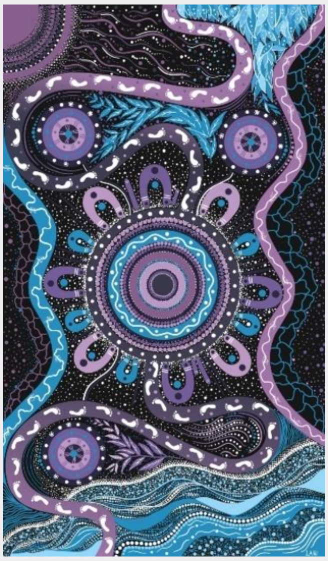
Supporting secure operation with high levels of distributed resources

Q4 2024

A report for the National Electricity Market



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This report provides stakeholders with a status assessment on some of the new capabilities required to securely operate the National Electricity Market (NEM) in periods with high levels of generation from distributed PV and low demand. To facilitate continuing growth in customer distributed PV, in addition to a broad suite of complementary measures including accelerating efforts to provide customers access to market frameworks, the report recommends urgent action to introduce "emergency backstop" capabilities for all new distributed PV installations so that the NEM can operate securely in these periods.

This report aims to highlight technical risks and provide the technical basis for further actions to address them. It focuses on articulating the technical power system needs, and the technical solutions required, as a basis for collaboration with stakeholders on the broader measures required to introduce those technical capabilities.

This report is published in accordance with AEMO's responsibilities under the National Electricity Rules (NER) 4.3.1(n), to refer information of which AEMO becomes aware in relation to significant risks to the power system where actions to achieve a resolution of those risks are outside the responsibility or control of AEMO.

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Executive summary

Today one in three Australian homes have rooftop solar. These households and businesses are having a meaningful impact on Australia's energy transition. Because of these investments in rooftop solar, at certain times, rooftop solar is now supplying more than half the grid's energy needs. This is expected to grow in just the next few years to 90-100% of the grid's energy needs supplied from rooftops in some periods. This an example of how Australia is leading the way in the global energy transition.

Australia's power grids rely on a balance between generation and demand. This is managed every five minutes, every day of the year. Just as it is necessary to make sure that there is enough generation when there is very high demand, it is also necessary to make sure there is not too much generation in the power system. If there is too much generation in any one location then power flows will exceed stable limits.

To maintain system stability today, some larger generators need to remain online. These larger generators have minimum generation levels, which also contributes to the available generation. If power flows exceeds stability limits, or if there are not sufficient large generators online, then the grid will not be strong enough to handle disturbances like a sudden loss of a transmission line or generating unit.

While AEMO can, and does, control large scale generation to manage security limits through dispatch in the electricity markets, it is not possible at present to do this for most small scale generators like rooftop solar. Now that rooftop PV is supplying more than half the grid at times, this requires introduction of a new “emergency backstop” mechanism, to allow rooftop PV systems to be curtailed or turned off briefly if necessary in rare emergency conditions, similar to the capabilities normally required of any large scale generator.

With suitable complementary measures progressed in parallel, these interventions won't happen often, and won't last very long, but they will help keep the grid secure for millions of homes and businesses.

These measures will support continued flourishing of consumer energy resources, and ensure Australia’s grid remains stable and secure.

Australians continue to invest in distributed photovoltaics (PV) and other consumer energy resources (CER) at world leading- levels. More than one-third of homes across the country now host rooftop solar systems, helping households and businesses reduce their energy bills and directly contributing to the decarbonisation of the energy system.

The last decade has seen significant effort to support the transition to greater amounts of large-scale renewables, including improved performance standards and new operational approaches to maintain system security and reliability. A similar concerted effort is required to ensure CER are effectively integrated within the power system as uptake continues, in a way that supports the secure and reliable delivery of electricity to all consumers now and into the future.

Given the growing installation of distributed PV, there are increasing periods where there is a significant amount of generation from distributed PV in the daytime, resulting in low operational demand from the transmission network. CER and behind-the-meter flexibility (including electric vehicles [EVs], storage and demand response) can be harnessed to “soak up” this excess distributed PV generation. This represents a major opportunity for consumers and businesses to capitalise on abundant cheap electricity by shifting consumption to the middle of the day, further reducing their energy costs.

