Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV

April 2020

Important notice

PURPOSE

This is Appendix A to the Renewable Integration Study Stage 1 report, available at https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/4/2020	
2.0	1/5/2020	Minor clarifications to data references in Section A3.5 case study, and Section A4.1.

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A1. Appendix A summary

This Appendix to AEMO's *Renewable Integration Study: Stage 1* report[1] provides additional technical detail related to the overview information in Chapter 3 of that report.

A1.1 Overview

Distributed photovoltaic (DPV) is revolutionising the operation of the power system. Until recently, power flowed in one direction, from large-scale controllable generators to households. Today, power also flows in the opposite direction, from uncontrolled DPV at household level through distribution feeders to neighbouring customers.

With higher penetration levels of DPV, power from these devices will ultimately flow into parts of the higher voltage sub-transmission and transmission networks. Significant amounts of uncontrollable DPV generation will replace large-scale generators, requiring new techniques and potentially services to adequately manage system security matters.

The significant majority of the DPV fleet is currently **passive**, meaning that it is uncontrollable, and invisible to the system operator (behind the meter and unmonitored in real time). The passive nature of the majority of the DPV fleet in the NEM today is beginning to pose challenges to both distribution network and bulk power system operation, especially in regions with higher DPV uptake relative to local load.

Proper integration of DPV across the network will be required to manage the needs of the power system.

A1.2 Distribution network challenges

- Distribution networks in the NEM are beginning to experience technical challenges associated with increasing penetrations of passive DPV generation. The scale and nature of these challenges differ across networks, depending on penetration levels and specific local network factors, but are generally more significant in regions with higher DPV penetrations relative to local load and network capacity, such as South Australia and Queensland.
- All distribution network service providers (DNSPs) have started to experience voltage management challenges in their low voltage (LV) networks in locations with sufficiently large clusters of installed DPV capacity.
- DNSPs are implementing a range of measures to improve DPV hosting capacity within their networks:
  - **Network strategies** – remediating and reconfiguring network assets, augmenting network capacity and flexibility to securely accommodate the impact of the DPV generation profile.
  - **Behind-the-meter strategies** – reconfiguring settings or limiting export from DPV systems and activating other distributed energy resources (DER) in the LV network, such as loads and storage devices, to 'soak up' excess DPV generation in the daytime.
- DNSPs' ability to effectively integrate DPV generation is severely hampered by a lack of **visibility of the LV network**. Most are undertaking measures to improve visibility of locations with higher penetrations.

[1] At https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

- From the bulk system perspective, AEMO expects the growth in regional DPV generation to continue as uptake continues to grow, and DNSPs implement such measures.

A1.3 Bulk system challenges

As penetrations of passive DPV continue to increase and become significant at the regional level, the aggregated impact affects almost all core duties of the bulk system operator in some way, due to:

- **An increasingly large component of generation not currently subject to the same bulk system disturbance withstand requirements as utility-scale generation**, resulting in increasing contingency sizes following transmission faults due to the potential mass disconnection of DPV systems.
- **The ongoing reduction in the daytime system load profile due to continued growth in distributed solar generation**, contributing to:
  - Reducing availability of stable load blocks necessary for the effective operation of emergency mechanisms such as emergency frequency control schemes and system restart.
  - Reducing system demand, potentially to the point of insufficient load to support minimum synchronous generation levels necessary for system strength, inertia, frequency control, and other services required for system security.
  - Reducing load at transmission network connection points serving locations with high DPV generation relative to load, introducing voltage control challenges in the daytime.
- **An increasingly large source of variable generation**, resulting in increasing ramps associated with daily diurnal solar profile at the regional level, and faster, less predictable ramps in significant PV clusters at the sub-regional level due to cloud movements.
- **An increasingly large source of generation that cannot be curtailed,** resulting in a less dispatchable power system. Unlike large-scale generation, most DPV generation cannot be curtailed by AEMO even under extreme, abnormal system conditions.

Due to its relatively high DPV penetration and low load base, the passive nature of DPV is already affecting bulk system operation in South Australia today. Under current DPV uptake projections, these issues will also be increasingly prevalent in other NEM regions by 2025.

A1.4 Summary of actions

The actions listed in Table 1 are supported by this report. Section A5 has a detailed discussion of these actions.

Table 1 Summary of DPV challenges and proposed actions

Challenge	Proposed action	Reference to this appendix	Reference to main report
The aggregate performance of the DPV fleet is becoming increasingly critical as penetrations increase. Without action, the largest regional and NEM contingency sizes will increase due to DPV disconnection in response to major system disturbances.	2020-21: AEMO to fast-track requirement for short duration voltage disturbance ride-through for all new DPV inverters in South Australia (and Western Australia, with other NEM regions encouraged) and investigate need for updating existing DPV fleet to comply with fast tracked short duration voltage disturbance ride-through requirement.	• **Section A4.1:** Sets out the impact of plausible DPV disconnection behaviour on contingency sizes and the impact on power system security. • **Section A3.4 and A4.5:** Considers the role of autonomous grid support functionality from DPV inverters in assisting to manage distribution network and bulk system challenges associated with increasing DPV generation. • **Section A5.1.1** Discusses this action in more detail.	**Action 3.1**
	2020-22: AEMO to collaborate with industry, through Standards Australia committee, to progress update to national standard for DPV inverters (AS/NZS 4777.2) to incorporate bulk system disturbance withstand and autonomous grid support capability.		**Action 3.2**
Governance structures for the setting of DER technical performance standards, and enforcement of these standards, are inadequate. Currently there is: • No formal pathway to ensure power system security and other industry requirements are accounted for within technical standards set by consensus. • Inconsistent compliance with technical performance standards across the DPV fleet today and a lack of clarity around enforcement.	2020: AEMO to collaborate with the ESB, Australian Energy Regulator (AER), AEMC, and industry to: • Submit a rule change establishing the setting of minimum technical standards for DER in the NEM (with similar reforms to be proposed for Western Australia's SWIS) covering aspects including power system security, communication, interoperability, and cyber security requirements. • Develop measures to improve compliance with new and existing technical performance standards and connection requirements for DPV systems, individual DER devices, and aggregations in the NEM (and SWIS).	• **Section A5.1.2**: Discusses this action in more detail.	**Action 3.3**
System dispatchability is decreasing as invisible and uncontrolled DPV increases to levels not experienced elsewhere globally. In 2019, South Australia operated for a period where 64% of native demand was supplied by DPV; by 2025, all mainland NEM regions could be operating above 50% at times.	2020-21: AEMO to collaborate with industry to: • Mandate minimum device level requirements to enable generation shedding capabilities for new DPV installations in South Australia (other NEM regions and Western Australia encouraged). • Establish regulatory arrangements for how distribution NSPs (DNSPs) and aggregators could implement this as soon as possible. • Investigate the need for updating the existing DPV fleet to comply with regional generation shedding requirements[A].	• **Section A4.2** Sets out the need for curtailment capability for some portion of the DPV fleet during extreme, abnormal system conditions. • **Section A5.2**: Discusses this action in more detail.	**Action 3.4**

Challenge	Proposed action	Reference to this appendix	Reference to main report
	2020-21: AEMO to collaborate with DNSPs to establish aggregated predictability or real-time visibility requirements for DPV systems available for curtailment, and consistent real-time SCADA visibility for all new commercial scale (> 100 kilowatt [kW]) systems.	• **Section A3.4.3** Discusses the importance of enhanced DPV generation visibility and/or predictability for improving distribution network hosting capacity and secure bulk power system operation. • **Section A5.3** Discusses this action in more detail.	**Action 3.5**

A. For the purposes of maintaining adequate levers for secure system operation in abnormal operating conditions during high DPV generation periods, AEMO's work to date has found:

- Generation shedding capability as a "back-stop" measure is essential. This is required in addition to ongoing investment in storage and development of distributed markets for daily efficient market operation.
- When it is required, the necessary change in the supply-demand balance that needs to be managed could be very large and increasing as DPV generation continues to grow.
- Harnessing load and storage flexibility may reduce the amount of DPV generation shedding necessary. However, given uncertainties in the availability of this flexibility in real time, this does not remove the need for the generation shedding capability to be available in the first place.

A2. Introduction

A2.1 Scope and structure of this Appendix

The structure of the Appendix is as follows:

- Section A2 provides a summary on the context of DPV in the NEM and presents forecasts for its continued growth.
- Section A3 provides a snapshot view of the current challenges that are being experienced by DNSPs from increasing amounts of DPV on their networks.
- Section A4 details the challenges that are forecast to be experienced at the bulk system level with unrestricted, uncoordinated, and uncontrolled DPV. This section also considers the forecast penetration of DPV and overlays the various impacts identified, to visualise how challenges might emerge in each region of the NEM.
- Section A5 considers the interdependencies around distribution and transmission level challenges, to combine these learnings to provide a number of key actions that will support customers and DNSPs, and allow AEMO to continue to manage the power system in a secure and stable operating state.

This Appendix and the case studies focus on the NEM regions that are most susceptible out to 2025. Without any actions, many of these issues are forecast to have impacts on other regions in the NEM and Western Australia's South West Interconnected System (SWIS).

This study is focused on the system limits to distributed, passive solar PV, due to its high levels of uptake and expected ongoing growth. AEMO acknowledges that other emerging DER may also create potential challenges if their integration is not properly managed. However, if integrated effectively, these technologies can help address the system challenges associated with DPV and increase overall system flexibility. AEMO's DER Program[2] has been established to address the effective market and technical integration of DER into the electricity system.

A2.2 Objectives of this study

The study reported in this Appendix looks specifically at power system challenges during operation with high penetrations of passive DPV.

The study aims to form a view on the various system limits DPV will encounter as its penetration increases across the network, and the extent to which these limits may constrain PV export into the broader distribution and transmission systems.

The key objectives are to:

- Gather a snapshot of the current challenges being experienced by DNSPs due to the increasing uptake of passive DPV.
- Identify and evaluate the future limits to increasing that DPV generation in the bulk system and provide a perspective on how NEM regions might experience these issues by 2025.

[2] For more about AEMO's DER Program, see https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program.

- Consider possible means of managing these challenges to define possible solution frameworks. By identifying the challenges across operational environments, this study seeks multi-faceted solutions delivering efficient outcomes. The solutions proposed will consider customer, distribution, transmission, and bulk system needs, while respecting the timeframes and frequency of the challenges identified.

A2.3 Background

In the context of this study, DPV includes all grid-connected solar installations that are not part of central dispatch. AEMO classifies these devices under the following groupings:

- **Rooftop PV** captures systems up to 100 kilowatts (kW) in size, with systems up to 10 kW labelled residential and systems from 10 kW to 100 kW labelled commercial.
- **PV non-scheduled generators (PVNSG)** refers to systems larger than 100 kW and smaller than 30 megawatts (MW)[3] (the current threshold for semi-scheduled status).

DPV falls within the broad class of DER located behind the customer meter. This report is focused specifically on the implications of increasing levels of DPV on the power system, because it is the dominant form of DER in the Australia today, and given the high (by global standards) levels of uptake and projections for this growth to continue.

Other forms of DER – such as storage and electric vehicle charging, and demand response – can also assist by 'soaking up' excess DPV generation in the daytime, but could also create their own system challenges if not harnessed effectively.

Distributed energy resources (DER) comprise devices and capability behind the meter that offset or shift individual customer demand, including:

- Generation: both renewable (such as rooftop solar, wind turbines, biofuels) and non-renewable (for example, diesel generation).
- Demand response: shifting or activating loads at certain times, for example, pool pumps, hot water systems, and appliances such as air-conditioners.
- Storage: including batteries, thermal storage, and electric vehicle charging.

A2.3.1 Growth in DPV generation

Australia has experienced strong growth in DPV generation over the last decade, from fewer than 100,000 systems in 2010 up to over 2.2 million by the end of 2019[4]. Some parts of the county are now at world-leading installation levels[5]. AEMO expects this growth to continue over the next decade.

For this study AEMO has compared the 2019 historical year against the forecast projections of DER uptake from *AEMO's Draft 2020 Integrated System Plan* (ISP) Central and Step Change scenarios in 2025. The recent development of DER since the projections were developed has trended towards the higher end of the forecast range, resulting in little difference between the Central forecast and historical PV installed capacities. The Step Change analysis provided here therefore provides a more reasonable forecast estimate given current installation levels[6].

Figure 1 shows historical and projected DPV uptake in the NEM, under AEMO's Draft 2020 ISP Central and Step Change scenarios.

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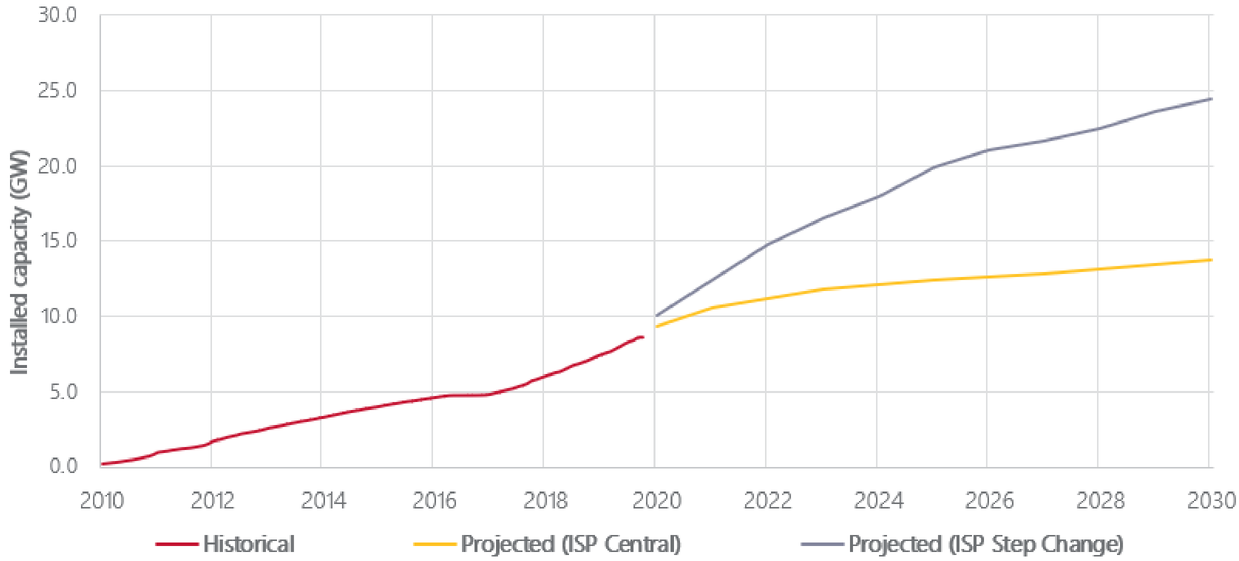
[3] This is generally 5 MW but more commonly 30 MW. AEMO allows an exemption of generating systems (except battery storage) with a total nameplate rating of at least 5 MW but less than 30 MW, to register as a Generator, but must apply for an exemption. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/New-Participants/Generator-Exemption-and-Classification-Guide.docx.

[4] See http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Smallscale-installations-by-installation-year.

[5] AEMO, *Maintaining Power System Security with High Penetrations of Wind and Solar Generation: International Insights for Australia*, October 2019, at https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

[6] AEMO's 2020 *Electricity Statement of Opportunities* (ESOO) forecasts, currently under development, will provide revised DER uptake forecasts taking into account these recent observed trends. The impacts of COVID-19 will also be considered, particularly the potential impact the pandemic is having and may continue to have on customer installations.

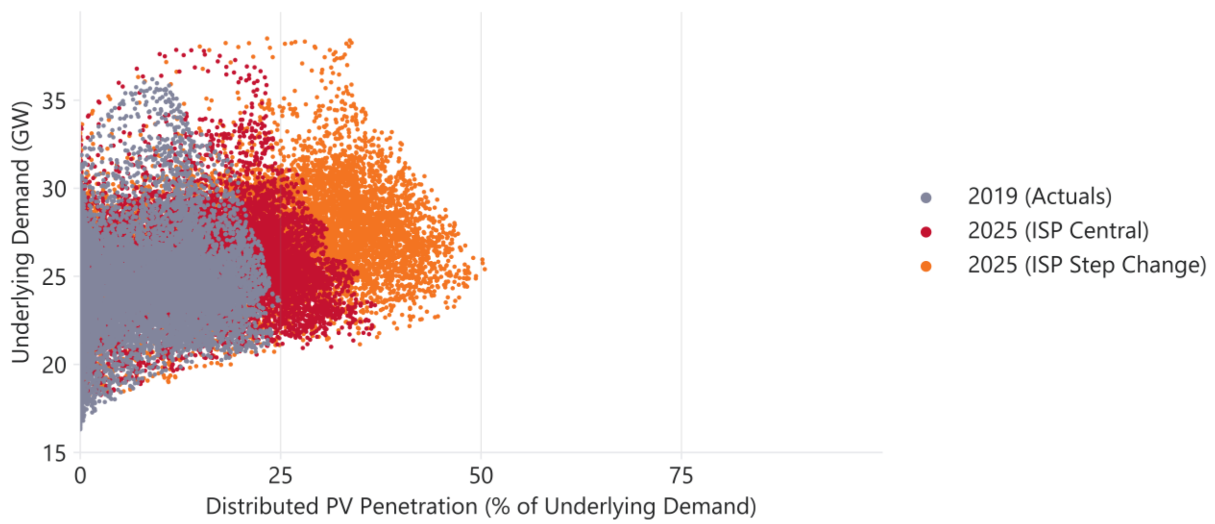
Figure 1 **Historical and projected installed DPV capacity in the NEM**



Source: Clean Energy Regulator (actual) and AEMO Draft 2020 ISP Input and Assumptions Workbook (forecast).

Figure 2 shows the total NEM system demand for each half-hour period plotted against DPV generation for the last year (2019), and projected under the Draft 2020 ISP Central and Step Change generation builds for 2025.

Figure 2 **Historical (2019) and projected (2025) half-hourly instantaneous penetration of DPV generation NEM-wide**



Penetration values on this graph represent non-overlapping half hourly DPV generation divided by the total underlying demand across the NEM during the same half-hours.

This shows that the increase in installed DPV capacity is forecast to drive up both the maximum half-hourly DPV penetrations and the frequency of high DPV penetration events:

- In 2019, DPV was already at times supplying 25% of underlying demand in the NEM.
- By 2025, the Draft 2020 ISP Central scenario forecast assumes enough installed DPV that it could at times meet 41% of NEM demand.
- Under the Draft 2020 ISP Step Change scenario, enough DPV is assumed to be installed that 50% of NEM demand could be met by DPV for certain half-hour periods.

