led initiative with support from AEMO and Western Power, the WoSP will set out how best to manage and coordinate the transformation occurring throughout the electricity supply chain today and over the 20-year outlook of the plan | The initial WoSP modeled the lowest cost to supply mix for transmission, generation and storage capacity required to meet demand under four demand scenarios. The plan identifies network and non-network challenges and solutions of the power industry transformation, and the identification of any 'priority projects' requiring new investment. | Inaugural WoSP dated August 2020 provided insight into potential futures in multiple 'bookend' scenarios. No priority projects were identified. The second WoSP is planned to commence development end-2021. AEMO believes having a 'likely' scenario will be necessary to guide the planting of technologies in the short-term to resolve existing and forecast power system challenges. | ● | ✓ |
| **Distribution storage initiatives[18]** | DER Roadmap Action items #5a through #8 – Installation of community PowerBanks, the development of a distribution storage plan for 2021-24 and changes to regulatory instruments to support opportunities for deployment of storage | Initiatives to provide a cost-effective solution for managing network and power system risks, while offering opportunities for customers to access storage products. Changes to the *Electricity Networks Access Code 2004* (ENAC) and Western Power's Technical Rules necessary for efficient procurement of storage and storage services by Western Power | Western Power has deployed 13 PowerBanks[19] and released the *Distribution Storage Opportunities Information Plan* (11 December 2020[20]). Network Opportunity Map expected for release 1 October 2021. Synergy is working with Western Power to deliver the PowerBank Energy Storage Trial - currently in its third phase – which concludes September 2020. ENAC amended (18 September 2020) and Technical Rules currently undergoing amendment. | ● | ✓ |

[18] Energy Transformation Taskforce (2021*), Distributed Energy Resources Roadmap Progress Report*, April, pp.9-10.

[19] At https://www.westernpower.com.au/faqs/community-batteries/community-batteries/where-are-the-community-batteries-located/.

[20] Energy Transformation Taskforce (2021), *Distributed Energy Resources Roadmap: Progress Report*, April, pp.9-10.

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| **Enabling market participation of Energy Storage Resources (ESR)** | New WEM Rules are enabling the registration and connection of ESR facilities, which include utility-scale storage resources connected to the transmission network, either standalone or co-located with another type of generation technology as part of a 'hybrid' facility, and to small-scale aggregated storage connected to the distribution network[21] | ESR can now obtain certification to provide capacity and can now compete in energy and ESS markets[22] | The Expression of Interest (EOI) window for the 2021 Capacity Cycle closed on 16 August 2021. AEMO received submissions from 7 entities proposing to connect 196 MW of battery capacity to the network, for installation between 1 July 2022 and 1 September 2023. | ● | ✓ |
| **Distributed photovoltaic (DPV) generation management** | Introduction of management capability for new and upgraded inverter-connected DPV systems in the SWIS | Last resort measure to "keep the lights on" in extreme events or operating conditions. DPV installed or upgraded post the 'go live' date will be able to be turned down, to effect increased system load during low load events to maintain power system security | Under development and implementation | ● | ★ |
| **Non-Co-optimised Essential System Service (NCESS) contract** | Contract made under the WEM Rules (under new marker arrangements) with a generator that can be called upon by AEMO to operate to support system security and reliability, where this is not already covered by other ESS | The NCESS would operate in combination with AEMO's other actions taken under its empowerments under the WEM Rules. The service would address specific challenges exacerbated by low system load or other operational conditions. It could potentially be fulfilled by a utility-scale Battery Energy Storage System (BESS) with no minimum loading requirement, intermittent loads or other resources. | AEMO's recent annual Ancillary Services reports flagged the possible need for a Dispatch Support Contract prior to the full implementation of WEM Reforms.<br>NCESS may be a preferred option, however unless action is taken to bring the commencement date of NCESS arrangements forward, they will start as part of the new market arrangements. | ● | ★ |

[21] Energy Transformation Taskforce (2021), Reserve Capacity Mechanism, Changes to support the implementation of constrained access and facilitate storage participation, Informal Paper, May, p. 20. See https://www.wa.gov.au/sites/default/files/2021-05/Information%20Paper%20Reserve%20Capacity%20Mechanism%20-%20Changes%20to%20support%20the%20implementation%20of%20constrained%20access%20and%20facilitate%20storage%20participation.pdf

[22] Energy Transformation Taskforce (2021), *Reserve Capacity Mechanism, Changes to support the implementation of constrained access and facilitate storage participation, Informal Paper*, May, p.6.

| Mitigation measure | Description | Mitigatory effect | Current status | Short-term availability and impact | Longer-term outlook |
|---|---|---|---|---|---|
| **Aggregated minimum stable loading** | Reducing a facility's minimum stable loading enables it to provide both energy and ancillary services at lower output levels, increasing resilience against lower system load. Aggregated minimum stable loading is the minimum output at which several such facilities can operate, in aggregate | There has been a net reduction of 393 MW in the aggregated minimum stable loading as facilities have undergone works to reduce their minimum stable loading | The reduction in the aggregated minimum stable loading is providing resilience against lower levels of system load; however, the SWIS will likely soon experience circumstances where, even with the benefit of the reduction, the number of facilities online will be insufficient to maintain adequate system strength and other ESS. | | ✓ |
| **Utility-scale Battery Energy Storage System (BESS)** | Utility-scale BESS (transmission-connected) | BESS of material size and capabilities can provide services essential to maintaining system security and reliability, such as frequency control and contingency response services, as well as storing 'excess' energy for use during periods of peak demand | Synergy is building a 100 MW/200 MWh BESS in Kwinana which is expected to become operational by September 2022[23].<br>Media have reported that Alinta is planning to build a 100 MW (likely 200 MWh) BESS in Wagerup. | | ✓ |

Table 4 below identifies the ongoing and further mitigation measures required to manage power system security risk (see Chapter 6) and maps those measures against the operational conditions driving security risk (see Chapter 3). The table includes:

- Relevant mitigation measures being implemented as part of ETS Stage 1.
- Actions AEMO recommends for inclusion within the scope of ETS Stage 2.
- Extra actions that will be required which are likely to be additional to work being done under the ETS reforms.

[23] At https://www.mediastatements.wa.gov.au/Pages/McGowan/2020/10/Big-battery-to-power-160000-homes-in-WA-and-create-100-local-jobs.aspx.

### Table 4 Ongoing and further mitigating measures required to address the drivers of risk to power system security

| | | Operational conditions to be managed or mitigated | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Further required mitigation measure** | Detail | Increasing DPV penetration | DPV tripping | Large load swings | Unpredictable DER performance | Rapid RoCoF | Export into grid | Declining system load | Inertia decline | Load volatility | Generation volatility | Lack of coordination between parties | Declining synchronous generation | UFLS compromised | Increasing contingency size | Inadequate load for minimum loading | Deviation from forecast generation response | Voltage issues | Lack of standardised approach | Indicative mechanism [24] |
| **Management of DPV** | Export management (i.e., reduce to zero) | ● | ● | | | ● | ● | ● | ● | ● | | ● | ● | ● | ● | ● | | ● | | ETS 1 |
| | System restart | | | | | | ● | ● | | | | ● | | | | ● | | | | ETS 1 |
| | Market ESS | | | | ● | ● | | | | ● | | ● | | | ● | | ● | | | ETS 1 |
| **Inverter performance** | Monitoring and compliance | | ● | | ● | ● | | | | | | | | | ● | | | ● | ● | ETS 1 |
| **DPV disconnection response** | Real-time contingency size management | ● | ● | | | ● | | ● | ● | | | | ● | | ● | ● | | | | ETS 2 |
| | Enabling more Spinning Reserve | | ● | | | ● | | | ● | | | | | | ● | | | | | BAU |
| | Interim FFR service (via NCESS) | | ● | | | ● | | | ● | | | | | | ● | ● | | | | Extra (ETS 1) |
| **FFR service** | Fast Spinning Reserve (via NCESS) | | ● | | | ● | | | ● | | | | | | ● | ● | | | | Extra (ETS 1) |
| | Add more / shift UFLS load | ● | ● | | | | ● | | | | | | | ● | | | | | | BAU |

[24] ETS 2 items in Table 4 are those recommended by AEMO for inclusion within the scope of the ETS Stage 2 Reform program of work.

| | | Operational conditions to be managed or mitigated | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **UFLS operational adjustments (cont.)** | Real-time UFLS load monitoring | ● | ● | | | | ● | | | | | | | ● | | | | | | BAU / ETS 2 |
| | Dynamic disarming / blocking arming | ● | ● | | | | ● | | | | | | | ● | | | | | | BAU |
| | Granular load shedding | ● | ● | | | | ● | | | | | | | ● | | | | | | ETS 2 |
| **Flexible load incentives** | Retailer arrangements | ● | | ● | | | | ● | | ● | | ● | ● | | | ● | | | | Extra |
| | DX network arrangements | ● | | ● | | | | ● | | ● | | ● | | | | ● | | ● | | ETS 1 |
| | Market arrangements | | | | | ● | | ● | ● | ● | | ● | | | | ● | | | | ETS 2 |
| **Ramping service** | Higher ramping requirement (via NCESS) | ● | | ● | | | | ● | | | | | ● | | | | | | | Extra (ETS 1) |
| **Contingency planning and management** | Frameworks for power system resilience | ● | ● | | | | | | ● | | | ● | | | ● | ● | | | ● | ETS 2 |
| **'Separated' hybrid facility** | Separate offer each component | | | | | ● | | | ● | | ● | | ● | | ● | | ● | | | Extra |
| **Revised cost allocation** | Ex-ante forecast and Causer Pays | | | | | | | | | | ● | | | | | | ● | | | ETS 2 |
| **SWIS reliability standard** | Reliability metric(s) and framework | | | | | | | | | | | ● | | | | | | | ● | ETS 2 |
| **RCM enhancements** | Value flexibility in dispatch | | | ● | | | | | | | ● | ● | ● | | | | ● | | | ETS 2 |
| **WoSP improvements** | Determination of future SWIS needs | ● | | | | | | | | | | ● | ● | | | | | | | BAU / ETS 2 |

| | | Operational conditions to be managed or mitigated | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Interoperability / cybersecurity** | Supportive 'ecosystem' under wider ETS Reforms | | | | ● | | | | | | | ● | | | | | ● | | ● | BAU / ETS 1 / ETS 2 |

## 1.3 Context for this report

The policy environment for this Report differs markedly from that in which the March 2019 Report was drafted. The March 2019 Report acknowledged the critical role of the WEM Reform Program in accommodating the uptake of utility-scale renewable generation, and of AEMO's ability to manage an effective response to increasing DER penetration and grid-connected renewable generation. The action taken by the WA Government to establish and quickly progress the ETS program of reforms, including continuing the WEM program, has been key to ensuring the SWIS and the WEM are well placed to accommodate necessary changes to transition the power system.

The reforms comprise a comprehensive program of work to improve WEM operation through security-constrained economic dispatch (SCED), enable a more responsive capacity regime and market power mitigation measures. The core reforms would enable power system security and reliability through the better management of constraints and intermittency by:

- Increasing automation and transparency in market dispatch processes necessary for managing power system security and reliability in a constrained grid and to support an efficient market.
- Improving arrangements for ESS, which will replace existing Ancillary Services procurement and operation. The new arrangements will provide for:
  - Markets for critical ESS, including Regulation, Contingency Reserve and Inertia (Rate of Change of Frequency [RoCoF] Control Service).
  - The co-optimisation of energy and ESS in real-time.
  - A flexible approach to dynamically set required quantities of ESS to minimise costs and reflect changing system needs.
  - ESS required to be explicitly defined, valued, and incentivised to keep the power system secure and reliable as it transforms.
  - The procurement of Non-Co-optimised Essential System Services (NCESS), which are services that are required to support power system security and/ or reliability but by their nature cannot be easily co-optimised with energy dispatch in real-time.
- Reduced reliance on, and cost of, ESS to manage forecasting uncertainty by dispatching energy more frequently and reducing the gate closure period.
- Enabling the registration of bi-directional resources (BESS) to participate in the market.
- Applying a Network Access Quantity (NAQ) framework within the RCM to reflect the impact of constraints while proving long-term revenue certainty for facilities holding capacity.
- Allowing the certification of new technologies under the RCM, including BESS.
- Improving arrangements for the application and enforcement of Generator Performance Standards (GPS).
- Improving frameworks for the technical reliability and operation of the power system, including revised system standards, the clear assignment of role responsibilities and the establishment of robust governance mechanisms for the ongoing review of technical requirements and standards.

AEMO's March 2019 Report recommended seven additional actions that could build on the WEM Reform program to deliver more optimal outcomes for electricity consumers, industry participants, investors and the operation of the SWIS in an environment of increasing renewable penetration:

- Update inverter standards to include advanced capabilities and implement within distribution connection requirements.
- Enable the registration, connection and operation of BESS in the SWIS.
- Determine and evaluate system security technologies.

- Expand the WEM Reform Program's detailed design to include mechanisms and amendments to regulatory frameworks to enable DER integration, including the establishment of a DER Register.
- Implement a system planning function for the SWIS to facilitate modelling for future developments and identify developmental pathways for energy transition.
- Develop a DER Roadmap to identify technical, operational and regulatory arrangements to provide value to the market.
- Confer Distribution System Operator and Distribution Market Operator functionality.

The Western Australian State Government's ETS has since delivered several of the recommended additional actions, including:

- Revised AS/NZ 4777.2 were published on 18 December 2020; all inverters installed after December 2021 must comply with enhanced autonomous settings. Some components of the new standard commenced in July 2021 in Western Australia.
- The DER Roadmap was published in December 2019. The document provides guidance on the integration of onsite generation (solar panels), battery storage and future technologies such as EVs.
- The DER Register went live in April 2021. At the time of network connection, information is collected on all those DER for which visibility, predictability, and coordination is determined to be necessary.
- The inaugural WoSP to facilitate system planning was published in September 2020.

The ETS has also delivered gazetted rules for several core elements of the WEM Reforms. These rule amendments effectively represent the start of the transition to the new arrangements for power system operation in the SWIS and wholesale market operation. The rules are facilitating the implementation of:

- A new GPS framework that enables AEMO and Western Power to better manage their respective responsibilities as System Management and the Network Operator in respect of the connection of transmission-connected facilities that intend to participate in the wholesale electricity market - WEM Rules commenced 1 February 2021.
- Reform of the Reserve Capacity Mechanism for the 2021 Reserve Capacity Cycle facilitating certification of Electric Storage Resources (ESR – storage technologies) and a framework to manage separate certification of technologies within hybrid facilities – Rules commenced 2021.
- Reform of the Reserve Capacity Mechanism for the 2022 Reserve Capacity Cycle to reflect constrained access through the new NAQ framework – Rules commencing across 2021 and 2022.
- Revised Frequency Operating Standard (FOS) for the SWIS (and their relocation from the Technical Rules to the WEM Rules) to better facilitate the application of the FOS - WEM Rules commenced 1 February 2021.
- A new framework to allow Western Power to communicate network limits to AEMO alongside a process for AEMO to formulate Network Constraints and a transparent publication mechanism through the Congestion Information Resource. These reforms will allow AEMO to manage constrained access within SCED in the new Market - WEM Rules commenced 1 July 2021.
- A new governance and change management regime for the Technical Rules - WEM Rules commenced 1 January 2021.
- Revised Technical Rules for network connection, planning and operation, which are currently before the Economic Regulation Authority (ERA) for approval. The revised rules will, among other things, recognise that System Management functionality now resides with AEMO under the WEM Rules.

The early implementation of the above-mentioned reforms both facilitates transparency and provides AEMO, Western Power and Market Participants with several critical preparatory functions to facilitate the full implementation of the broader WEM Reform program.

# 2. Key themes of the March 2019 Report

This chapter revisits the main themes of the March 2019 Report as context for Chapter 3, which updates the status and criticality of the drivers of system security risk, based on newer data and analysis.

**Table 5 Major themes in AEMO's March 2019 Report**

| | Theme |
|---|---|
| **1** | Declining levels of operational demand (and system load) was starting to characterise the power system operating environment |
| **2** | System security risks were emerging as the increase in large-scale renewable generation displaced dispatchable synchronous thermal generators that would need to be constrained-on to provide inertia, frequency control, system strength and voltage control |
| **3** | Without accommodating new technologies, voltage in the SWIS could not be controlled within technical limits as the level of minimum operational demand approached an indicative threshold of 700 MW, likely between 2022 and 2024 |
| **4** | Market efficiency will deteriorate as the level of operational demand declines, resulting in poor pricing signals for investment and potentially market exit |
| **5** | Last resort measures would be required from 2022 |
| **6** | Revised technical standards, market and regulatory constructs were urgently required to allow the entry of new technologies in the SWIS |
| **7** | It is critical to implement reforms and new investments by October 2022 or earlier |

## Theme 1: The SWIS is experiencing low system load conditions

AEMO tracks system load to inform its day-to-day system management functions and operational demand as part of market data to support its functions as the market operator. Operational demand has exhibited a steady decline, particularly in the daytime, which is also reflected in a commensurately steady decrease in system load levels.

The decline in system load, especially in terms of the level of minimum system load, is a direct consequence of the increasing penetration of DPV systems and is adding a further dimension of complication to the management of power system risk. This is because of the effects that the downward trend in system load is having on the daily load profile, which includes increased intra-day and intra-week volatility in the movement of system load, the shifting of the daily consumption peaks, and the deepening of the mid-day demand trough (that is, the belly of the "duck" of the duck curve). The latter is disguising the level of 'underlying demand' for electricity (see Table 6).

The decline in system load is happening at a time when low-cost renewable (variable non-synchronous) generation is continuing to displace synchronous generation in the SWIS. As system load further declines to ever lower minimum levels, the power system becomes less resilient and more vulnerable to disturbances and contingencies as fewer synchronous generators can remain online to provide sufficient inertia and other services essential for keeping the power system secure. This continues to be a challenge and this challenge is expected to become more pronounced as system load continues to decline sharply.

There are three major types of "demand" that are sometimes interchangeably (and confusingly) used in discussions of system challenges. These are outlined in Table 6 below to facilitate an understanding of their use in this Report, specifically in terms of describing the effects of the drivers and challenges facing the SWIS and the remedial actions that are required.

**Table 6 System load, operational demand and underlying demand**

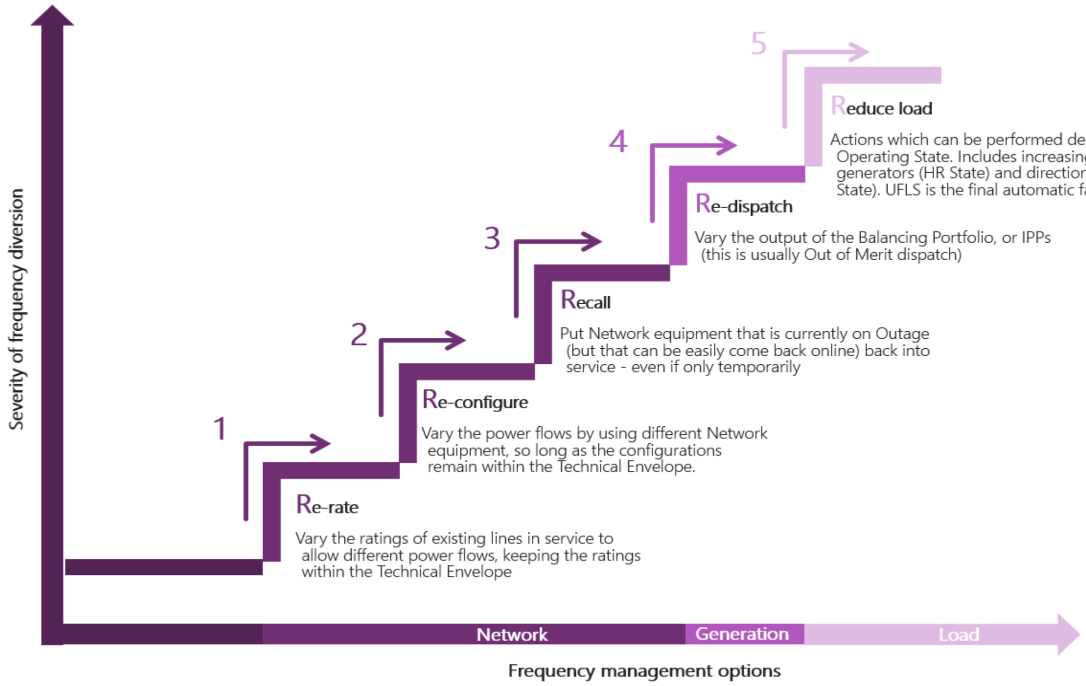
| Item | System load | Operational demand | Underlying demand |
|---|---|---|---|
| **Application** | System operation | Market reporting | Market reporting |
| **Data source** | SCADA | SCADA (sent-out MW quantities) | Operational demand plus estimate of behind-the-meter DPV generation |
| **Measurement frequency** | 4-second instantaneous | 30-minute average | 30-minute average |
| **Loss factor adjusted to Reference Node** | No | No | No |
| **Registered (Scheduled and Non-Scheduled) generation** | Measured at generators terminals | Measured as 'sent-out' at the connection point | N/A |
| **Unregistered generation** | Not included / inferred | Not included / inferred | Not included / inferred |
| **DER generation** | Not included | Not included | Estimate included |
| **Used by AEMO for:** | • Operational forecasting<br>• Monitoring of system performance | • WEM ESOO<br>• Quarterly Energy Dynamics (QED) Report<br>• Market Insights<br>• Facility Testing<br>• RCM calculations | • WEM ESOO<br>• QED Report<br>• Market Insights |
| **Used in this report to facilitate discussion of:** | • Quantum of peak DPV output<br>• Levels of minimum system load<br>• Size of load swings | • Indicative 700 MW threshold<br>• Zone of heightened power system security risk<br>• Demand forecasts based on ESOO data | • Profile of the duck curve<br>• Impact of DPV penetration<br>• Impacts on market prices |

## Theme 2: Managing security risk with a rapidly changing generation mix becomes more challenging as operational demand declines

AEMO has several obligations imposed on it under the WEM Rules in respect of operating the power system. To enable the power system to be managed securely, there is a requirement on AEMO to dispatch generators connected to the network to provide ESS and to operate the system within technical standards in respect to inertia, frequency control, voltage control and system strength. Not only must ESS be always provided to adhere to technical standards, but the power system needs to be operated such that power system security is maintained even where the next 'worst' contingency was to occur, so the system can sustain secure operations despite the contingency event.