However, the significant majority of the distributed PV fleet is currently not monitored in real time or able to be controlled or actively managed even under emergency conditions. This is posing challenges to both distribution network and bulk power system operation, especially in sub-regions and regions with higher distributed PV uptake relative to local load.

This is a complex task given the millions of individual consumers and devices involved, the large number of stakeholders across the CER ecosystem and supply chain, and the extent of integration and coordination required across different systems and parties. Effective integration of CER will involve the intersection of power system engineering, technological innovation, consumer choice and experience, and government policy.

In July 2024, Australia's Energy Ministers agreed to a National CER Roadmap[1], building on advice from the Energy Security Board (ESB) around critical technical capabilities for ongoing power system security. The CER Roadmap sets out an overarching vision and plan to unlock CER at scale and identifies measures to "unleash the full potential of CER" by establishing the required mechanisms, tools and systems. This includes both:

- Reforms to increase the opportunities for market participation of CER, including through enhanced coordination, allowing customers to respond to market-based incentives which will also help meet the challenges of low operational demand.
- Measures to support ongoing power system security, particularly the requirement for "backstop mechanisms to be in place" by the end of 2025 for "emergency response to ensure operational security when required".

Minimum operational demand in the National Electricity Market (NEM) has been falling on average more than 1.2 gigawatts (GW) per year and is projected to continue on this trajectory. During these periods, there is limited demand being supplied from the main transmission system. At present, the power system relies on large-scale plant to deliver a range of system security services (system strength, inertia, voltage management and ramping). To deliver these services, these large-scale plant need to operate above minimum safe operating levels. In periods of very low operational demand, it may not be possible to dispatch enough large-scale plant above their minimum safe operating levels to deliver these essential security services.

There are a range of solutions to these challenges, with many of these being actively considered, noting that implementation of these through regulatory mechanisms can take some time while the need for action is already urgent, and more so in some regions:

- **Reduce the amount of generation that needs to remain online to provide essential services** – this can be done by reducing the minimum safe operating levels of essential units, or investment in new assets that can provide system services in other ways (such as synchronous condensers, batteries, and/or reactive power management devices). AEMO will publish the *Transition Plan for System Security* in December 2024, which will provide further detail on these options.
- **Increase demand in daytime periods** – Increasing demand in daytime periods can make more effective use of the abundant distributed PV generation available in these periods. This may include new industries which increase constant or flexible demand, and may also include electrification of appliances and transport, and

[1] See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

increased demand response and coordination of CER. Practical options to increase responsive demand may evolve over time, but are operationally very limited at present.

- **Store energy** – storage can help move energy from daytime periods to other periods, increasing demand when required particularly during emergency conditions (and facilitating efficient use of the abundant energy available in low demand periods). This capability is very limited at present, but will likely increase due to increased investment in storage technologies, and through the coordination of CER storages.
- **Decrease distributed PV generation** – along with reducing generation from non-essential generating units (scheduled, semi-scheduled, and non-scheduled), it is crucial that sufficient operational levers are available to actively manage distributed PV. Under normal conditions this might include development of various market mechanisms to provide incentives for customers to manage their CER in line with market signals. To manage high-risk conditions that occur on the power system from time to time, it must be technically possible to reduce generation from all large-scale generators, and now that distributed PV is supplying more than half the grid at times (and projected to grow to ~90% in the next few years), a similar capability is now required for distributed PV systems. An "emergency backstop" mechanism is now needed to allow emergency curtailment of distributed PV when needed to maintain system security when the above options are insufficient. If appropriate market mechanisms and incentives are introduced to encourage customers to respond to market signals, the emergency periods where this kind of intervention is required should remain infrequent, but essential for maintaining a secure and reliable supply of electricity for customers.

> "Emergency backstop" capability refers to operational measures to reduce aggregate distributed PV generation if required for system security, when other options have been exhausted.

AEMO is working on all these options, including through the National CER Roadmap, and supported by information published through compliance reporting, the Engineering Roadmap Priority Actions reports, the *Electricity Statement of Opportunities* (ESOO), and the upcoming *Transition Plan for System Security*.

This report adds to those activities, with a focus on articulating the technical challenges emerging in minimum system load (MSL) periods, and the technical basis of the need for implementation of emergency backstop capabilities.