Figure 3 and Table 2 show that projected DPV penetration levels are even higher on a regional basis, particularly for South Australia, with prospects of DPV at times supplying up to 85% of the entire region's demand by 2025.

Figure 3 Historical (2019) and projected (2025) half-hourly daytime instantaneous penetration of DPV generation and duration curves by NEM region

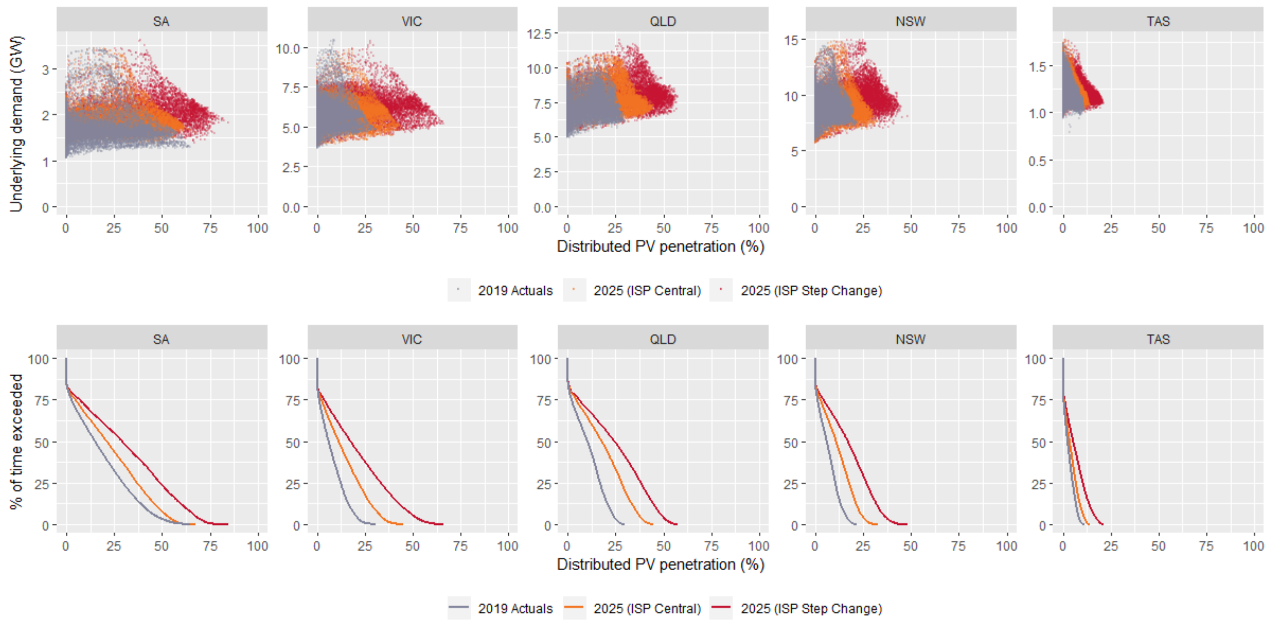


Table 2 summarises maximum instantaneous penetrations for all regions for 2019 and projections under the Draft 2020 ISP Central and Step Change scenarios for 2025.

Table 2 Historical (2019) and projected (2025) maximum instantaneous penetration of distributed solar generation for each NEM region

Maximum instantaneous DPV penetration (%)	Historical (2019)	Projected (2025, ISP scenario)	
	Actual	Central	Step Change
South Australia	64	68	85
Victoria	31	45	66
Queensland	30	45	57
New South Wales	21	33	48
Tasmania	12	14	21

A2.3.2 Impact of passive DPV generation on power system operation

The **passive** nature of the majority[7] of the DPV fleet in the NEM today is beginning to pose challenges to both distribution network and bulk power system operation, especially in regions with higher DPV uptake relative to local load.

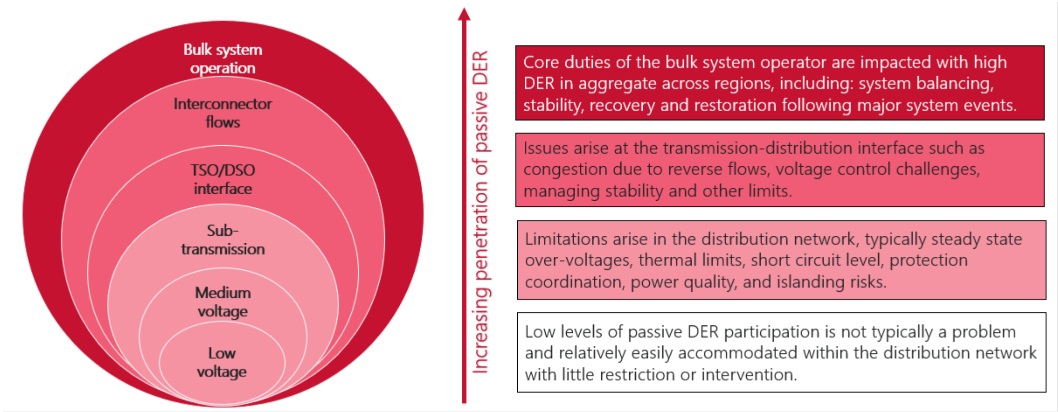
As outlined in the RIS International Review[8], experience from other jurisdictions indicates a typical trajectory of system challenges (summarised in Figure 4) with increasing penetrations of passive DPV generation:

- At low levels, passive DPV participation is not necessarily a problem, and is relatively easily accommodated within the distribution network with little restriction or intervention.
- As penetrations increase or concentrate in certain areas, limitations first arise within the distribution network, typically voltage management. As DPV generation clusters continue to grow, they eventually impact the distribution-transmission interface in the co-ordination of voltage control devices and the management of transmission level congestion due to reverse flows.
- Once penetrations have become significant at the regional level, the inability to see and actively manage DPV impacts almost all core duties of the power system operator, including managing the supply-demand balance in real time, system stability, and recovery and restoration following major system events.

The **passive** operation of DPV systems is characterised by three main attributes:

- **Performance:** how they respond to fluctuations in the power system. DPV generation is not subject to the same grid support and disturbance withstand requirements as large-scale generation.
- **Visibility**: how visible their output is to system operators. Given their location behind the meter, generation from most of the DPV fleet today is not visible in real time to DNSPs or AEMO.
- **Controllability**: whether they can respond to instructions from system operators to adjust their output. In contrast to large-scale generation, most DPV generation cannot currently be curtailed by DNSPs or AEMO, even under extreme abnormal system conditions.

Figure 4 Typical trajectory of system challenges associated with increasing penetrations of passive DPV



Each NEM region is at different points along this trajectory today. The DPV penetrations outlined in Section A2.3.1 suggest that all NEM regions will continue to progress along this trajectory. This report examines the technical challenges that will arise as this trajectory takes place over the next five years. The secure integration of DPV generation into the future will require DPV to transition from a largely passive fleet to a more active participant in the power system – operating in a way that better aligns with both the distribution network and the bulk power system.

[7] Some larger DPV systems have controllability through DNSP Connection Agreements; for example. SA Power Networks (SAPN) requires SCADA monitoring and curtailment for generating systems above 200 kW. For more see: https://www.sapowernetworks.com.au/public/download.jsp?id=9565.

[8] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

A3. Distribution network challenges

Key insights

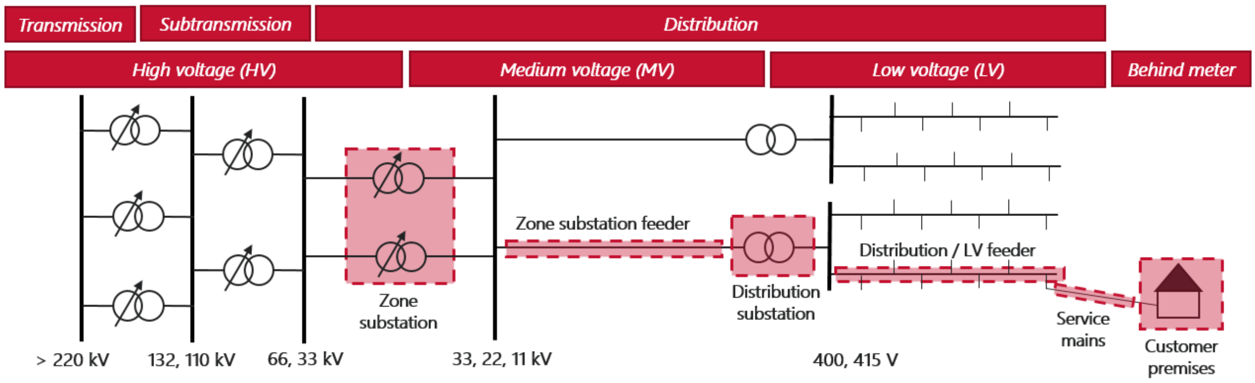
- Distribution networks in the NEM are beginning to experience technical challenges associated with increasing penetrations of passive DPV generation. The scale and nature of these challenges differ across networks, depending on penetration levels and specific local network factors but are generally more significant in regions with higher DPV penetrations relative to local load and network capacity, such as South Australia and Queensland.
- All DNSPs have started to experience voltage management challenges in their LV networks in locations with sufficiently large clusters of installed DPV capacity.
- DNSPs are implementing a range of measures to improve DPV hosting capacity within their networks:
  - **Network strategies** – remediating and reconfiguring network assets, augmenting network capacity and flexibility to securely accommodate the impact of the DPV generation profile.
  - **Behind-the-meter strategies** – reconfiguring settings or limiting export from DPV systems and activating other DER in the LV network, such as loads and storage devices, to 'soak up' excess DPV generation in the daytime.
- DNSPs' ability to effectively integrate DPV generation is severely hampered by a lack of **visibility of the LV network**. Most are undertaking measures to improve visibility of locations with higher penetrations.
- From the bulk system perspective, AEMO expects the growth in regional DPV generation to continue as uptake continues to grow, and DNSPs implement such measures.

A3.1 Impact of distributed solar PV on distribution network operation

Distribution networks were historically designed for the one-way transfer of electricity generated from centralised supplies to customers. They are comprised of feeders (overhead lines or underground cables) and substations that successively transform power to lower voltages suitable for transport and end use.

A schematic representation of key elements of a distribution network is shown in Figure 5, highlighting substation voltages and illustrating terminology used by DNSPs and key terms referenced in this section.

Figure 5 **Schematic representation of the distribution network**



DPV generation in the NEM is dominated by residential installations in the LV network, with some larger, commercial installations connected at the medium voltage (MV) level. As more DPV capacity is installed, local generation eventually offsets demand to the point where power flows on the LV feeders are reversed at times. By introducing electrical flows in the other direction, increasing penetrations of DPV generation result in several integration challenges within the distribution network, summarised in Table 3 below.

Table 3 **Impact of DPV generation on distribution network operation**

Issue	Requirement	Impact of distributed solar generation
Voltage management	Managing customer voltages within an allowable range and quality of supply.	DPV export into the grid resulting in lower load on feeders and consequential voltage rise in the middle of the day. DNSPs must also still manage voltage drops during the evening load peak. Voltage must be kept within allowable limits for an increasingly wider range of scenarios.
Thermal ratings	Maintaining electrical flows within permissible loading levels of network elements.	DPV generation at the LV network introduces reverse flows on feeders and transformers. Where this bi-directional cycling on distribution assets does not allow some lighter loading periods, the thermal limits of plant may be exceeded, impacting service life.
Protection coordination	Effective operation of protection schemes.	DPV introduces fault current in the reverse direction impacting the ability of protection systems to see or discriminate between fault locations.

A3.2 Current status

Distribution network hosting capacity limits for DPV generation are highly location-specific and depend on several factors, including:

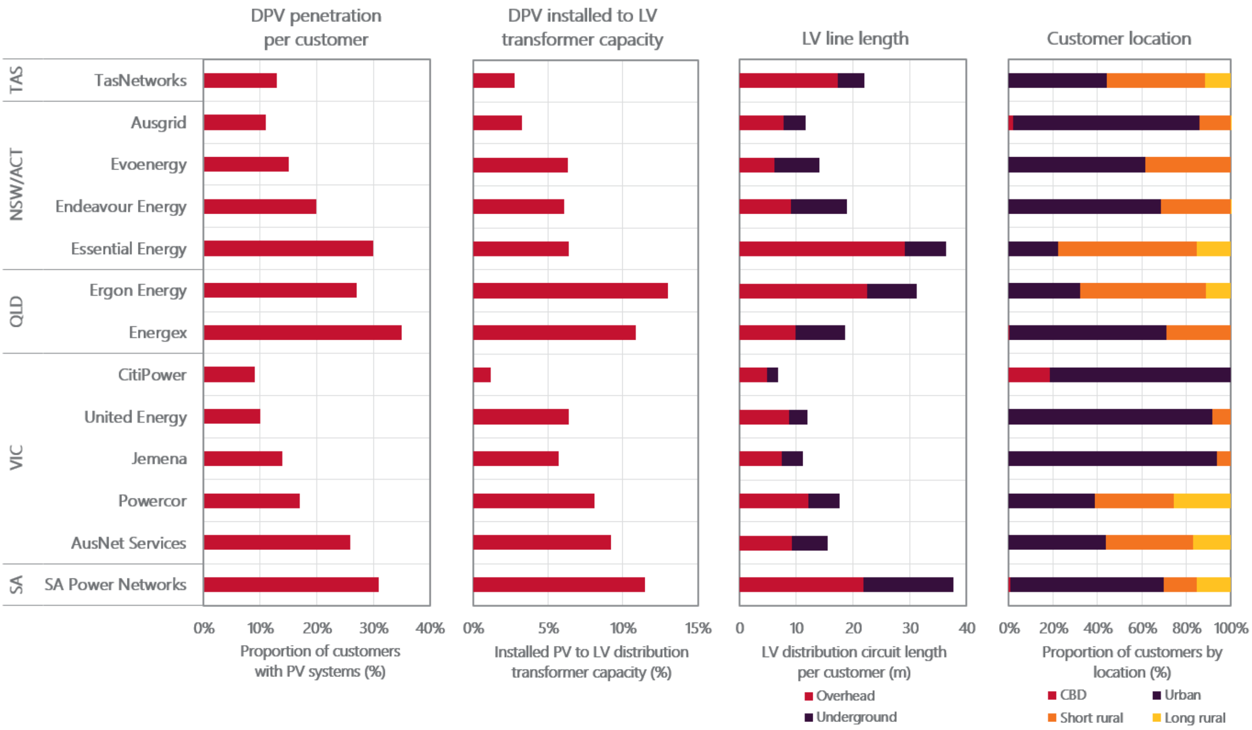
- **The DPV generation** that is installed – including its performance and mode of operation. This includes:
  - Capability and settings of inverters, particularly whether smart autonomous grid support functionality has been enabled; inverters' compliance with relevant standards and DNSP connection requirements.
  - Whether the system is operating passively in a 'set and forget' manner or actively controlled by a facility-level or home energy management system or aggregator (responding to price signals not necessarily aligned with distribution network needs).
- **Local load profile** – including how local demand compares to DPV generation and the extent to which they match.

– Commercial loads that operate during the day may act as local sinks to excess generation from DPV, while residential load profiles peak in the morning and evening, exacerbating reverse flows and the range of power flows that need to be managed.

- **Physical and electrical network characteristics** – including local network capacity and impedance.
  – Central business district (CBD) and many suburban networks are more interconnected, span shorter distances with higher load density and lower impedance, and can accommodate more DPV generation than long radial rural feeders.

Current installed DPV capacity across NEM DNSPs, and aggregated summary statistics of the physical factors impacting hosting capacity, are shown in Figure 6 below. It is important to note that such statistics are indicative only, as there is substantial variation in operating environments within each DNSP area which is not necessarily reflected completely in such aggregated network-wide measures.

Figure 6 **Distributed solar PV penetration within each NEM DNSP and other metrics that impact hosting capacity**



Source: AEMO analysis of DNSP responses to AER Regulatory Information Notices for 2018 and DNSP 2019 Annual Planning Reports.

To gain a better understanding of technical challenges with integrating increasing levels of DPV generation within the distribution networks, AEMO surveyed DNSP planning documents and engaged with DNSPs over a series of workshops in June 2019. Table 4 sets out the issues that have begun to emerge in each DNSP franchise area, and summarises the issues identified in this process.

The extent of integration challenges being experienced by each DNSP is specific to the size and location of PV clusters within their networks, relative to physical network characteristics and load. Currently, South Australia and Queensland are experiencing the most significant challenges due to their high DPV penetration levels, exacerbated by these areas also having generally lower network capacity and higher impedance.

These issues are explained in more detail in Section A3.3.

Table 4 Summary of DPV integration issues experienced by DNSPs

Level		Issue	SA	QLD		VIC					NSW/ACT				TAS
			SA Power Networks	Energex	Ergon Energy	CitiPower	Powercor	United Energy	AusNet Services	Jemena	Ausgrid	Evoenergy	Endeavour Energy	Essential Energy	Tas Networks
Behind meter	Customer premises	Over voltage complaints	●	●	●	●	●	●	●	●	●	●	●	●	●
		DPV inverter settings	●	●	●	●	●	●	●	●	●	●		●	●
		Under voltage	●	●	●	●			●				●		
		Other power quality	●	●				●		●	●	●			
LV	LV feeder	Voltage regulation	●	●	●	●	●	●	●	●	●	●	●	●	●
		Phase balance	●	●	●		●	●	●	●	●	●		●	●
		Thermal capacity	●	●	●	●	●	●	●	●		●			●
	Distribution substation transformer	Tap setting	●	●	●	●	●	●	●	●	●	●	●		●
		Thermal capacity	●	●	●	●	●	●	●	●		●			
MV	Zone substation feeder	Voltage regulation	●	●	●				●						
		Thermal capacity	●	●										●	
	Zone substation transformer	Tap range	●	●	●				●		●	●	●		
		Voltage set point	●	●	●			●	●		●	●	●		
HV	Sub trans. transformer	Voltage set point	●	●	●				●		●		●		
Protection		Low background fault level	●		●							●			
		Fault discrimination		●								●			

● indicates the DNSP has started to experience the issue in parts of their network or planning for it to arise under current DPV projections. It does not provide any indication of materiality across the DNSP's network.
Source: AEMO analysis of DNSP 2019 Annual Planning Reports, workshops with DNSPs in June 2019.