Achieving power system security and reliability outcomes is dependent on effective, sequential management of network assets, generation assets and assets that consume electricity (loads), as shown is shown in Figure 3 below. The figure outlines the steps System Management uses to manage power system security and reliability in the SWIS, commonly referred to as the five 'Rs'. These span the steps to managing the system across the full suite of technical parameters, including frequency, voltage and system strength, using the network, generation and load to ensure system security and reliability is managed in accordance with the requirements of the operating state. Only as the last step will load be managed to mitigate the frequency deviation. The type of load mitigation option used is dependent on the operating state of the power system.

**Figure 3 The steps applied to manage power system security and reliability (the five 'Rs')**




Just as the power system has become more dynamic and nuanced, so must the processes to manage the power system. Management of the power system now requires action to deal with circumstances of a tight balance of sufficient generation as well as the exact opposite circumstance, where there is excess generation relative to the prevailing system load.

As DPV penetration increases, the magnitude of volatility in load that is attributable to uncontrollable and largely unpredictable cloud movement also increases. To respond to this volatility, generators that are online are required to increase and decrease their output within a relatively short period of time. Each generator has a minimum operating limit below which they can no longer stay connected to the grid and will have to disconnect. With sufficient generators online, the amount of movement needed to address volatility can be accommodated within the operational range of the generators. However, as minimum system load reduces, the number of generators that can be accommodated on-line to provide these services also reduces as operational flexibility is impinged. With fewer generators online, there is less range of movement capable of being achieved within a short time frame. This continues to be a challenge.

## Theme 3: Without new technologies, the SWIS could not be controlled within technical limits as demand approaches 700 MW

The WEM Rules define Power System Security as "the ability of the SWIS to withstand sudden disturbances, including the failure of generation, transmission and distribution equipment and secondary equipment". In broad terms, 'withstand' in the context of security means that the system remains operating within all relevant limits and technical standards.

Modelling for the March 2019 Report determined that without changes to accommodate new technologies, the SWIS could not be controlled within technical limits as the level of minimum operational demand approaches 700 MW. Voltage limits were identified as the first to be breached; with inertia issues materialising below the 700 MW threshold where demand was met entirely by utility-scale synchronous generation (based on present facility capabilities and dispatch)[25].

At the time, forecasts of DPV growth indicated that minimum operational demand would likely breach 700 MW between 2022 and 2024, depending on the DPV installation rate and load growth, and taking into account day-to-day variability in weather and load conditions. This would require AEMO instructing generators to stay online to absorb reactive power and manage voltage issues on the network and/or require last resort rotational load shedding to curtail DER export to the grid. Alternatively, incentives could be provided to BESS operators to 'soak up' excess generation via the RCM, to provide 'Reserve Load', and to give Reserve Capacity payments to BESS operators for making this reserve available. However, even where issues with voltage control were resolved (for example, through the installation of additional network reactive devices) then inertia or system strength difficulties would soon manifest.

Analysis continues to be necessary to understand, from a holistic perspective, when and how the breaches to the technical limits would occur. It will also help identify the remedial actions to be taken when demand is too low to enable sufficient utility-scale synchronous generation to be online to provide the services necessary to support secure power system operation.

## Theme 4: Market efficiency will deteriorate as more offers at the market floor result in negatively priced market intervals

Some level of negative pricing in a wholesale electricity market is not atypical. However, clearing at the price floor is a market outcome that is symptomatic of low demand, and reaching the negative price cap for prolonged periods may be creating a distorted investment signal. This is likely to place financial distress on market participants as electricity prices fall below short run marginal cost.

In addition to the increasingly prevalent incidence of negatively priced trading intervals, this is expected to be exacerbated by an increase in the number of intervals whereby AEMO will be required to intervene in the market. During trading intervals where AEMO intervenes in the market, AEMO deviates from the merit order to ensure the appropriate mix of generation is brought online and remains online to secure necessary ESS. Therefore, while system security can be managed by successively more intrusive interventions and directions, market efficiency will be adversely impacted.

Market intervention may occur for many reasons; one such reason is that the existing market design does not support mechanisms that enable the provision of the full suite of system security services. As a consequence, AEMO must intervene in the market to provide an administrative solution in absence of a market solution in which these services are appropriately valued.

[25] AEMO (2019), *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS*, March, pp.21-22.

## Theme 5: Last resort measures would be required from 2022

The March 2019 Report indicated the likelihood of AEMO taking last resort measures from 2022, where constraining off non-synchronous generation and constraining on synchronous generation was insufficient to maintain system security. These measures would include rotational load shedding to disconnect excess DER export into the grid.

One form in which this load shedding could be implemented is via schemes deployed by the Network Operator (Western Power). This present capability de-energises whole parts of the distribution network resulting in the disconnection of customers connected to that part of the network. This means consumers can no longer keep their appliances or DPV running unless they have a battery and an islanded controller. Ideally, only the excess DPV capability would be temporarily disconnected.

The Technical Rules contain technical engineering standards for power system performance, including acceptable frequency and voltage limits. Under these rules Western Power has an obligation to install equipment for automatically dealing with voltage and frequency excursions (via UFLS schemes) outside of defined limits, or otherwise to manually deal with these matters, and to make sufficient load available for shedding through disconnection. This is generally achieved via switchgear at substations from which distribution feeders originate.

The Technical Rules work in conjunction with the WEM Rules; Western Power is required to take direction from AEMO to manually shed load, in accordance with its load shedding plans (made under the WEM Rules), to restore the power system to a secure state[26]. In the presence of high levels of DER, some distribution-level feeders can become net exporters at certain times of the day. The action must be undertaken judiciously as it can exacerbate system issues. For example, if the feeder is exporting during an under-frequency event and disconnected, system frequency can decay further[27]. A reconfiguration of UFLS schemes was required to be completed with some urgency.

The UFLS schemes were recently improved. However, this is not a long-term solution, such that AEMO will be working with Western Power on further enhancements to UFLS arrangements.

## Theme 6: Revised technical standards, market and regulatory constructs are urgently required to allow entry of new technologies

The March 2019 Report highlighted the urgency of making reforms to technical standards, market, and regulatory mechanisms to integrate new technologies to better manage the effect of increased non-synchronous generation and DER penetration on the SWIS. The reforms would need careful design to provide for improved inverter capabilities, uplifted UFLS schemes and enablements under the WEM Rules and other instruments for AEMO, Western Power and other participants.

In addition, the reforms should enable incentivised investments and allow new business models to usher in a range of technologies such as synchronous compensation, Virtual Power Plants and energy storage. Noting that regulatory change and capital investments takes time to implement, from inception to implementation to outcome (project commissioning), timely and clear policy guidance and clarity on regulatory intent was crucial for creating the impetus for future investment and market participation.

Specifically, the March 2019 Report called for an update to AS/NZ 4777.2 and commensurate capabilities in network connection processes, regulatory changes to establish a DER Register, to enable the market participation of aggregations of DER (and pilot projects to validate DER capabilities) and for integrated system planning. While the ETS Reforms, particularly the DER Roadmap, are delivering on these specific initiatives, a comprehensive vision and plan with recommendations to guide SWIS development (potentially

[26] See for example, the prescription in WEM Rules 3.6.6A and 3.3.6B.

[27] Severe contingency events involving multiple concurrent generator failures can cause system frequency to fall to a level that triggers automated load shedding as a means of arresting frequency decline and potentially system collapse. The automated UFLS schemes are implemented based on static settings using broad assumptions on load distribution and profile on the distribution network.

articulated through the next WoSP and applied through supporting processes) is required that puts consumers and new technologies at the focus of market arrangements, to ensure the power system can continue to operate securely and cost-effectively.

## Theme 7: Criticality of implementing WEM Reforms and investments by October 2022

The March 2019 Report stated that the SWIS was expected to enter a zone of unacceptable risks to system security and reliability as system load approached the indicative 700 MW which was anticipated to occur between 2022 and 2023. One of the key assumptions associated with the 700 MW system security threshold was that it was based on a continuation of the status quo trends, market arrangements, tools and assets connected to the network for the management of system security.

Much has changed in respect to the market operational framework and the drivers since the release of the March 2019 Report. While operational conditions have continued to become more challenging, the implementation of specific reforms, operational initiatives and tools, and investments as outlined in this Report have materially enhanced the capability to manage system security outcomes within operational limits to defer the immediacy of the system security challenge.

# 3. Status of drivers of system security risk

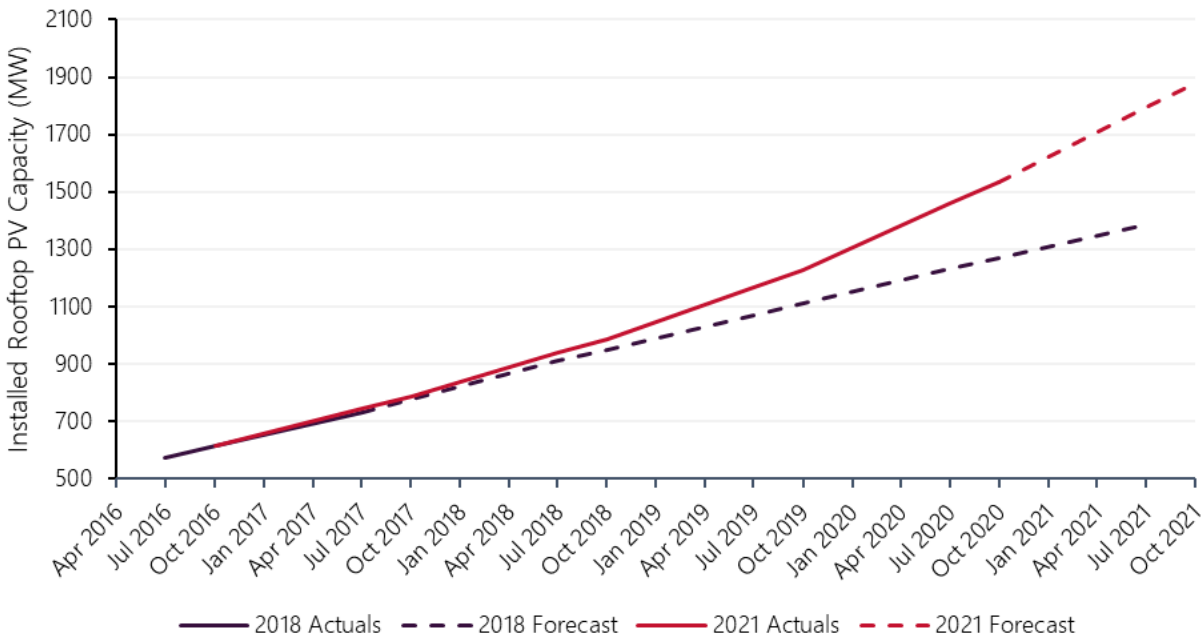
The following sections provide an overview of the status of the drivers changing power system conditions that the March 2019 Report identified as contributing to an increase in system security risk.

## 3.1 Stronger than expected growth in DPV

Year-on-year DPV installations have grown at a consistently high pace since 2015. As of April 2021, the DER Register indicated that generation capacity of residential, commercial and industrial PV reached a total of 1.74 gigawatts (GW) (panel capacity). This growth was higher than forecast in the 2018 ESOO, which projected forecast that installed DPV capacity in 2020-21 would reach 1.42 GW (for the High PV scenario, with 1.39 GW for the Expected scenario)[28].

The effect of growth in DPV is most clearly illustrated by the proportion of underlying demand met by this generation source. A new record value of estimated instantaneous non-synchronous generation output compared to total underlying demand was set at 69.9% on Tuesday 7 September 2021 at 12.10 PM. Based on analysis of meter data during similar events, AEMO estimated that over 35% of the total DPV output (that is, over 400 MW) was exported to the grid instead of being used on the premises where the DPV was located ('behind the meter').

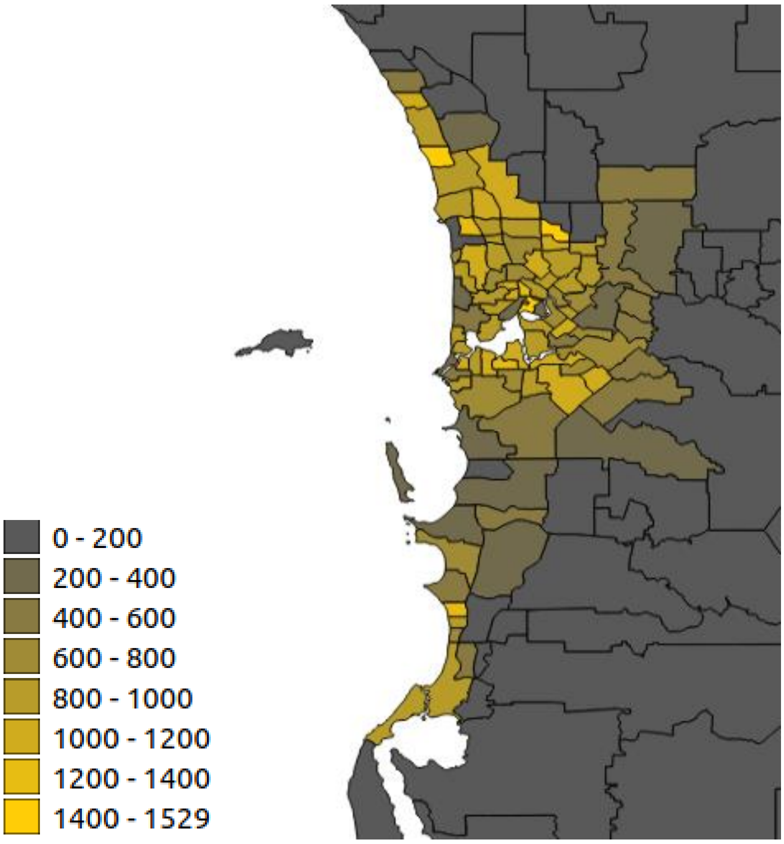
**Figure 4 Installed DPV capacity is increasing at faster than expected rates**




[28] Forecasting energy market outcomes has become increasingly challenging due to the rapid growth in the installation of DPV. Enhanced visibility and data analysis arising from the DER Register will enable improved forecasting in the future.

AEMO is now able to use data from the Western Australia DER Register to develop insights into the growing capacity of distributed energy resources (DER) such as DPV. According to the register, 1.5 gigavolt amperes (GVA) of DPV (inverter capacity) was installed in the SWIS as of 9 August 2021, which is almost 450% larger than the single largest synchronous generator in the SWIS. Figure 5 shows the density of installed DPV by postcode, highlighting that 79% of DPV is located in the Perth metropolitan area (postcodes between 6000 and 6199). There are particularly high densities (>1,200 kilovolt amperes per square kilometre (kVa/km2)) in newer suburbs such as Burns Beach and Iluka in the North West and Canning Vale in the South East of Perth.

**Figure 5 Installed DPV by postcode (kVA/km²)**



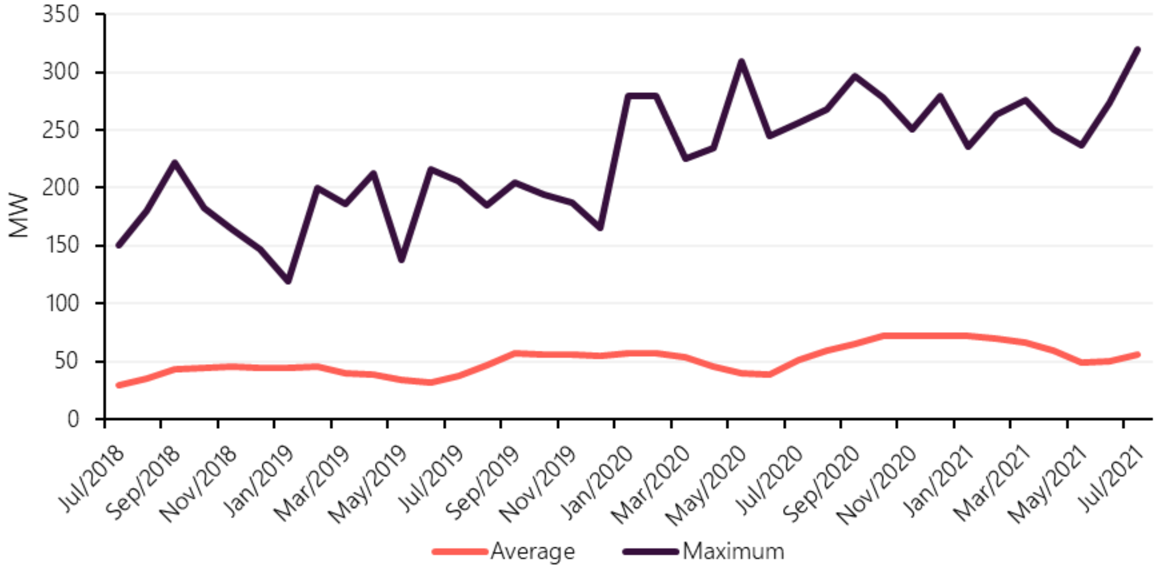

## 3.2 Greater load swings with higher levels of DPV operation

Since the March 2019 Report, the maximum intra-interval load swing, which is the difference between the highest and lowest MW value of estimated DPV output per interval (based on a 5-minute estimate), has significantly increased.

Figure 6 below plots the monthly maximum intra-interval load swing for the trading intervals (5:30 AM to 7:30 PM[29]) and the monthly average maximum intra-interval load swing from mid-2018. The plot for the monthly maximum intra-interval load swing trends upwards and shows that the magnitude of load variability has increased from late 2019. It also shows greater load variability in almost all months of the year. Load variability tended to be greatest on sunny days with moderate temperatures and intermittent cloud cover, most prevalent around September to November. However, the cooler months are now also experiencing significant intra-interval load swings.

[29] This period matches the higher Load Following Ancillary Services (LFAS) requirement time.

**Figure 6 Maximum intra-interval estimated DPV output change by month**




## 3.3 Renewable generation is changing frequency management requirements

Higher levels of DPV penetration increase the volatility (the real-time up and down movement) in load that is attributable to uncontrollable and largely unpredictable weather events, for example, cloud movement. The continued uptake of DPV and trend toward larger residential DPV systems is dramatically impacting the level of load to which AEMO must operate the power system.

In addition, an increasing contribution from utility-scale renewable PV and wind generation creates increased generation volatility, thereby challenging the way in which load is to be met.

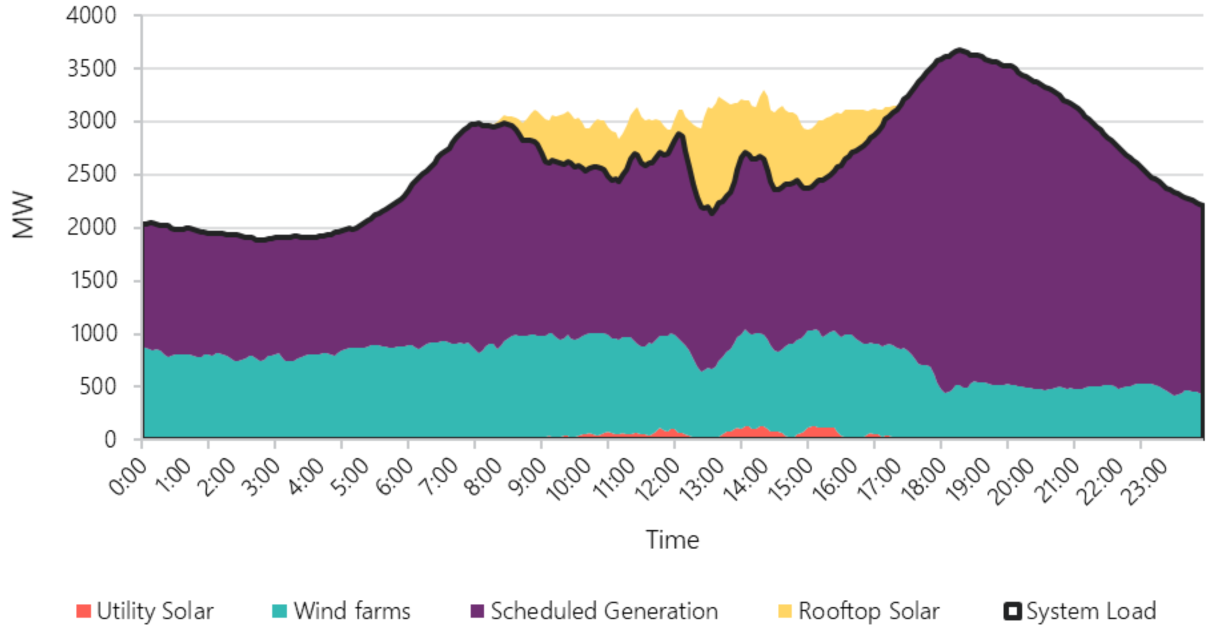
AEMO's present ability to maintain frequency within the Normal Operating Frequency Band is primarily met through mandatory governor actions (as per GPS requirements) and the procurement of Ancillary Services, where Load Following Ancillary Services (LFAS) is the primary real-time mechanism to ensure supply and demand are balanced within a dispatch interval. LFAS is a market service that AEMO uses to manage intra-interval volatility in load and generation.

While geographic diversity in production from utility-scale renewable generation mitigates a proportion of generation load volatility, the net impact has been an increase in the required LFAS quantities that AEMO must procure for frequency management. This is particularly apparent where weather conditions result in rapid changes in DPV generation, resulting in the rapid and significant movement in system load.

On three occasions on 18 October 2018, Backup LFAS from synchronous generation was utilised for the first time to respond to significant load swings in excess of 250 MW over 30 minutes due to cloud cover.

A more recent example of load swings resulting from rapidly moving cloud cover is illustrated in Figure 7, which shows DPV generation and its contribution to system load on 10 August 2021. The data reveals a significant ramp in output of DPV of approximately 750 MW over half an hour from 12.00 PM, before dropping by approximately 630 MW at 1.00 PM. These rapid fluctuations in DPV resulted in an impact to system load of 712 MW and 577 MW respectively.

Figure 7 SWIS system load swings, 10 August 2021




## 3.4 Lowering levels of 'minimum' system load and operational demand

The SWIS is experiencing lower levels of minimum system load, with four records set between August 2020 and March 2021, as shown in Table 7 below. The reducing levels of minimum system load are generally coincidental with an increasing proportion of DPV penetration and therefore higher levels of DPV output.

Consistent with the findings of the March 2019 Report, periods of low minimum system load are occurring during the middle of the day in autumn (March, April and May) and spring (September, October and November) when the weather is mild and sunny. More recently however, low minimum system load periods are being experienced in the period leading up to spring (August) as well as in summer.