AEMO understands the urgent need to introduce mechanisms to incentivise CER participation in coordinated action to meet system needs. These mechanisms will be discussed in later reports and regulatory reforms.

Given the complexity and timeframes associated with market reform and the uptake of sufficient load and storage flexibility in the daytime, there are likely to be periods where there is an excess of solar generation at certain times of the year. During these periods, it is essential that there are systems and processes to balance generation and demand within the stable, technical operating envelope of the power system to mitigate the risk of widespread and prolonged outage situations.

If there are insufficient emergency backstop capabilities, alternative higher impact interventions may be needed, such as:

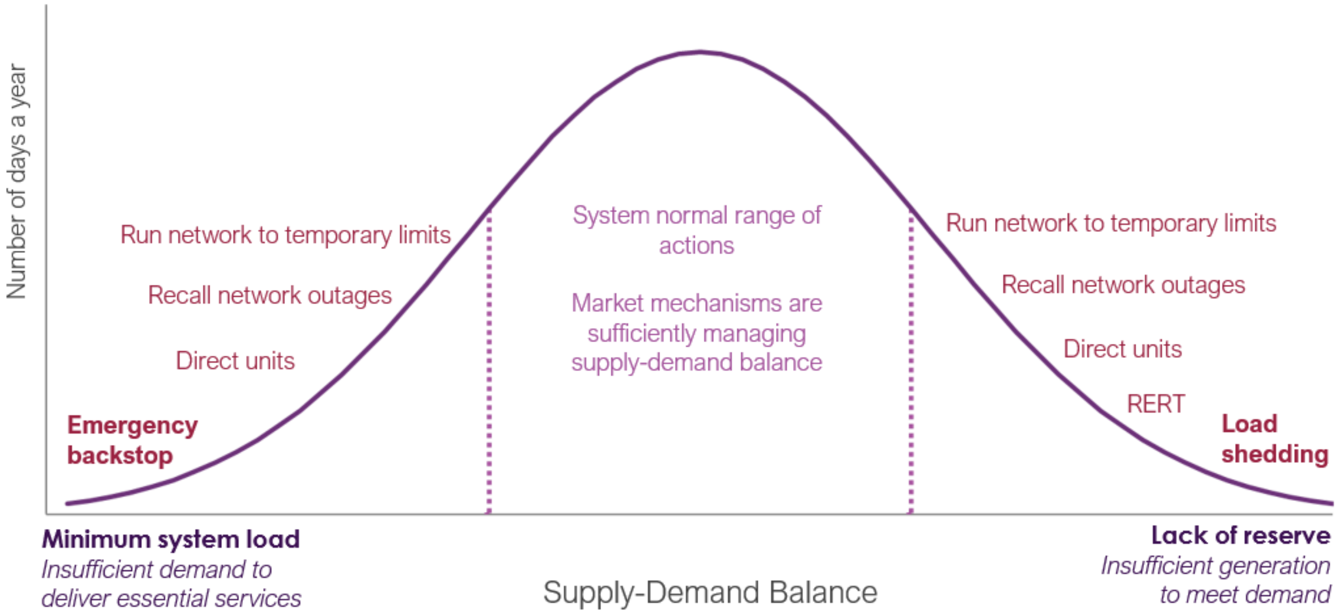
- Distribution voltage management – in some regions, it is possible to increase distribution voltages to the level required to deliberately trip/curtail distributed PV. This is a crucial backup mechanism to resecure the system if needed in rare emergency events, but should not be used on a regular basis. It may require jurisdictional support to operationalise.

- Shedding of reverse flowing feeders – the only mechanism remaining to increase operational demand to the levels required would be to shed entire feeders that are in reverse flows (for example, 11 kilovolts [kV] or 22 kV circuits). This would shed all consumer load on the feeder and have a very high impact on homes and businesses.

If sufficient backstop capability is not available, and the above mechanisms are also exhausted, the NEM may be operating insecure for extended periods, and therefore be operating outside of the risk tolerances specified in the National Electricity Rules (NER), where the loss of a single transmission or generation element may lead to reliance on emergency control schemes to prevent system collapse. This places customers at elevated risk of system collapse. The ability to restore the system following a black system event may also be compromised at times of very high distributed PV generation.