A3.3 Summary of technical challenges

A3.3.1 Voltage management

DNSPs are responsible for maintaining voltages at customer premises within required limits. In doing so, they must also regulate voltages throughout their networks to acceptable limits for safe and secure operation. Across the NEM distribution networks today, this is achieved as follows[9]:

- Tap changing[10] between transmission voltages (high voltage [HV] and above) are normally automatically controlled.
- Zone transformers are fitted with online tap changers to keep the voltage output of the transformer relatively constant by compensating for voltage and load changes on the higher voltage side.
- Some tap changer control schemes also compensate for the variable voltage drops along the lower voltage feeders caused by load variations (known as "line drop compensation").
- Distribution transformers are normally fixed tap, meaning they are set in a static fashion and cannot dynamically adjust their operation with loading on the LV circuits. To ensure customers are supplied at a reasonably steady voltage, the settings of the fixed tap transformers are designed for their location along the MV feeder and the expected range of customer loads in the area.

[9] Refer to Figure 5 in Section A3.1 for a schematic representation of distribution network elements.

[10] Transformers are used for increasing low AC voltages at high current (a step-up transformer) or decreasing high AC voltages at low current (a step-down transformer). 'Tap changing' refers to the mechanism which allows this voltage transformation to be selected in distinct steps and can be online/on-load (dynamically adjust with network loading) or offline/no-load (statically set in a fixed position).

- Line voltage regulators[11] may also be used at strategic locations along long MV feeders to regulate the supply voltages; these can also include some line-drop compensation.

Until recently, the distribution network has been designed and operated to manage voltage drops associated with serving load, not voltage rise associated with local generation[12]. This means that during low-loading conditions, maximum voltages may already be close to the allowable limits. Local generation, causing a voltage rise, may then result in the maximum voltage limits being violated. In the absence of other measures, this is one factor contributing to the LV network being able to accommodate significantly less generation compared to the maximum amount of load that it can supply. The use of line drop compensation is one tool that can be used to manage this, but because a zone substation transformer can supply numerous MV feeders, line drop compensation can be difficult to implement in practice.

Low voltage during peak demand is still a significant challenge for network businesses. With increasing levels of passive solar generation, networks are now required to manage both extremes. This is experienced at the LV feeder level, where increasing DPV penetration increases the dynamic range of power flows between peak demand and peak export and the rate at which the system can swing from one end of this range to the other, given distribution transformers are normally fixed tap.

Excluding Victoria, NEM DNSPs have little to no visibility of their LV networks[13], meaning they cannot monitor LV network voltages in real time. Accordingly, voltage issues are typically first identified through customer complaints; however, most DNSPs are undertaking measures to improve their visibility of the LV assets. All DNSPs indicated they have started to experience an increase in quality of supply complaints in higher DPV penetration parts of their LV networks. These are most commonly voltage rise, flicker, other power quality issues, and DPV system disconnection. In several cases, complaints associated with high voltage now exceed those associated with a historical prevalence of complaints associated with low voltage, sometimes initially identified by customers through poor performance of appliances.

Another voltage management challenge several DNSPs are experiencing is the uneven allocation of PV installations (and loads) within their LV network. This results in unbalanced voltages across the three phases, resulting in unbalanced load flow and reduced efficiency of three phase equipment that is connected. In the most extreme case, if all PV installations on an LV network are connected to the same phase, the resultant voltage rise would be in excess of three times the balanced scenario.

Mitigation approaches

To manage voltages across networks, DNSPs have begun to:

- Require reactive response capability enabled for new solar PV installations to mitigate the voltage impact of PV generation.
- Rebalance connections such that DPV and load is evenly distributed across each phase in the LV network. Several DNSPs consider this to be the first consideration when addressing LV network voltage rise.
- Lower zone substation MV voltage setpoints
- Adjust distribution transformer and zone transformer tap settings. In some instances, there may be insufficient tapping range to achieve the required voltage levels on the higher voltage side of the transformer.
- Trial distribution transformers with automatic "on-load tap changing" capability and low voltage static synchronous compensator (STATCOM) technology.
- Trial dynamic voltage management control schemes utilising some form of LV network monitoring in the setting of zone substation target voltage.

[11] A voltage regulator is a system that automatically maintains a constant voltage level for any changes to the input voltage or load conditions.

[12] Voltage along an LV feeder will generally decrease during high load periods and increase during low load, high local generation periods.

[13] Discussed further in Section A3.4.3.

Case study | AusNet Services voltage management implications of DPV generation

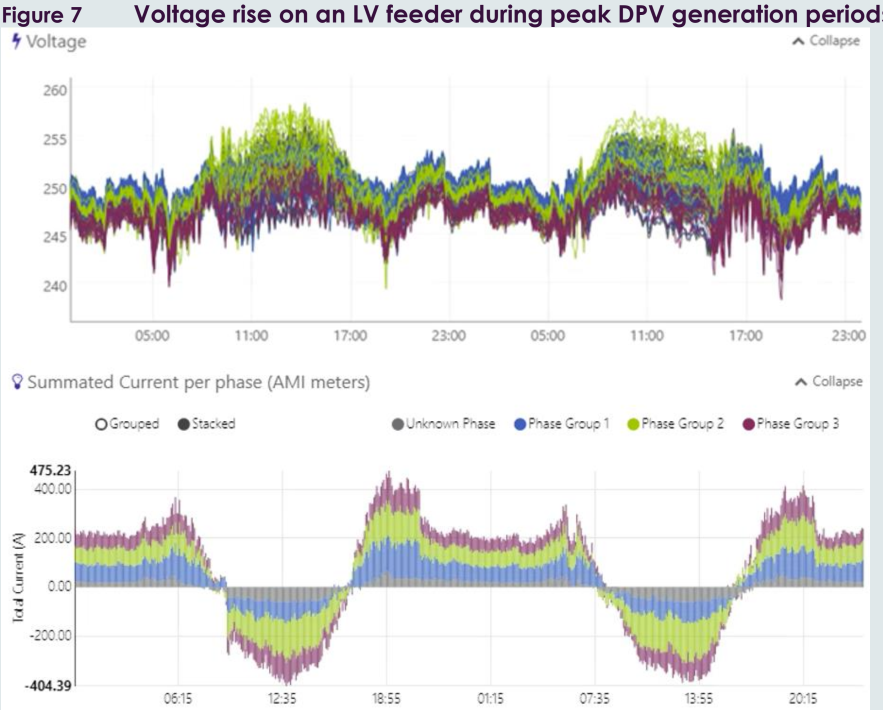
AusNet Services and the other Victorian distribution businesses have a level of visibility other NEM DNSPs do not have, through their Advanced Metering Infrastructure (AMI) or 'smart meter' fleet. This access to customer metering data has enabled AusNet Services to achieve a widespread and granular understanding of the impact of residential DPV generation on their LV assets.

Figures 7 and 8, extracted by AusNet from its AMI data analytics platform, illustrate the impact of DPV generation on the voltage profile for a particular distribution transformer for different two-day periods:

- Figure 7 highlights the voltage rise associated with DPV generation export from customers in the middle of the day.
- Figure 8 highlights the voltage swings associated with managing both DPV generation export in the middle of the day and increasing load into the evening peak.

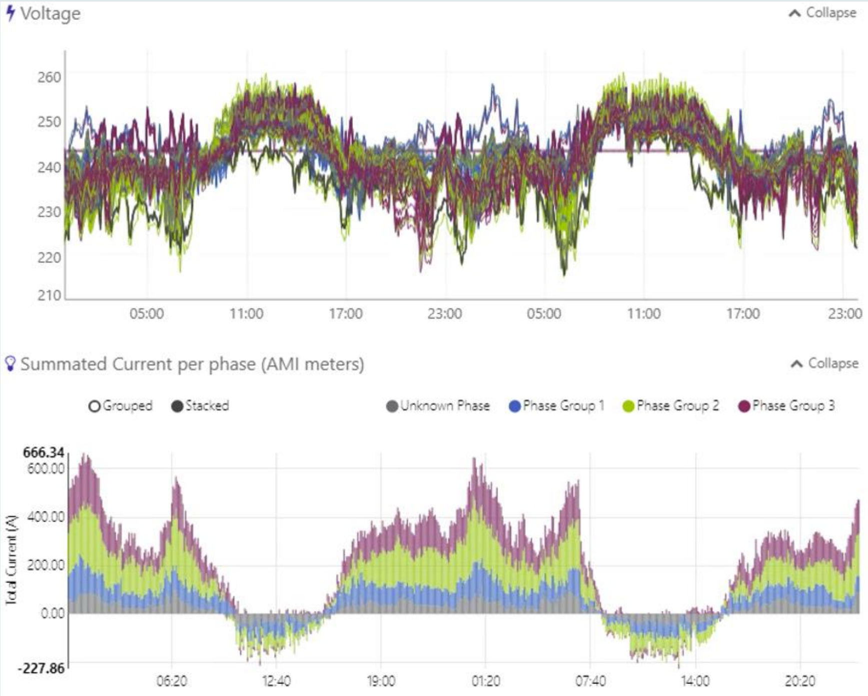
The level of visibility available to AusNet from its smart meter fleet has allowed it to proactively plan for future network capacity requirements to support the projected volume of DPV connections in their network in the future, balancing the costs of doing so against customer expectations for export.

Figure 7 Voltage rise on an LV feeder during peak DPV generation periods in the daytime



Provided by AusNet Services to AEMO in April 2020.

Figure 8 Voltage swings on an LV feeder associated with peak DPV generation and peak demand



Source: Provided by AusNet Services to AEMO in April 2020.

A3.3.2 Thermal capacity

Each element of the distribution network is characterised by a maximum current-carrying capacity. DPV generation alters current flows in the network, which may lead to violation of the loading levels of network elements, especially under maximum generation and minimum load conditions. Such situations may occur more frequently as DPV penetrations grow, owing to the relative lack of diversity of peak DPV generation times, compared to peak load:

- Customer loads vary considerably throughout the day and year, and the periods of maximum demand occur when individual customer loads coincide. In most of the NEM, maximum loading conditions typically only occur for a few hours in a year during the summer evening peak.
- By comparison, generation from DPV systems in a local area will all peak at the same time, in the middle of the day. High solar production often occurs from late spring until early autumn and is often coincident with low demand conditions.

Several DNSPs are projecting LV network thermal capacity constraints to emerge in the near future as DPV generation clusters continue to grow, exacerbated by the relatively low diversity of DPV exports compared to load diversity. In addition, the trend in increasing average DPV system sizes means that a household's DPV export can exceed its load requirements.

Mitigation approaches

To manage thermal capacity issues, DNSPs have begun to:

- Augment LV network thermal capacity, by adding new distribution lines and feeders.
- Replace (or reconductor) distribution lines or parts of their MV networks to increase feeder capacities.
- Install network storage at well-planned locations with charging and discharging controlled based on DPV generation to manage network loading within limits.

Case study | Ergon 'hidden' demand

Ergon identified increasing DPV penetration within its LV networks. Because DPV operates behind the meter, it is more challenging to identify underlying load growth, as additional daytime load can be offset by local generation. This becomes apparent if DPV systems ever suddenly and unexpectedly reduce their output or stop generating.

Figure 9 Ergon Dundowran feeder: storm event example

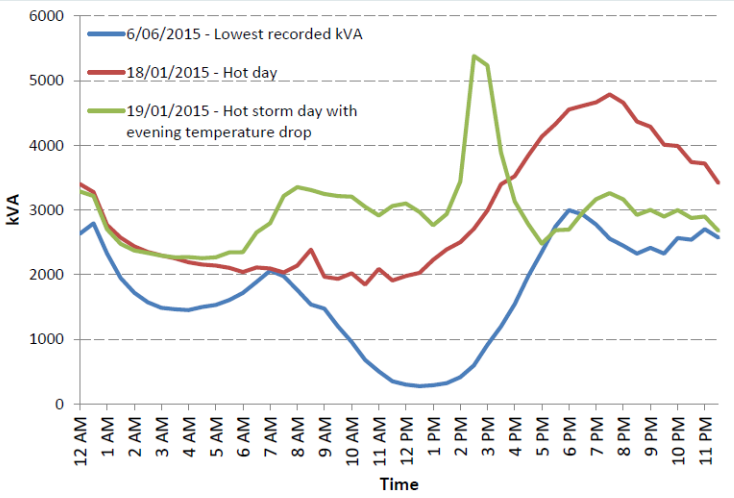


Figure 9 shows an example of the impact of an afternoon thunderstorm on PV generation (in green) resulting in the full customer load needing to be supplied from the network. This sudden change can result in large and rapid variations in energy flows in the LV network. In this instance, the net result was a peak demand event in the early afternoon that was higher than the feeder's usual evening peak (see the red and blue lines for comparison). Eventually this swing may exceed the feeder's thermal limit.

As networks are designed for supplying the maximum demand, increasing penetrations of intermittent embedded generating units will significantly increase the complexity of planning and operating networks.

Extreme net load volatility events could result in excessive voltage swings, overloading of components, protection operation issues, or loss of supply if not appropriately managed.

Data from Ergon Energy, Distribution Annual Planning Report 2019-20 to 2023-24, December 2019, at https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report.

A3.3.3 Protection coordination

Distribution LV feeder protection is based around the concept of a single direction of power flow. By introducing current flow in the reverse direction, increasing DPV generation can impact the protection system's ability to detect faults. The DPV contribution may reduce fault current to below the pick-up current of the relay, resulting in the protective devices being unable to reach the 'distance' required to cover its protection zone.

Several DNSPs identified protection coordination issues in their LV networks associated with protection schemes not being able to see or discriminate between fault locations, leading to increased clearing times or excessive customer interruption. Reversal of power flows in the network may have a negative effect on certain types of tap changers and on the operation of voltage control schemes. For example, older voltage regulating relays may not be bidirectional.

Mitigation approaches

To manage this issue, DNSPs have begun to:

- Reconfigure and upgrade network components to accommodate changing fault level requirements.
- Upgrade protection and/or modify protection settings.
- Apply modified and improved voltage control schemes in HV and MV substations, line voltage regulators, and switched capacitors.

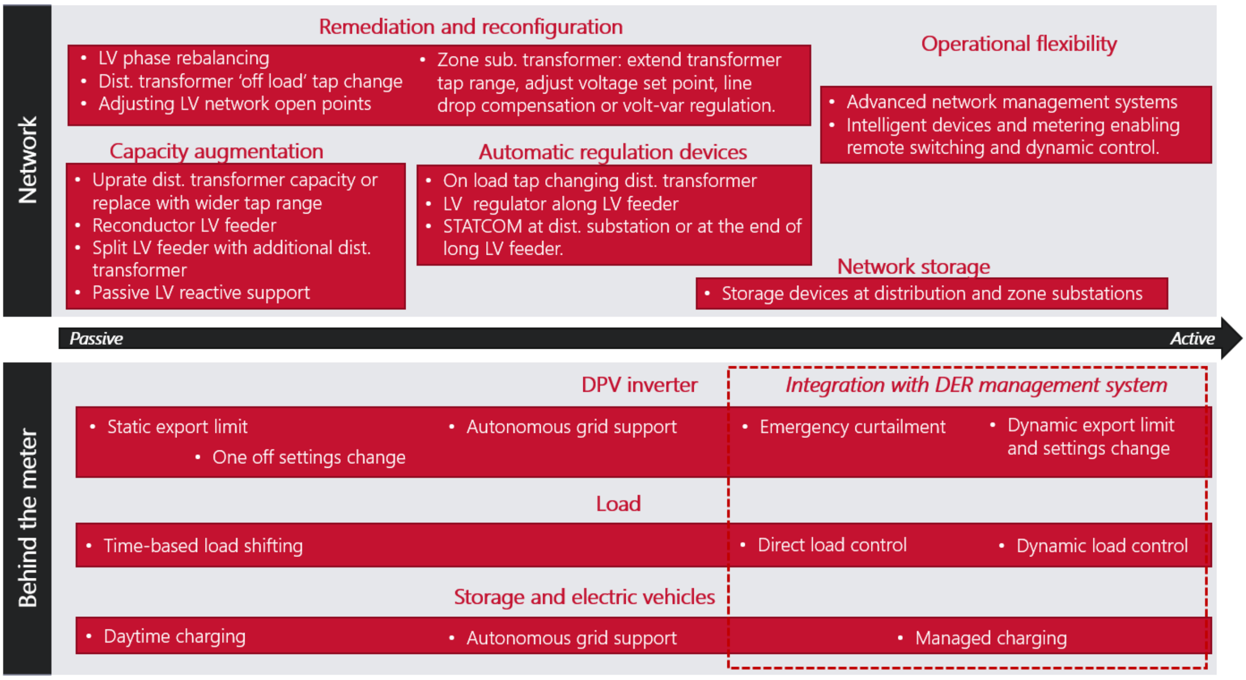
A3.4 Integration of distributed PV within distribution networks

DNSP strategies to increase the DPV hosting capacity of their networks span two dimensions: network and behind the meter, as shown in Figure 10 and explained further below the figure:

- **Network** strategies include remediating and reconfiguring network assets, augmenting network capacity and flexibility to securely accommodate the impact of the DPV generation profile. Section A3.4.1 provides further detailed examples.
- **Behind-the-meter** strategies include reconfiguring settings or limiting export from DPV systems and activating other DER in the LV network, such as loads and storage devices, to 'soak up' excess DPV generation in the daytime. Section A3.4.2 has more detailed examples.

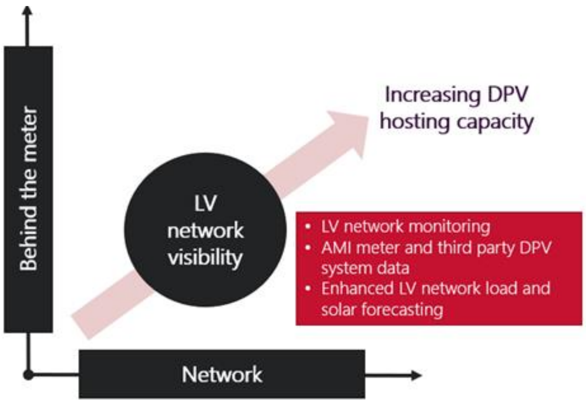
As Figure 10 shows, strategies across these two dimensions range from passive 'set and forget' actions to more active measures allowing dynamic adjustment depending on prevailing load DPV generation conditions at any given time.

Figure 10 Measures to improve distribution network DPV hosting capacity



LV network visibility is a key enabler for DNSPs to be able to efficiently implement measures across both of dimensions. This is summarised in and discussed further in Section A3.4.3.