It is worth noting that the week 24-31 August 2020 saw records set for peak DPV generation (1,108 MW) and low system load (1,218 MW). That week also saw a new record for peak wind generation (716.4 MW) on 29 August 2020 at 1:04 PM. In 2021, the period 16-25 August 2021 similarly saw peak DPV generation records (in which the previous record of 1,304 MW was exceeded four times). The new record of 1,360 MW was set on 24 August 2021.

Based on forecast trends in growth in DPV installations, the 2021 WEM ESOO forecast a rapid decline in minimum operational demand to 232 MW WEM by 2025-2026 (expected scenario), as Figure 8 shows.

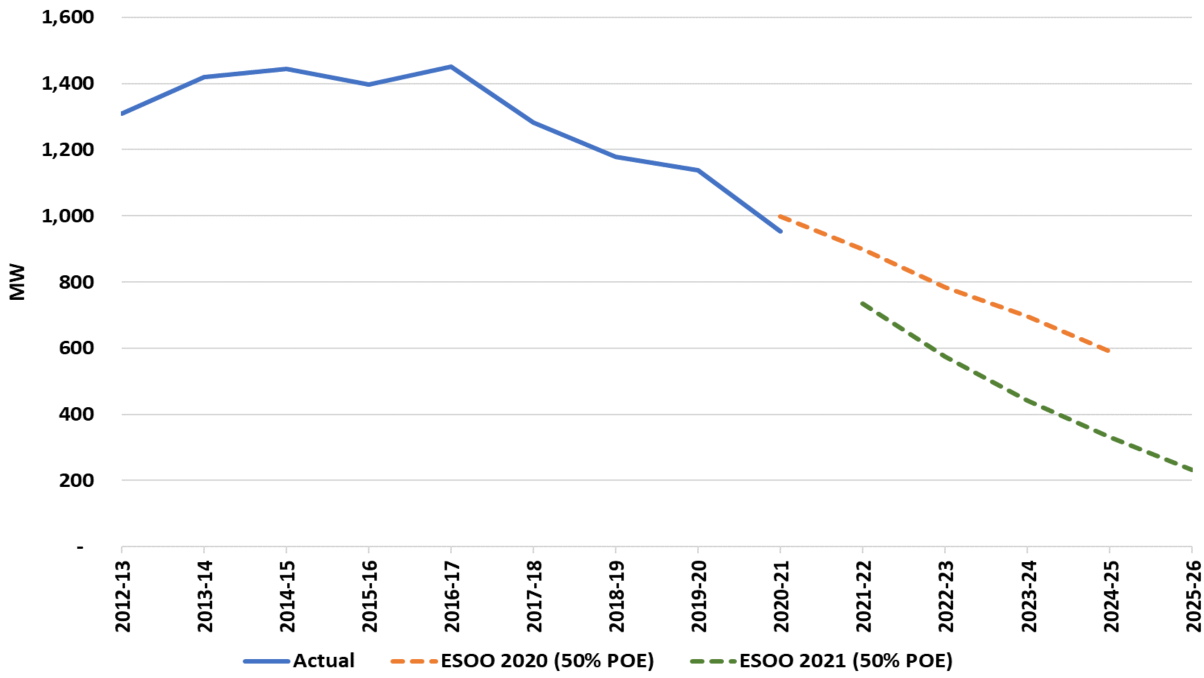
Table 7 Minimum system load, maximum NSG* fraction and peak DPV records since mid-2020

| Date | Time | Day | Minimum system load | NSG* fraction | Peak DPV |
|---|---|---|---|---|---|
| **12 September** | 11:50 AM | Sunday | - | - | 1,518 MW |
| **7 September 2021** | 12:10 PM | Tuesday | - | 69.9% | - |
| **5 September 2021** | 12:25 PM | Sunday | 984 MW | - | - |
| **24 August 2021** | 12:25 PM | Tuesday | - | - | 1,360 MW |
| **15 August 2021** | 12:25 PM | Sunday | - | - | 1,304 MW |
| **14 March 2021** | 12:05 AM | Sunday | 1,074 MW | - | - |

| Date | Time | Day | Minimum system load | NSG* fraction | Peak DPV |
|---|---|---|---|---|---|
| **13 March 2021** | 1:20 PM | Saturday | - | 65.2% | - |
| **11 February 2021** | 12:15 PM | Thursday | - | - | 1,269 MW |
| **16 January 2021** | 12:40 PM | Saturday | - | 61.6% | - |
| **28 November 2020** | 12:51 PM | Saturday | 1,144 MW | - | - |
| **3 October 2020** | 2:39 PM | Saturday | - | 61.5% | - |
| **20 September 2020** | 11:10 AM | Sunday | - | 54.6% | |
| **13 September 2020** | 12:18 PM | Sunday | 1,157 MW | - | - |
| **12 September 2020** | 12:10 PM | Saturday | - | - | 1,189.1 MW |
| **30 August 2020** | 12:39 PM | Sunday | 1,218 MW | - | - |
| **29 August 2020** | 11:45 AM | Saturday | - | | 1,108 MW |
| **15 August 2020** | 12:15 PM | Saturday | - | - | 1,022 MW |

*NSG fraction = (Total wind + total solar PV) / (system load + total rooftop PV + embedded generation)
Source: AEMO

**Figure 8 WEM ESOO minimum operational demand forecasts**




## 3.5 Non-synchronous renewable generation will soon exceed synchronous generation in the SWIS

Table 8 shows the March 2019 Report's proposed and forecast quantities of utility-scale renewable generation and DPV installations (for 2018-21), the actual installed capacity (2018-21) and AEMO's expectation of likely connections to SWIS in the next three years. The March 2019 Report projected that a total of 1,267 MW was projected to be installed in this period, but the actual quantity of deployed utility-scale renewable generation and DPV was 1,552 MW, exceeding expectations.

The continuous uptake of DPV coupled with utility-scale wind and solar projects (see Table 8) is facilitating the rapid change in the ratio of synchronous and non-synchronous generation in the SWIS.

**Table 8 Projected and actual increase in DPV and renewable generation in the SWIS between 2018 and 2021, with forecast increases for 2022-24**

| Source* | Forecast scale (MW) | Status | Actual scale (MW) | Year |
|---|---|---|---|---|
| **Rooftop and commercial solar PV (DPV)** | 477** | Exceeded forecasts | 889*** | Cumulative including 2018-19 to 2020-21 |
| **Northam solar farm** | 10 | Complete | 10 | 2018 |
| **Ambrisolar** | - | Complete | 1 | 2018 |
| **Greenough River solar farm expansion** | 30 | Complete | 30 | 2020 |
| **Badgingarra wind farm** | 130 | Complete | 130 | 2019 |
| **Merredin solar farm** | 100 | Complete | 100 | 2020 |
| **Warradarge wind farm** | 180 | Complete | 180 | 2020 |
| **Yandin wind farm** | 210 | Complete | 212 | 2020 |
| **Other wind or solar farm(s)** | 130 | Not progressed | - | 2020-21 |
| **Total 2017 – 2021** | 1,267 | | 1,552 | |
| **Rooftop and commercial solar PV (DPV)******** | 816 | Forecast | - | Cumulative including 2021-22 to 2023-24 |
| **New solar farms** | 147 | Forecast | - | 2022-2024 |
| **New wind farms** | 183 | Forecast | - | 2022-2024 |
| **Total 2022 – 2024** | 1,146 | Forecast | | |

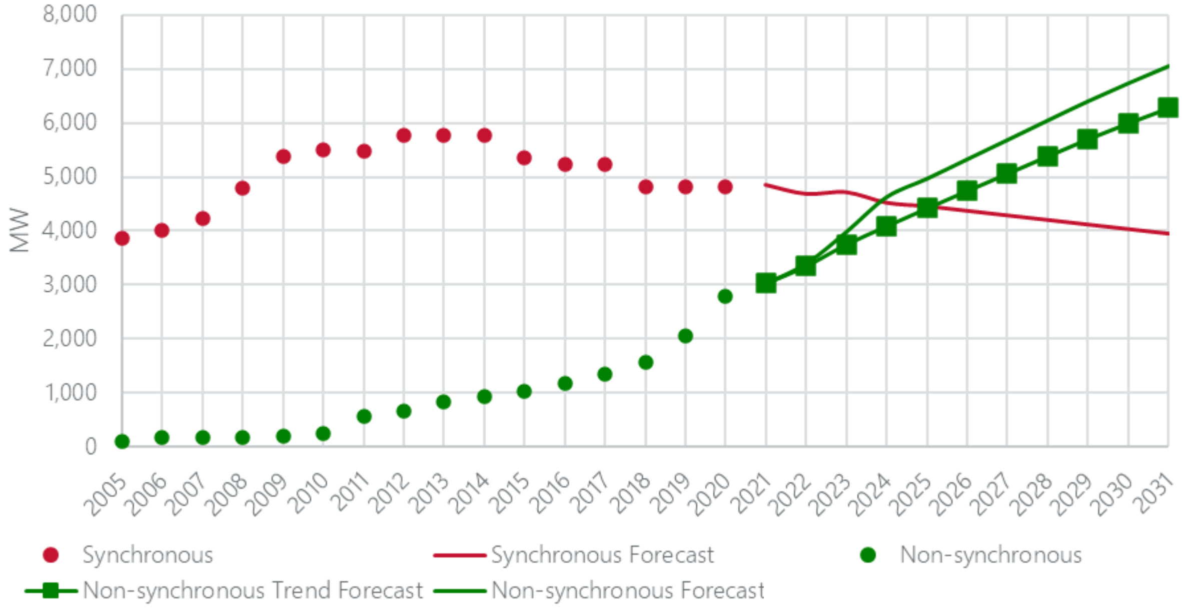
* The utility-scale renewable projects in the table are those that have either signed a network connection contract (including Generator Interim Access) with Western Power or are being developed by a Market Participant that is a retailer in the SWIS
** 2018 WEM ESOO total expected increase from 2017-18 Capacity Year
*** 2021 WEM ESOO actuals from 2017-19 Capacity Years and forecast for the 2020-21 Capacity Year
**** 2021 WEM ESOO forecasts for 2021-22 to 2023-24 Capacity Years

The existing mix of synchronous and non-synchronous generation in the SWIS is going through a rapid change, as shown in Figure 9. Except for expected small increases of the registered maximum capacity of existing thermal power plants, the retirement of Muja Units G5 in 2022 and G6 in 2024 enforces the descending trend of synchronous generation.

Based on the increase in behind-the-meter PV generation forecast in the 2021 WEM ESOO, the level of non-synchronous generation inclusive of existing utility-scale wind and solar generation will continue to increase. By 2024-25, total non-synchronous generation capacity could reach 4,417 MW, compared to 4,450 MW of synchronous capacity. Where that proposed utility-scale wind and solar generation becomes operational, the total of forecasted non-synchronous generation could reach 4,627 MW by 2023-2024, exceeding the 4,516 MW synchronous generation forecast to be operating.

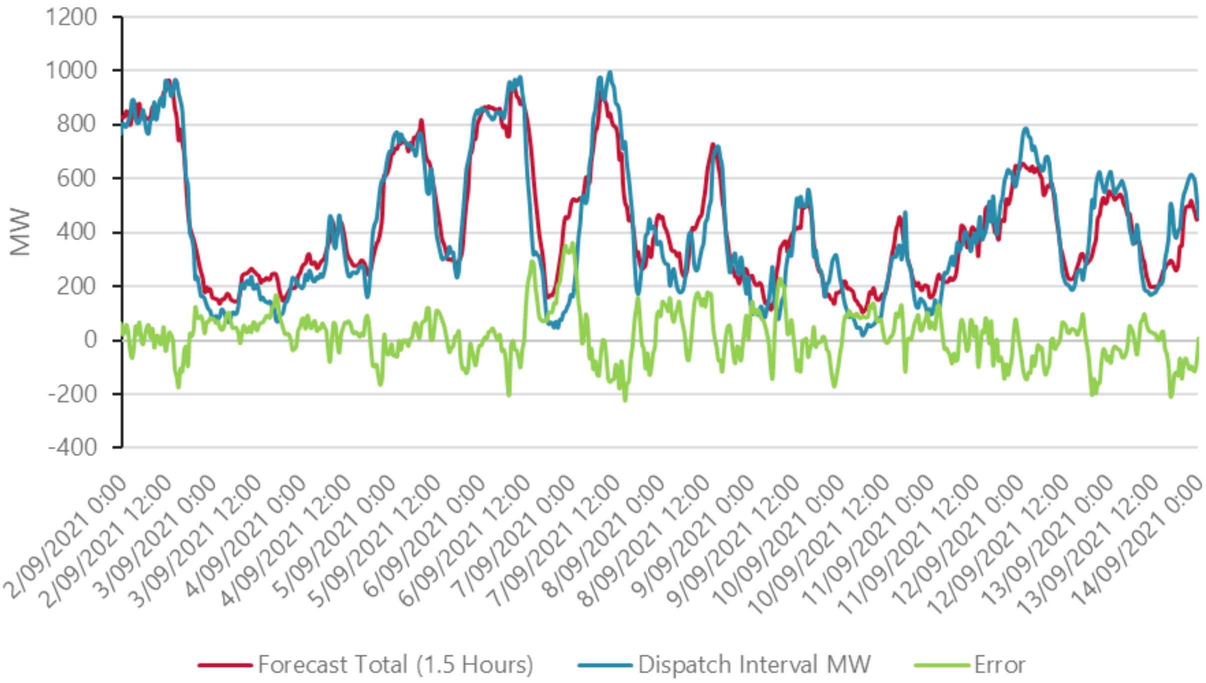
The mix of synchronous and non-synchronous generation online has practical implications for power system operation, specifically how 'resilient' the power system is in responding to disturbances and contingencies. Key to ensuring a resilient power system is having sufficient generation online of the right technical capabilities (such as controllability and ramping), and providing adequate levels of necessary ESS as a by-product of generating (such as inertia and reactive power absorption/generation). The following sections 3.6 through 3.8 highlight the implications for power system management and the impact on the market arising from lowering levels of synchronous generation online.

**Figure 9 SWIS synchronous and non-synchronous generation mix, actual and forecast, 2005 to 2031**




Larger contributions from non-synchronous generation also impact AEMO's ability to dispatch energy accurately, as the uncertainty over resource availability (wind speed or solar irradiance) limits the ability to forecast non-synchronous generation. Figure 10 shows a comparison of forecast generation (provided 1.5 hours ahead) and actual generation (or capability where curtailed) for all non-synchronous generation in the SWIS, for the period 2-14 September 2021. This data clearly demonstrates the difference between forecast quantities and capability, which peaks at an overestimate of 400 MW on 6 September 2021.

**Figure 10 Comparison of intermittent Facility forecasts (1.5 hour ahead) and actual generation/capability, over 2-14 September 2021**



## 3.6 Lowering levels of system inertia

Frequency control is a fundamental system requirement for sustaining power system security and reliability. System inertia, as the name suggests, makes the electricity system more stable in the event of a power system disturbance.

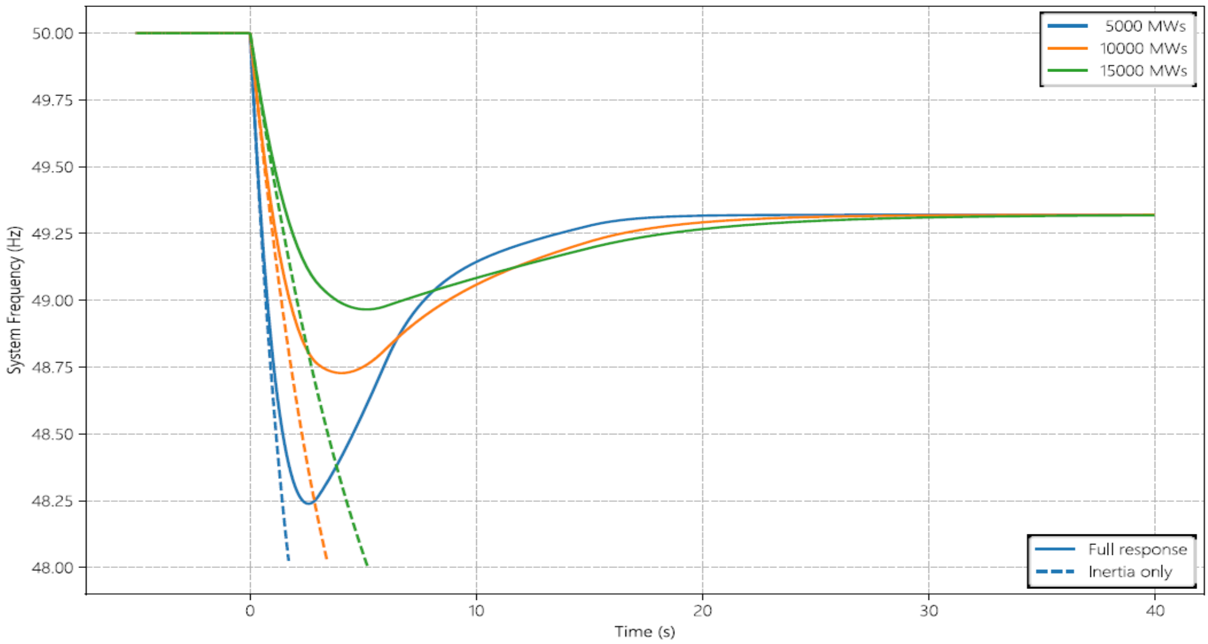
When synchronised, synchronous generation (and some loads) offers an inertial response, that is, a rapid and automatic injection of energy to suppress rapid frequency deviations. The response assists in reducing the RoCoF resulting from contingencies. This 'inertial' characteristic arises because the rotating parts of synchronous generating units (such as the turbine and rotor) are connected to an AC power system and spin synchronously with the system frequency[30].

Non-synchronous generation does not characteristically provide the same inertial response. While some technologies can provide a very fast frequency response that may be equivalent to a 'synthetic' synchronous inertial response, this is yet to be demonstrated at sufficient scale in the SWIS.

Figure 11 shows that, at the lower levels of system inertia that arise as synchronous generation exits the market, frequency will drop lower and at a faster rate in response to a system disturbance.

The lower system frequency drops, or the more significant the RoCoF (the magnitude and speed at which the frequency drops in an uncontrolled manner), the greater the risk that frequency is either unrecoverable, or may result in a consequential cascade of trips of other facilities and loads connected to the grid. The availability of synchronous generation and alternative technologies (such as synchronous condensers) becomes critical to the provision of robust and dependable response to disturbances.

**Figure 11 The relationship between inertia and frequency control**



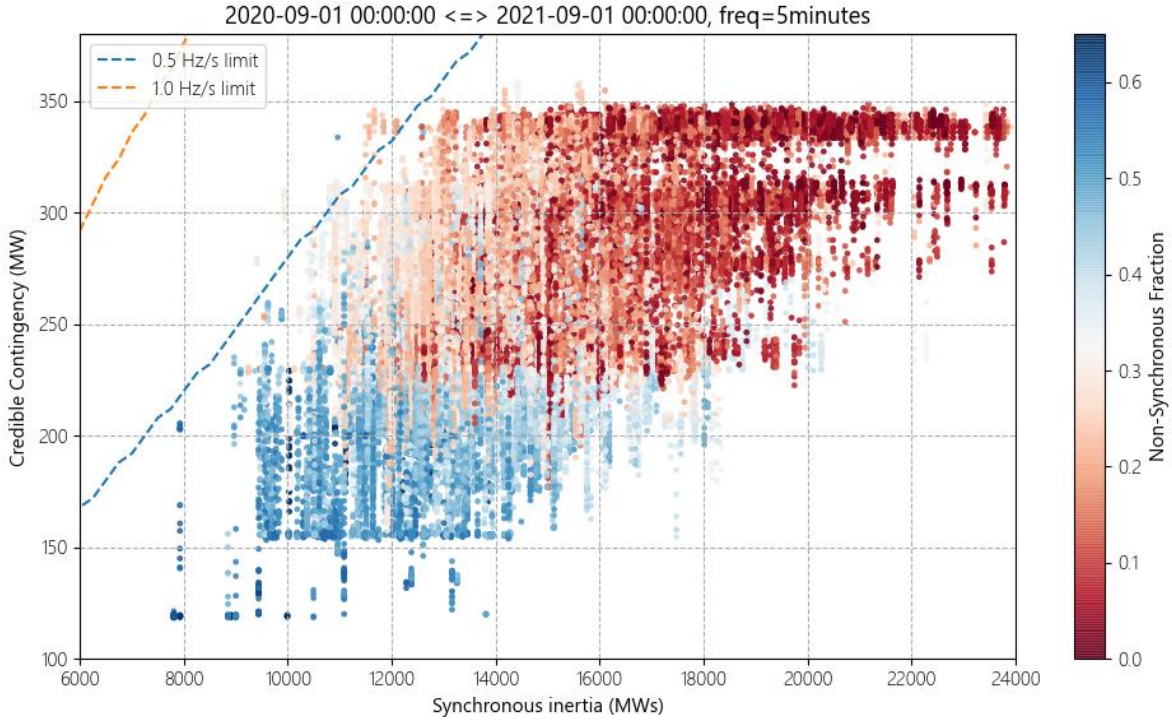

AEMO (2019), Contingency Frequency Response in the South West Interconnected System – Technical Proposal for the Power System Operation Working Group, July, p.10.

Figure 12 shows the trend in total system inertia (in megawatt-seconds [MWs]), measured at 5-minute intervals for the year to September 2021, as a function of credible contingency size (as the other variable). The colouring shows the level of non-synchronous penetration at that measurement, highlighting the general correlation of inertial reserves declining with increased inverter-based generation. The blue and orange dotted lines on the plot show where RoCoF would reach 0.5 hertz per second (Hz/s) and 1.0 Hz/s respectively, for the credible contingency size at that system inertia. The areas to the lower right of these lines represent

[30] AEMO (2018), *Power system requirements: Reference paper*, March, p.15.

the "RoCoF safe area" for a credible contingency of the size indicated on the vertical axis when sufficient inertia is provided.

**Figure 12 Trend in total system inertia in MWs as a function of credible contingency size**




A RoCoF of 0.5 Hz/s is the known safe (secure) operating limit for all electrical connections (both loads and generators). A limit of 1 Hz/s is also shown as an aspirational target, at which point RoCoF would largely cease to economically restrict operation of the SWIS, although it is not confirmed within the industry (world-wide) if all connection types, especially older synchronous generators, can operate to this limit.

The reformed market arrangements incentivise participants to investigate and improve RoCoF ride-through capability, by allocating a smaller portion of RoCoF control service costs to generators that tolerate higher values.