Figure 1 illustrates the spectrum of options used to manage emergency conditions, needed for managing periods of both low and high demand.

Figure 1 Emergency backstop to be used only when other options have been exhausted



RERT refers to the Reliability and Emergency Reserve Trader, an NER mechanism for AEMO to contract capacity electricity reserves when a reserve shortfall is projected up to nine months in advance.

To maintain system security, all mainland NEM regions (South Australia, Queensland, Victoria and New South Wales/Australian Capital Territory) need operationally effective emergency backstop capabilities as soon as possible.

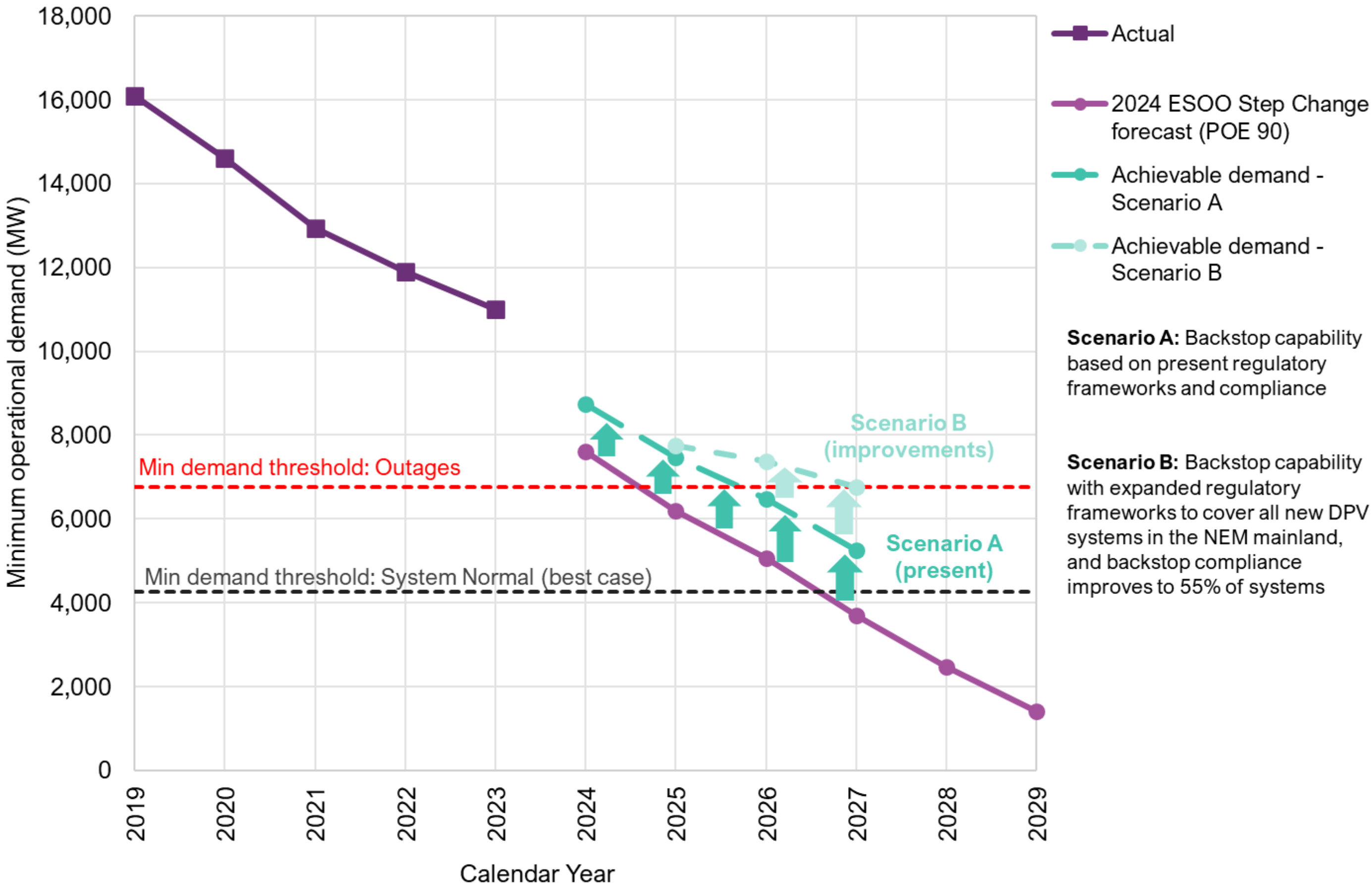
This includes extending backstop application to all distributed PV systems in Queensland, implementing a backstop mechanism in New South Wales/the Australian Capital Territory, and implementing effective monitoring and enforcement regimes to increase compliance in all regions.