Figure 11 Role of LV network visibility in enabling efficient improvement in distribution network DPV hosting capacity



A3.4.1 Network strategies

Network measures to increase DPV hosting capacity include:

- **Remediation and reconfiguration of network assets –** mostly low-cost incremental remediation measures to assist in managing LV network voltages within the allowable range, including:
  - Rebalancing customer connections across LV phases (phase balancing) and shifting open points in the LV network to better match DPV generation and load.
  - Adjusting distribution transformers tap positions.
  - Tap changing or adjusting set points on zone substation transformers.
- **Augmenting network capacity** – typically more lumpy network investments to accommodate even higher DPV generation, including:
  - Uprating distribution transformer capacity.
  - Reconductoring LV feeders and/or splitting LV feeder lengths with an additional distribution transformer.
- **Automatic regulation devices** – can automatically adjust operation based on grid conditions, including:
  - Distribution transformers fitted with automatic on load tap changing (OLTC) capability.
  - Automatic LV feeder voltage regulation through in-line LV regulators and STATCOMs at the end of long LV circuits.
- **Network storage –** grid-scale storage co-located with distribution and zone substation transformers.
- **Operational flexibility** – measures to enhance 'grid intelligence' and enable the network to dynamically respond to underlying load and DPV generation conditions, including:
  - Advanced network management systems.
  - Intelligent devices and metering enabling remote switching and dynamic control.

An indication of the hosting capacity improvements possible from these measures is shown in Figure 12, published by the Queensland DNSPs.

Figure 12 Network remediation options to address varying levels of distributed PV penetration

Solar PV Penetration Level	Network Solutions
From 30% to 70%	1. Balance of PV load 2. Change transformer tap
From 40% to 100%	3. 1 and 2 above 4. Upgrade transformer 5. Additional transformer (incl. reconfigure LV area) 6. Re-conductor mains
From 100% to 200%	7. 1 to 6 above 8. New technology (On load tap transformer, LV regulator, Regformer, Statcom)

Source: Ergon and Energex 2019 Distribution Annual Planning Reports.

DNSPs will generally implement the most efficient solution depending on the particular LV network situation and other factors in line with their asset management strategies. Incremental remediation and augmentation could address more immediate hosting capacity limits, but may not be the most efficient long-term solution if DPV generation is projected to continue increasing. More dynamic options (such as an OLTC distribution transformer or a STATCOM) that are able to accommodate very high DPV levels may be less costly than successive incremental investments as penetrations increase over time.

A3.4.2 Behind-the-meter strategies

Behind-the-meter strategies to improve distribution network DPV hosting capacity involve better integrating DER operation with the needs of the distribution network. These include:

- **Reconfiguring or more actively managing the DPV generation** utilising different functions and capabilities of DPV inverters, including:
  - Static export limits – restrictions on allowable export from DPV systems in constrained locations within the LV network.
  - Autonomous grid support – most DNSPs now require voltage support capability from DPV inverters to be enabled for new installations.
  - Remote settings update – amending DPV inverter settings after installation if underlying LV network circumstances have changed.
  - Emergency control – disconnection or curtailment of DPV under rare emergency system conditions.
  - Dynamic export limits – setting limits on DPV system export dependent on underlying network conditions, resulting in generation curtailment only when necessary to maintain network limits.
- **Behind-the-meter load and storage within the LV network –** activating loads (such as electric hot water systems, pool pumps, air-conditioners, and electric vehicle charging) and charge/discharge behaviour of storage to utilise excess DPV generation in the middle of the day, including:
  - Load shifting – shifting load to peak solar generation times in the middle of the day through direct aggregator or DNSP interaction with devices or via home energy management systems.
  - Emergency control – remotely commanding loads to turn on during rare, emergency conditions in the distribution network, if they were to arise during solar generation peak times.

A3.4.3 LV network visibility

For most DNSPs in the NEM today, the ability to effectively and efficiently implement both network and behind-the-meter strategies to improve DPV hosting capacity is severely hampered by a lack of visibility of their LV assets. While DNSPs do have visibility at the MV and HV level, through supervisory control and data acquisition (SCADA) systems, they generally have limited visibility at the LV level where most DPV hosting capacity constraints occur.

The Australian Energy Market Commission (AEMC), with Energy Networks Australia (ENA), surveyed DNSPs on their LV network visibility in 2019[14]. The results of this survey, summarised in Table 5, indicate there is:

- Little direct monitoring of loads and voltages on LV transformers and circuits, and on individual phases of those circuits. Some monitoring that occurs is ad hoc or measures only maximum load over a long period of time.
- Little information beyond settlement and billing data that is directly available to DNSPs at the customer premises level. The exception is Victoria, where meters are still owned and controlled by DNSPs, and AMI penetration is close to 100%. LV feeder and distribution substation transformer visibility is derived through the aggregation of customer connection metering data.
- Very little direct monitoring of DER generation output. Net metering arrangements mean that only the total site is monitored.

[14] AEMC, *Integrating Distributed Energy Resources for the Grid of the Future – Economic Regulatory Framework Review*, September 2019, at https://www.aemc.gov.au/market-reviews-advice/electricity-network-economic-regulatory-framework-review-2019. This includes the comprehensiveness of the information, the sampling period, and the retention period.

This limited visibility makes it difficult for DNSPs to quantify the secure technical operating envelope of their LV networks, necessary to determine where constraints exist or where they are likely to develop in the future. This in turn makes it difficult for DNSPs to identify and develop optimal strategies for alleviating the constraints. Without this visibility, DNSPs have had to evaluate DPV hosting capacity (and subsequent export limits) conservatively, based on an assessment of worst-case operating scenarios. Several DNSPs have indicated to AEMO that their primary means of identifying potential DPV hosting capacity limits to date is through quality of supply complaints from customers.

Several DNSPs have programs in place to improve LV network visibility in the future. For example:

- SA Power Networks (SAPN) has proposed a methodology combining modelling of its network's ability to host varying levels of DPV with sample data on the real-time performance of its network from smart meter providers, inverter manufacturers, and home energy management providers[15].
- Energex has identified the need for further monitoring of its LV network, in addition to the 40% coverage of distribution transformers currently with power quality monitoring. It is planning an additional 3,750 monitors over the next five years for distribution transformers where DPV penetration levels are exceeding 25% of the transformer rating and where LV circuit exceed 400 metres in length, as well as at the end of long LV feeder runs. This data will be used to develop predictive LV network models and will ultimately be adopted within real-time state estimation algorithms[16].

Table 5 DNSP LV network visibility (DNSPs surveyed by the AEMC and ENA in 2019)

	DNSP	MV	LV		Behind meter		
		Zone substation feeder	Distribution transformer	LV feeder	Customer connection	Inverter exports	Customer consumption
SA	SA Power Networks	80%	3.4% ↑	↑	0.1% ↑	0.0%	
QLD	Energex	100%	40% ↑		1.5% ↑		
QLD	Ergon Energy	95%	3.5% ↑				
WA	Western Power	100%	1.0% ↑	↑	5.0% ↑		
VIC	Citipower and Powercor	100%	99% ↑	99%	99%		
VIC	United Energy	100%	100%	100%	100%		
VIC	AusNet Services	100%	98%	98%	98%	↑	↑
VIC	Jemena	100%	98%	98%	98%		
NSW/ACT	Ausgrid	100%	17% ↑	24% ↑	9.0% ↑	0.5%	0.5%
NSW/ACT	Evoenergy	100%	3.0%	10% ↑	↑	3.3% ↑	3.3% ↑
NSW/ACT	Endeavour Energy	95%	1.8%		15% ↑	0.05%	
NSW/ACT	Essential Energy	85%	0.014% ↑		7.0% ↑	7.0%	

Bar and value indicate level of visibility. Upward arrow indicates increasing trend.
Source: Derived from detailed DNSP responses to AEMC LV network visibility survey in 2019.

A3.5 Implications for the bulk system

The future impact of DPV generation at the bulk system level will depend on the extent to which distribution networks are able to accommodate increasing penetration levels within their LV networks.

DPV systems can and do disconnect or reduce output in response to local network conditions. However, there are reasons to believe that despite the installed capacity of DPV continuing to increase, most NEM regions are far from this local curtailment resulting in a ceiling on DPV generation at the bulk system level, because:

[15] In its regulatory proposal for 2020-2025, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25.

[16] As part of its Power Quality strategy for 2020-25, See Energex Distribution Annual Planning Report (DAPR) for 2019-20 to 2023-24, at https://www.energex.com.au/about-us/company-information/company-policies-And-reports/distribution-annual-planning-report.

- Distribution limits are not going to bind uniformly along every LV feeder. Only DPV systems remote from the distribution transformer or voltage regulating point are likely to experience over-voltage.
- DNSPs in most regions are now requiring the new DPV inverter fleet to have some degree of autonomous voltage response capability enabled by default. Systems experiencing high voltage will trade some active power generation for reactive power during these periods rather than disconnect. This will also assist with managing voltage profiles overall.
- As discussed above, DNSPs are implementing initiatives to gradually increase DPV hosting capacity over time by addressing locational limits as they arise. This includes progressively amending transformer tap settings, as well as active DER management programs which will implement local constraints in the setting of dynamic export limits.
- There will be a natural diversity in the distribution of load and DPV generation across locations within a region, even when there is high PV generation and low load at the aggregate regional level.

The case study from SAPN below considers the extent of DPV curtailment across a sample of inverters in its network during the 2018-19 financial year. The analysis indicates that in South Australia, which has among the highest DPV penetrations in the NEM, disconnection due to local over-voltage does not materially impact aggregate DPV at the bulk system level. During high DPV generation and light demand conditions regionally, over-voltage within the LV network is highly location-specific and the response from inverters is not uniform.

While only a small fraction of inverters may be impacted today, DNSPs in high penetration areas expect the proportion of affected inverters to increase significantly into the future under current DPV growth projections. Zero export limits on new DPV installations will be necessary if no action is undertaken. DNSP efforts to improve DPV hosting capacity (for example, SAPN and the Victorian businesses) will alleviate these export limits, resulting in a continued increase in DPV generation at the aggregate level.

Today, DNSPs apply restrictions on allowable generation export from DPV systems to minimise network risks associated with increasing DPV penetration. The most common limit on DPV export across NEM DNSPs is 5 kW. In some cases, this has reduced to 2.5 kW or even zero (0 kW). Recent DNSP revenue proposals to the Australian Energy Regulator (AER) (including SAPN and the Victorian businesses) justify measures to increasing hosting capacity by quantifying the value of additional DPV generation at the bulk system level through alleviating export limits. The AER is currently assessing how this might be done consistently as future DNSP DER integration programs are assessed, and considers neither zero export nor network augmentation costs to represent a long-term sustainable solution to the continuing deployment of consumer DER[17].

Case study | SA Power Networks distributed solar PV systems experiencing over-voltage

SAPN examined the impact of inverter disconnection on DPV generation in its network, under a grant with Solar Analytics from the Co-operative Research Centre. Using 5-minute measured voltage data provided by Solar Analytics for a sample of 2,693 DPV systems over the 2018-19 financial year, SAPN evaluated the extent to which inverters may have disconnected due to over-voltage. Data was anonymised to ensure system owner and address could not be identified.

The study assessed potential disconnection based on a comparison of the maximum measured voltage over each 5-minute interval against requirements set out in the version of AS/NZS 4777.2 applicable when the DPV system was installed:

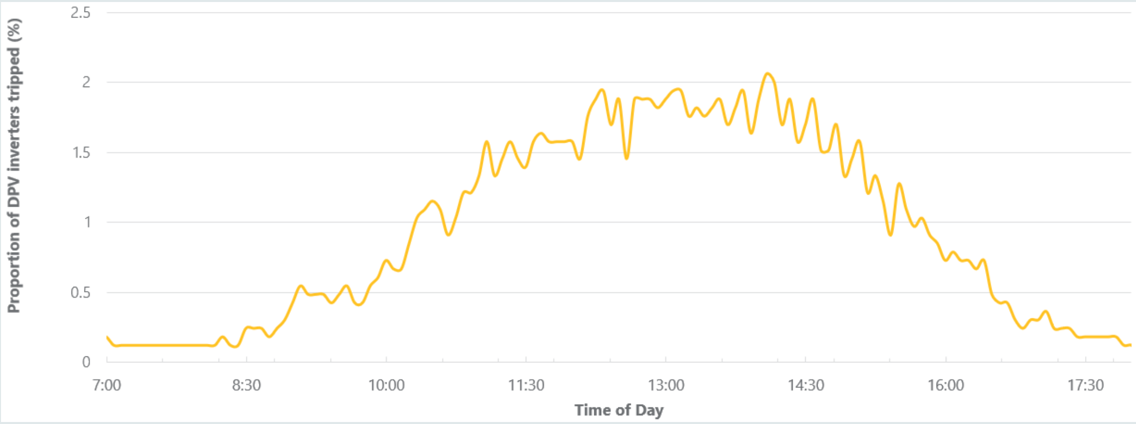
- Inverters installed before October 2016 subject to AS/NZS 4777.3:2005: which allows an over-voltage trip setting anywhere in the range 230-270 volts (V). For the analysis the trip setting was assumed to be 270 V.
- Inverters installed after October 2016 subject to AS/NZS 4777.2:2015: which specifies an over-voltage trip setting for an average voltage over a 10-minute period exceeding 253 V, or exceeding 260 V for 1 second, or exceeding 265 V for 0.2 seconds. The analysis assumed that the trip setting was 253 V for readings averaged over a 10-minute period, or 260 V for a single reading.

Figure 13 shows the proportion of DPV inverters that could have disconnected during the day of minimum regional operational demand in 2018-19 (599 MW on 21 October 2018). On this day, only about 1.5% to 2.1% of systems would have experienced over-voltage that could have led to disconnection during peak solar generation, light load conditions in the middle of the day. For the analysis, all inverters installed after October 2016 that experienced voltages above 253 V were assumed to disconnect. This was

[17] AER, *Assessing Distributed Energy Resources Integration Expenditure – Consultation Paper*, November 2019, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/initiation.

based on maximum voltage experienced over a 5-minute period, while the standard requirement is specified in terms of average voltage over a 10-minute duration. It is therefore likely that the evaluated disconnection levels over-estimate actual disconnection.

Figure 13 Proportion of inverters in South Australia that would have disconnected on the regional minimum operational demand day in 2018-19 (21 October 2018)



For more on the CRC-P60984 Integrated Smart Home Energy Management, Control and Data Visibility project, see https://www.grants.gov.au/?event=public.GA.show&GAUUID=7F359F40-D559-4E78-72C3410DBFF03558.

A4. Bulk system challenges

Key insights

As penetrations of passive DPV continue to increase and become significant at the regional level, their aggregated impact affects almost all core duties of the bulk system operator in some way, due to:

- An increasingly large component of generation not currently subject to the same bulk system disturbance withstand requirements as utility-scale generation, resulting in increasing contingency sizes following transmission faults due to the potential mass disconnection of DPV systems.
- **The ongoing reduction in the daytime system load profile due to continued growth in distributed solar generation**, contributing to:
  - Reducing availability of stable load blocks necessary for the effective operation of emergency mechanisms such as emergency frequency control schemes and system restart.
  - Reducing system demand potentially to the point of insufficient load to support minimum synchronous generation levels necessary for system strength, inertia, frequency control, and other services required for system security.
  - Reducing load at transmission network connection points serving locations with high DPV generation relative to load, introducing voltage control challenges in the daytime.
- **An increasingly large source of variable generation**, resulting in increasing ramps associated with daily diurnal solar profile at the regional level, and faster, less predictable ramps in significant PV clusters at the sub-regional level due to cloud movements.
- **An increasingly large source of generation that cannot be curtailed**, resulting in a less dispatchable power system. Unlike large scale generation, DPV generation cannot be curtailed by AEMO even under extreme, abnormal system conditions.

Due to its relatively high DPV penetration and low load base, the passive nature of DPV is already affecting bulk system operation in South Australia today. Under current DPV uptake projections, these issues will also be increasingly prevalent in other NEM regions by 2025.

To maintain a secure and reliable power system, capable of supplying consumers with the electricity they demand with a very high degree of confidence, AEMO and NSPs must have access to a number of critical operational tools to manage the power system within its technical limits. The key operational pre-requisites are discussed in AEMO's *Power System Requirements*[18] paper.

The sections below detail the implications of growth in DPV for a variety of functions that AEMO is responsible for.

[18] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

A4.1 Increasing contingency sizes

Increasing amounts of DPV generation impact AEMO's management of contingency events in the power system through two main channels:

- **Size of the contingency event** – the potential disconnection of DPV generation during a contingency event effectively increases the size of the contingency that needs to be managed.
- **Ability for the system to recover** – reducing system load leading to a reduction in synchronous generation online, and associated reduction in services aiding system recovery following a disturbance. This is discussed further in Section A4.2.2 and in Appendix B, Section B4.9.

A considerable body of evidence now exists to suggest DPV systems disconnect following voltage disturbances – including analysis of actual system events and laboratory bench testing of inverters. This was highlighted in AEMO's *Technical Integration of DER*[19] report, published in April 2019.

Since this report, AEMO has analysed DPV system disconnection behaviour from more than 20 historical voltage disturbances that occurred between 2016 to 2020 during periods with material levels of DPV generation. For each disturbance, data from a sample of hundreds of individual DPV inverters was provided by Solar Analytics, with anonymisation to ensure that system owner and address could not be identified, under a joint ARENA-funded project[20].

AEMO is required to maintain the power system in a **secure operating state** – able to withstand a single **credible contingency event** without loss of load and remain in a **satisfactory operating state.** This is done through the procurement of ancillary services and constraints within the dispatch process designed so that the power system can return to a satisfactory state in case a credible contingency event were to occur.

The power system is in a **satisfactory operating state** when it is stable and technical parameters (such as power flow, voltage, and frequency) are within limits.

From time to time, the power system may experience significant **disturbances** where there is a temporary and unexpected imbalance of supply and demand.

Contingency events are power system disturbances resulting from the failure or sudden and unexpected removal from service of a generating unit or transmission element.

Credible contingency events are those that AEMO considers to be reasonably possible to occur, with the potential for significant impact on the power system.

Following a major contingency event that takes the power system from a secure to a satisfactory operating state, AEMO has 30 minutes to restore the system to a secure operating state. During this time, AEMO will undertake a range of measures such as redispatch of generators, interconnectors and reactive power supplies, as well as directing any necessary line or load switching.