At present, AEMO has only limited control over the maximum contingency size of a generator contingency through Synergy's portfolio and out-of-merit dispatch. Under the new market arrangements, SCED will operate so that sufficient inertia (via the RoCoF Control Service) is procured alongside Contingency Reserve Raise to ensure RoCoF is maintained beneath the RoCoF Safe Limit. This optimisation may include the planned reduction of the size of the largest contingency and the constrained-on operation of facilities providing RoCoF Control Service and Contingency Reserve Raise in preference to those not providing these services.

While such actions can ensure optimal dispatch based on available offers, any level of operational demand that cannot sustain the minimum generation requirements of facilities providing ESS will present a significant risk to secure dispatch outcomes.

## 3.7 Fewer synchronous generators online to sustain power system security and reliability

AEMO relies on a range of ESS that can respond to variations in frequency and voltage in a timely manner. These services ensure power system operations are maintained within sustainable bounds by facilitating outcomes vital for managing system security risk. They include frequency control (including in response to contingency events), voltage control, inertia, system strength and ramping management (for system operability).

As noted earlier in this report, the management of power system security is reliant on the characteristics of the generating units that are online and providing these ESS when the system is under stress. This means adequate system load must be available to support a minimum number of synchronous generators that are capable of providing these services. The percentage of feasible combinations of synchronous generating units that may be kept online at each level of system load decreases as system load decreases, which reduces operational flexibility.

There has been a growing incidence of prolonged planned outages for synchronous facilities (such as gas generating units) that occurred due to a combination of factors, including the availability of critical parts and labour for facility maintenance. The global transition to gas generation during the global COVID-19 pandemic has stretched the availability of parts and labour due to greater demand and travel and transportation restrictions. If planned outages overran due to unintended circumstances, this could create the risk of a shortfall in available capacity and potentially comprise system strength.

To inform minimum load thresholds, AEMO is undertaking ongoing analysis to ascertain the combinations of required and available generating units needed to provide the services that are essential for maintaining power system security and reliability. AEMO's approach to the analysis is technology-neutral, recognising the needs of a power system that was designed around the operation of synchronous generating units. It is a more evolved and sophisticated methodology than the (somewhat rudimentary) methodology that underpinned the derivation of the indicative 700 MW system security threshold in the March 2019 Report.

The analysis used by this Report is preliminary. The present conclusion is that:

- below 600 MW the dispatch options materially decrease such that AEMO considers it a zone of heightened power system security threat.
- The implementation of specific reforms, operational initiatives, investments and tools as outlined in this report have materially enhanced AEMO's capability to manage the power system to lower levels of operational demand (and relatedly, system load) than indicated in the March 2019 Report.
- Further measures will be required to ensure power system security can be maintained as operational demand (and system load) declines to lower levels.

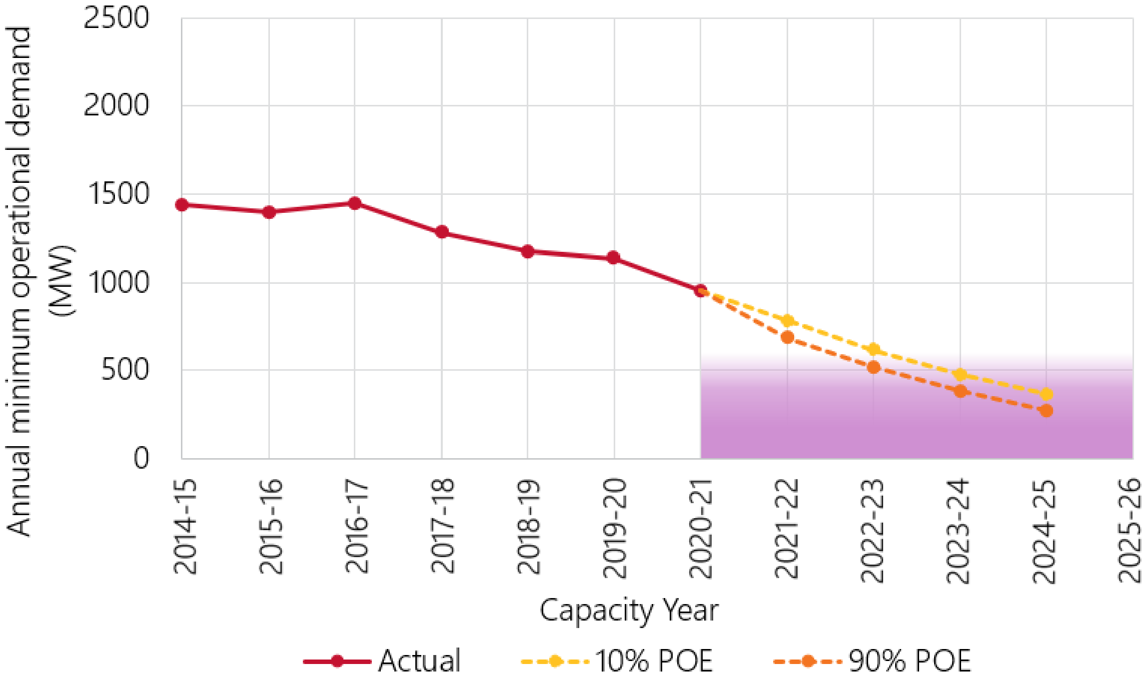
Figure 13 provides an indicative view of the preliminary modelling, which aimed to quantify the zone of heightened system security threat under the present suite of operational tools[31]. As demand descends deeper in the zone, operational flexibility becomes greatly reduced and there are likely to be considerable operational challenges to manage system security.

It is important to recognise that the preliminary outcomes in Figure 13 are based on the present suite of operational tools and mechanisms available to System Management under the WEM Rules. With investment in BESS and/or procurement of other resources through market-based mechanisms to provide Fast Frequency Response (FFR), the installation of synchronous condensers to provide inertia and system strength, further adaptations to ESS, and taking other measures (such as interventions), it will be possible to operate the power system securely at lower levels of system load in the coming years. Just how low this level can reach remains the subject of AEMO's ongoing studies and analysis.

While contingency planning operates the system to N – 1 to account for the risk of a contingency event, at very low levels of system load some significant units may decommit, which may result in an extended ramp period during which the unit is brought back online to provide Spinning Reserve. Should another generator be required for ESS (and inertia) trip-off, system security and reliability will be threatened, especially during abnormal periods with multiple line or unit outages. A coincidence of challenging events means the power system will have insufficient resilience to sustain security.

[31] A 'significant' generating unit in this context is one that is considered large enough to be likely to contribute meaningfully to system strength.

**Figure 13 Zone of heightened system security threat and reduced operational flexibility in relation to minimum operational demand levels[A,B]**




[A] Minimum load thresholds are calculated based on system load and have been converted to operational demand for the purposes of this figure, to allow for comparison with WEM ESOO forecasts. However, the relationship between system load and operational demand is dynamic and may change over time, as it is dependent on the mix of generation and load resources within the SWIS that themselves change over time.

[B] 2021 actual data valid at 31 March 2021.

Figure 14 shows the number of significant generating units operating in the SWIS in 2016, 2018, and 2020, based on actual dispatch. Between 2016 and 2020 there is a downward trend in the number of significant synchronous units operating, and in 2020, the SWIS reached a minimum of only eight significant generating units online in some periods. Preliminary modelling for the period 2021-23 indicates that this trend of reducing number of synchronous generating units online will continue as minimum demand is forecast to decline.

A point will be reached where the services required to stabilise the power system and maintain its ability to operate with operational limits will be compromised, unless these requirements can be met through services that can be procured from new technologies. In the interim, the continued decline in significant units will impinge operational flexibility to respond the prevailing system security risk.

The SWIS is already experiencing periods in which the number of significant generating units online is providing reduced flexibility to maintain adequate system strength and other ESS necessary to address operational conditions. The preliminary modelling suggests that the power system will become very difficult to manage beyond 2024 unless new mechanisms to address system security risk – of the type identified in Chapter 6 – are implemented. This is a topic of ongoing investigation, especially in regard to the determination of the system strength limit thresholds of the SWIS.

While the reforms, initiatives, and investments identified in this Report are deferring the immediacy of the system security risks (which the March 2019 Report indicated would occur between 2022 and 2024), system load has declined faster than forecast in the March 2019 Report requiring additional priority actions outlined in this Report to improve resilience.

**Figure 14 Number of significant synchronous units operating based on actual dispatch – 2016, 2018 and 2020**

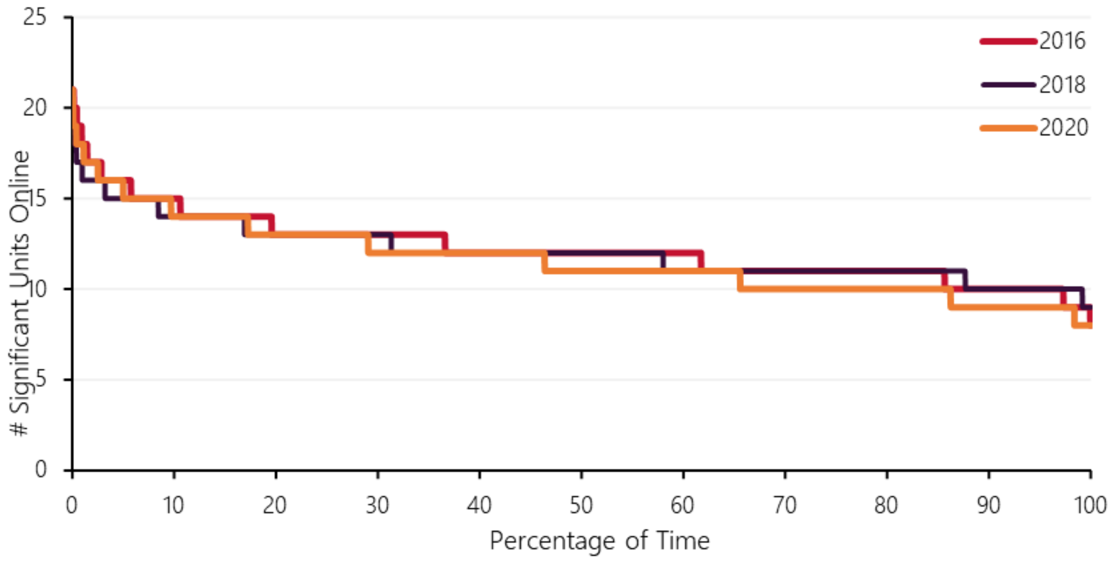
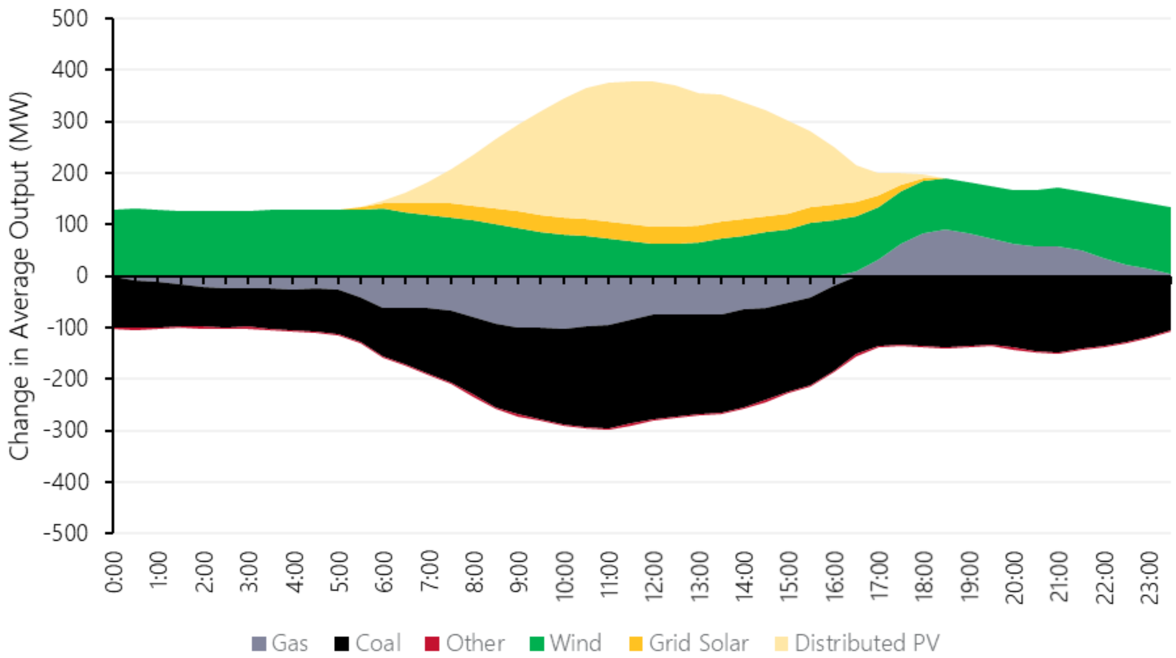



Figure 15 highlights the transition in the generation fuel mix between calendar years 2018 and 2020. There has been an increase in utility-scale renewable solar and wind generation of 100-150 MW throughout the day, and an additional increase in output up to 300 MW (average) by DPV during midday. As a result, the average output of synchronous generators (coal and gas) has fallen by 100-300 MW throughout the day, except around the evening peak. However, coal generation has decreased as gas generation increased by up to 100 MW to meet the energy and ramp rate requirements of the peaking demand.

**Figure 15 Change in average generation by fuel types, 2018 to 2020**



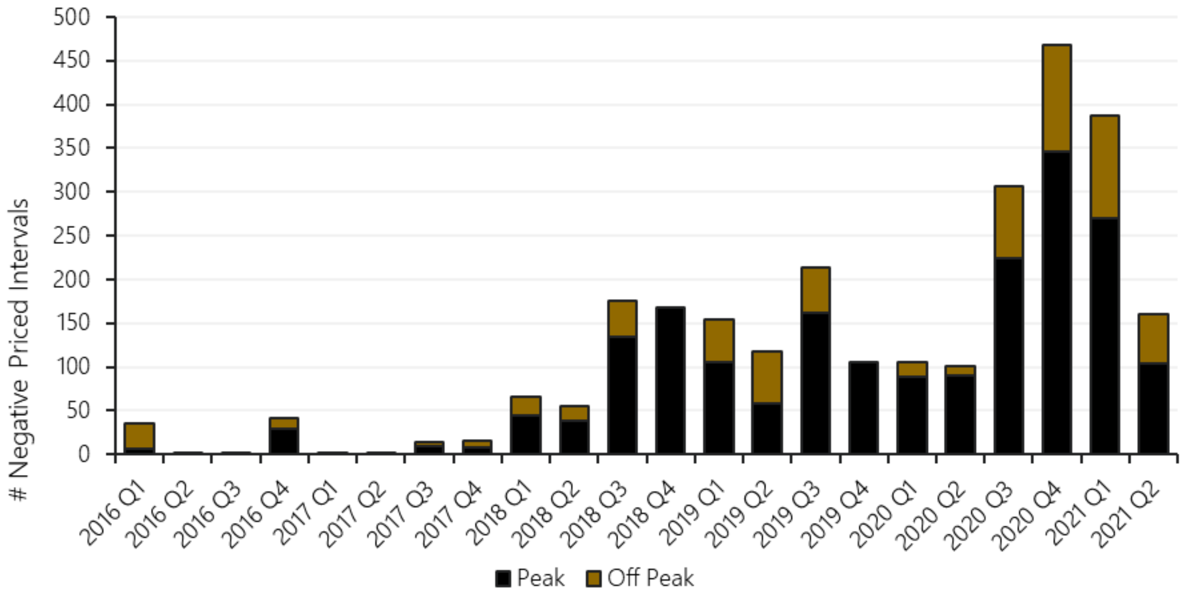

## 3.8 System challenges are impacting market outcomes

Since the release of the March 2019 Report, the trend towards lower minimum demand has led to an increasing frequency of negative prices in the Balancing Market; the proportion of negative or zero price intervals increased from 0.2% in 2018 to 5.6% in 2020 (see Figure 16 below). Furthermore, the Balancing Market cleared at the price floor of -$1,000 per megawatt hour (MWh) for the first time ever in October 2019, and as of June 2021, the Balancing Market has cleared at the price floor in a total of nine intervals.

Some level of negative energy pricing is expected, and is not inherently detrimental to the interests of the market and customers, as it signals an excess of energy. However, the rapid increase in and persistence of negative price trading and price floor events may lead to distorted investment signals, inefficiencies, and other commercial implications for incumbent Market Participants:

- Long-term persistence of prices below short-run marginal costs may result in financial distress of Market Participants. The feasibility of synchronous generators with high minimum generation levels and less operational flexibility (such as baseload coal fired generation) may deteriorate, creating greater impetus to exit the market unless other sources of revenue are available to these facilities.
- Anticipated negative pricing may incentivise Market Participants (synchronous generators) to decommit for periods in which the facility might otherwise provide services that are essential to maintain system security. While there is capability to recover losses when dispatched for energy in periods of negative prices through enablement losses, the risks remain that facilities may choose to decommit and not be available for dispatch.
- Prices may become more volatile as Market Participants seek to recover costs during periods of lower penetration of non-synchronous renewable generation, where ramping requirements are most acute, to bring their units back online.
- Under the Renewable Energy Buy Back Scheme (REBS), some customers must be paid for their DPV generation ($71.35/MWh), and from August 2020 new customers will also be paid ($100/MWh between 3.00 PM and 9.00 PM, and $30/MWh at all other times) under the Distributed Energy Buy Back Scheme (DEBS). The DEBS rate is set annually through the annual State Budget process.

**Figure 16 Number of Trading Intervals with negative balancing prices, Q1 2018 to Q2 2021**




Off-Peak Trading Interval: a Trading Interval occurring between 10 PM and 8 AM as defined in the WEM Rules. Peak Trading Intervals are all other Tracing Intervals.

AEMO's modelling to estimate the future trend in the occurrence of zero or negative Balancing Prices[32] indicated a significant increase in occurrence (see Figure 17 below). The actual proportion of intervals with

[32] The modelling was based on energy supply (quantity and price) and End of Interval demand from Capacity Year 2019/20 - it was assumed that supply prices and quantities would remain the same while demand was scaled in accordance with low and high growth forecast scenarios from the 2021 ESOO. The modelling also assumed purely economic dispatch in accordance with the Balancing Merit Order.

zero or negative prices increased from 2.5% in October 2018 to 10.7% in October 2020, and is forecast to increase to 32% in October 2022. A gradual decrease is expected in subsequent years, due to underlying demand growth and the assumption of relatively modest installation of utility-scale renewable generation compared to previous years. The modelling did not account for potential changes in bidding behaviour from Market Participants that may lessen the increases in the proportion of zero or negative price intervals.

AEMO's review of market outcomes, as highlighted in AEMO's *Quarterly Energy Dynamics* reports, showed that in the WEM the trend in Balancing Price over 2020 and 2021 shows not only increasing frequency of zero or negatively priced intervals, but also a high proportion of high-priced intervals. This indicates an increase in the spread and volatility of Balancing Prices in the WEM.

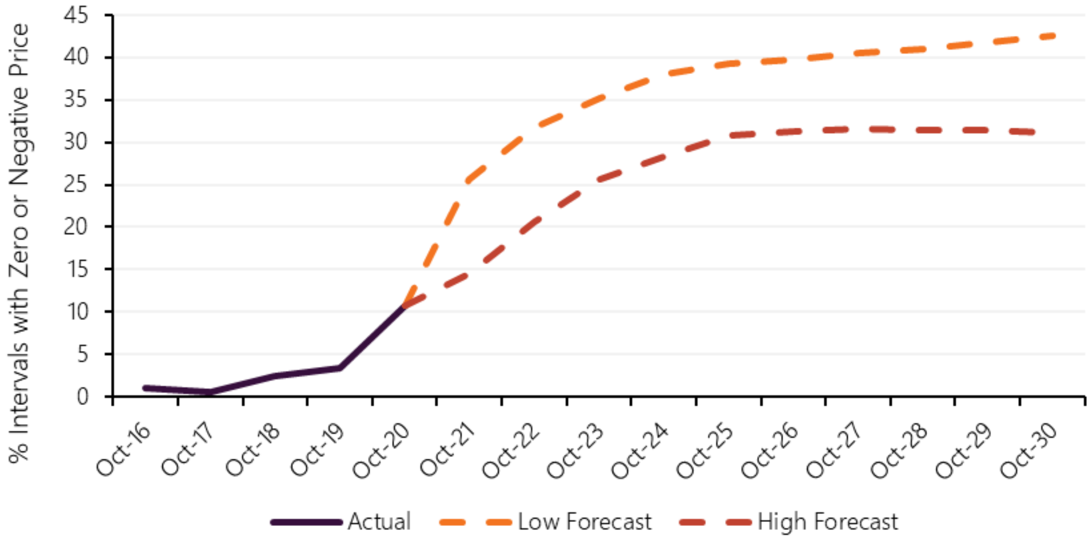
As an example, the average Balancing Price increased to $58/MWh from $52/MWh in Q2 2020[33], despite there being a higher proportion of negative (including zero) priced intervals (3.7% of all intervals up from 2.3%)[34]. The prices realised in Q2 2021, however, highlighted the complex set of conditions at play in that quarter:

- More energy was made available in the Balancing Market at or below $0/MWh, largely due to the commencement of trading of new utility-scale wind and solar facilities in the last few years.
- Growth in DPV output was leading to falling midday demand, resulting in more zero or negatively priced intervals since Q2 2020, despite an estimated increase in underlying demand[35].
- There was a high proportion of high-priced market intervals due to an increase in operational demand.

Figure 17 reflects an underlying assumption that there is no change to the shape and profile of the supply curve from October 2020 to October 2030. The demand curve is consistent with the ESOO forecast over this same period. These simplifying assumptions mean that Figure 17 is an indicative forecast of the percentage of trading intervals with zero or negative prices.

The forecast is consistent with that included in the March 2019 Report, although the highest percentage of zero and negative prices occurs later in the modelling exercise undertaken for this report compared with the March 2019 Report. The outcome of this modelling exercise reflects the most recent bidding behaviour and supply curve characteristics (an update of those used in the March 2019 Report).

**Figure 17 Percentage of Trading Intervals with zero or negative prices, 2016 to 2030**




[33] This was the highest quarterly average since Q3 2017.

[34] AEMO (2021), *Quarterly Energy Dynamics* Q2 2021, pp.46-47.

[35] In Q2 2021, operational demand between 1100 hrs and 1300 hrs decreased by 10 MW compared to Q2 2020 despite an estimated increase in underlying demand of 181 MW during the same period. See AEMO (2021), *Quarterly Energy Dynamics Q2 2021*, p.47.