AEMO's assessment indicates:

- In 2024, some regions (South Australia, Victoria and Queensland) are already at or beyond thresholds where use of emergency backstop capability may be required to maintain power system security in the event of rare but plausible emergency conditions (such as combinations of unplanned outages of generation and/or transmission).
- By 2025:
  - The backstop capability available may no longer be adequate in South Australia, Victoria and Queensland. These regions are projected to reach rare but plausible emergency conditions where the total backstop capability may not be sufficient to maintain power system security (based on forecast PV installation rates and assuming a continuation of present regulatory arrangements and backstop compliance rates).
  - Furthermore, AEMO projects that as early as 2025, the whole NEM mainland could reach minimum operational demand thresholds where use of emergency backstop capability may be required on rare occasions.
- By 2026, the projected available backstop capability may not be adequate for management of rare but plausible emergency conditions for the whole NEM mainland.

Figure 2 illustrates the imminent emergence of these challenges projected for the whole NEM. AEMO estimates that a minimum of approximately 4.3 GW of operational demand is required in the NEM to support the minimum generation levels of units providing required essential services across the NEM, with the present operational toolkit. This is the demand that is needed on the transmission network to support operation of synchronous generation which is currently required to provide essential power system security services. This could increase to as high as approximately 6.8 GW in the event of unplanned network or unit outages.

Figure 2 Minimum demand in the NEM



Note: Forecasts take into account increasing levels of storage and CER coordination. "Achievable demand levels" include capabilities to curtail distributed PV via emergency backstop mechanisms, tools to increase demand (such as hot water shifting), and enhanced voltage management (increasing distribution voltages to trip/curtail distributed PV and increase load). Use of enhanced voltage management to curtail distributed PV is not recommended for regular use.

Figure 2 indicates that demand on the transmission network (operational demand) could fall below 6.8 GW by as early as spring 2025 (under low demand 90% probability of exceedance [POE] conditions which are most likely to occur during spring). This means that under emergency conditions (involving unplanned outages), action which increases demand on the transmission network may be required as a last resort to maintain power system security across the whole NEM by as early as 2025.

The ability to maintain power system security in these plausible forecast conditions is currently uncertain. There has been a regulatory framework in South Australia for a backstop mechanism since 2020, but compliance rates were initially poor. SA Power Networks has major work programs to improve compliance which are seeing compliance rates climb, but further work is required to achieve the levels of compliance needed for ongoing operational effectiveness. In Queensland, the backstop mechanism only applies to inverters larger than 10 kilovolt amperes (kVA), and compliance rates have been extremely poor (with site audits identifying that only ~16% of systems which should have backstop are correctly configured and performing as designed). Victoria recently introduced a backstop mechanism (commencing from October 2024); the capability is small at present, and experiences to date suggest a learning period should be anticipated, and considerable efforts will be required to achieve the necessary levels of compliance. For New South Wales, AEMO is engaging with Governments and network service providers on recommendations to introduce a backstop mechanism as soon as possible; there is no framework at present.

Figure 2 also shows the current estimated capability of emergency backstop mechanisms accounting for these factors. Scenario A indicates a projection based on present regulatory coverage and present compliance rates, while Scenario B represents increasing coverage of backstop requirements to all new distributed PV systems in the NEM mainland, along with significant improvements in compliance with backstop requirements in all regions. Under Scenario A (in the absence of major uplift), the total amount of capability available becomes inadequate from 2026 for managing rare but plausible outage conditions.

Challenges are emerging earlier in local NEM regions. Table 1 summarises estimates of the total capability required in each region to maintain power system security, compared with the total emergency backstop capability available to DNSPs in each region. Under some possible outage conditions in Spring 2025, South Australia, Victoria, Queensland and New South Wales may be exposed to regional shortfalls in the ability to deliver backstop capability required for management of severe emergency outage conditions. This means that use of high customer impact mechanisms (such as feeder shedding) may be required in some circumstances.