This investigation demonstrated consistent DPV disconnection behaviour that scales with the severity of the voltage disturbance, as illustrated in Figure 14. DPV disconnection behaviour was also further validated by bench testing of individual inverters under laboratory conditions, conducted by UNSW Sydney[21]. Their analysis has shown that 14 out of 25 inverters tested (including a mix across both the 2005 and 2015 versions of AS/NZS 4777.2) disconnected or significantly curtailed when exposed to a 100 ms voltage sag to 50 V.

This evidence base has helped to inform development of composite load and DER models for the South Australia region that are able to simulate actual DPV disconnection behaviour to around +/-7% accuracy, based on validation against six historical disturbances where DPV disconnection was observed.

[19] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

[20] ARENA, Enhanced Reliability through Short Time Resolution Data, at https://arena.gov.au/projects/enhanced-reliability-through-short-time-resolution-data-around-voltage-disturbances/.

[21] UNSW Sydney, Addressing Barriers to Efficient Renewable Integration – Inverter Bench Testing Results, at http://pvinverters.ee.unsw.edu.au/.

Figure 14 DPV disconnection behaviour following historical voltage disturbances

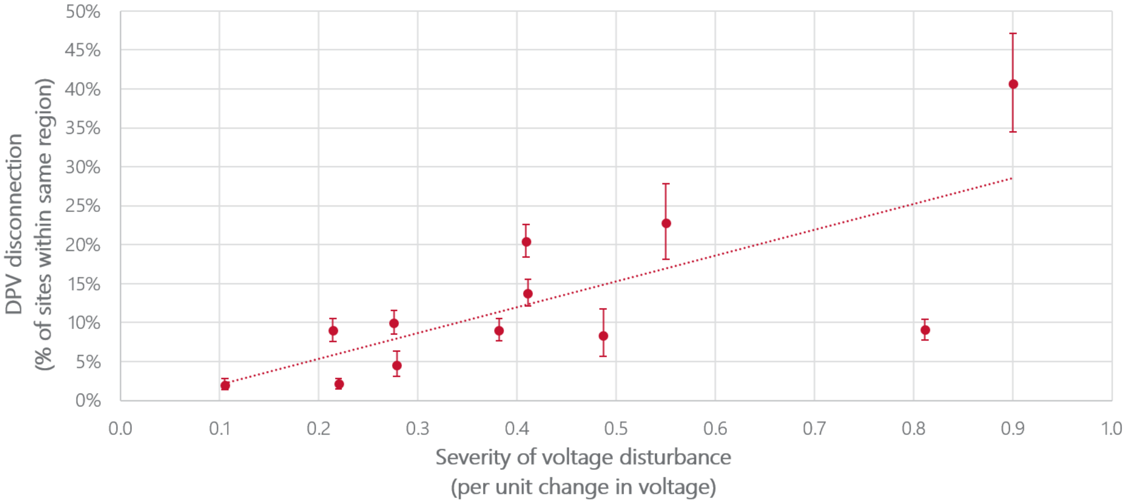


Table 6 summarises disconnection behaviour during the three most severe voltage disturbances in Figure 14. Typically, load also disconnects during voltage disturbance events. This is currently factored into the evaluation of contingency frequency control ancillary services (FCAS) requirements, however DPV disconnection is not. While the DPV disconnection was small relative to load disconnection for these particular historical events, if a similar voltage disturbance were to occur during high DPV generation, light underlying demand conditions, DPV disconnection net of load disconnection could be significant.

Table 6 Recent significant DPV disconnection events

Date	Region	Severity of voltage disturbance	DPV disconnection	Load disconnection	
		p.u.	MW	% of pre-disturbance DPV generation	MW
3 March 2017	SA	0.9	205	46	400
18 January 2018	Vic	0.55	170	25	550
25 August 2018	NSW	0.81	100	19	35

DPV disconnection has been assessed to be a major risk in South Australia today, if a severe credible transmission fault were to occur in the Adelaide metropolitan area while the region was operating as an island. The case study below provides further detail.

Mitigation approaches

Actions that would assist with reducing or managing DPV disconnection risk are listed below:

- At present, the voltage ride-through criteria in AS/NZS 4777.2:2015 do not reflect the needs of the power system, and this exposes the system to broad-scale loss of supply for significant transmission-based events. The current review[22] underway for AS/NZS 4777.2 aims to improve these standards to ensure that DPV can discriminate between transmission and distribution voltage events. During a fast voltage

[22] The findings that led to the review of AS/NZS 4777.2 can be found in AEMO's *Technical Integration of DER* report: https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

disturbance, the DPV remains in operation, to minimise the impact of DPV disconnections during contingency events while still delivering the essential passive anti-islanding detection required to safely manage distribution networks.

- Further visibility, monitoring, and post-event analysis of DPV (and other DER) can improve understanding of their response to disturbances. These learnings will support the development of improved models and tools to accurately represent DER behaviour, to undertake system studies that form an essential part of managing the power system.
- Introducing the capability to dynamically curtail DPV during extreme abnormal operating conditions (such as a region operating as an island) could minimise potential contingency sizes when they cannot be reasonably managed via alternate means. This is analogous to the generation shedding safety net that is available for utility-scale generation during extreme abnormal conditions and further discussed in Section A4.5.
- Reviewing FCAS procedures that apply during these periods, to consider appropriate capacity enablement, could help manage the greater contingency size. This is further discussed in Appendix B, Section B4.9.

Case study | South Australian voltage disturbance analysis

AEMO has recently conducted dynamic power system studies in PSSE and PSCAD, examining the response of the South Australian power system to a credible fault[23] at various locations in South Australia.

There is considerable evidence that large quantities of DPV and load disconnect from the power system following voltage disturbances, this behaviour has now been factored into detailed dynamic models for load and DPV behaviour[24]. Through these PSSE studies, it was shown that following the most onerous credible fault in the Adelaide metropolitan area[25], with the required set of generating units dispatched[26]:

- 14-28% of underlying load was projected to disconnect.
- 49-53% of DPV generation was projected to disconnect.

The percentage ranges quoted above are based on the estimated uncertainty in the dynamic load model and distributed PV model respectively, determined from validation studies.

Applying AEMO's Draft 2020 ISP High DER projections for DPV uptake, and assuming underlying load and DPV generation patterns as observed in 2019, this leads to the net contingency sizes (DPV disconnection net of load disconnection) in Table 7 below.

In these periods, the quantity of DPV disconnecting exceeds the quantity of load disconnecting, meaning that the combined (distributed PV minus load) contingency is a net loss of generation in these periods. In the worst case, these values could be additional to the loss of a synchronous generating unit, if they occurred as a result of a fault at the large generator's transformer.

The extreme worst case estimate is shown (with maximum PV loss, minimum load loss, and in the most severe period of the year), as well as a more moderate estimate of the 85th percentile case (assuming a middle projection of possible load and DER loss, and the 85th percentile of half-hourly periods in the year by severity of the possible net contingency size). The 85th percentile case could be expected to be exceeded on 55 days of the year.

The 85th percentile case also assumes that all > 200 kW distribution-connected PV has been curtailed (assuming AEMO requests this of the local DNSP, when operational demand reduces below 700 MW). In contrast, the extreme worst case assumes that DPV has not been curtailed, which may be the case in system normal conditions, or where operational conditions do not require curtailment for system security.

[23] Credible contingency events are defined in the National Electricity Rules (NER).

[24] These detailed dynamic distributed PV and load models are currently only available in AEMO's simpler RMS-type model (PSSE). Studies need to be conducted in AEMO's more sophisticated EMT-type model (PSCAD) to accurately represent behaviour in low system strength and low inertia conditions. PSCAD studies were therefore conducted by replicating the tripping observed in PSSE studies. Ultimately, these studies should be conducted with fully developed PSCAD models for distributed PV and load, so this analysis should be considered preliminary.

[25] Studies investigated the response of the power system to a credible (two phase to ground) fault in the Adelaide metropolitan area, associated with a trip of a unit (Torrens Island B or Pelican Point Gas Turbine [GT]). The level of underlying demand, distributed PV generation, and Heywood interconnector flows were varied. Operational demand was maintained at 200-300 MW, because the validity of the models with zero or negative operational demand is unclear and requires further investigation.

[26] The dispatch of synchronous generators was assumed to be the same as on the minimum demand day in 2019 (10 November), with two Torrens Island B units, and 1 Pelican Point GT and Steam Turbine (ST) online and operating at minimum loading levels (with sensitivities considered where indicated). It was assumed that the four new synchronous condensers were fully commissioned (two at Davenport, two at Robertstown). Reactive power support from South Australian wind farms was also assumed.

Table 7 Net DPV and load contingency sizes on the most severe day (DPV loss – load loss)

	85th percentile case	Extreme worst case
2019 (Actual)	70	280
2020	190	430
2021	260	520
2022	300	560
2023	330	600
2024	370	650
2025	390	680

These contingency sizes are comparable with (and soon exceed) the maximum size of credible contingency for which the South Australian power system is currently planned and operated. For comparison, at present the largest generation contingency in South Australia in any period is around 280 MW. Furthermore, it is credible for these net PV-load contingencies to be added to a unit trip, making the total contingency size even larger. At present, AEMO has limited effective tools available in real time to be able to reasonably manage such large contingency events in South Australia.

In the most extreme case today, when South Australia is operating as an island, the Frequency Operating Standard (FOS)[1] requires that frequency is maintained above 49 hertz (Hz) for credible contingency events, and that reasonable endeavours are made to keep frequency above 47 Hz for non-credible (including multiple) contingencies. AEMO considers that disconnection of DPV at the same time as a large generating unit trip should be considered part of the same credible contingency (that is, the 49 Hz lower frequency bound applies).

AEMO's PSCAD studies showed that when the disconnection of DPV exceeds disconnection of load contingency sizes by 150 MW (net generation loss), combined with the loss of a large-scale generating unit, frequency is likely to fall below 49 Hz. As Table 7 shows, in 2020 AEMO may already operating with these potential net contingency sizes.

Enabling more FCAS provides minimal benefit during this situation, due to the rapid rate of change of frequency, and the comparatively slow response of a typical FCAS provider. In this situation, activation of automatic load shedding would be inevitable. This is undesirable, not only because it represents customer disconnection, but because it is unclear whether the existing under frequency load shedding (UFLS) scheme is capable of arresting a frequency decline in these conditions. Analysis indicates there could be very little net load available to shed in periods with high levels of DPV operating. This means that disconnecting a large number of customers may have very little impact on arresting the frequency decline. Further, at present the UFLS relays operate at a feeder level without regard to the direction of flow. Some UFLS feeders already experience reverse flows in high PV periods, when operation of the relays could accelerate a frequency decline, rather than helping to arrest it.

Minimising the growth of these potential contingencies requires improvements to performance standards for DPV inverters to include adequate bulk system disturbance ride-through requirements.

To manage this risk in the short term, on 24 April 2020, AEMO increased contingency sizes on constraint equations for Victoria to South Australia power flow by up to 180 MW, dependent on estimated DPV generation online to account for the possible mass disconnection of DPV in South Australia in the daytime[27].

A4.2 Reducing operational demand

DPV generation in the daytime reduces **operational demand,** the share of underlying demand served by centralised resources in the bulk power system.

Figure 15 shows average operational demand for each NEM region over a day in 2019 compared against 2025 projections. DPV generation in the middle of the day has started to impact the system load profile across all regions today. South Australia is the one region where (on an average basis) minimum operational demand now occurs in the daytime, rather than in the early morning – which has been the historical norm in the NEM to date.

[27] See AEMO's Market Notice, at https://www.aemo.com.au/Market-Notices?marketNoticeQuery=75464&marketNoticeFacets=.

This ‘hollowing out’ is projected to continue as DPV uptake continues to grow, with Victoria and Queensland also experiencing minimum operational demand (on an average basis) in the daytime by 2025. Figure 16 shows the time of day and system loading during the lowest 10 minimum operational demand periods by season for each NEM region, and how this distribution may change from 2019 to 2025.

Minimum operational demand periods are occurring in the daytime today in South Australia and Queensland across all seasons, and with growing DPV this will continue to reduce. This has also started to occur during some periods in Victoria. By 2025, Victoria, New South Wales and Tasmania will also all be experiencing minimum operational demand in the daytime, across all seasons.

Operational demand in a region refers to electricity used by residential, commercial and large industrial consumers supplied by scheduled and semi-scheduled generating units in bulk system dispatch and significant non-scheduled generating units – both within the region and imports from neighbouring regions.

It excludes the demand met by DPV and other small-scale generation, and electricity used by scheduled loads.

The ongoing reduction in daytime operational demand as DPV growth continues will impact bulk system operation in several ways, including:

- Reducing load available to keep synchronous generating units operating at their minimum stable outputs in order to provide essential system services such as system strength, inertia and voltage control,
- Reducing the effectiveness of critical back-stop mechanisms necessary for system recovery or restoration during major power system events, due to the reduced availability of stable load blocks,
- Voltage control challenges in parts of the transmission network experiencing reducing load in the daytime due to the aggregated impact of significant clusters of DPV generation.

These implications and possible mitigation measures are discussed in the following section.

Figure 15 Historical (2019) and projected (2025) average daily operational demand profile for each NEM region

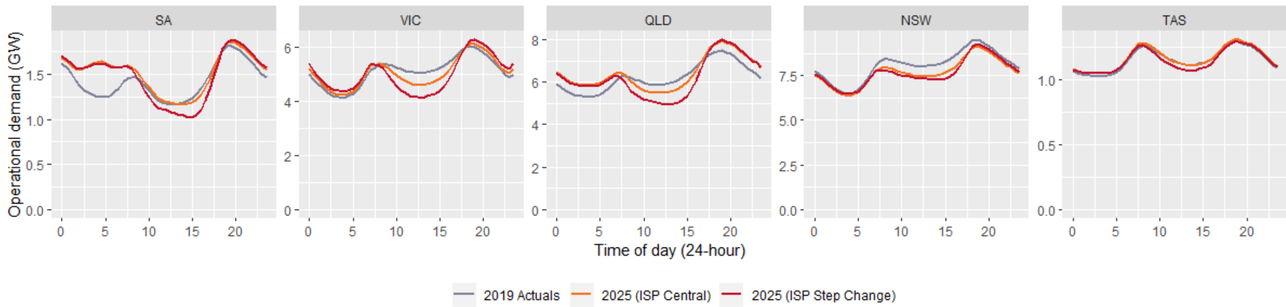


Figure 16 **Historical (2019) and projected (2025) lowest ten operational demand periods – level and time of day by season**

A4.2.1 Minimum synchronous generation requirements

Increasing DPV generation displaces synchronous generation in the daytime. This reduces the availability of system support services that have historically been provided as a by-product of dispatch of large synchronous generating units in the energy market, including:

> A minimum level of system load is required to support minimum online synchronous generation requirements necessary for the sufficient provision of essential power system security services such as system strength, inertia and frequency control ancillary services (FCAS).

- **System strength and inertia requirements** – as discussed in Chapter 5 of the RIS Stage 1 report, in regions such as South Australia and Victoria, specified combinations of synchronous generating units are required to be online in order to maintain minimum required system strength levels. Similarly, minimum inertia requirements are also in place in each NEM region, which are more pronounced when a credible risk of separation exists, or if the region is operating as an island. Synchronous generating units have minimum loading levels below which they cannot generate.
- **FCAS requirements** – for regions operating under islanded conditions or under credible risk of separation (where the amount of FCAS that can be sourced via interconnection is limited), there must be sufficient local raise and lower FCAS available for regulation and contingency management. Contingency FCAS requirements are determined based on the largest generating unit (for raise services) and the most significant load (for lower services) across various time scales (6-second, 60-second, and 5-minute). During times of high DPV, many large-scale generators could be restricted towards their minimum loading, so

following a generation contingency could likely have sufficient headroom to provide raise services. The provision of adequate lower contingency services (to manage the trip of a large load, for example) can require that units are dispatched above minimum loading levels, to allow lower room to reduce frequency if required. Adequate load is required for unit dispatch at these levels.

Given the rapidly declining minimum demand levels recorded in South Australia recently, together with the unique operational challenges of that state, including the need to operate as an independent island at times, AEMO is completing studies to determine the minimum load required for secure operation of the South Australian power system. The most onerous operational condition is when South Australia is operating as an island, and therefore defines the highest threshold for operational demand that may be required to maintain system security for system strength, inertia, FCAS, and other system services. While analysis is ongoing, it appears likely that South Australia has reached minimum demand levels close to this threshold. Other regions will face similar challenges as DPV penetration levels grow.

Secure management of interconnector flows is the next most onerous challenge with declining minimum operational demand levels as passive DPV generation grows. If DPV and other non-scheduled generation is contributing a large percentage of interconnector exports from one region to another, situations will be reached where flows will need to be managed by reducing DPV generation in the exporting region. This would be required under certain abnormal operating conditions where interconnector capacity is required to be restricted to manage system security (such as during periods of forced outages, bushfires, or other emergency conditions) at a time of high DPV generation. Without the capability to reduce aggregate regional DPV output during these extreme abnormal conditions there is a risk that interconnector flows could exceed secure operating limits.

Mitigation approaches

Measures that could assist with managing reducing operational demand include:

- Feed-in management for all new DPV systems enabling the managed shedding of DPV generation during extreme, abnormal system conditions where required for system security.
  - Longer term, any transition to two-way markets incentivising storage and demand response (aligned with power system needs) could reduce the need to actively manage DPV generation during normal operation. There is potential for the dynamic shifting of electric vehicles and storage charging and significant residential and commercial load (such as water heating, air-conditioning, and water pumping) and large industrial loads to the act as a 'sink' for excess DPV generation in the daytime.
  - Even with the abovementioned market responses, a safety net capability will always be needed to actively reduce aggregate regional DPV output during extreme abnormal system conditions.
- Increased interconnection, to reduce the likelihood of any region needing to operate as an island.
- Improving DER standards for voltage ride-through, to limit contingency sizes and therefore limit the amount of FCAS that needs to be enabled.
- Optimising use of battery storage for provision of both raise and lower services during minimum load periods, possibly including commercial arrangements to recognise the expanded capabilities the batteries offer for frequency control under extreme conditions. Battery state of charge may need to be managed to ensure they can sufficiently provide the appropriate service for the operating scenarios.
- Optimising frequency control arrangements, and a suite of other operational measures to streamline operation in minimum demand periods.

Case study | Minimum operational demand in South Australia

DPV has already noticeably shifted the minimum demand period in South Australia to the middle of day, and the region is experiencing an ongoing reduction in minimum operational demand as DPV generation continues to increase in the daytime. This is of increasing concern, as AEMO has identified that there are minimum operational levels that are required to maintain South Australia in a secure and reliable state, particularly when South Australia is islanded or has a credible risk of separation from the NEM. During these times, there is a need for sufficient demand to match the minimum output of the synchronous generating units needed to provide required levels of system strength, inertia, frequency control, and voltage management.