# 4. Risk mitigation actions since the March 2019 Report

Several actions from the Western Australian State Government ETS Stage 1 have been delivered ahead of the implementation of the broader reform program and are helping mitigate system security risks. AEMO has also implemented operational improvements since the publication of the March 2019 Report that have enhanced its ability to maintain power system security in the interim before the full roll-out of the WEM Reforms and DER Roadmap.

In addition, investments by Western Power in shunt reactors are assisting AEMO to manage low system load days, and measures undertaken by large generator operators to reduce plant minimum stable loading levels have increased the flexibility of these generators to reduce their output during the middle of the day and remain online for the evening peak. In March 2021, Energy Policy WA, AEMO and Western Power formed a joint Low Load project team to fast track measures to address low load.

## 4.1 DER Roadmap actions

### 4.1.1 DER Register

The DER Register is now a requirement of the WEM Rules[36] and went 'live' in April 2021 following the collaborative efforts of AEMO, Western Power and EPWA. Under the WEM Rules, Western Power is required to regularly provide prescribed DER device data to AEMO for the DER Register. The data is gathered by electrical contractors who confirm the 'as-installed' DER devices and provide this information to Western Power[37].

The DER Register records details on DER devices that can generate or store electricity – such as DPV, behind-the-meter batteries and EVs – where they have been required to obtain connection approvals from Western Power. The DER Register enables AEMO to[38] forecast, plan, and operate the power system more efficiently, and provides an important input into understanding how DER can be utilised to respond to major outages or disruptions in the system and network. AEMO can now use the data input to the DER Register to supplement insights on the growing capacity of DER, to improve its forecasting capabilities and to assist in real-time power system operation.

The register will be fundamental to the integration of DER innovations across the energy supply chain in the SWIS. It will facilitate:

- The market participation of virtual power plants (VPPs) and opportunities for customers to participate in new markets with their DER.

[36] The rule changes to introduce the DER register were an initiative from the WA Government's DER Roadmap.

[37] Data from the DER Register can be used to provide insight into DER trends, performance, and behaviours to benefit system design, planning and operations in the SWIS. Data on the DER connected in the SWIS by postcode and type from the DER Register is now publicly available on AEMO's website.

[38] At https://aemo.com.au/en/initiatives/major-programs/wa-der-program/wa-der-register.

- The SWIS Network Operator (Western Power) in making better informed decisions about the network for the future, as demand changes and DER penetration increases.
- Other industry participants in better understanding DER, to inform their decision-making.

### 4.1.2 Revised inverter standard AS/NZ 4777.2

Western Power updated its Network Integration Guidelines in July 2019 and again in May 2021. The guidelines cover DER devices, such as DPV, that are connected to the network via an inverter.

At the same time, AEMO's work in the WEM and NEM has contributed to the review of the current Australian Standard for inverter-connected DER devices, Australian Standard AS/NZ 4777.2, and involved working with EPWA and Western Power in the Low Load Working Group to fast-track priority changes to inverter functionality[39], including:

- Implementing the Volt-Var and Volt-Watt functionality in AS/NZ 4777.2 as part of the July 2019 update to the Network Integration Guidelines.
- Introducing the requirement to comply with AEMO's Low Voltage Disturbance Ride-Through (LVDRT) Test Procedure to reduce the exposure of the power system to one potential cause of DPV tripping (the quantum of which is under investigation, as noted below in Section 6.1.2).
- Uplifting the Frequency-Watt response of inverters in AS/NZ 4777.2, as the prevailing prescription was broad and unlikely to bind or provide support in the context of the SWIS. Consequently, AEMO sought to align the Frequency-Watt response with the performance standards that apply to transmission-connected generators participating in the WEM (the GPS, discussed in Section 4.3.2 below). AS/NZ 4777.2 now prescribes a tighter deadband limit, and a similar rate of response[40] to that of the GPS, making it more likely that DPV will act to resist frequency disturbances.

The revised AS/NZ 4777.2 was published on 18 December 2020 and enhances the autonomous settings of inverters installed after December 2021, with some components commencing in July 2021 in Western Australia. Analysis undertaken by AEMO shows that at the revised standard, each DER device will experience a minor reduction in output only a few times in the year. However, the benefit will be material, as DER devices will collectively provide an 'automatic' contribution to frequency support for the power system.

**The uplift to AS/NZ 4777.2 is the most significant step AEMO has taken to ensuring the SWIS can be operated securely with high levels of DER.**

### 4.1.3 Uplift to AEMO's system model

DER Roadmap Action 13 pertains to the uplift to AEMO's system modelling to incorporate DPV under steady state and dynamic conditions, as well as load tripping behaviours, in addition to power flows during contingency events. The validation of the steady state model has been completed and the dynamic model is currently undergoing validation studies. When operational, the models will augment AEMO's capability across several planning functions.

AEMO has traditionally relied upon the Western Power's PowerFactory model, which was developed to facilitate the assessment of generator connections and Transmission network planning over a range of forecast scenarios. It is very detailed, comprising a large number of settings and bespoke models, which together make the system model difficult and time intensive to operate outside of forecast scenarios.

Consequently, AEMO has created a new PowerFactory model with a simplified network configuration that has been validated against Western Power's model. The new model can be automatically populated with historic SCADA data for ease of set-up and for the investigation of historical events. For the model to reflect DPV and load tripping behaviours, the Complex Load and DER A models developed by the Western Electricity

[39] Noting the May 2021 NIG update also introduces references to AS/NZ 4777.2.

[40] The revised standard has improved the response by narrowing the deadband limit from 50.25 Hz to 50.15 Hz (GPS is ±50.025 Hz) and with the rate of response decreasing from 0.08%/0.1 Hz to 0.054%/0.1Hz, closely matching the GPS rate of 0.05%/0.1 Hz.

Coordinating Council[41] were incorporated and are undergoing verification against high-speed recorder data, SCADA data, and the Western Power complex model. The Complex Load and DER A models are identified as international best practice for allowing for the incorporation of DER dynamic behaviour and load tripping during system events and have been adopted for this purpose in the NEM.

The new PowerFactory model is currently being developed to account for distribution load types. This functionality is successively being integrated and will be initially operationalised in October 2021 and then enhanced through to mid-2022, after which time the model will undergo continuous review and updates to maintain its suitability.

### 4.1.4 Revised UFLS arrangements

The UFLS schemes are the "safety net" that arrests a severe frequency decline following large contingency events, such as the simultaneous loss of multiple generating units. It involves the automatic disconnection of customer loads to rapidly correct the supply/demand balance and arrest the frequency decline, to maintain the SWIS within the allowed operating frequency band.

The current traditional UFLS arrangement is generally predicated upon a certain amount of load being available at a feeder at all times of the day and year. As DPV levels have grown, the available net load on UFLS is reduced by DPV output, reducing the effectiveness of UFLS. A number of feeders are now no longer appropriate for utilisation in UFLS because they become net exporters during the day; this means the tripping of that circuit by an UFLS event would accelerate, rather than arrest, frequency decline. It is expected the number of feeders that are unavailable or inappropriate for UFLS during daylight hours will increase.

AEMO and Western Power have been working together on DER Roadmap Action 10 which involves a revision of the UFLS arrangements. This work is being conducted in line with good industry practice internationally, and will help form a view on how UFLS can continue to provide a critical 'safety net' in an environment of high DPV output and low system load. To date, a review of frequency stability with ideal levels of UFLS load available has been completed. Reviews on voltage stability and frequency stability (with actual levels of UFLS load available) are in progress and will facilitate an understanding of the efficacy of current UFLS arrangements and the approach to future arrangements. AEMO has worked with Western Power to remove or shift backfeeding and high DER feeders to later UFLS stages so Stage 1 and 2 UFLS are less compromised. AEMO and Western Power have subsequently identified the enhanced risk associated with deteriorating UFLS due to high penetration of DPV, which resulted in re-dispatch and Western Power deployment of enhanced UFLS schemes

The improvements progressed under the WEM Reform program include clarification on the roles and responsibilities of AEMO and Western Power, which is better facilitating the coordinated delivery of UFLS outcomes.

### 4.1.5 Revised System Restart arrangements

In the unlikely event of a black system, AEMO needs the ability to restart the power system. This presently requires start-up of utility-scale synchronous generating units, which need adequate stable load to meet their minimum loading requirements. Sufficient stable load may not be available in the vicinity of these units in high DPV output periods. In the future, BESS with grid-forming inverters may also be an option.

For the last 30 years[42], the System Restart Plan relied on the fast re-energisation of the Muja power plant from Pinjar or Kwinana to restore auxiliary supply to the Muja coal-fired power station boilers as soon as possible to prevent the boilers going cold. This was critical when Muja represented the bulk of the SWIS's generation capacity, and necessitated the energisation of the long 330 kilovolt (kV) transmission lines such as MU-NT 91. Significant load in the Northern Terminal (North Perth metro) area was critical to supporting the energisation.

[41] The Western Electricity Coordinating Council promotes bulk power system reliability and security in the Western Interconnection of Canada, the United States and Mexico.

[42] Covering four editions of the System Restart Plan.

The uptake of DPV, which removed reliable stable load, necessitated a significant change in the approach. In 2020, a new System Restart Plan was developed that utilises the stable load in areas of comparatively lower DPV density (the Perth CBD and inner metro areas) as quickly as possible via the 132 kV network. The plan prescribes a solution for restarting the network under forecast minimum load conditions and high DPV output, and specifies restart paths that avoid picking up load from high DPV feeders and allow sufficient load to be reached using flexible gas generation. It will be refreshed over the next 12 months to ensure the paths are still valid for the next two years. Where it is determined that there are insufficient options available, options such as leveraging DPV management or similar initiatives designed to constrain DPV output will need to be considered.

### 4.1.6 Battery Energy Storage System initiatives

Since the March 2019 Report, Western Power has progressed several DER Roadmap actions in regard to BESS connected to the distribution network[43], including the release of the *Distribution Storage Opportunities Information Plan* (11 December 2020)[44]. The plan is agnostic to the location of the BESS technology, being either front-of-meter or behind-the-meter. The imperative lies in the technology meeting the minimum standards specified by Western Power and its ability to safely and efficiently address network challenges. These challenges include maintaining voltage levels and voltage step changes within technical limits, the management of voltage constraints, thermal overload, and providing network reliability in the event of an upstream fault event.

The plan identifies indicative locations where distribution BESS, as a single installation or service, can provide an alternative to conventional network augmentation and multiple network benefits through a network support value stack. While the plan identifies multiple values streams[45] that distribution BESS might access, the focus is on delivering solutions for Network Capacity and Support, and Network Reliability.

Recent changes to the *Electricity Networks Access Code 2004* (ENAC) included provision for distribution BESS as an Alternative Options Strategy (AOS) and a requirement for a Network Opportunity Map (NOM). Western Power is now required to publish an annual NOM[46] as part of its non-network solution obligations, to provide greater transparency and opportunity for 'alternative options' service providers. These providers can offer a contracted service with their equipment to remedy network capacity constraints. Western Power is now seeking vendor interest for future storage opportunities and expects the first AOS to be released 1 October 2021.

Western Power is also trialling community batteries in partnership with Synergy to integrate bulk solar battery storage into the grid[47]. This initiative includes the roll-out of PowerBank batteries across 13 locations in the SWIS[48], principally to address thermal overload. In twelve of these locations, customers can automatically store (notionally) the unused energy generated by their DPV during the day and withdraw energy from mid-afternoon (when evening demand from the grid starts to peak) until midnight[49].

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[43] For voltages from 415V to 33kV inclusive. See Western Power (2020), *Distribution Storage Opportunities - Information Paper*, p.6.

[44] Western Power (2020), *Distribution Storage Opportunities - Information Paper 2020*. At https://www.westernpower.com.au/media/4659/distribution-storage-plan-wp201211.pdf.

[45] These include:

- Customer self-consumption: Storage can provide customers with an opportunity to achieve maximise consumption of any self-generated energy.
- Network Capacity & Support: Distribution Storage can provide capacity value by deferring or avoiding investment in network assets.
- Network Reliability: Storage can improve reliability performance though providing an alternative supply to customers when the main grid supply is unavailable.
- Essential System Services (ESS): Storage may provide flexibility value across a range of ESS such as frequency control.
- Reserve Capacity: Storage could be used as an alternative supply of capacity.
- Wholesale Energy: Storage could provide energy value through energy arbitrage if it displaces the need to produce energy from another generating resource.

[46] Western Power expects it will release the first iteration of the NOM on 1 October 2021.

[47] At https://www.westernpower.com.au/faqs/community-batteries/community-batteries/where-are-the-community-batteries-located/.

[48] At https://www.westernpower.com.au/media/4659/distribution-storage-plan-wp201211.pdf.

[49] At https://www.westernpower.com.au/faqs/community-batteries/powerbanks/.

### 4.1.7 Network voltage management

In addition to its community batteries, Western Power has undertaken other measures to improve network voltage control. This includes enabling real-time intervention to manage minimum system load conditions, and set-and-forget solutions such as re-arranging feeders to 're-balance' loads in light of increasing DER penetration. Additionally, as of 30 June 2020, Western Power committed works to remedy high voltage issues experienced at various sites across the metropolitan area during low load conditions[50]. To date, Western Power has commissioned 350 megavolt-amperes reactive (MVAr) of Shunt Reactors to absorb reactive power and is reviewing the requirement for additional reactive capacity.

## 4.2 Whole of System Plan and priority projects

In October 2020, the Energy Transformation Taskforce released the inaugural *Whole of System Plan* (WoSP) Report[51], to provide an informed view on the likely evolution of the system and market from 2020 to 2040[52]. The WoSP was informed by data provided by industry and modelled four scenarios that considered how changes in demand, technology and the economy may shape the use of electricity and guide investments to achieve lowest-cost, lower-emissions electricity.

The WoSP Report revealed the following 10 key findings:

1. The SWIS already has a strong mix of renewables, with renewables comprising 34% of installed capacity at the beginning of the modelling period (2020).
2. Under all four modelling scenarios, over 70% of generation capacity is renewable by 2040.
3. DPV will continue to displace other forms of generation, most significantly coal and large-scale solar.
4. Growth in renewables reduces emissions over the study period, despite the overall increase in end-user demand.
5. Growth in intermittent generation is supported by firming from storage and gas facilities.
6. New generation connections are best located in the South West transmission network zone to utilise existing network capacity and add generation diversity.
7. Coal-fired generation declines under all scenarios, and partially exits the market in the mid-2020s in the low demand growth scenarios.
8. There is opportunity for storage and renewables to provide ESS.
9. As new ESS and capacity mechanisms are embedded, revenue streams for generation will become more diverse.
10. Little or no major transmission network augmentation is required in the near future.

The ENAC was amended on 18 September 2020 to, among other things, enable processes to support the efficacy of the WoSP. The changes enable the WoSP to identify a 'priority project[53] and a 'streamlined' regulatory approach for priority projects to ensure their timely delivery[54]. Where Western Power is required to undertake a priority project, a high-level summary must be provided in the NOM.

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[50] Installation of reactors at Yanchep, Clarkson, Henley Brook, Wanneroo, Joondalup, Southern River, Neerabup Terminal, Guildford Terminal, Southern Terminal and Northern Terminal substations. See Western Power (2020), *Annual Planning Report 2020*, p.37 at https://www.westernpower.com.au/media/4768/annual-planning-report-2020-20210211v2.pdf.

[51] At https://www.wa.gov.au/sites/default/files/2020-11/Whole%20of%20System%20Plan_Report.pdf.

[52] ENAC clause 1.3 defines the "whole of system plan" as "the document published by the Minister from time to time as the Whole of System Plan for the efficient development of the SWIS over a 20-year period".

[53] The ERA only needs to assess the unit costs of a priority project for the purposes of a New Facilities Investment Test (ENAC clause 6.52(b)(iv) and 6.54(a)). A priority project is not subject to the regulatory test (ENAC clause 9.24B).

[54] Energy Transformation Taskforce (2020), *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code Consultation Paper*, May, p.10 at https://www.wa.gov.au/sites/default/files/2020-05/PUBLIC%20RELEASE%20-%20Consultation%20Paper%20-%20Proposed%20Changes%20to%20the%20Electricity%20Networks%20Access%20Code%202004.pdf.

Importantly, the amendments embed the WoSP into Western Power's planning process and will be a key influence on the development of Western Power's Annual Planning Reports[55]. This is because the WoSP considers the contribution that efficient investments in renewable generation and energy storage can make to the transition to a secure and reliable lower-emissions power system[56].

The WoSP process performs a parallel function to the regulatory test and New Facility Investment Test (NFIT) traditionally required by the ENAC for network investments, and determines the best, least-cost network investment options from a system-wide perspective, taking into account the solution size and timing to achieve security and reliability[57,58].

Although the inaugural WoSP[59] did not identify any priority projects, it did provide welcome visibility on the changes being experienced in the SWIS and the likely evolution of the SWIS over the next two decades.

## 4.3 WEM Reforms – early activities

The Foundation Regulatory Frameworks delivered under ETS Stage 1 will introduce several critical capabilities to allow AEMO to manage the power system under rapidly evolving requirements, including reforms to ancillary services (though the creation of the ESS framework), dispatch (through SCED) and a range of other reforms across the WEM Rules. In advance of the full implementation of reforms, AEMO and EPWA have introduced and are operating several reform components which have improved AEMO's capability to manage the risks identified in this report.

### 4.3.1 Revised Frequency Operating Standards

The Frequency Operating Standard (FOS) specifies the frequency levels for the operation of the power system in the SWIS, that is, the network and its connected generation and loads operated as an integrated system. The FOS provide for the allowable frequency ranges for various events and are integral to the effective operation of frameworks for (among other things) the setting of ESS quantities, facility commissioning and testing, generator monitoring and performance, System Restart, UFLS, and dispatch. It is also fundamental to the Operating States framework which both informs and empowers System Management's actions to maintain power system security and restore the power system to a secure state following an event.

From 2007 until recently, the FOS were located in the Technical Rules, reflecting Western Power's former System Management responsibility. System Management functionality was transferred to AEMO in July 2016 and the FOS was revised and relocated to the WEM Rules as part of foundational WEM Reforms.

The revised FOS was introduced into the WEM Rules on 1 February 2021 alongside the new GPS provisions, and while it is not yet fully operational it:

- Inserted definitions for previously undefined key concepts, for example, for 'island' and for some of the operating bands.
- Removed the ambiguity on response and recovery times through the adoption of revised frequency bands in regard of containment, stabilisation and recovery and their respective time settings.

[55] Western Power (2020), *Annual Planning Report 2020*, p.9.

[56] Western Power (2020*), Annual Planning Report 2020*, p.9.

[57] Energy Transformation Taskforce (2020), *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code Consultation Paper*, May, pp.22-23 at https://www.wa.gov.au/sites/default/files/2020-05/PUBLIC%20RELEASE%20-%20Consultation%20Paper%20-%20Proposed%20Changes%20to%20the%20Electricity%20Networks%20Access%20Code%202004.pdf.

[58] The ENAC allows the ERA to waive the application of a regulatory test where it is redundant, or the ERA forms a view that there are no viable alternatives to the solution identified by Western Power. As part of the developing the WoSP, if a project is determined as a priority project, the requirement for a regulatory test will be automatically waived. In addition, the ENAC requires the ERA to apply the NFIT following the commissioning of a project. The Energy Transformation Taskforce determined that if Western Power is undertaking a priority project, it would be unreasonable for the ERA to retest the prudency of the project. However, as there would still need to be surety that Western Power's investment into the network was efficient, the ERA can review the unit cost of a priority project.

[59] Energy Transformation Taskforce (2020), *Whole of System Plan*, August, p.17.

- Identified the situations in which the FOS do not apply, for example, certain microgrids and stand-alone power systems.
- Clarified and simplified terminology, wording and descriptions pertaining to the application of the operating bands.
- Introduced the concept of a 'RoCoF Safe Limit' which will support the new RoCoF Services market to be introduced under ETS Reforms. In the interim, the concept is being used to guide operational planning and decision-making.

The revisions are instrumental to the new market design as implemented by the WEM Reforms, specifically SCED, new ESS arrangements, and the co-optimisation of energy and ESS. The early implementation of the FOS has provided more clarity and transparency on to facilitate AEMO's day-to-day decisions as System Management.

### 4.3.2 Generator Performance Standards (GPS)[60]

A generator's technical capability and its response to disturbances has a direct effect on the resilience of the power system as a whole. AEMO's ability to manage power system security is dependent on having visibility of, and reliable access to, the technical capabilities of generators. Under previous arrangements, AEMO did not have a formal role in negotiating new generator connections in regard to GPS, and Western Power's options for resolving a non-compliance with performance were largely limited to disconnection. This limited response was impractical and potentially created additional risk to the management of the system.

Under the WEM Reforms, the relevant standards for generator performance were given a significant refresh that resulted in new performance standards being introduced and the ability to cater for different types of technology. The performance standards themselves were moved from the Technical Rules to the WEM Rules, with the rules for the new GPS framework applying from 1 February 2021.

The GPS framework now includes the revised performance standards for new connections of Transmission-connected Generating Facilities who intend to be registered for participation in the WEM, a new monitoring, rectification and compliance regime, and transitional arrangements for registering the performance standards of existing market generators. Importantly, AEMO now has a shared role with Western Power in negotiating GPS with market generators and in managing GPS obligations, so that both network and system requirements are considered.

AEMO has implemented a new GPS System (an IT solution) to support its new obligations in managing GPS processes[61]. These include obligations in respect of:

- The submission, review and agreement of the core data that makes up a GPS Submission.
- Validating and storing Generator Monitoring Plans.
- Monitoring Non-Compliance and approval of Rectification Plans.

The GPS System went live in late July 2021 and provides Western Power and AEMO visibility of the performance capabilities of existing and new market generators. A feature of the new GPS System is the capability to ensure that GPS are maintained on an ongoing basis, and also provides the means of ensuring the GPS remain appropriate as the power system transitions.

### 4.3.3 Reserve Capacity Mechanism (RCM) improvements

Capacity payments play a critical role in ensuring sufficient capacity is available to meet AEMO's demand forecast (through the Planning Criterion) and provides an additional revenue stream for facilities participating

[60] Information Paper: Generator Performance Standards and Information Paper: Generator Performance Standards - Regulatory Framework, Monitoring and Rectification, at https://www.wa.gov.au/government/document-collections/taskforce-publications.