Table 1 Summary of emergency backstop status in each NEM region

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

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

Implementation of backstop capabilities with high levels of compliance is an urgent priority. The identified shortfalls can be addressed by improvements to compliance with existing backstops, expansion of backstop and other complementary measures in a timely manner, as well as full implementation of the National CER Roadmap recommendations.

Achieving an effective backstop mechanism at operational scale is complex. The SA Government, working closely with SA Power Networks, has taken comprehensive steps to build significant curtailment capacity since 2020. Already, this has been relied upon to maintain energy security and has provided key learnings for other jurisdictions as they do likewise. Experiences to date suggest that at least 1-2 years should be anticipated to achieve implementation of basic curtailment capabilities for a proportion of new installations using manual processes, and at least 2-5 years to achieve the needed levels of operability and compliance across the majority of new installations. Significant resourcing efforts are required to achieve the levels of compliance with backstop capabilities necessary for operational effectiveness.

The mechanisms and regulatory arrangements to implement backstop mechanisms in each NEM jurisdiction need to be implemented in collaboration between governments and distribution network service providers (DNSPs), supported by knowledge-sharing between all parties and AEMO, targeting national consistency where possible.

AEMO recommends the following capabilities are implemented to support the management of minimum system load conditions, in all NEM mainland regions as soon as possible:

- Governments and/or regulatory bodies introduce regulatory frameworks for emergency backstop mechanisms in all NEM mainland regions by spring 2025, including allowance for regular testing,
- DNSPs introduce:
  - Mechanisms for delivering emergency backstop capabilities
  - Frameworks and systems for efficient compliance monitoring and enforcement,
  - Capabilities for estimating available capacity for curtailment and real-time verification,
- AEMO and NSPs collaborate on:
  - Introducing and uplifting minimum system load procedures,
  - Ongoing work to reduce minimum demand thresholds to the lowest possible levels, and
  - Identification and procurement of new services or investments where suitable, including options to minimise need to utilise backstop capabilities.

Ideally, under most conditions distributed PV generation will be managed within secure system limits through efficient market and network signals and regulatory frameworks incentivising distributed PV management and the enablement of load and storage flexibility in the daytime. These investments and reforms will take time to implement. AEMO recommends escalation of industry-wide efforts to urgently develop and implement these mechanisms, including pathways to achieve CER participation at a scale that is sufficient to keep up with projected levels of distributed PV uptake, to materially arrest the reduction in operational demand in the daytime.

With eventual maturity in CER market participation, together with growth in energy storage, load-shifting capabilities and reduction in minimum demand thresholds, extreme low demand conditions may still arise (including under outage conditions). Hence, while the above reforms and resources are necessary and are being pursued as complementary measures to reduce the frequency of emergency backstop usage, they do not replace the need for emergency backstop capability as a last resort measure to maintain system security.

AEMO looks forward to collaborating with NSPs, industry and governments towards establishing effective CER and distributed PV integration across the NEM. Delivery of these recommendations will provide a key underpinning towards successful operation of a secure and reliable power system that can accommodate much higher levels of distributed PV generation and other consumer assets.

In parallel with these practical solutions, there is a need to engage with current and prospective CER owners on their rights, the steps they can take to maximise the value of their CER investments, and the potential limitations that may be applied to their CER investments at times if there is an oversupply of electricity on the power system.

Integrated effectively, CER can continue to be a driving force in Australia's energy transition and key component of a least-cost pathway for all consumers. Yet the effective integration of CER is a complex task, spanning multiple sectors and interest groups. Success lies in the collaborative efforts of many parties: governments and policy-makers need to set clear rules and regulatory frameworks for NSPs and other accountable parties to implement, capturing new CER devices as they connect to the power system, integrated into AEMO's operational systems and processes.

AEMO will continue to communicate its latest understanding of CER integration challenges in line with its responsibilities under NER 4.3.1(n), to refer information of which AEMO becomes aware in relation to significant risks to the power system where actions to achieve a resolution of those risks are outside the responsibility or control of AEMO.