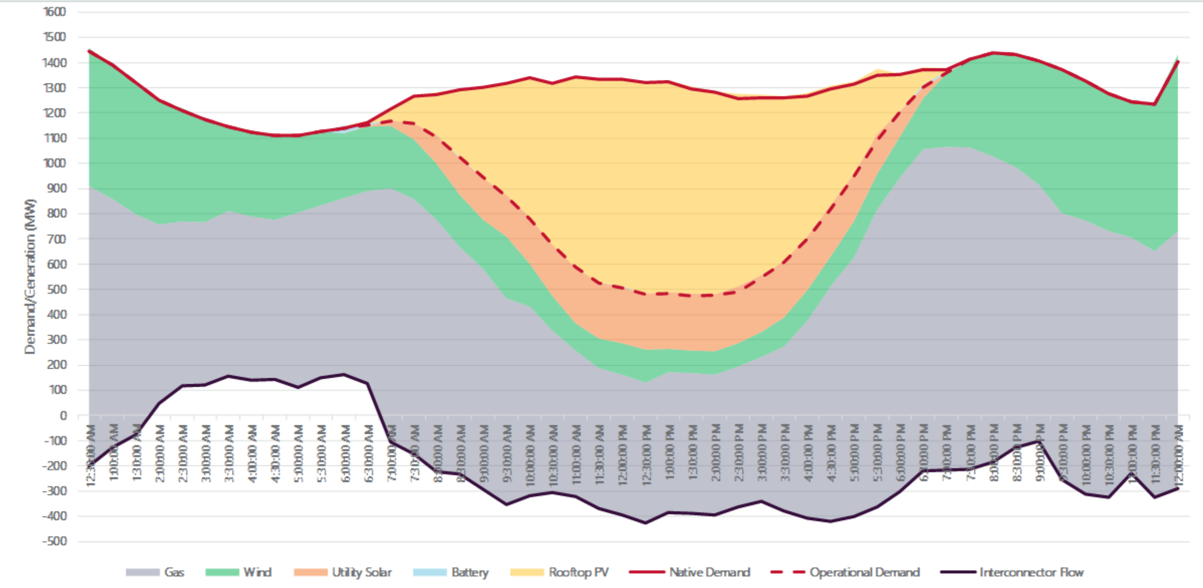
Evidence of declining demand can be seen during spring-summer 2019. During this time, South Australia experienced four consecutive minimum operational demand records, with an all-time low of 458 MW set on 10 November 2019 at 13:30. Prior to 2019 spring season, the minimum demand was 599 MW, set on 21 October 2018. Table 8 shows all the minimum demand day records (at the time) that have been experienced in the 2019 spring-summer season in South Australia. This highlights that the events are increasing in both frequency and magnitude, and the decline in operational demand is occurring rapidly, as is evident with a reduction of 116 MW through the season.

Figure 17 shows the demand profile on one of these minimum operational demand days (Sunday 20 October 2019). On this day, DPV generation accounted for approximately 64% of the underlying demand over this period. DPV in aggregate was also the largest generator in the region at the time, and its combined generation exceeded the combined generation from all other generators.

Table 8 Minimum demand events in South Australia during September to November 2019

Date/time	Operational demand (MW)	DPV gen (MW)	Scheduled gen (MW)	Non-Scheduled gen (MW)
Sunday 29/09/2019 12:30:00	574	751	544	29
Saturday 12/10/2019 13:00:00	533	789	517	20
Sunday 20/10/2019 13:30:00	475	813	441	37
Sunday 10/11/2019 13:30:00	458	821	428	31

Figure 17 South Australia demand profile – Sunday 20 October 2019



Risk of separation

South Australia is defined as being at credible risk of separation from the rest of the NEM when the occurrence of a single credible contingency event would result in the loss of its synchronous connection to Victoria. This risk arises, for example, during outages of certain of transmission lines, including either of the two South East – Heywood 275 kV lines or any 500 kV line between Sydenham and Heywood terminal stations in Victoria. South Australia is also considered to be at credible risk of separation when the loss of any dual-circuit transmission lines between South East and Sydenham terminal stations is reclassified as a credible contingency.

Under these conditions, AEMO must have the capability to reduce exports on the Heywood interconnector to 250 MW, within 30 minutes of the unplanned line outage, to return the power system to a secure state. AEMO also requires some frequency control services to be provided locally in South Australia. If the outage is extended, AEMO would reduce exports on the Heywood interconnector to 50 MW.

From this point, a single credible contingency could cause the loss of the Heywood interconnector. Under these conditions, AEMO must have the capability to operate South Australia as an island in a secure state, and within 30 minutes of islanding provide all the required system strength, inertia, frequency control, voltage control, and other factors required for stable and secure islanded operation.

Studies have shown that while that there is some risk of a large disconnection of DPV causing a separation event when the Heywood interconnector is operating with a single circuit, these conditions rarely coincide. The risk can be managed with a new constraint to require a minimum level of export from South Australia in periods with a credible risk of separation (this constraint should bind very rarely and therefore have minimal market impact and cost). It should also be possible to schedule network maintenance away from these periods, to further reduce the need to operate with a credible risk of separation during moderate demand and high PV generation periods.

Operation as an island

Although South Australia rarely operates as an island, it is the most onerous operational condition for the region. The ability to operate South Australia as an island determines the earliest timelines on which action may be required to facilitate secure operation in periods with low load and high levels of DPV generation.

South Australia can separate from the rest of the NEM at any time. If separation occurs, AEMO will take whatever reasonable actions are available, as soon as practicable[28], to restore all the required system strength, inertia, frequency control, voltage control, and other system security services required for stable and secure islanded operation in South Australia.

The analysis assumed a moderate contingency size (including disconnection of up to 130 MW of DPV) that can occur during single unit trips with a mild voltage disturbance. A more severe contingency event during an island is assessed in the case study on South Australian voltage disturbance analysis in Section A4.1 above. In the scenario where South Australia separates from the NEM, AEMO is required to take reasonable actions (wherever possible) within 30 minutes of islanding to provide all the required system strength, inertia, frequency control, voltage control, and other essential services required for stable and secure islanded operation in South Australia, for a variety of unit combinations, taking into consideration these interrelated factors:

- It is not possible to export generation via the Heywood interconnector, and exports on the Murraylink interconnector are limited. Murraylink exports were assumed to be limited to the same level as Olympic Dam load (due to co-optimisation with contingency lower services availability), up to a maximum of 170 MW (often observed due to thermal constraints in the surrounding network). This means that Murraylink exports are limited to 150 MW in most scenarios in the analysis.
- Sufficient headroom is allowed in unit dispatch to enable all frequency control services locally in South Australia. This includes a minimum of ±35 MW of regulation, and adequate raise and lower contingency services on 6-second, 60-second, and 5-minute response timeframes[29].
- Maximum contingency sizes were determined based on the size of the largest load (assumed to be Olympic Dam operating at 150 MW), and the size of the largest generating unit dispatched[30].
- A net DPV and load disconnection of 130 MW was assumed and added to the largest generation contingency.
- Load relief was assumed to be 0.5%, as per AEMO's recent analysis[31].
- Minimum inertia requirements are increased from 4,400 megawatt seconds (MWs) to 6,000 MWs[32], as well as accounting for the introduction of synchronous condensers, as appropriate in each time frame.

[28] NER 4.2.6(b) states: Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.

[29] The Mandatory Primary Frequency Response rule change (https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response) may lead to increased delivery of frequency response from many units, and may somewhat improve findings compared with those modelled in this analysis.

[30] At present, Pelican Point is assumed to set contingency sizes based upon the dispatch of the gas turbines only. In practice, when one Pelican Point gas turbine is operating, the loss of this gas turbine will be followed by the loss of the steam turbine over the following minute. This has been accounted for in this analysis by determining 60-second and 5-minute raise requirements based on the combined dispatch of the gas turbine and steam turbine. This increases minimum load requirements.

[31] AEMO (August 2019) Changes to Contingency FCAS Volumes, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf. Load relief was calculated based upon operational demand, as per the existing constraint equations. In future, it may be preferable to calculate load relief based upon underlying demand.

[32] AEMO, Inertia Requirements Methodology, Inertia Requirements and Shortfalls, June 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

- The frequency control capabilities for each unit in South Australia were based on their registered "FCAS trapeziums". Wind farms were excluded, because their availability in low load periods cannot be guaranteed. Solar farms and battery systems were considered likely to be fully available, although there are no solar farms registered for FCAS in South Australia at present[33]. All synchronous generating units were dispatched to at least 20 MW above their respective lower FCAS trapezium breakpoint for fast lower service, except Osborne which is dispatched at 10 MW above its breakpoint. This is as per operation in the recent South Australian islanding event.
- Batteries were assumed to deliver their full frequency response capacity in all timeframes[34]. Batteries were modelled in this manner for this analysis because it was thought to better represent their potential contributions to system security. Regulation FCAS from batteries was limited to ±5 MW each, as per operation in the recent South Australian islanding event. This acts to maximise battery availabilities for contingency frequency control.

A range of results were found as different generating unit combinations require very different amounts of load. The smallest generating unit combination uses only Torrens Island units. Due to the low minimum load requirements of these units, and their strong frequency control capabilities, a minimum South Australian operational demand of ~150-200 MW suffices in this case (assuming some Murraylink exports, and other factors as outlined above). However, to maintain the dispatch flexibility to operate generating unit combinations that include the larger units, such as Pelican Point or Osborne, much larger amounts of load are required. For the largest unit combination considered in this analysis, around 550 MW of load is required to operate in a secure state (under the power system conditions assumed in spring 2020). Having the larger units online leads to larger contingency sizes, which then require more units online to provide adequate inertia and frequency control to manage their possible loss.

Minimum load requirements change year to year, as the system operational requirements and capabilities evolve over time. Upon the installation of an additional two synchronous condensers, the minimum load requirement reduces to 450 MW from late 2021.

That means there is an urgent need to establish a back-stop that allows AEMO to curtail DPV when extreme and unusual operational circumstances arise. The back-stop measures include generation shedding, storage as a 'solar soak', increasing load, and using demand reserves.

A4.2.2 Implications for emergency mechanisms

Although applied only in rare circumstances, AEMO is required to ensure last resort emergency mechanisms are in place, including:

- Emergency frequency control schemes (EFCS) – needed to arrest large frequency disturbances to prevent a system imbalance that could otherwise lead to a black system.
- System restoration – utilised in the event of a black system to restore the power system.

Both these mechanisms are impacted by DPV growth, as described below.

Emergency Frequency Control Schemes

AEMO is responsible for maintaining three types of schemes – under-frequency load shedding (UFLS), over-frequency generation shedding (OFGS), and special protection schemes (SPS).

These are described in 0 below.

This means that at certain times when DPV generation is significant, the NEM may not have the available security of these emergency frequency control schemes (UFLS, OFGS, and SPS) to prevent a black system in the event of an extreme disturbance.

AEMO is responsible for maintaining power system frequency within a set range (47-52 Hz). In rare circumstances following unlikely, or non-credible contingency events, the frequency deviation can be large, and exceed these limits. If this happens, EFCS may be activated as a last resort to try to arrest the frequency disturbance, by automatically disconnecting generation or load.

[33] The Mandatory Primary Frequency Response rule change (https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response) will require that scheduled and semi-scheduled solar farms deliver a frequency response if they are dispatched above 0 MW. However, when curtailed to 0 MW (as may be the case in very low demand periods, particularly under islanded conditions) they will not be required to deliver a frequency response.

[34] This means the BESS were assumed to contribute more frequency response than their registered FCAS quantities. Future commercial arrangements for batteries to deliver fast frequency response are yet to be determined, but may result in better alignment of battery capabilities with the prescribed FCAS contribution calculations outlined in the Market Ancillary Service Specifications (MASS).

Table 9 **Impact of DPV on emergency frequency control schemes**

Scheme	Purpose	Implementation	Impact of increasing DPV generation
Under-frequency load shedding (UFLS)	Rapid disconnection of load to manage a large drop in frequency following significant loss of generation.	Frequency-sensitive relays at distribution network zone substations that trip distribution feeders upon detecting an extreme under-frequency condition. Currently, installed UFLS relays cannot discriminate between the flow direction.	Initially, reduced effectiveness through a reduction in load available for shedding. As penetrations increase, zone substation feeders begin to experience reverse power flows at certain times, effectively becoming net "generators" – tripping these feeders if the scheme is triggered would result in further generation loss exacerbating the disturbance, rather than helping to correct it,
Over-frequency generation shedding (OFGS)	Rapid disconnection of large-scale generation during a severe over-frequency event.	Trip settings for relays across generating units set at a range of frequencies, coordinated across the region to produce a progressive response that can arrest an over-frequency event in a controlled manner.	Initially, reduction in centralised generation operating and available to shed in a coordinated way, reducing the ability of the scheme to arrest an equivalent over-frequency event. Eventually, the scheme will be essentially unavailable during high DPV, light load conditions, unless some form of DPV curtailment is obtained.
Special protection schemes (SPS)	Additional schemes in place to reduce effective contingency sizes, or to respond to specific contingency events to prevent system separation and uncontrolled frequency disturbances in the resulting islanded sub-networks.	Complement UFLS and OFGS, acting to trip load or generation based on triggers to address specific circumstances, to rapidly rebalance the system.	Affected similarly to UFLS and OFGS, and may be affected depending on whether they disconnect loads or generation.

Mitigation approaches

There are measures that could assist with safeguarding the effectiveness of EFCSs as DPV growth continues:

- Imposing network limits on interconnector flows to reduce potential generation contingency sizes, based on the ability of UFLS to arrest frequency decline in the event of the non-credible loss an interconnector.
- Increasing the amount of load on UFLS feeders. This could include adding new customers to UFLS schemes, or shifting load to the middle of the day to increase the available load for shedding such as moving hot water loads, or incentivising charging of electric vehicle and customer loads at this time, or contracting large-scale load to cover non-credible events.
- For UFLS, extending Australian Standards AS/NZS 4777.2[35] to include a brief emergency injection from distributed batteries. Currently, the Standards require that distributed inverters with energy storage reduce charging linearly with a decrease of frequency below 49.75 Hz, until 49 Hz, at which point they should reach 0 MW. This could be extended to provide additional benefit by specifying a discharge response from distributed storage between 49-48Hz.

[35] AS/NZS 4777.2:2015 also specifies that DPV systems should remain in operation until frequency reaches 47 Hz for at least 1 second. Bench-testing identified that many inverters conform to this standard, so it is unlikely that PV would disconnect rapidly before UFLS relays operate to solve this issue.

- AS/NZS 4777.2:2015 already requires an over-frequency droop response from DPV inverters by which systems respond with a controlled ramp down in an over-frequency event, assisting with correcting the imbalance, and could provide an increasingly important contribution to managing extreme over-frequency events. There is evidence where this response has assisted in previous bulk system events[36].

- Increasing the emergency frequency response from generation, including utility-scale batteries.
- Dynamically arming feeders that behave as load sources (and disarming those that are in reverse flows), tripping only feeders that have load to shed. This measure will not restore the capability of the UFLS, but will mitigate the risk of UFLS acting in reverse to exacerbate frequency disturbances.
- Increase visibility of flows at a feeder level to improve situational awareness of load availability and reverse flows to understand the level of dynamic arming required.
- Under extreme abnormal conditions, it may be appropriate to dynamically curtail DPV during times of high penetration to ensure that UFLS schemes operate appropriately.

Case study | South Australia under-frequency load shedding analysis

DPV has significantly reduced the amount of network measured load on UFLS feeders in South Australia. Figure 18 below shows:

- In grey, the UFLS demand profiles in South Australia on the day of lowest network measured load on UFLS feeders in 2017-18 (25 December 2017) and 2018-19 (21 October 2018). The network measured load on UFLS feeders reached as low as 273 MW in 2017-18, and 239 MW in 2018-19, from a total of approximately 1,300 MW of underlying demand.
- In black, the estimated total underlying customer load on SAPN's network, and the load as measured by SAPN (net of DPV generation) in red. A significant proportion of SAPN's load was being met by DPV at these times (57% in 2017-18, and 64% in 2018-19).

SAPN's data indicates that 91% of DPV installed in South Australia is located on feeders included in the UFLS, but these feeders comprise only around 69% of the average SAPN demand during the day (based on average half-hourly values). This suggests that DPV is installed disproportionately on load feeders that are included in the UFLS. This means UFLS feeders show a strong reduction in load related to DPV in daytime periods, as illustrated in Figure 18.

Figure 18 UFLS capability on the lowest day in 2017-18 (25 Dec 2017) and 2018-19 (21 October 2018)

While periods of very low network measured load on UFLS feeders do not tend to coincide with high imports on the Heywood interconnector, AEMO's studies indicate that in 2020-21, network measured load on UFLS feeders may be less than imports on the Heywood interconnector for 3% of the year under the Draft 2020 ISP Central DPV installation forecast, or possibly as high as 7%

[36] Including during the 25 August 2018 Queensland and South Australia Separation; see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf. Preliminary analysis of 16 November 2019 and 31 January 2020 appear consistent.

under the High DER DPV installation forecast. AEMO's preliminary dynamic studies suggest that the UFLS may remain adequate in many of these periods, unless Heywood flows are close to import limits and system inertia is close to minimum thresholds. Further analysis is underway.

AEMO has investigated the ongoing effectiveness of UFLS in South Australia and found that:

- Today – under low inertia conditions, if a large contingency event were to occur, UFLS in South Australia may already have insufficient load to shed to arrest a frequency decline.
- December 2021 – if no action is taken in South Australia, up to 85% of all UFLS stages (trip frequency bands) could be in reverse flows in certain periods. If the scheme was enacted, this could instead exacerbate the disturbance, possibly leading to a black system.
- By 2025 – other NEM regions are projected to also experience periods with less availability of stable residential load, with further investigation required.

The immediate actions to address this risk include:

- Implement a constraint to limit imports on the Heywood interconnector in periods where there is inadequate load available on the UFLS to manage loss of the interconnector within the FOS.
- Increase the amount of load on the South Australian UFLS. By including new customers in South Australia under the UFLS, investigate moving hot water to daytime, negotiate load shifting with large customers.
- Increasing the emergency frequency response from distributed resources through the review of AS/NZS 4777.2.
- Explore possible augmentation of Murraylink to add frequency control capabilities.
- Use dynamic arming as an important measure to slow deterioration of the UFLS and mitigate risks of UFLS acting to exacerbate a frequency disturbance.
- Implement suitable long-term measures for replacement of EFCSs.