[61] To make a GPS submission a Market Participant completes and submits a form to Western Power. This is reviewed by Western Power and if acceptable, it is uploaded to AEMO's GPS System by Western Power. The submitted data is then jointly reviewed and agreed between AEMO and Western Power. Once an agreement is reached, the approved submitted data is uploaded to AEMO's GPS database, where the Market Participant can interact and manage aspects of their registered information.

in the market. The RCM is focused on procurement of sufficient capacity to meet peak demand for the purpose of system reliability. Improvements to the RCM for the 2021 Reserve Capacity Cycle include the capability to value the contribution of energy storage; which is facilitating the participation of Electricity Storage Resources (ESR) in the market for the first time.

With RCM incentivising entry of ESR, the technologies will likely support other market services (including ESS) and be capable of mitigating low system load conditions (via their ability to charge during periods of negative pricing). There is potential of over 780 MWh of large-scale storage becoming available in the SWIS based on the Expressions of Interest received for the 2021 Reserve Capacity Cycle.

Further RCM reforms for the 2022 Reserve Capacity Cycle are designed to reflect constrained access through the new NAQ framework, in order to incentivise investment in areas of the system that are less congested.

## 4.4 Business as usual reforms

### 4.4.1 90-minute gate closure and real time forecasting enhancements

On 4 April 2017, Perth Energy submitted a Rule Change Proposal, *Implementation of 30-Minute Balancing Gate Closure* (RC_2017_02) to the Rule Change Panel. This Rule Change spanned the Balancing Market gate closure, the LFAS gate closure and Synergy's gate closure. It resulted in the following:

- The move from a 120-minute rolling to a 90-minute rolling Balancing Market gate closure.
- The move from a 240-minute gate closure for Synergy for the Balancing Market with a 6-hour bidding block, to a 150-minute rolling gate closure.
- The move from a 300-minute LFAS gate closure, with a 6-hour bidding block, to a 210-minute LFAS gate closure, with a 4-hour bidding block, for Independent Power Producers (IPPs).
- The move from a 600-minute LFAS gate closure, with a 6-hour bidding block, to a 210-minute LFAS gate closure, with a 4-hour bidding block for Synergy.

The reductions in gate closure are an important interim step to improving the manageability of system volatility prior to the full implementation WEM Reforms, where gate closure will ultimately be reduced to real time (an initial 15-minute gate closure will apply at 'go live'). These changes provide an interim measure that facilitates a statistically significant increase in the accuracy of the Load for Scheduled Generation forecast, and as a consequence, will assist with reducing risk to power system security and reliability.

## 4.5 AEMO initiatives to underpin system security and reliability

### 4.5.1 Real Time Frequency Stability Tool (RTFS)

Following the most severe credible generation contingency event, the frequency band of 48.75-51 Hz must be maintained if there is no shortage of Spinning Reserve in accordance with Clause 3.10.2 of the Market Rules, without the use of load shedding under all credible power system load and generation patterns and the most severe credible contingency event.

The WEM Rules[62] require adequate Spinning Reserve to cover the greater of:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and

ii. the maximum load ramp expected over a period of 15 minutes.

The increasing penetration of utility-scale renewables and DPV has necessitated consideration of whether reserves to cover 70% of the largest contingency is adequate for maintaining system security, particularly under conditions of low system inertia, low system load and high contingency size.

[62] See WEM Rule 3.10.2.

AEMO has developed a Real Time Frequency Stability (RTFS) tool that allows AEMO to be better informed when using available resources to maintain system security. It is used by AEMO Controllers and System Planners to assess actual Spinning Reserve requirements to avoid the activation of Stage-1 UFLS.

The RTFS tool is already in operation. It allows AEMO to better understand system conditions and how the system will respond to a disturbance, for example, whether sufficient Spinning Reserve is available to inform AEMO's determination of what operating state the power system is in. Where there is insufficient system inertia, the controller can take action to rectify (as noted in Section 3.7).

The RTFS Tool takes the following real time information into consideration:

- Spinning Reserve providers
- System largest generation / inertia contingency.
- System load
- System inertia
- System frequency
- Governor response of all online generators

### 4.5.2 Sculpted LFAS and Back-up LFAS requirements

LFAS is procured through a market mechanism[63] under the WEM Rules, which also provide for Back-up LFAS[64] where the cleared LFAS quantity is insufficient[65]. As noted in the March 2019 Report, Backup LFAS was utilised on three occasions on 18 October 2018 in response to significant demand swings in excess of 250 MW due to cloud cover over 30 minutes. The volatility in non-synchronous generation and DPV resulted in insufficient cleared LFAS quantities, such that Backup LFAS was required for the first time since the commencement of the LFAS market in 2014.

AEMO's ongoing analysis has shown that the prevalence and timing of volatility necessitated an update to LFAS requirements, such that sculpting peak (5:30 AM to 7:30 PM) and off-peak (7:30 PM to 5:30 AM) LFAS requirements would deliver an improved and cost-efficient solution. Therefore, in 2019-20, AEMO proposed two sculpted LFAS requirements to reflect the absence of variability in DPV systems during the night. In that year, Backup LFAS was utilised on 10 occasions.

In September 2020, the ERA approved AEMO's recommendation for a revised LFAS requirement, to apply for the remainder of 2020-21. The revised LFAS requirement represented a 20 MW increase for the peak and a 30 MW increase for the off-peak, which were implemented in a phased manner. Backup LFAS was utilised on six occasions.

For 2021-22, AEMO's determination of ancillary service requirements took into account the 520 MW[66] of utility-scale non-synchronous renewable generation that connected to the SWIS and the trend in DPV connections. It also considered the likelihood that increased volatility experienced over the last two years would continue. The expectations for 2021-22 meant another increase in peak LFAS quantities would be required, with an initial (lower) quantity implemented and monitored, with adjustments made as needed. It was also identified that the peak to off-peak transition was occurring an hour before volatility reduced in the evening[67], such that peak requirements needed to be extended to 8:30 PM.

Table 9 provides a comparison of 2018-19 to 2021-22 FCAS timings and quantities.

Although the average LFAS requirement increased from 2019-20 to 2020-21, lower LFAS cost were realised due to the efficiently sculpted LFAS requirements, and through changes in prices offered by Market Participants, likely due to increased competition and other external factors[68].

[63] See WEM Rule 3.10.
[64] See WEM Rule 7B.4.1 (inserted 1 January 2014).
[65] AEMO enables specific Facilities, through certification, to be LFAS provides based on LFAS Market outcomes. A Facility may provide LFAS Upwards, LFAS Downwards, or both. At present, Synergy is the Backup LFAS provider.
[66] This included 390 MW of wind generation and 130 MW of grid-scale PV Facilities which completed commissioning in Q3 of 2020-21. See AEMO (2021), *Ancillary Services Report for the WEM 2021*, June, p.20.
[67] AEMO (2021), *Ancillary Services Report for the WEM 2021*, p.20.
[68] AEMO (2021), *Ancillary Services Report for the WEM 2021*, June, p.15.

**Table 9 Changing LFAS and Backup LFAS requirements 2018-19 to 2021-22**

| Financial Year | LFAS Upwards requirement | Enablement period (Trading Intervals) | LFAS Downwards requirement | Enablement period (Trading Intervals) | Backup LFAS utilised | Number of occasions Backup LFAS utilised | LFAS standard (met / not met) |
|---|---|---|---|---|---|---|---|
| **2018-19** | 72 MW | All | 72 MW | All | - | 3 | Met |
| **2019-20** | 85 MW[1] | 5:30 AM to 7:30 PM | 85 MW[1] | 5:30 AM to 7:30 PM | 25 MW to 88 MW | 10 | Met |
| | 50 MW[1] | 7:30 PM to 5:30 AM | 50 MW[1] | 7:30 PM to 5:30 AM | | | |
| **2020-21** | 95 MW[2] | 5:30 AM to 7:30 PM | 95 MW[2] | 5:30 AM to 7:30 PM | 25 MW to 50 MW | 6 | Met |
| | 70 MW[2] | 7:30 PM to 5:30 AM | 70 MW[2] | 7:30 PM to 5:30 AM | | | |
| **2021-22[4]** | 100 MW[3] | 5:30 AM to 8:30 PM | 100 MW[3] | 5:30 AM to 8:30 PM | 10 MW to 80 MW | 11 (plus 2 upgrades) | TBD |
| | 65 MW[3] | 8:30 PM to 5:30 AM | 65 MW[3] | 8:30 PM to 5:30 AM | | | |

[1] From 28 August 2019.
[2] From 25 September 2020.
[3] From 15 July 2021.
[4] For the period 1 July 2021 to 6 September 2021.

### 4.5.3 Dynamic Load Rejection Reserve (LRR) requirement

Load Rejection Reserve (LRR) service requires that generators be maintained in a state where they can rapidly decrease their output should a system fault result in the loss of load. LRR is provided by those generation facilities in the Balancing Portfolio that are capable to do so, where they are online and producing output within the correct range. These facilities are not specifically enabled to provide this service[69]. The quantity of available LRR therefore depends on the generators' output and their ability to respond when the frequency increases.

In April 2019, AEMO started a real-time trial to determine if it was possible to practically manage a 'dynamic' LRR requirement, with some margins included, while still ensuring power system security. The dynamic formulation incorporates physical aspects of the power system, including setting the upper limit of the requirement based on the largest credible contingency in real time (of 120 MW). The formulation:

- Allows for the consequential corresponding change in load as a result of an increase in frequency, known as load relief; and
- Where required by the Network Operator as a requirement of connection to the SWIS, allows for the operation of Facility protection systems in response to frequency fluctuations.

The trial's success meant AEMO adopted a dynamic LRR for the first time in 2020-21. For that year, AEMO planned for 90 MW[70] LRR in the planning horizon while operating the dynamic requirement in real time. This was a significant improvement on the static 90 MW that previously applied as it meant that lower quantities could be operated.

[69] AEMO (2021), Ancillary Services Report for the WEM 2021, p.11.

[70] This is a dynamic requirement in response to a sudden drop of up to 120 MW load less a minimum of 30 MW load relief.

## 4.6 Other measures

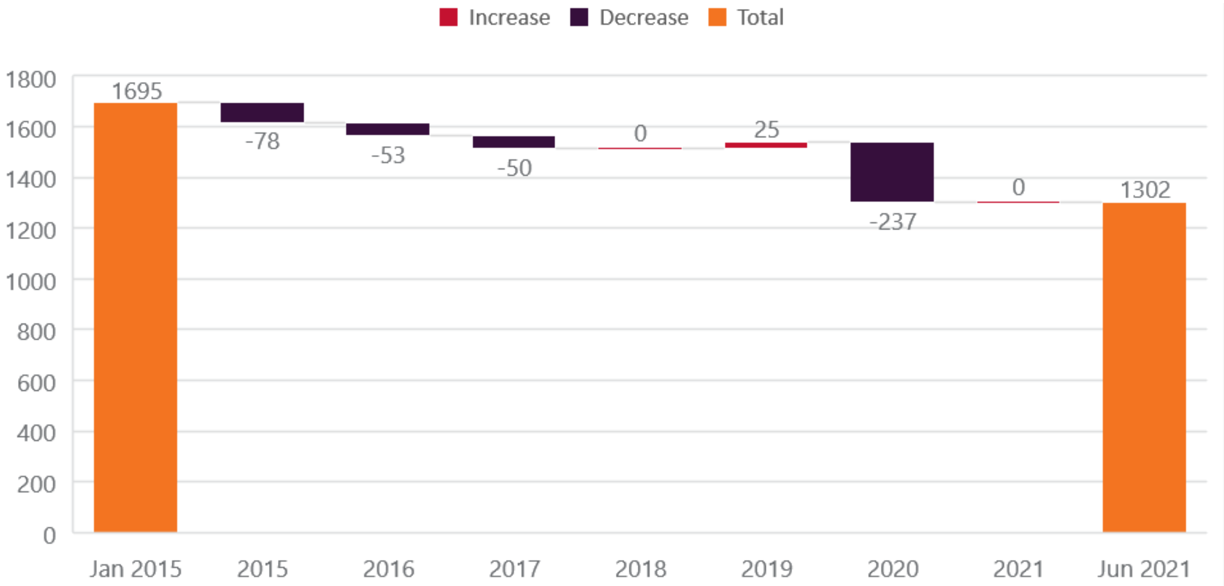
### 4.6.1 Changes to 'significant' generating unit minimum stable loading

As indicated in Section 3.7, the services required to stabilise the power system and maintain its ability to operate with operation limits when the power system is under stress is dependent on the characteristics of the generation assets that are online. Without the benefit of new technologies, the aggregate response of the significant generating units that are online is the means of achieving stability. However, as each of these units has a minimum loading requirement, as the system load declines, so too does the number of significant generating units that can remain online to provide the services necessary for maintaining power system security.

Figure 18 shows the change in the aggregated minimum stable loading of significant generators (that is, the minimum output at which those generators can collectively operate) over the last six years. In total, there has been a net reduction of 393 MW as operators have undertaken works to reduce their facilities' minimum stable loading. Reducing a facility's minimum stable loading enables it to provide both energy and services essential for system security at lower output levels, increasing resilience against lower levels of system load.

Similar attempts to reduce the minimum stable loading level of synchronous plant in the NEM have been observed in recent years. This ongoing testing and investment is required to increase the flexibility of the coal and gas fleet, allowing them to remain online during the daytime system load trough and ready to ramp for the evening peak.

**Figure 18 Change in 'significant' generating unit minimum stable loading**




### 4.6.2 Proposed BESS investments – Synergy and Alinta

Synergy is in the process of the procurement and construction of a 100 MW/200 MWh BESS to provide additional security and stability to the power system. If designed with the required capability, the BESS could be utilised as a resource to provide frequency control and contingency response services under the future reformed market arrangements. It is expected to become operational by September 2022[71].

The BESS will be built at Synergy's decommissioned fossil fuel complex at Kwinana and connected to the transmission system[72]. It represents the largest utility-scale facility of its kind in Western Australia, and

[71] At https://www.mediastatements.wa.gov.au/Pages/McGowan/2020/10/Big-battery-to-power-160000-homes-in-WA-and-create-100-local-jobs.aspx.

[72] At https://www.pv-magazine-australia.com/2020/10/05/synergy-seeking-100-mw-of-storage-to-follow-the-sun/.

Australia's third biggest battery after South Australia's 150 MW/194 MWh battery at the Hornsdale Power Reserve and Victoria's 300 MW/450 MWh battery (the 'Victoria Big Battery').

Synergy will operate the BESS to optimise the use of its existing power generation assets to reduce 'wear and tear' on assets that were not designed to fluctuate in response to high levels of renewable energy on the grid[73]. It will be capable of storing electricity for two hours to power 160,000 homes. It will be charged during the midday and discharged when energy is most needed during the afternoon and evening peak.

Alinta is also planning to build a 100 MW (likely 200 MWh) BESS next to its 380 MW Wagerup peaking gas and diesel plant. It will be the second big battery to be built by Alinta (after the Newman 30 MW/11.4 MWh located in Newman, Western Australia) and may also be a candidate to provide frequency control and contingency response services under the new market arrangements.

The Expression of Interest (EOI) window for the 2021 Capacity Cycle closed on 16 August 2021. As a consequence of the new rules coming into effect, which enables Energy Storage Resources to participate in the WEM, AEMO received submissions from seven entities proposing to connect a maximum of 196 MW of battery capacity to the network.

[73] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2020/10/Big-battery-to-power-160000-homes-in-WA-and-create-100-local-jobs.aspx.

# 5. Current challenges

Further risks to power system security and reliability have arisen in the day-to-day management of the SWIS that had not fully manifested at the time AEMO drafted the March 2019 Report, or were not contemplated by that report. This chapter provides an overview of these new or evolving challenges facing the SWIS, and builds on AEMO's observations regarding the status of drivers of system security risk set out in Chapter 3.

## 5.1 DPV tripping in response to disturbances

There are multiple sources of evidence which show that a large proportion of DPV can disconnect in response to power system disturbances[74]. DPV inverters are particularly sensitive to severe voltage disturbances such as faults, although disconnections are also observed to occur (although at lower rates) during frequency disturbances, or in response to power system phenomena such as phase angle jumps or RoCoF.

A severe fault in the transmission network close to a high concentration of DPV installations (such as in the Perth metropolitan area) could lead to significant DPV disconnection as the effect of the fault propagates throughout the power system. In conditions where a high level of DPV is in operation and exporting to the grid, the disconnection could represent the largest contingency event in the SWIS, (meaning the loss of DPV is equivalent or greater than the loss of the largest utility-scale generator).

Unplanned DPV disconnection, irrespective of cause, also has the potential to increase the size of a contingency[75]. For example, when a generator trip coincides with a power system disturbance causing a proportion of DPV to disconnect, the amount of total generation lost to the system can be greater than if no DPV had disconnected. This, in turn, increases the magnitude of effect to the power system and results in greater deviations to frequency[76] and further disconnections.

To date, there have been several power system events where the total loss in generation has been greater than expected due to unplanned DPV disconnection. As a result of this operational experience and supporting analysis, AEMO has increased the amount of Spinning Reserve it holds for periods of time when this is required. In 2020, the Spinning Reserve requirement that AEMO was obligated to procure was 238 MW – this requirement increased to 310 MW in 2021. While this additional Spinning Reserve caters for faults known to be credible, there is ongoing analysis by AEMO to improve the accuracy of its DPV and load tripping estimates to refine the amount of additional Spinning Reserve to be enabled, and the associated pre-contingent mitigation actions that will be required.

Without adequate management, contingencies may result in the activation of UFLS where customer load is disconnected to maintain power system security. As the level of low system load decreases commensurate with increasing levels of DPV penetration, AEMO's ability to adequately manage the effects of a contingency as part of keeping the system secure becomes increasingly untenable.

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[74] AEMO (2019), *Technical Integration of Distributed Energy Resources – Improving DER capabilities to benefit consumers and the power system*, April, at https://aemo.com.au/-/media/files/electricity/nem/der/2019/operations/technical-integration-of-der-report.pdf?la=en&hash=65EAE8BA3C64216F760B16535CE2D3ED.

[75] A contingency event is an event affecting the power system that AEMO expects would likely involve the failure or removal from operational service of one or more generating units and/or transmission elements.

[76] To operate, the power system must have the ability to set and maintain frequency within acceptable limits. For a basic synopsis on power system frequency and the implications of changes in frequency see: AEMO (2020), *Energy Explained: Frequency*, July. https://aemo.com.au/en/learn/energy-explained/energy-101/energy-explained-frequency.

## 5.2 Low load conditions are now a permanent SWIS feature

The rapid increase in unmanaged generation from DPV is causing material challenges to the management of power system security and reliability. The more salient challenges are summarised below.

### 5.2.1 Insufficient load for minimum unit requirements

As previously mentioned, utility-scale synchronous generators have minimum loading levels and require sufficient system load to operate above those levels. As the level of minimum system load declines, there will be periods of insufficient load to operate these large units to provide services essential for maintaining system security.

Each time a synchronous generator decommits, the proportion of non-synchronous generators to synchronous generators online increases, and the ability to maintain adequate levels of system strength, inertia, frequency control, ramping, and voltage control with the prevailing generation mix reduces.

Further, some generators need time to resynchronise to the power system when they have decommitted, or have issues in resynchronising, and therefore may not be available in the evening peaks.

### 5.2.2 Heightened difficulty in responding to contingencies

The WEM Rules place obligations onto AEMO as System Management regarding the dispatch of market generators for services to keep the power system operating within acceptable limits. These services are required at all times. In addition, the power system must be operated such that, should the next worst contingency occur, power system security would still be maintained and it is possible to resecure the system after the contingency.

In the context of low system load there are more options (and combinations) for the 'next worst' contingency:

- The consequence of a loss of a generator that provides ESS, which becomes more profound with fewer generators online. Adequate contingency reserves (spinning reserve) must be available from remaining generators to respond to the next largest generator contingency to ensure the system remains secure.
- The concurrent loss of generation and any DPV that fail to ride through the disturbance, such that the size of this largest contingency is exacerbated.
- The loss of generation from DPV alone, where it has tripped off as the result of voltage disturbance due to a network fault
- The loss of a large load. While generators will reduce their output below the prevailing level of output to compensate, adequate contingency response (lower) needs to be available to allow for this reduction in output.

### 5.2.3 UFLS is being compromised

ULFS is a last resort strategy to prevent a system black cascading failure if all other preceding system management operational responses are insufficient to arrest the frequency deviation beyond the technical limits. Given the gravity of a failure of ULFS to operate as required it is important to account for the impact that DPV has on ULFS. The increased growth in DPV can impact UFLS arrangements in several ways:

- Where net load on UFLS is reduced, the effectiveness of UFLS, is reduced as there is less available load to shed to restore the frequency.
- Where circuits move into reverse flows (from net exporters during the day to net importers at night) this changes the way circuits interact with UFLS functionality and can exacerbate an under-frequency disturbance.
- In conditions of low system inertia and few synchronous generators online, the resultant high RoCoF could interfere with the operation of UFLS.

AEMO undertook analysis for the SWIS in 2018-19 that showed that a number of distribution feeders in the UFLS scheme were in reverse flows in some daytime intervals. Some of these feeders were in Stage 1 of UFLS, meaning this circumstance could contribute to the decline of frequency as the result of the occurrence of contingencies during daylight hours. AEMO has since worked with Western Power to move high DER feeders to later UFLS stages so that Stage 1 and 2 UFLS are less compromised or alternatively remove the High DER feeders from the UFLS program entirely. These actions help to mitigate the immediate risk to UFLS, and further action will be required to ensure the viability of UFLS in the longer-term.

## 5.3 Action on interoperability and cyber security is critical

Power system operators use their dispatch systems to balance supply and demand to maintain secure and reliable electricity supply. The conventional approach depends on a centralised and controllable generation fleet responding to a coordinating entity. Providing dispatch capability with aggregations of DER will require devices to be controllable and responsive to a remote signal while returning enough data to inform the system operator (and other participants) of the status of those devices. Data exchanges will be managed across various ‘layers’ and multiple actors, meaning that DER device interoperability and robust data exchange systems are of fundamental importance.

The device level layer will likely cover the format and frequency that information relating to operating parameters (for example, to manage voltage constraints, thermal constraints, market-based responses) must be communicated between the DER Aggregator, DER devices, System Manager, Market Operator, Network Operator, and Distribution System Operator.

These exchanges are critical for enabling the integration of DER into power system operational processes. Where data sets are not defined and standardised between all actors, data inconsistencies can lead to a failed dispatch outcome as the expected level of service may not be delivered or network limits may be breached (for example).