System restart and restoration

Increasing levels of DPV generation impede the availability of stable load blocks, necessary for the restoration process if a black system event were to occur in the daytime. During this process, load must be progressively added to the island system in a controlled and stable manner.

With large quantities of passive or uncoordinated DPV generation, it will become increasingly difficult to anticipate and schedule the quantity of load being added to the island. The inadvertent energisation of a large amount of DPV generation, when a net load was expected, could cause large signal voltage and frequency oscillations and inadvertently disconnect restored generators (including black start services) or sensitive load.

While black system events are rare and undesirable, AEMO must have reliable and controllable resources (**black start services**) available to restart and restore the system to a secure and reliable operating state as safely and quickly as possible in the event of a major supply disruption. During a black system event, it is necessary to activate at least one of these resources to carry out initial energisation of a section of the power system, to restore sufficient supply to create and control a stable power island. The energised part of the power system is then used to start up additional generation and restore more load, so the power system is gradually restored.

At present, only capable synchronous generating systems have been procured and tested for provision of black start services. This is due to their ability to provide dispatchable voltage and grid forming frequency services.

As supply is restored, some synchronous generating units (including the black start units) may have minimum loading level requirements, also called **stabilising load**. To restart successfully, these units must have access to a stable load block in close proximity that is at least equal to their minimum loading level for stable operation.

Mitigation approaches

Potential mechanisms that can help support these challenges include:

- Introducing the capability to dynamically curtail DPV during a restart process to ensure stable loads are available for system restart. This would require defining communication and response requirements during black system situations, and careful demonstration that this is effective.
- As a short-term measure, in some cases it may be possible to define alternative restart pathways to avoid distribution feeders with reverse flows due to DPV

generation in the daytime or through known stable load blocks such as large industrial loads not impacted by DPV generation – noting this is not always feasible given proximity to black start/other generators.

- Updating Australian Standards AS/NZS 4777.2 so new inverters provide an autonomous response to black system events.
  - A potential mechanism that would help to mitigate DER generation is to limit the export from these devices once they interpret a black system event has occurred (for example, due to a minimum time elapsed without a system response). DPV could then respond by slowly ramping generation output to full capacity over a matter of hours.
- Distributed batteries may be able to assist with provision of load or generation during the load restoration process, if they can be coordinated and are designed to behave appropriately.

A4.2.3 Transmission voltage control

At the transmission level, high levels of DPV operation can displace the operation of utility-scale generation, which may be providing reactive power services. Additionally, high DPV generation reduces the loading of transmission lines and, as a consequence, network voltages increase, which can eventually exhaust network voltage management measures such as transformer tap changing and reactive plant switching.

Combined, these impacts reduce the operational tools available to AEMO and NSPs to maintain voltages within acceptable ranges. In extreme circumstances, de-energising of high voltage lines to maintain transmission voltages within limits may be required. This approach decreases the operational life of circuit breakers and escalates reliability risks.

AEMO operates the power system to maintain voltage levels across different points in the transmission network within acceptable ranges. At connection points, these are set by NSPs to a target voltage range.

Voltage control is managed through balancing the production and absorption of reactive power. For normal operation, slow voltage response is used to manage small adjustments to reactive power, as demand and generation varies.

Mitigation approaches

At a transmission level, TNSPs are required to appropriately plan their investment to anticipate for low load periods, and have adequate voltage control equipment installed, which can include a range of devices such as capacitor banks, reactor banks and more dynamic devices (for example, static Var compensators [SVCs] or synchronous condensers. There may be opportunities to coordinate voltage control strategies in parallel with other system needs like system strength and inertia.

Case study | Western Australia | 20 October 2018

AEMO observed a minimum demand day on Western Australia's SWIS on 28 October 2018 at 10:35 am. At this time, DPV output was estimated to be approximately 754 MW and system load was 1,324 MW. Due to high DPV generation and low self-consumption, over-voltage conditions were experienced throughout the network. To resolve this, existing voltage control capability from many distribution transformers attempted to reduce their tap settings. However, by this time, the lowest tap positions had already been achieved and no further voltage support management was attainable through tap changing. In addition, reactive power flows were observed upstream, transferring from the distribution to the transmission network, requiring this to be absorbed by large-scale synchronous generators.

This highlights one example of upstream power flows from DPV. In the SWIS it has been observed that during 2018 alone, this issue has already been identified at over 30 distribution feeders, occurring at least once per month. With increasing amounts of DER on the network, these phenomena will continue to increase, with more feeders exhibiting reverse active power flows, greater frequency and magnitude for reverse reactive power flows to be absorbed by larger, upstream, synchronous generators, and more zone substation transformers operating at the lowest transformer tap settings.

Potential solutions include ensuring local voltage control capabilities are enabled in connecting DER, through standards and other connection requirements. Initiatives in this area have already begun; as of July 2019, Western Power has amended its connections requirements to ensure all new DPV connection applications require the mandatory enablement of volt/var and volt/watt capability.

For more on requirements, see Western Power, Network Integration Guideline, at https://westernpower.com.au/media/3403/network-integration-guideline-inverter-embedded-generation-20190802.pdf.

A4.3 Managing DPV generation variability

Increasing level of uncontrolled DPV generation will impact AEMO's ability to balance supply and demand in real time, through:

- Fast ramping up or down of the DPV generation in response to cloud movements, given there are significant clusters of DPV in close proximity within metropolitan load centres.
- The resulting demand variability at certain transmission connection points may result in voltage stability challenges.
- At the regional level, the growth in DPV generation may result in increasing forecast uncertainty. To date, this has been sufficiently managed by AEMO's forecasting and frequency management processes, but may require increasing enablement and use of regulation FCAS in the future.
- The ramp down in DPV generation coincides with the ramp up in demand into the evening peak over a three- to four-hour period. Sufficient fleet flexibility will be needed to manage these ramps as DPV growth continues.

A detailed exploration of system balancing requirements with increasing levels of distributed and utility wind and solar generation is presented in Appendix C. It considers the contribution of DPV generation to net demand variability over different time scales (from 30 minutes to four hours) and assesses regional system flexibility requirements over these time scales out to 2025.

For the power system to operate securely and reliably, energy supply and demand must always be balanced. This requires managing variability and uncertainty (on both the supply and demand side) over different operational timescales.

- Frequency control services are designed to inject or remove power to address deviations in the supply-demand balance between 5-minute energy dispatch intervals.
- AEMO's centrally coordinated, security-constrained economic dispatch process balances supply and demand in 5-minute increments.
- Projected Assessment of System Adequacy (PASA) processes consider the supply demand balance for the current and following day (Pre Dispatch PASA) and two to seven days ahead (Short Term PASA) – including assessment of reserve requirements

The impact of DPV generation is reflected in the demand forecast, as AEMO considers rooftop PV as negative demand, rather than supply.

Case study | Alice Springs | 13 October 2019

On 13 October 2019, Alice Springs experienced a black system event at 2:18 pm, with approximately 12,000 customers impacted. The event was triggered by sudden cloud cover reducing generation from a large-scale solar farm and residential DPV systems. This sudden loss of generation caused a surge of demand on the grid which the Alice Springs power system was not able to accommodate.

The Commissioner's review into the event identified that there were key failures in the lead up to the black system, including operating the system in an insecure state with insufficient spinning reserve and limited regulating reserve, and issues with the AGC, Jenbacher generator controls, battery energy storage system (BESS), and the settings of the UFLS scheme.

While an event of this nature is unlikely to have similar consequences in the NEM, given the much larger geographic area and size of the power system, it does highlight the importance of investigating the implications of possible rapid changes in generation. This may have implications for interconnector flows or intra-regional line limits.

For more, see Utilities Commission of the Northern Territory, Independent investigation of Alice Springs System Black Incident on 13 October 2019, at https://utilicom.nt.gov.au/__data/assets/pdf_file/0011/767783/Independent-Investigation-of-Alice-Springs-System-Black-Incident-on-13-October-2019-Report.pdf.

Case study | Europe solar eclipse | 20 March 2015

On 20 March 2015, Europe experienced a near-total solar eclipse. Knowing both that a disruptive event was going to occur, and the location and capacity of DER across continental Europe, system operators across 23 countries spent the preceding six months extensively planning together for the event and putting in place measures to maintain system security throughout the eclipse.

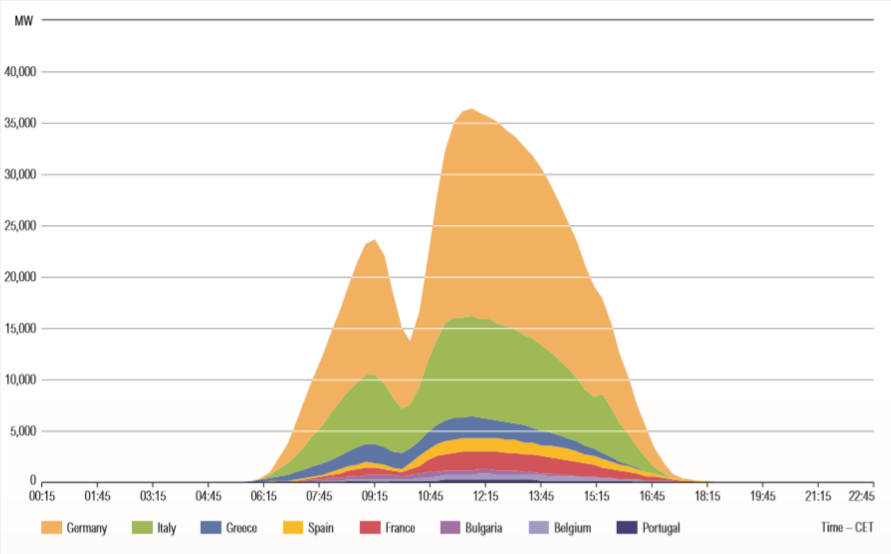
The eclipse occurred on a sunny weekday morning and affected an area that had around 89 gigawatts (GW) of PV installed. (Some countries, such as Italy, have mostly utility-scale PV while others, such as Germany, have predominantly rooftop PV.) Preliminary forecasts estimated that if the day remained clear, the PV output would decrease by around 20 GW within the first hour of the eclipse and increase by almost 40 GW after the maximum impact of the eclipse. That is the equivalent of the entire NEM system coming online.

The system operators procured enough ancillary services, among other measures, to provide the support that was projected to be required to keep the system operating. In the event, there was more cloud cover over Western Europe than had been forecast, so the impact was slightly subdued. Nevertheless, a large and fast decrease in PV output occurred, and, more significantly, so did a rapid ramp-up in PV generation as the eclipse passed. Figure 19 shows the aggregated PV feed-in during the solar eclipse from a subset of European transmission system operators (TSOs).

Because they could forecast and plan ahead, power system operators were able to maintain the interconnected system within relevant frequency operating standards. One of their main lessons was the importance of understanding the technical characteristics of PV generation, specifically:

- A clear description of installed PV capacity and its capabilities is needed for the accuracy of forecast studies (like technical data, retrofitting campaign, and disconnection/reconnection settings and logics).
- Real-time measurement of dispersed PV generation is the key for adapting the operational strategy in real time.

Figure 19 Aggregated PV feed-in from a subset of European TSOs



Source: ENTSO-E Solar Eclipse March 2015: The successful stress test of Europe's power grid (15 July 2015).

A total solar eclipse will cross the Australian continent on Saturday 22 July 2028. AEMO will draw on the European experience on in preparing how this will be managed in the NEM. The eclipse will reduce the available solar resource across the full extent of the NEM over the period spanning 12:15 pm to 1:50 pm AEST. AEMO has prepared estimates of solar generation during the 2028 solar eclipse for clear sky weather using three 2018 ISP scenarios of distributed and utility-scale solar uptake, displayed in Figure 20.

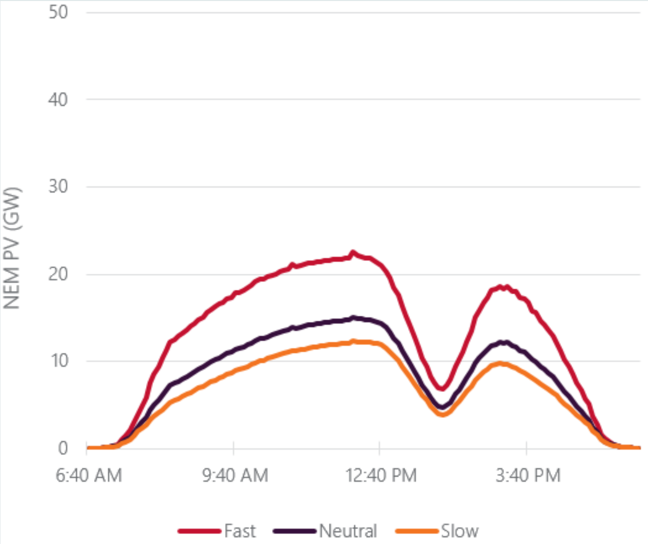
Scheduling adequate flexible generation and network capacity to maintain system security and resilience during this unprecedented event will require an extensive effort of collaborative preparation and co-ordination. Key system operator concerns will be sustaining frequency, voltage, angular and transient stability, and adequate reserves within secure limits during the period of fluctuating generation and network flows, at both transmission and distribution levels.

The power system significance of this event may exceed recent international experiences in Europe and the USA, due to the:

- Path of totality passing over the NEM's largest population centres, impacting the vast majority of distributed and utility-scale solar generation near the time of solar noon.
- Concurrent timing of the maximum eclipse effect across all NEM regions due to the NEM's primarily north-south axis of orientation, limiting the viability of resource-sharing as a mitigation strategy.
- High proportion of solar generation relative to non-solar generation installed in the NEM.
- High proportion of solar generation without feed-in management installed in the NEM.

Power system management strategies that have been implemented internationally include preparing solar generation forecasts, modelling secondary meteorological impacts, increasing frequency regulating reserves, strategic scheduling of flexible and/or off-market resources, enhanced collaboration between neighbouring jurisdictions to maximise resource-sharing, pre-curtailment of controllable solar where feasible, training of operations staff and real-time co-ordination of wide-area operations on the day. Further measures may be required in Australia to maintain system security and resilience during this significant natural phenomenon.

Figure 20 Estimated NEM solar generation profiles, 22 July 2028, 2018 ISP Fast, Neutral & Slow scenarios



For more, see ENTSOE, Solar Eclipse: The successful stress test of Europe's power grid, 2015, at https://www.entsoe.eu/Documents/Publications/ENTSO-E%20general%20publications/entsoe_spe_pp_solar_eclipse_2015_web.pdf.

Mitigation approaches

Measures that would assist with managing DPV generation variability are listed below:

- Further visibility and monitoring of DPV (and weather) to better understand the anticipated changes in generation due to cloud cover and weather impacts, to manage forecast ramp requirements. There is a need for AEMO to improve the performance of weather forecasting and power forecasting models to appropriately manage uncertainty under variable or extreme weather conditions.
  - Further information on improvements to forecasting tools can be found in Appendix C, Section C6. These improvements are generalised across utility-scale wind and solar generation and DPV. However, additional focus is warranted for DPV, due to the low levels of visibility and monitoring currently available.
- Longer term, two-way markets incentivising active demand side participation from load and storage in the distribution network would assist with managing DPV generation variability.
- Introducing the capability to dynamically curtail DPV as a last resort if this is required for system security, to manage net load variability and satisfy ramping availability.

A4.4 Bulk system operation in 2025

This section brings together the different challenges considered in this section to present a high-level overview of potential DPV impact on bulk power system operation in 2025.

Figure 21 shows, for each NEM region, a comparison of projected half-hourly dispatch outcomes in 2025 against the 2019 historical year. Overlaid on each plot are zones reflective of the different operating conditions under which challenges associated with increasing levels of DPV online might arise.

Each NEM region is projected to be frequently operating with significantly higher penetrations of passive DPV generation than today. Further analysis is required to better understand the operational implications of this transition for each region, but the charts do present a preliminary indication for a subset of challenges that may emerge by 2025.

Zone A: instantaneous penetrations of DPV generation above 20%, beginning to noticeably impact the system load profile

As penetrations continue to increase, specific operational challenges may arise associated with:

- **Load necessary for emergency mechanisms** – increasing levels of DPV generation online during low underlying demand periods begin to impact the availability of stable load blocks necessary for the effectiveness of emergency mechanisms following rare high impact, low probability events during daytime. UFLS schemes require sufficient load available for shedding to arrest a frequency decline. System restart requires dependable load blocks for the sequential activation of load and generation following a black system event.
- **Transmission network voltage control –** reducing daytime load as seen by the transmission network in locations with sufficiently large clusters of DPV generation. The purple line traces out historical night-time minimum demand levels. Minimum operational demand occurs in the daytime in South Australia and Victoria today and this is projected to be the case all NEM mainland regions by 2025. Sufficient reactive capability will be necessary to maintain transmission voltages as loads continue to reduce.
- **Managing net load variability** – sufficient flexibility is required in the system to cover increasing ramps in solar generation as PV penetrations increase, including the daily ramps especially DPV ramp down at the end of the day coinciding with the ramp up of underlying demand leading into the evening peak. Cloud movements may also result in faster, less predictable net load ramps at the regional level, and for significant PV clusters at the sub-regional level, potentially resulting in transmission voltage control challenges.

Zone B: the potential mass disconnection of DPV begins to materially impact the effectiveness of contingency management practices

At this point, loss of DPV generation might exceed potential load disconnection following plausible transmission disturbances. If this is coincident with the loss of the largest generating unit, it would result in a contingency exceeding the largest credible risk in the region. Beyond this point, additional measures will need to be in place to manage increasing contingency sizes. Eventually, contingency sizes may become unmanageably large, especially for regions of the NEM that may operate as an island under some conditions.

The disturbance withstand capability of the DPV fleet will be increasingly critical to securely manage the power system. Improved performance standards, compliance with these standards, and the ability to remotely update settings in the existing fleet will all contribute to reducing this risk into the future. In the absence of these measures, regional hosting capacity limits on DPV will become increasingly necessary to manage this risk.

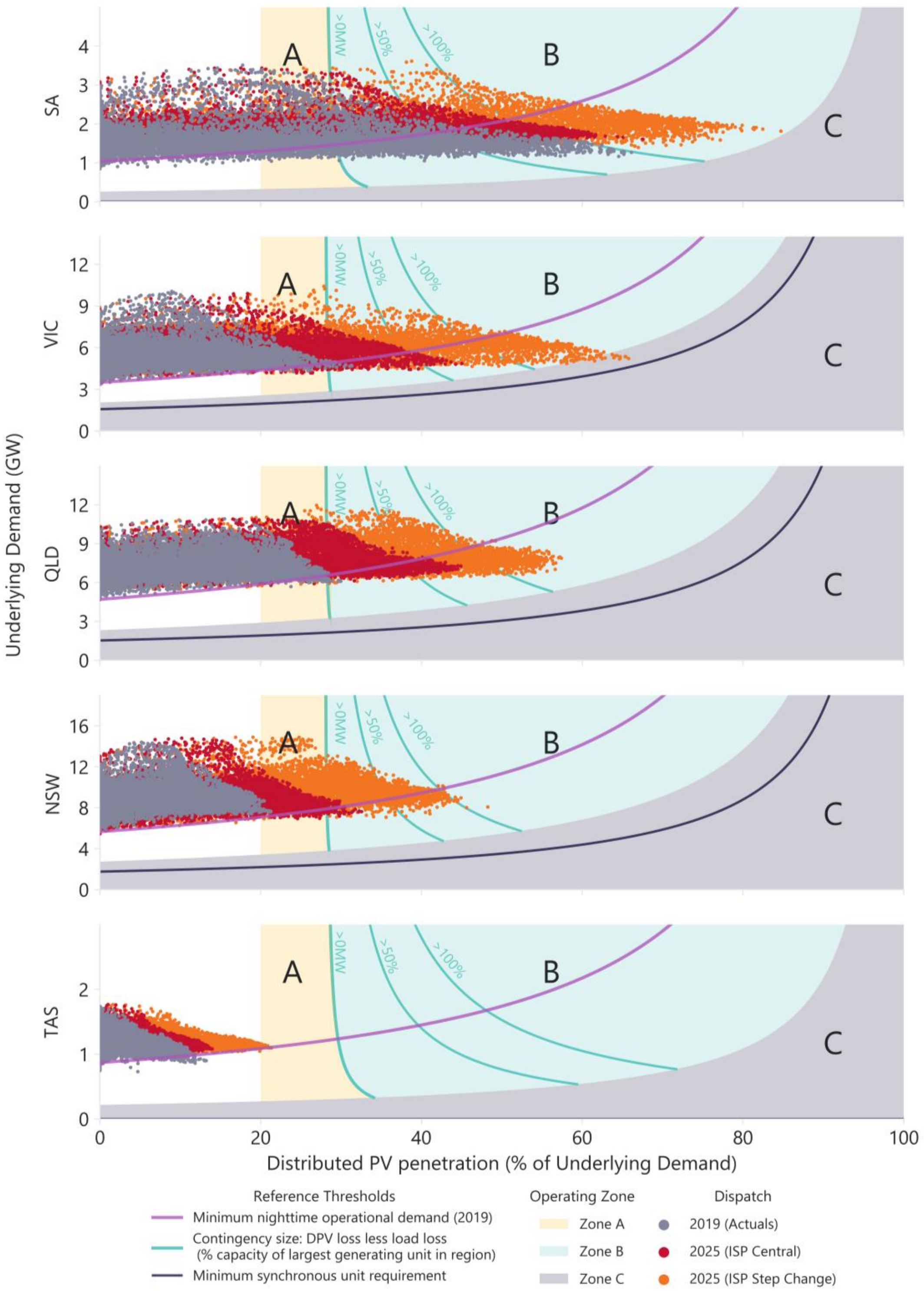
Zone C: operational demand has reduced to such a point that there is insufficient load to support minimum synchronous generation requirements for system security

The provision of required system strength, inertia, and FCAS services for system security requires sufficient load available for minimum synchronous unit operating levels. This provides a hard limit to DPV penetrations. By 2025, South Australia and Victoria are projected to be operating close to or into Zone C. Analysis for South Australia has identified that under system normal conditions, there is sufficient interconnector capacity for the minimum synchronous unit requirements to be met even if operational demand in South Australia is zero or negative. Under credible risk of separation or islanded conditions (with reduced or no AC interconnector export available to support local FCAS enablement and inertia requirements), additional local load or PV curtailment will be required.

Zones have been defined based on AEMO's analysis to date of system challenges associated with increasing DPV generation in the South Australia region, including ULFS adequacy in the daytime, system security implications of DPV disconnection, and minimum load requirements during islanded conditions. This has highlighted the need to plan and implement operational strategies to manage these impacts in the short term.

As part of this, urgent changes to improve the performance of the DPV fleet in response to disturbances, improved compliance with standards, and a level of real-time visibility of, and generation shedding capability in, the DPV fleet will all assist with managing these challenges in South Australia. Over the next five years, other NEM regions are projected to enter similar operating zones as South Australia today. Based on the South Australian experience, implementing these changes for new DPV systems nationally, in anticipation of high penetration in other regions, would assist with securely integrating the future DPV fleet with the needs of the power system.

Figure 21 Current and projected distributed solar penetration and underlying demand for all half-hour periods



A4.5 Integration of distributed solar PV within bulk system operation

A range of measures can assist with the secure and efficient integration of increasing levels of DPV generation in the bulk power system. Figure 22 below summarises the mitigation approaches identified for the different bulk system challenges identified in this section, with an indication of the relevant operating conditions under which they may be necessary.

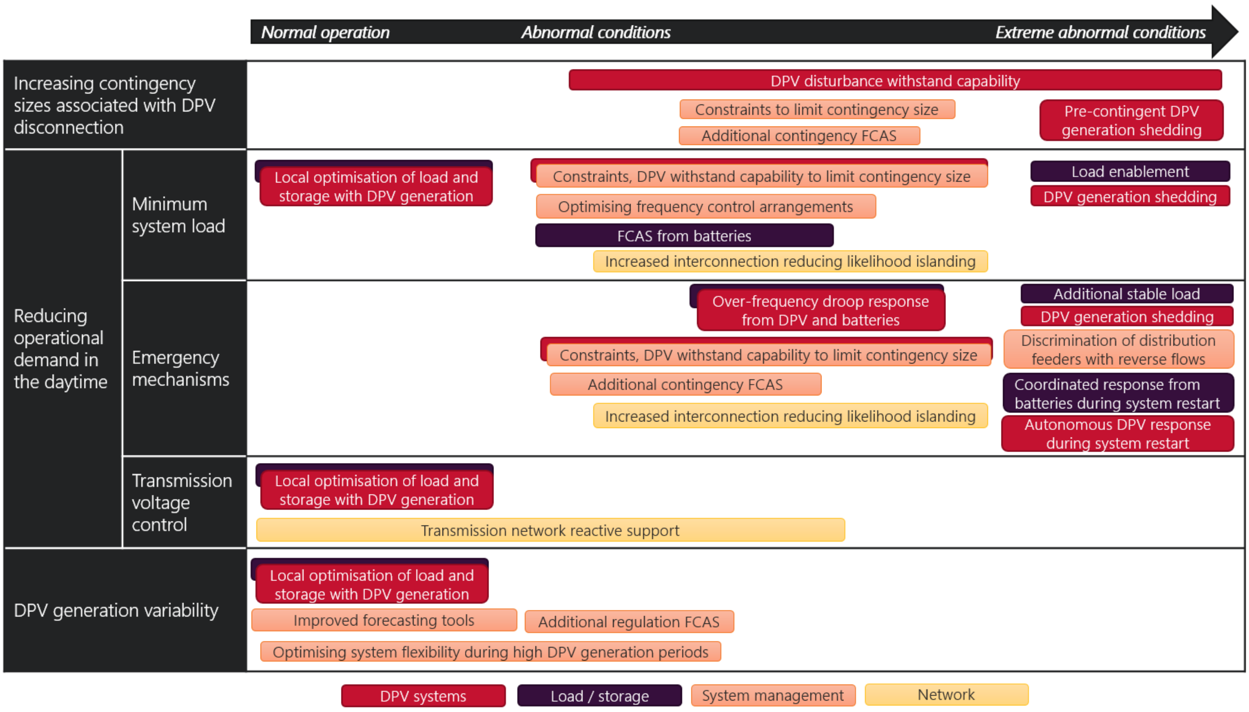
Operating conditions span a range from normal daily operation to extreme abnormal system conditions. Contingency events in the power system may result in any number of **abnormal conditions**. The power system is planned and operated so that it can cope with the abnormal conditions resulting from single credible contingency event by procuring ancillary services and utilising constraints in the dispatch process. **Extreme abnormal conditions** represent system operation during exceedingly rare circumstances such as unusual outage conditions, regions islanded from the NEM or at risk of separating, and system recovery and restoration following major non-credible events.

Measures have been categorised across the following dimensions:

- **DPV systems**, which includes:
  - Local active management of DPV generation on a daily basis.
  - Inbuilt autonomous grid support and withstand capability in the inverter.
  - Generation shedding capability during extreme abnormal system conditions.
- **Load and storage**, which includes:
  - Active management to act as a 'solar sink' on a daily basis.
  - Grid support during abnormal system conditions.
  - Enablement during extreme abnormal system conditions when required to offset DPV generation for system security.
- **System management**, which includes:
  - Procurement of reserves.
  - Operational measures to ensure adequate system security services are available during periods with high levels of passive DPV generation online.
- **Network** – network development options helping to mitigate the consequences of high DPV generation in the daytime and reducing the likelihood of regions islanding from the NEM. This can include the likes of building new transmission lines, or network resistor banks.

Figure 22 does not intend to provide the relative priority or effectiveness of individual specific measures. However, as noted in Section A4.5.3, DPV generation shedding capability is AEMO's only feasible operational lever to securely manage the power system if extreme abnormal conditions were to arise during high DPV generation periods.

Figure 22 Measures assisting with the integration of DPV generation in the bulk power system



A4.5.1 System normal conditions

Local co-optimisation of DPV generation with storage and load behind-the-meter, through the development of two-way market frameworks at the distribution level, will be important for the long-term efficient integration of DER within Australia's energy systems. This would unlock efficiencies on a daily, system normal basis by better aligning load and generation activity behind the meter with power system needs.,

In doing so, local optimisation of DER can become a valuable source of flexibility in the reliable real-time balancing of supply and demand during normal power system operation. Other mechanisms, however, will be necessary in addition to these measures to manage power system security during abnormal system conditions.

A4.5.2 Abnormal system conditions

Autonomous grid support and disturbance withstand from DPV and storage inverters can assist with system recovery following credible contingency events. In the absence of these measures, other system management strategies (such as constraints to limit contingency and procurement of additional contingency FCAS) would be necessary to manage power system security.

Without changes to the performance requirements for DPV generation, these measures will be increasingly costly as DPV generation increases.

A4.5.3 Extreme abnormal system conditions

Adequate back-stop mechanisms will be necessary to maintain system security during extreme abnormal system conditions.

AEMO has identified an urgent need for DPV generation shedding capability over a sufficient proportion of the DPV fleet as a critical back-stop mechanism for maintaining power system security in the South Australia region as daytime operational demand continues to reduce. This would be activated during rare operational periods when South Australia is operating as an island, or during unusual power system outage or other abnormal conditions. For the purposes of maintaining adequate levers for secure system operation in extreme abnormal operating conditions during high DPV generation periods, AEMO's work to date has found:

- Generation shedding capability as a "back-stop" measure is essential. This is required in addition to ongoing investment in storage and development of distributed markets for daily efficient market operation.
- This back-stop capability is likely to be utilised very rarely.
- When it is required, the necessary change in the supply-demand balance could be very large and increasing as DPV generation continues to grow.
- Harnessing load and storage flexibility may reduce the amount of DPV generation shedding necessary, however does not remove the need for the generation shedding capability to be available in the first place, due to the scale of imbalances that would need to be managed in extreme abnormal conditions.

A sufficient level of DPV generation shedding capability available during extreme abnormal system conditions will help to ensure other sources of system flexibility (such as load and storage within the distribution network) can be used more efficiently on a day-to-day basis, by not having to be reserved or set aside for exceedingly rare system events.

A5. Actions

This section summarises key actions to securely integrate increasing penetrations of DPV with the needs of the power system. Actions are centred around three key priority areas:

- **Device performance –** a minimum and consistent level of performance across the DPV fleet in response to small deviations and larger disturbances in the power system.
- **Active management capability –** the ability to curtail some portion of the DPV fleet during extreme, abnormal system conditions as a last resort measure to maintain power system security.
- **Visibility –** a sufficient level of real-time visibility of the PV fleet at the appropriate level of aggregation for situational awareness.

In the absence of such reforms, AEMO will increasingly need to recommend hard regional hosting capacity limits for passive DPV, which may necessitate moratoriums on new DPV installations or costly retrofit of existing DPV systems.

A5.1 Aggregate performance of the DPV fleet

The aggregate performance of the DPV fleet is becoming increasingly critical as penetrations increase. Without action, the largest regional and NEM contingency sizes will increase due to DPV disconnection in response to major system disturbances.

Performance requirements for DPV systems during power system disturbances are defined in the Australian Standards for small-scale inverters (AS/NZS 4777.2:2015) and called upon in DNSP connection requirements. Strengthening how these requirements and governance arrangements are set and enforced will help better align the aggregate capability of the future DPV fleet with power system needs.

A5.1.1 Performance and capability

Identified priority actions associated with addressing DPV disconnection risks are centred around improving device performance and capability:

- Progress the urgent introduction of short-duration voltage disturbance ride-through requirements in South Australia and Western Australia to assist with managing the risks associated with DPV disconnection during plausible contingency events in the power system.
- Progress the update to AS/NZS 4777.2 to ensure DPV inverters provide an autonomous response that supports the power system during normal variability and during abnormal conditions through withstand requirements more consistent with large-scale generation. (More details about proposed changes to performance standards can be found in AEMO's *Technical Integration of DER* report[37].)

Action 3.1	By 2021: AEMO to fast-track requirement for short duration voltage disturbance ride-through for all new DPV inverters in South Australia and Western Australia (other NEM regions encouraged) and investigate need for updating existing DPV fleet to comply with fast-tracked short duration voltage disturbance ride-through requirement.

[37] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

Action 3.2	By 2022: AEMO to collaborate with industry, through Standards Australia committee, to progress update to national standard for DPV inverters (AS/NZS 4777.2) to incorporate bulk system disturbance withstand and autonomous grid support capability.

A5.1.2 Governance and compliance

Power system security obligations for large-scale, centralised generation are specified in requirements for generators in the NER. In comparison, governance arrangements for the DPV fleet (and other distributed energy resources) are set out across a variety of regulatory instruments. Coordination and collaboration is required across industry to ensure the secure and efficient integration of these devices within the power system, especially in relation to technical performance requirements and their enforcement.

Currently, there is:

- No formal pathway to ensure power system security and other requirements are accounted for within technical standards set by industry consensus. Without change, there is no guarantee that the future DER fleet will perform in a way that aligns with power system requirements as penetrations increase into the future.
- Inconsistent compliance with technical performance standards across the DPV fleet today and a lack of clarity around enforcement. Feedback from DNSPs and post-event analysis of recent system events indicate non-compliance with AS/NZS 4777.2:2015 and distribution network connection requirements is a significant problem.

Action 3.3	In 2020: AEMO to collaborate with the Energy Security Board (ESB), AER, AEMC, and industry to: • Submit a rule change establishing the setting of minimum technical standards for DER in the NEM (with similar reforms to be proposed for Western Australia's SWIS) covering aspects including power system security, communication, interoperability, and cyber security requirements. • Develop measures to improve compliance with new and existing technical performance standards and connection requirements for DPV systems, individual DER devices, and aggregations in the NEM (and SWIS).

A5.2 Active management capability

System dispatchability is decreasing as invisible and uncontrolled DPV increases to levels not experienced elsewhere globally. In 2019, South Australia operated for a period where 64% of native demand was supplied by DPV; by 2025, all mainland NEM regions could be operating above 50% at times.

In the short term, secure integration of DPV generation within the power system urgently requires a level of generation shedding capability over a sufficient portion of the DPV fleet during extreme, abnormal system conditions. This would involve collaboration with DNSPs and the wider industry to:

- Technically define power system needs for DPV generation shedding capability to inform technical requirements for response and enablement.
- Establish DPV device level requirements and engage with DNSPs to mandate in connection requirements for new DPV installations.
- Establish if there is a need for generation shedding capability in the existing DPV fleet and, if necessary, determine the feasibility of doing so.
- Establish technical and regulatory pathways for DNSPs to be able to design and implement DPV generation shedding schemes.

Action 3.4	By 2021: AEMO to collaborate with industry to: • Mandate minimum device level requirements to enable generation shedding capabilities for new DPV installations in South Australia (other NEM regions and Western Australia encouraged). • Establish regulatory arrangements for how DNSPs and aggregators could implement this as soon as possible. • Investigate the need for updating the existing DPV fleet to comply with regional generation shedding requirements.

Longer term, the efficient integration of DPV generation will require active management with other DER on a daily basis to better align load and generation behind-the-meter with power system needs. Several initiatives in this regard are being considered within AEMO's DER Program and collaboration with wider industry, including:

- Interoperability requirements for remote interaction with DPV allowing remote querying and updating of settings for inverters.
- Communication protocols and information models for the coordination of instructions to individual DPV systems near real time to enable their participation in future markets.
- Cybersecurity requirements for secure remote interaction with DPV devices.
- Extending the activities in activating the PV fleet to further activate load and energy storage (either large-scale or distributed) to shift and increase demand during high DPV generation periods.

A5.3 Real-time visibility

Real-time visibility goes hand-in-hand with active management of DPV generation. DPV generation shedding capability will require a level of visibility or predictability over the generation available for shedding at any given time in order to quantify the secure technical operating envelope of the power system.

To obtain increased visibility of DPV operation in real time, a combined work program with distribution businesses is required to define and increase the amount of real-time visibility (as a suitable level of aggregation) to ensure AEMO and the distribution networks have sufficient situational awareness to maintain power system security and make efficient decisions.

Action 3.5	By 2021: AEMO to collaborate with DNSPs to establish aggregated predictability or real-time visibility requirements for DPV systems available for curtailment and consistent real-time SCADA visibility for all new commercial scale (> 100 kW) systems.

Maximising the contribution of DPV and other DER in the future may necessitate increasingly detailed mapping of distribution networks to provide increased visibility of locations and times when various limits are binding in pockets of the network. A level of real-time visibility would be required to securely integrate coordinated action of high penetrations of aggregated DER within AEMO's centralised dispatch process.