Cyber security is a major related concern for device interoperability and remote device management, and the security levels of the associated communications and remote-control systems. Cyber security requirements cover both physical and remote access to devices as well as the communications links used to facilitate remote access. Cyber security controls must be in place prior to any interoperability functionality being activated. There is significant risk in allowing uncontrolled access to potentially thousands of devices, as this exposes those devices to being compromised and used for nefarious purposes.

The widespread use of DER devices and their interconnectedness with the power system can cause power system operations to be significantly impacted where communications and autonomous response requirements are compromised. In the absence of appropriate measures, the market may also be exposed to a coordinated cyber-attack. Early consideration of the cyber security requirements for all DER ecosystem actors, devices and communications pathways is therefore critical.

# 6. Ongoing and further mitigation measures

The future power system is likely to characterised by prevalent conditions of minimum system load and occasional instances of 0 MW operational demand, lower levels of synchronous generation (potentially zero) within a highly diversified generation mix, and greater reliance on ESS to manage both higher and lower levels of load, and generation volatility. Along with operational adjustments, and a greater dependency on dynamic models and settings, and revisions to ESS, a range of further measures for risk mitigation are needed in the short-term and longer-term to supplement the new arrangements implemented under the WEM Reforms and DER Roadmap. Some of these measures will specifically need to address power system operation in the context of low system load, others will be necessary to provide the right conditions for market entry, participation and reward. This will ensure that the needs of both consumers and the power system can be met in the most effective and efficient way as the power system transitions.

Most of the mitigations outlined in this Chapter are being completed as part of ETS Stage 1, through the Low Load Working Group or are in scope for the WA Government's ETS Stage 2[77]. AEMO will continue to engage with EPWA, the broader industry, and consumers on these options, to enable the continued evolution of the ETS Stage 2 scope to preserve power system security and reliability while balancing the need for low cost and sustainable outcomes.

## 6.1 Addressing the decline in minimum system load

As the level of minimum system load declines, there will be periods of insufficient load to operate sufficient numbers of the synchronous generating units that provide the services needed for keeping the power system secure, where these services cannot otherwise be provided by non-synchronous generators. Solutions that 'lift' load, for example, through incentivising the reduction in the export of DPV to the grid, or to 'shift' load, for example, through the aggregated action of DER integrated into the market and through BESS, are likely to become critical for secure power system operation.

Together with AEMO's analysis and program of work to manage low system load, AEMO is part of a joint Low Load working group with Western Power, led by EPWA. Preliminary findings of AEMO's program of work support the view that security risk may be mitigated through taking immediate action on the measures described in the subsections below. Additional actions and longer-term solutions to reduce the power system's reliance on synchronous units remaining online will be identified as further analysis is completed by EPWA, AEMO and Western Power, with potential mitigants to be considered for inclusion in ETS Stage 2.

### 6.1.1 Management of DPV

The March 2019 Report identified that complementary actions would be required to address the issues outlined in that report, including emergency DPV feed-in management as an alternative to disconnecting a distribution feeder or substation (thereby disconnecting the associated load as well). The management of

[77] At https://www.wa.gov.au/government/announcements/western-australias-energy-transformation-strategy-moves-its-next-stage.

DPV would initially involve an intervention to reduce DPV export to the grid as an emergency fallback measure (where needed), which in future, could extend to the orchestrated participation of DER in the market and through other incentivised arrangements.

Consistent with the March 2019 Report, and in consideration of the escalation in the drivers of change as highlighted by this Report, urgent action is now required to enable the capability to manage DPV output to the grid as an emergency fallback. Action must commence as soon as practically possible to implement capability for all newly installed[78] and upgraded DPV to be managed in respect of their output on instruction from AEMO to another agency or entity. Specifically, action is needed to provide for reduction or curtailment in the output of DPV where required to maintain power system security and reliability in emergency operational conditions. This includes during extreme low system load conditions and as part of System Restart procedures, which may require the development of separate methodologies for managing DPV output, depending on the relevant operational condition.

Commencing work to implement this capability as soon as practicable will ensure that sufficient numbers of 'manageable' DPV are installed and available to provide a sufficiently material response in future when the capability to manage DPV output as an emergency fallback is required.

Priority should be given to the management of DPV as a measure of last resort to keep the power system secure under extremely low system load conditions; that is, where the present suite of operational tools and mechanisms available to AEMO under the WEM Rules to maintain system security are no longer sufficient. Under such conditions, the management of DPV offers a better option for responding to extreme conditions than the alternative, presently available option which is a blunt load shedding measure involving the tripping of whole distribution feeders (in which customers lose supply).

The WEM Rules empower AEMO to leverage a considerable 'toolkit' of responses to maintain power system security, such that the management of DPV will be required only rarely, and in extreme circumstances, as a measure of last resort. The impact on consumer bills, should DPV management be required by AEMO, is therefore expected to be immaterial.

As DPV penetration increases over time, the resulting decrease in system load means the SWIS is at increasing risk of experiencing extreme low system load conditions. It is therefore imperative to implement arrangements for managing DPV as soon as possible, to provide an effective and targeted response that (where sufficient volumes of manageable DPV are available) will remove the need to turn off distribution feeders under emergency conditions.

AEMO is undertaking studies and analysis that are contributing to the determination of when minimum system load thresholds likely to place power system security at risk will be reached, and when remedial action, including reducing DPV export to the grid, will be required.

There may be other reasons which could make it necessary to control the output of DPV. Where there is sufficient installed capability within the DPV 'fleet', the management of DPV output could potentially be used under separate, tailored arrangements to facilitate System Restart. The inclusion of 'manageable' DPV within System Restart procedures will ensure that:

- There is adequate stable load available in the vicinity of synchronous generators to support the effective restart and restoration of the system.
- DPV does not reconnect to the power system immediately when power is restored to a circuit.
- DPV is restored in a managed way during the fragile restart process.

The DER Roadmap specifically calls out declining system load resulting from DPV uptake as an increasing risk to power system security and has a number of actions to address risks and realise the benefits of DER, although some of these are pilots which will then need to be implemented at a wider scale. The DER orchestration pilot, for example, will focus on demonstrating the capability of a DER aggregation to coordinate active control of its DER in response to market signals and dispatch instructions from AEMO. The

[78] This will be implemented when AS4777:2020 is applied as of 18 December 2021, however there is a likely need for enhanced compliance frameworks.

pilot's scope includes exploring a use case to dispatch DER to 'zero' for the purposes of system security, such that data from the pilot could be used to ascertain the requirements for managing DPV export to the grid to assist with System Restart, including in low system load conditions.

There is also opportunity to align the delivery of market participation models for DER aggregations with the new market arrangements being implemented under the WEM Reforms, giving specific consideration to the contribution that aggregated DER could make to the provision of services essential for managing the power system in low system load conditions.

Further consideration needs to be given to the coordinated provision of network support services from DER with market services (such as ESS) from DER, and the role of incentives. Specifically, what role incentives and legacy incentives (such as REBS scheme, the DEBS scheme, retail tariffs and network charges) could play in determining the scope and prospect for market-based mechanisms to manage minimum system load should be investigated.

The scope of activities in relation to DER participation in the market could be broadened for Synergy to trial customer incentive arrangements for existing DPV owners to allow export management of their DPV systems in periods with negative balancing prices. This will allow an incentivised market-based response for managing DPV in the first instance, potentially via a demand-side program or an NCESS (or other) arrangements, rather than activating the management of DPV as a measure of last resort. Consideration will need to be given to establishing arrangements to promote customer enrolment with DER aggregators and the provision of sufficient storage to maximise the efficacy of new arrangements when they 'go live'.

AEMO views the DER Roadmap as providing a strong foundation for facilitating further installation of DER and its integration into the SWIS for the benefit of all consumers. A number of the opportunities outlined in this section are already in the DER Roadmap actions whilst others would be an embellishment or extension.

### 6.1.2 Ongoing Inverter Performance Monitoring and Compliance

With the publication of the new inverter performance standard (AS/NZ 4777.2:2020) coming into effect on 18 December 2021, and the advance implementation of the LVDRT requirements via Western Power's Network Integration Guideline, the focus shifts to monitoring, compliance, and the ongoing development of the DPV fleet's performance via driving standards.

To build confidence that the performance of inverters is as expected, ongoing investigation into inverter performance at the fleet and individual inverter level is required. Evidence must be gathered and analysed to determine whether DPV will respond to grid changes in the timeframes required to maintain system security, in accordance with the relevant version of AS/NZ 4777.2.

AEMO's investigations in the NEM have identified areas where there is a shortfall in the standard or the standard's implementation[79], which will potentially require the evolution of future standards. As the rate of DPV installation and the resultant DPV generation share increases, DPV performance becomes more and more critical, driving the need for more frequent updates to standards in order to respond to developing issues and capture new technologies.

The DER Roadmap Action Item #4 acknowledges that a key means for improving confidence in the performance of the DPV fleet is ongoing monitoring and compliance capability. The action was established to develop a process to ensure that inverters are installed compliant with connection requirements and will remain compliant with the latest settings over time, including when inverters are upgraded.

### 6.1.3 Response to unplanned DPV disconnection

The periods in which system conditions are creating the majority of UFLS risk are those in which inertia and Spinning Reserve are both low and DPV output is high.

Consequently, AEMO is undertaking studies and using its RTFS Tool to better understand the impact of unplanned DPV disconnection on frequency stability. Preliminary modelling looked to assess the likelihood of

[79] At https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

a contingency event caused by a severe voltage disturbance, as potentially exacerbated through unplanned DPV disconnection (where DPV tripping is based on assumptions still to be finalised), resulting in the frequency declining to a level that puts the system at risk of triggering UFLS[80]. The preliminary modelling also sought to identify how additional Spinning Reserve, and limiting contingency size through curtailments of utility-scale generators could contribute to the mitigation of security risk in the short term. The value of a FFR service, potentially sourced from BESS, was also considered.

The preliminary modelling results highlighted that:

- Under a central estimate of DPV tripping, the SWIS is at risk of UFLS as a consequence of a severe fault with a unit trip around 20% of the time and intervention was required to reduce this risk.
- Material levels of intervention via a FFR service (potentially sourced from BESS) was advantageous in providing a rapid controlled response to frequency deviation, in addition to the scheduling of additional Spinning Reserve and occasional utility-scale generator curtailments.

In the interim to the full implementation of the new market arrangements, a market-based contract could be used to procure sufficient FFR, potentially from a utility-scale BESS, Interruptible Load or other resource, to reduce security risk. AEMO's Ancillary Services Reports for the WEM for 2019[81] and 2020[82] flagged that AEMO may need to seek approval from the ERA for a Dispatch Support Service (DSS)[83] contract in the short term under the existing Ancillary Service framework to deal with emerging system challenges. However, an opportunity may exist under the ETS Reform program to procure FFR services by bringing forward the commencement date of NCESS arrangements, so a contract for FFR can be activated as soon as possible.

### 6.1.4 Fast Frequency Response (FFR) service

In low load conditions where fewer synchronous generators are online, the quantity of system inertia, spinning reserve, and governor response that is available from those generators is also reduced. As inertia levels decline, the RoCoF in response to a disturbance increases. This can mean that faster frequency services are required to maintain frequency within acceptable limits.

FFR service is a sub-second frequency response that can be delivered by inverter-connected generation or contracted load shedding to assist with managing frequency in response to contingency events. Utility-scale BESS, solar farms, and some kinds of loads are particularly effective providers of FFR, within the following limitations:

- BESS can deliver FFR when dispatched to a level that leaves adequate 'headroom' or room to lower.
- Solar farms generally need to be pre-curtailed to provide a frequency raise service but can deliver a fast frequency lower service in periods where they are operating.
- Some loads can also provide a rapid 'switched' service to assist with fast frequency raise response.

Wind farms may be able to deliver some frequency services but can be limited in how this is delivered due to mechanical stresses on turbines.

With the planned entry of utility-scale BESS and solar generation in the near future, there is an opportunity to design the control schemes of these facilities to maximise their delivery of FFR services. The more transparent and cost-effective approach is to implement capability at the time of installation, when the original

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[80] The RTFS Tool was used to generate a synthetic frequency trace representing post-contingency frequency outcomes, based on a given set of system conditions. Synthetic generator dispatch scenarios were created on actual (2019-20) and projected (2021 to 2023) DPV and demand outlooks and then input into the RTFS Tool. In this way, the frequency outcomes following a largest contingency event could be assessed under two different scenarios – Linear decline in minimum demand and High PV growth. Outcomes under the two scenarios were not significantly different, likely due to the up lift in voltage ride-through specifications under the AS4777.2:2020 (to apply from December 2021), which is expected to limit the growth of DPV disconnection rates.

[81] See https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf. See the ERA's response at https://www.erawa.com.au/cproot/20630/2/AEMO-s-Ancillary-Services-Requirements-decision-201920.PDF.

[82] AEMO (2020), Ancillary Services Report for the WEM 2020, June, p.11.

[83] See WEM Rule 3.9.9. DSS refers to a service provided to AEMO under contracted by a generator who can be called upon to operate to support system security and reliability that is not already covered by other ancillary service categories. There is ancillary service standard for DSS – see WEM Rules 3.11.8A and 3.11.8B.

equipment manufacturer is involved in plant design and commissioning, compared with later retrofit. It is therefore important that suitable arrangements are in place to clearly specify the design requirements, and to incentivise delivery of this service, ahead of when it is required.

As part of the WEM Reforms, the ESS framework will include a Contingency Reserve accreditation test that will determine a 'speed factor'. The speed factor reflects a facility's response to frequency deviation and the profile (of time) in which the facility is capable of responding. The framework therefore provides for responses over Fast Frequency, Primary Frequency and Secondary Frequency timeframes.

However, there is opportunity for AEMO to enter into a contract (DSS or NCESS, if possible) with a Rule Participant other than Synergy to provide Spinning Reserve in a fast frequency response timeframe, where existing provision cannot meet the response requirements, or where a contract presents a cost efficient alternative. This may allow AEMO to contract with new entrants for delivery of FFR services prior to the implementation for the ESS reforms that constitute ETS Stage 1.

### 6.1.5 UFLS improvements

Work is currently being undertaken to improve the effectiveness of UFLS under the auspices of the DER Roadmap and the revised UFLS framework to be introduced under ETS Stage 1 Reforms in which AEMO will have an obligation to work with Western Power on setting the UFLS requirements and UFLS design. Consistent with this work, AEMO has identified short-term actions that can be implemented relatively quickly to improve UFLS arrangements, and identified other improvements that will likely be necessary in the medium and longer term.

Short-term improvements involve making operational adjustments to the existing UFLS regime, such as adding more customers to the UFLS scheme (and moving them to other bands), and introducing the real-time monitoring of loads. In addition, where UFLS load is insufficient, improvement could include the management of contingency sizes in real time and, potentially, enabling larger quantities of Spinning Reserve or other types of frequency control services.

Medium-term actions may include dynamically disarming (or blocking arming) of UFLS relays when circuits are experiencing reverse flows. This would maximise the amount of net load in the UFLS scheme and prevent tripping of circuits that will exacerbate a disturbance, rather than correcting it. Another action might be adaptive arming, that is, adjusting the frequency trip settings of relays in an adaptive manner based on real-time parameters such as the amount of DPV in operation, or the amount of net load available on each UFLS circuit.

In the longer term, more granular load shedding at the individual customer level (separate from the DPV) could be worth exploring through trials to test device, communications and control requirements and technology capabilities. This could have the benefit of reducing the impact to individual customers by tripping the less essential loads of customers while retaining their other primary loads. This is a nascent technology at present and has not been implemented anywhere at scale (although some parts of this capability have been demonstrated in small trials).

### 6.1.6 Incentives for flexible load

The WEM integrates several incentives for load flexibility, specifically the Demand Side Program (through Reserve Capacity payments) and the Interruptible Load framework (for provision of rapid load reduction for Contingency Reserve). These incentives are targeted at specific capabilities for load flexibility and do not incentivise the full capabilities of load to flexibly manage low system load or to participate in other ESS.

Flexible loads may be capable of responding to directions to increase demand to improve power system conditions, including during periods of minimum system load. Western Power has been undertaking a Flexibility Services trial, that has demonstrated the technical capability of customers to provide a service. It is worth noting that there is no ongoing obligation on Western Power for this to continue within current regulatory framework. The State Government's ETS Stage 2 could further consider options for increasing the visibility of loads and incentivising load behaviour to release the value of flexible load to the power system, thereby building on ETS Stage 1 activities. Pathways could include:

- Retailer arrangements – undertake tariff reform to drive opportunities for flexible load that are better aligned with and complement the availability of renewable sources of energy. This will enable retailers to utilise DPV management by rewarding customers for this service.
- Distribution network arrangements – design mechanisms to reward customers to increase their load (or curtail their DPV) to mitigate distribution network limits. These opportunities are currently being explored through Western Power's flexibility services trial to encourage the provision of network services from DER.
- WEM arrangements – further develop, or enhance, market participation frameworks[84] that will support the provision of ESS with flexible load (noting that under the WEM Reforms, a flexible load will be able to register as a Scheduled Facility and provide energy and/or ESS). This could be explored with large industrial customers in the SWIS. It is also important that market participation frameworks provide for DER aggregators to use load control in conjunction with generation (from DPV, for example) and with BESS.

### 6.1.7 Ramping Service

As variable non-synchronous generation constitutes a larger proportion of the generation mix, the diurnal pattern of DPV operation in particular will have a larger impact on the net system load profile. This impact on the profile is often referred to the "duck curve", a feature of which is an increasingly steep neck of the "duck". The combination of the deep belly of the duck and the steep neck means that, under specific scenarios, some or most synchronous generation facilities may decommit as it is not commercially or technically feasible given their minimum loading requirements to stay online. This means these synchronous generating units are not immediately available, as they require time to synchronise in order to provide the energy and ESS needed as system load increases to its peak in the evening.

The effect of the deep belly duck curve is higher ramping requirements from the daytime trough to the evening peak. This circumstance may warrant the investigation of the need for a ramping service. AEMO has undertaken in-depth analysis of the ramping requirements for the SWIS. The analysis indicated the SWIS is challenged to meet the requirement for ramping by 2024 subject to the installation of battery capability that has been committed. In this period, when a clear sunny day is followed by a night with cold ambient temperatures, the result is a low daytime trough (from the clear sunny day) followed by a high evening peak (from the cold night-time temperatures). On such days the ramping requirement is up to 1,500 MW over a 4.5 hour period. The ramping requirements for flexible generation could be higher still when coupled with coincident reductions in generation from utility-scale wind and solar generating units.

The SWIS is characterised by a relatively high proportion of flexible gas, diesel and Demand Side Management service providers that have capability to provide relatively fast and long ramping. AEMO can also intervene in advance to keep more utility-scale generators online during the daytime "belly of the duck" to ensure these resources will be available to assist with the afternoon ramp. Ensuring this availability comes at a cost to the market. As the size and speed of the daily ramp increases with increasing DPV penetration, and the minimum level of system load is driven lower, the generation options to keep the system secure during that minimum load period are limited. As the energy transition continues, there is a risk that some of this faster, dispatchable generation will retire and will likely be replaced by lower energy cost non-dispatchable utility-scale renewables.

AEMO recommends that the case for a ramping service is investigated further as part of ETS Stage 2. This will allow consideration of the impact of the new RoCoF control service in providing a suitably effective "ahead" signal to stay synchronised through the low-load period and therefore be available to contribute to the afternoon ramping requirements, which may obviate the need for a more specifically designed service. Market arrangements that support a ramping service could influence the decisions of Market Participants to enter, exit or change the way they participate in the market (such as becoming scheduled). This could be an

[84] For example, within Reserve Capacity Mechanism arrangements.

important alternative to AEMO intervening in the market as a ramping service may provide a more transparent investment and participation signal to new and existing participants.

In the interim, before the investigation of arrangements under ETS Reforms for a ramping service, mechanisms that enable such a service to be procured should be leveraged where AEMO determines there is a need. The DSS construct under the existing WEM Rules may be one option to contract that service. Alternatively, an opportunity may exist under the ETS Reform program to procure ramping services by bringing forward the commencement date of NCESS arrangements, so that a contract for ramping services can be activated when the need arises.

## 6.2 Contingency planning and management for power system resilience

The framework that presently governs the management of power system security is based on the concept of ensuring the power system is operated in a Normal Operating State, allowing for a 'Credible Contingency Event' to occur. A Credible Contingency Event is a Contingency Event that AEMO determines is reasonably possible in the prevailing circumstances. Everything else is a Non-Credible Contingency Event.

In contrast, power system resilience is the ability to withstand (or adequately manage) the extent, severity and duration of power system degradation following an extreme event. The focus of system resilience is therefore to ensure that the power system can continue in, or return swiftly to, a normal operating state following the occurrence of an extreme event. An extreme event may not be a 'credible contingency event', and while such an event could be of low to very low probability, its occurrence would most certainly result in a significant disruption to security and reliability of supply.

The proportion of synchronous controllable generation is declining, which accentuates the system resilience risks as synchronous controllable generation tend to support the power system in remaining stable following system disturbances. As a result, the power system is exhibiting reduced inertia and decreasing voltage and frequency stability which means, among other things, there is reduced system strength during disturbances. This necessitates a role for managing, and investing in, mechanisms to ensure adequate system strength is maintained, which requires clarity on how shortages are identified and resolved.

Calculating the minimum levels of inertia and system strength is necessary to understand minimum level can operate the system on. Through the use of additional engineering studies, investigations and large-scale trials it may be possible to more accurately determine the minimum operating levels of the SWIS and de-risk operation near those bounds. For example, by better understanding the specific combinations of units that can contribute towards stable operation at low levels of operational demand it may be possible to retain secure operation at a lower level than would otherwise be predicted by a simple fixed MW threshold of minimum demand. Contributing to this, trials and investigations in new technologies may further identify methods of operating a secure system near current bounds.

The management of power system security necessitates judgement on the level of risk that an event poses to power system security and reliability (that is, the probability of disruption) relative to the cost of achieving an acceptable level of risk. The new Operating States framework to commence under the WEM Reforms will allow AEMO to reclassify contingency events to better allow AEMO to plan for, and respond to, contingency events to achieve acceptable outcomes.

It is not feasible (operationally and economically) to seek to mitigate against the occurrence of every possible event at any time. However, it may be possible to invest in measures that can be activated when those conditions are forecast to be more likely than usual, or provide backup capability to assist in mitigating the extent of the issue or otherwise aid the quick return of the power system to normal following the event. Examples such as gas pipeline storage, portable transformers and regional restart contracts are examples of longer-term planning processes identifying solutions to mitigate risk or impact as part of making a case for strategic investment.

The WoSP's focus on broader system-wide issues means the timeframes and underlying assumptions used by the WoSP may not necessarily be best suited to capturing more localised or operational issues. There may be opportunity to develop supporting arrangements that focus on short- to medium-term planning activities to address high impact/low probability events, system strength shortages, and other stability related issues, and facilitate the making of a case for investment. This will ensure sufficient 'reasonable' measures are in place should the event occur. Changes to the Access Code and/or Technical Rules would allow for a transparent mechanism to identify these types of high impact, low probability events. The changes should also allow for reasonable investments to be made to prevent or control these events on the basis of cost and impact, with appropriate regulatory oversight and governance (including where non-network investment is identified as the best option).

The identification of system strength shortages (and other stability related issues), as well as the likelihood and impact of high impact/low probability events, should be a joint exercise including Western Power and AEMO, and bring together both market and power system/network operation knowledge and experience. An investment mechanism to address these issues in the short to medium term, based on an assessment of reasonable risk, reasonable costs, and ongoing suitability of the solution will also be required. The mechanism might be governed by the Coordinator of Energy and/or the ERA. The governance framework would coordinate with other planning processes (such as the WoSP and SWIS reliability planning).

From a cost-recovery/efficacy perspective, consideration should be given to including mechanisms to identify where there are clear 'causers' of the underlying issue, in order to allocate and recover costs. This will help reduce the overall burden on consumers, and incentivise changes in behaviour and innovation over time. This may necessitate different charging arrangements, so costs can be recovered from clear 'causers' rather than via network tariffs.

It is pertinent for the foundational work delivered as part of ETS Stage 1, along with the recent work on the Access Code and Technical Rules, to be leveraged and expanded to address power system resilience through the Low Load Working Group and more broadly through the scope of the ETS Stage 2 'Keeping the Lights On' sub workstream, under the Contingency planning and management project that will focus on power system security and reliability.

## 6.3 Changing the approach to hybrid facilities

Under the new market arrangements, hybrid facilities comprising two or more separate but co-located components (such as a generating unit plus a BESS) that are to be operated together, will be treated as a single facility for the purposes of dispatch, ESS delivery and settlement. The GPS and the RCM, however, recognises each component and imposes specific requirements on each component based on its type.

It is worth considering the development of rules that will allow the hybrid facility the option to offer each of its components separately into the market. This will would allow Market Participants to offer, and AEMO to dispatch, each facility component as necessary, based on its technology type and its technical capability to provide those services of most value to the power system as dictated by the prevailing operational conditions. Such an arrangement could also open up additional revenue streams for hybrid facilities.

## 6.4 Market cost allocation that reflects system security issues

Utility-scale renewable (intermittent) generation typically aims to maximise the energy that is available from its renewable facilities to maximise its energy revenues This behavior results in a higher degree of volatility in renewable generation, making energy dispatch more challenging and increasing reliance on ESS. Measures are required to ensure intermittent Facilities offer generation to a degree of certainty and accuracy, and endeavour to ramp in accordance with dispatch instructions-will help reduce ESS quantities and allow sufficient signals in energy market where shortfalls are anticipated. However, mechanisms that incentivise forecasting accuracy, to ensure dispatchable generation is accurately dispatched to meet the balance of load, are limited in the WEM.

Furthermore, mechanisms penalise facilities which do not meet their forecasts may be insufficient, meaning there is little incentive for renewable facilities to match their forecast and minimise (to the extent possible) the intra-interval volatility of their generation.

These two issues may be mitigated through rewarding accurate forecasting of energy quantities (see Section 6.6) and through enhancing 'Causer Pays' for ESS (regulation services), where causers of a service pay in proportion to their contribution to that cause. Options include 'Causer Pays' based on intra-interval deviation from dispatch (as applied in the NEM), or through an ex-ante forecast of volatility from each facility (with a consequent charge and additional penalty regime for exceeding forecasts). Of these options, ex-ante forecasting may also provide a means of quantifying system requirements based on the expectations of the facility's forecasts (and a diversity factors across the system, including load).

AEMO understands that the Coordinator of Energy is developing a scope for a Cost Allocation Market Evolution Review, addressing the issues outlined above, and is scheduled to submit the draft scope to the Market Advisory Committee (MAC) for endorsement at the MAC's November 2021 meeting.

## 6.5 Develop a SWIS reliability standard and supporting frameworks

To date, the WEM Planning Criterion has ostensibly fulfilled the role of a reliability standard for the WEM, by setting the threshold for the acceptable amount of unserved energy experienced by customers to 0.002% of annual energy consumption (including transmission losses). It is used by AEMO in its Long-Term Projected Assessment of Supply Adequacy (LTPASA) study and is limited in its application to informing the requirements for 'available' generation capacity in each Capacity Year of the 10-year LTPASA study horizon,

The WEM Reforms will implement new frameworks for power system operation, including a revised Operating States framework that leverages a 'Reliable Operating State' supported by Power System Reliability Principles (and other requirements). For this framework to be properly operationalised it must incorporate a reliability standard; one that takes into account potential sources of reliability other than generation (that is, network, non-network solutions, demand response and other services, and system operator interventions).

A reliability standard is essentially a metric (or set of metrics) that reflects a determined, acceptable level of reliability (supply capacity) that is balanced against the costs of delivering that level of reliability across the various sources. It must be capable of being operationalised within several operational planning horizons, for example, to inform decisions on outage planning, pre-dispatch and dispatch.

Crucially, a reliability standard for the SWIS is needed to inform coordinated operational planning processes for both the network and the power system. It should recognise the increasingly important role the distribution network will play in the efficient, secure and reliable supply of energy. This standard should then be used:

- As an input to methodologies for the WoSP, Western Power's Annual Planning Reports and the NOM.
- To inform investment decisions, including any WoSP 'priority projects' and the procurement (where applicable) of AOS and NCESS.
- To facilitate operational planning processes for the power system and the network over the various planning horizons.

Importantly, consideration will need to be given to how the SWIS reliability standard will be applied by the WEM Planning Criterion under the RCM framework.

Without alignment of planning inputs for generation, network and services, for the holistic development of the network and markets, the ability to mitigate risk to system security and reliability will be limited. Through the alignment of planning inputs and by ensuring network planning considers the opportunities and barriers for generation, economic decisions for network investment and service structures can be made to reflect the changing needs of system and the role of the market in supporting efficient service outcomes.

The scope of the ETS Reforms includes the development of a SWIS reliability standard for the SWIS. The timeframe for development and delivery is expected to be long due to the complex nature of the task; AEMO is supportive of the continuing work that will be required under the ongoing ETS Reform program.

The Coordinator of Energy has already developed and submitted a scope for the RCM Market Evolution Review addressing the issues outlined in this section to the MAC, and the MAC has endorsed this scope at its September 2021 meeting.

## 6.6 Enhance the Reserve Capacity Mechanism (RCM)

As identified in the State Government's ETS Stage 2, changes will be required to the mechanisms supporting installed capacity (the RCM) to ensure that sufficient capacity is available and online to service load, and crucially, available for dispatch at times of need.

The enhanced role of the RCM should be to ensure entry of generation that can be available in more circumstances than just the peak and to support flexibility in dispatch as power system conditions change with increasing renewable penetration. Critical to any reform of the RCM is the review of the Planning Criterion to ensure the RCM achieves the reliability targets and underpins the principles for evaluating and assigning Certified Reserve Capacity. The following capabilities should be considered as part of Certification of Reserve Capacity to enhance the effectiveness of mechanism:

- Start-up times – valuation of a facility's ability to be available for dispatch at short notice.
- Controllability – the ability of a facility to be dispatched to a specified level between nameplate capacity and zero.
- Availability – ensuring the facility's capacity is available consistently, while being dispatchable and controllable.

A holistic review of these RCM elements, and review of obligations for capacity holders, should be made with consideration of the evolving energy-mix in the SWIS.

It should be noted that AEMO has made a submission to the Parliamentary Standing Committee on the Environment and Energy inquiry on the current circumstances of, and the future need and potential for, dispatchable energy generation and storage capability in Australia[85]. This submission discusses the properties that support reliability as the power system continues to transform, such as the need for dispatchable facilities to be controllable and flexible, which will require consideration when valuing capacity through the RCM in future.

## 6.7 Build on the utility of the Whole of System Plan (WoSP)

The inaugural WoSP provided an informed view on the evolution of the SWIS in the next two decades, that acknowledged the importance of centralised planning to accommodate greater variability in supply and demand from changes in technology, and to facilitate consumer engagement with technology.

The WoSP is set to play a vital role in determining the future requirements of the power system and guide how the SWIS will transition to this future design. This will ensure the power system remains secure while opportunities for market participation are afforded to new entrants and existing participants, and all energy users have access to affordable, sustainable energy.

To this end, AEMO suggests the following improvements to the next iteration of the WoSP, that builds on the achievements of the inaugural WoSP:

- The WoSP should specifically be required to look at the power system operability outcomes with the least cost supply mix and market outcomes across all markets and services.

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[85] AEMO's submission to the inquiry can be found at https://www.aph.gov.au/Parliamentary_Business/Committees/House/Environment_and_Energy/DispatchableEnergy/Submissions.

- Modelling for the WoSP should include a set of assumptions or forecasts for an 'expected' case in at least the earlier years of the 20-year outlook, within broader scenarios over the remaining outlook period.
- Sensitivities should be used to identify any 'no regret' actions; these can help inform a plan for the specific generation, storage, network solutions, and other necessary infrastructure investments such as the development of renewable energy zones.
- Revise the magnitude and approach to DER curtailment in the first WoSP to improve the accuracy of the model. An approach that includes appropriate incentives and/or charges to DER asset owners should be considered.
- Align with State Government's policy decisions on emissions, for example, reducing carbon emissions to reach net zero by 2050 arising from November 2020 Western Australia Climate Policy[86] and Infrastructure Western Australia's Consultation Paper, *Foundations for a Stronger Tomorrow*[87]. Options could include building an emissions pathway into the assumptions, or otherwise allowing for market forces to dictate the pathway in the modelling. The WoSP might also indicate a delta between the two. AEMO understands that EPWA's planning for the next WoSP includes consideration of modelling for net zero by 2050.
- As WEM Reforms and the DER Roadmap are now more clearly defined, incorporate the new arrangements in the modelling, including the updated provision and performance of services essential for system security. AEMO understands that EPWA's planning for the next WoSP includes consideration of other new ESS such as NCESS as well as new Reserve Capacity arrangements.
- Include decisions on transmission network and distribution network planning in the modelling, along with known and expected two-way energy flows and any additional services being offered.
- The WoSP should Identify solutions to the current and emerging challenges and develop recommendations to clarify the pathway along which the power system is to evolve. This includes identifying opportunities for the integration of DER as a resource for power system management.

Further clarity on how the outputs of the WoSP will be used to inform decisions across different parts of the energy supply chain – from network connection and planning to power system and market operation through consumer participation – is required. This will help eliminate any 'default' assumption that only small changes are required to the existing operational and regulatory frameworks, and will signal that the WoSP is the opportunity to identify the need for, and criticality of, changes that will be required.

## 6.8 Embed requirements for interoperability and cyber security

AEMO is part of a Distributed Energy Integration Program (DEIP) Interoperability Steering Committee[88]. The steering committee has initiated an Interoperability working group[89] and is in the process of initiating a cyber security working group. These bodies are working across all market participants to establish uniform interoperability and cyber security standards to better enable DER integration. The work is focused on two major workstreams:

- Interoperability – to ensure all DER devices can communicate effectively and respond to provide communication-enabled grid support functions as required.
- Cyber security – to establish the first phase cyber security controls required to mitigate the threats for DER market integration.

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[86] At htpps:// www.wa.gov.au/sites/default/files/2020-11/Western_Australian_Climate_Policy.pdf

[87] Infrastructure Western Australia (2021), *Foundations for a Stronger Tomorrow, State Infrastructure Strategy, Draft for Public Comment*, July, p.12. See https://www.infrastructure.wa.gov.au/sites/default/files/2021-07/Foundations-for-a-Stronger-Tomorrow-Draft-for-public-comment-web-standard_2.pdf.

[88] At https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/interoperability-steering-committee/.

[89] Other members are Australian Energy Council (AEC), Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), Australian Renewable Energy Agency (ARENA), Clean Energy Council (CEC), Commonwealth Scientific and Industrial Research Organisations (CSIRO), Energy Consumers Australia (ECA), Energy Networks Australia (ENA), Energy Security Board (ESB), Independent Chair.

AEMO's focus is on adopting existing international standards and practices. The Common Smart Inverter Profile for Australia (CSIP-AU)[90], an output of the DEIP Interoperability working group, has recently been released for public comment. This implementation guide for IEEE2030.5 communications within a DER network builds on the CSIP[91] developed to meet California Rule 21 interoperability mandate for DER integration.[92].

AEMO is also working with Western Power as part of DER Roadmap Action Item #3 to introduce mandatory inverter communications and functionality, including communications protocols and cyber security arrangements. This work will support remote and dynamic management of DER necessary to facilitate the integration of DER into the power system and aggregation of DER into the market.

Of critical importance is ensuring this integration is implemented in a way that is conducive to maintaining power system security, and the capability and willingness of affected parties in the supply chain actively engage with each other to coordinate their activities. Crucially, effective interoperability and cybersecurity outcomes can only be achieved within an ecosystem that is supportive of achieving these outcomes.

It is therefore necessary that ETS Reforms are guided by clear policy to facilitate integration, so that interoperability and cybersecurity arrangements implemented through the DER Roadmap can be fully and effectively embedded across, and leveraged by, the suite of reforms for power system and market operation.

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[90] At https://arena.gov.au/knowledge-bank/common-smart-inverter-profile-australia/.

[91] See https://sunspec.org/2030-5-csip/.

[92] See https://www.cpuc.ca.gov/Rule21/.

# 7. Conclusion

WA Government reforms and industry investments and initiatives implemented since the release of the March 2019 Report have, to date, deferred the immediacy of the operational challenges in managing the security risk identified in that report. However, as some of these challenges have become more pronounced as the power system transformers faster than forecast, some priority actions will be required in the short term to improve resiliency. The challenges are also expected to become more prominent over the medium and longer term as the power system continues to transform. The ongoing WA Government reform program, and further measures outlined in this Report will therefore be vital for addressing system security risk as it manifests over these timeframes. In conjunction with the WA Government's reform program, the actions recommended in this report will help the power system navigate its transition to higher levels of renewable energy connection.

AEMO's more recent analysis indicates that its ability to dispatch combinations of facilities providing the ESS needed to meet power system security requirements will become limited below the indicative 700 MW threshold in operational demand. However, there is a high probability that sufficient dispatch options will be available to manage the power system down to 600 MW. Below 600 MW the SWIS will be in a zone of 'heightened power system security threat' as the dispatch options materially decrease. It is likely the SWIS will enter this zone for periods of time before 2024. Consequently, AEMO has identified three priority actions that, in addition to the initiatives, WA Government reforms and investments already implemented or expected to be implemented, will need to be undertaken to increase the resiliency of the SWIS in the period to 2024.

These priority recommendations are in regard to:

1. Fast Frequency Response (FFR).
2. Under-Frequency Load Shedding (UFLS).
3. Management of DPV systems.

The issues facing the SWIS result from a varied set of interrelated drivers and challenges that must be managed in the prevailing operational conditions. This requires a broad ranging and integrated set of operational initiatives, investments and coordinated actions and this is the approach underlying the recommendations made in this Report.

The recommendations recognise that measures that facilitate the power system's ability to remain within operational limits are vital for ensuring the power system remains safe and secure. This includes measures that ensure sufficient:

- Visibility of those resources contributing to system conditions, and the means to forecast their behaviour and response.
- Fault ride through capability of the existing generation fleet.
- Dispatchability of the generation fleet, including the extent to which facilities within the fleet can reach a set point (and how quickly), and confirm their energy availability.
- Ramping capability of the generation fleet (to respond to intra-day and inter-day variability).
- System load to sustain minimum levels of utility-scale synchronous generation (to avert issues associated with voltage or frequency control or system strength).
- Load for the effective operation of UFLS.

AEMO's analysis indicates that without implementing these measures and the additional operational tools, new standards, investments and revised regulatory arrangements recommended by this Report the power system may become insecure after 2024. However, similarly to what has occurred since 2019 where new challenges have arisen, it is possible that further challenges may arise as the power system further transitions that will required additional actions to those identified in this report.

Implementing the recommendations in a timely manner will allow the focus to remain on the role of consumers and new technologies and their interactions with the power system and the market while ensuring the power system continues to operate securely and cost-effectively.

The SWIS is now well placed to continue its transition. The WA Government's ongoing reforms and ongoing operational measures undertaken by AEMO, Western Power and other Market Participants are, together, providing the SWIS with the resilience necessary for its ongoing transition.

# Glossary

This report uses many terms and common abbreviations for terms and measures as set out in the following table.

| Term | Meaning |
|---|---|
| **AC** | Alternating current |
| **AEMO** | Australian Energy Market Operator |
| **Ancillary Services** | Market-based services designed to sustain or return frequency and voltage of the electricity system to the range defined by the Technical Standards. This term as used in the WEM Rules will be replaced by the term of Essential System Service having the same meaning. |
| **AOS** | Alternative Options Strategy |
| **ASEFS** | Australian Solar Energy Forecasting System |
| **BESS** | Battery Energy Storage System |
| **BTM** | Behind-the-meter |
| **DC** | Direct current |
| **Demand** | • **Operational demand** is the demand met by scheduled and non-scheduled generation in the WEM and excluding DER such as rooftop PV. It does not include the effect of network losses.<br>• **Underlying Demand** is the total demand for electricity met by all generation devices in the SWIS including rooftop PV and DER.<br>• **System Load** is the sum of all generation on SWIS, excluding generation from embedded networks and from rooftop PV. It does not include the effect of network losses. |
| **DER** | Distributed Energy Resources |
| **DFS** | Demand Forecasting system |
| **DEIP** | Distributed Energy Integration Program |
| **DNSP** | Distribution Network Service Provider |
| **DPV** | Distribution-connected photovoltaic (system), including rooftop PV. |
| **ENAC** | *Electricity Networks Access Code 2004* |
| **EPWA** | Energy Policy Western Australia |
| **ERA** | Economic Regulation Authority |
| **ESOO** | Electricity Statement of Opportunities |
| **ETS** | Energy Transformation Strategy |
| **EV** | Electric vehicle |

| Term | Meaning |
| --- | --- |
| **FFR** | Fast Frequency Response |
| **FOS** | Frequency Operating Standards |
| **Frequency** | For alternating current (AC) electricity, the number of cycles occurring in each second, measured in Hertz (Hz). |
| **Over frequency**<br><br>**Under frequency** | Power system frequency is controlled by the constant balancing of electricity supply and demand. Table 2.1 of the Technical Rules specifies the Frequency Operating Standards applied in the South West Interconnected System (SWIS).<br>Over frequency and under frequency represent unsecure operating states where frequency is outside the normal range (49.8 to 50.2 Hz), where there is insufficient load to cover generation (over frequency) or insufficient generation to meet load (under frequency). AEMO uses ancillary services to ensure that the SWIS operates within the normal frequency bands and to restore the SWIS to the normal frequency bands within the target recovery time following a contingency event. |
| **GT** | Gas turbine |
| **GVA** | Gigavolt amperes |
| **Inertia** | Inertia is the rapid and automatic suppression of rapid frequency deviations, slowing the rate of change of frequency through a rapid change in generation levels. A lack of inertia in the network can present risks to system security. At present, inertia is predominantly provided by synchronous generators in the SWIS. |
| **Inverter** | Electrical equipment to converts DC into AC. DER is typically inverter connected. |
| **kV** | Kilovolt (1,000 Volts) |
| **kVA** | Kilovolt amperes |
| **LFAS** | Load Following Ancillary Services |
| **Load** | Refers to a connection point at which electricity is delivered, or the amount of electricity required from the power system. For the purposes of this report, load is used interchangeably with 'operational demand'. |
| **LLR** | Load Rejection Reserve |
| **MW** | Megawatt (1,000,000 Watts) |
| **NAQ** | Network Access Quantity |
| **NFIT** | New Facilities Investment Test |
| **NEM** | National Electricity Market |
| **NOM** | Network Opportunities Map |
| **Non-synchronous generation** | Non-synchronous generation (also referred to as asynchronous generation) includes wind farms, solar PV, and batteries that export power to the grid. They do not have moving parts rotating in synchronism with the grid frequency, but instead are interfaced to the power system via power electronic converters (refer to "power electronic converters") which electronically follow grid frequency. |
| **Power electronic converters (PECs)** | Power Electronic Converters (PECs) include rectifiers and inverters which convert AC to DC and DC to AC, respectively. Utility-scale wind generation is connected to the grid with complex PEC's whereas rooftop PV systems are connected to the grid with inverters (refer to "inverter"). |
| **PV** | Photovoltaic |
| **RCM** | Reserve Capacity Mechanism |

| Term | Meaning |
|---|---|
| **Reliability (Power system Reliability)** | Ability of the system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies. |
| **RoCoF** | Rate of Change of Frequency |
| **RTFS** | Real Time Frequency Stability |
| **SCADA** | Supervisory control and data acquisition |
| **SCED** | Security-constrained economic dispatch |
| **Security (Power system security)** | To be secure, the power system must operate within defined technical limits and be able to return within those technical limits after a disruptive event occurs, such as the disconnection of a credible power system element (such as a generator, major powerline or major industrial load). |
| **SWIS** | South West Interconnected System |
| **Synchronous generation** | Directly connected to the power system and rotates in synchronism with grid frequency. Thermal (coal, gas) and hydro (water) driven power turbines are typically synchronous generators. |
| **System resilience** | The ability to limit the extent, severity, and duration of system degradation following an extreme event |
| **System strength** | System strength is an umbrella term that refers to a suite of interrelated factors which together contribute to power system stability. It reflects the sensitivity of power system variables to disturbance, and indicates inherent local system robustness, with respect to properties other than inertia.<br>System strength affects the stability and dynamics of generating systems' control systems, and the ability of the power system to both remain stable under normal conditions and return to steady-state conditions following a disturbance.<br>For more detail on system strength, refer to https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-Fact-Sheet-System-Strength-Final-20.pdf |
| **UFLS** | Under Frequency Load Shedding |
| **Voltage** | The electrical force or electric potential between two points that gives rise to the flow of electricity. |
| **Voltage Control** | Voltage control in the power system acts to maintain voltages at different points in the network within acceptable ranges during normal operation, and to enable recovery to acceptable levels following a disturbance. |
| **LVDRT** | Low Voltage Disturbance Ride-Through |
| **WEM** | Wholesale Energy Market |
| **WoSP** | Whole of System Plan |