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1.1 Rooftop solar is a key enabler of the energy transition

As the energy transition progresses, many households and businesses are taking steps to shape their own energy futures. They are adopting innovative ways to reduce and manage their demand, investing in consumer energy resources (CER) including solar systems, batteries and electric vehicles (EVs), and contributing to virtual power plants (VPPs) to bring them together. These resources – supported by distribution networks, coordination systems and markets – are playing a transformative role in the energy transition.

Today, one-third of detached homes in the National Electricity Market (NEM) have rooftop solar. Rooftop solar is helping households and business reduce their energy bills while reducing emissions and is now three times as common in Australia as backyard pools, reaching 3.1 million systems in 2023.

Australia has the highest per capita uptake of rooftop solar in the world, thanks to a strong combination of community enthusiasm, government support, world-leading research and development, and co-operation between local and international businesses. In just the past decade, rooftop solar has grown from providing 2% of the NEM's energy needs to 12% and played a key part in the reduction of emissions intensity from the energy sector. At times, distributed photovoltaic (PV) systems are now supplying more than half of the underlying demand in the NEM. This growth is set to continue, with AEMO's *Integrated System Plan* (ISP) forecasting rooftop solar and consumer-owned storage could provide almost a third of energy needs in a 2050 net zero emissions economy[2].

Rooftop solar, and CER more broadly, has become an indispensable part of Australia's future energy system, offering a range of significant short and long-term benefits for consumers, communities and at a broader systems level.

However, the growth of CER has also resulted in growing complexity for operation of the grid, necessitating a suite of actions from industry, governments and market bodies including AEMO to ensure the grid can be kept reliable and secure at all times. While great progress has been made to date on these enabling actions, the rate of CER uptake is currently occurring faster than the deployment of complementary enabling actions, creating material risks for the security of electricity supplies in the short to medium term.

Building on the findings AEMO presented in the 2024 *Electricity Statement of Opportunities* (ESOO)[3], this report details the NEM's current readiness level for projected increases in CER, and calls for sustained urgency of action from governments and policy-makers to ensure power system security can continue to be maintained at all times.

1.2 Enabling CER while maintaining a secure and reliable power system

In Australia, rooftop solar is the most common application of distributed photovoltaic (distributed PV) systems – small-scale PV systems located within electricity distribution networks. Growth of distributed PV and other CER

[2] 2024 ISP, p30, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[3] 2024 ESOO, Section 7.6, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

has meant material changes and consideration about the way the grid is operated, to ensure the power system remains secure and reliable.

During the rapid growth of renewable energy across the NEM, industry, governments, research institutes, market bodies and network service providers (NSPs) have worked together to implement appropriate technical requirements and technology capabilities to maintain a secure and reliable power system.

Some of these are aimed at large-scale resources; for example, in 2018 the Australian Energy Market Commission (AEMC) completed a rule change that required tighter technical performance standards for all new generators larger than 5 megawatts (MW) connecting into the NEM. These rules ensure that large generating systems perform in a predictable way that helps maintain power system security.

Likewise, many changes have been made to support development of small-scale technology like rooftop solar and other CER like batteries, EVs and smart appliances. This includes important standards changes and introductions such as:

- The AS 4755 demand response standard, which facilitates remote control of CER to enable customers to manage their own costs and comfort, benefit from incentives to manage network constraints, or comply with specific regulations.
- The AS/NZS 4777.2 standard for grid connection of energy systems via inverters, which has undergone several updates, taking advantage of inherently sophisticated power-electronic capabilities to respond dynamically to measured grid characteristics, supporting both local network needs and the broader power system. This includes, for example, adjusting output when voltage or frequency move outside prescribed ranges. In 2020, AS/NZ 4777.2 was updated to ensure that inverters would remain connected following temporary grid disturbances. This change followed several years of collaboration between AEMO, industry and university researchers to analyse the response of distributed PV systems to transmission-level disturbances like a sudden trip of a generators or network asset.
- Recent changes to the accompanying AS/NZS 4777.1 standard, agreed to in 2024, which enable inverter requirements to be extended to vehicle-to-grid (V2G), allowing EV supply equipment to export energy to the grid, potentially helping meet energy needs at peak demand times while also mirroring the grid-protection capabilities of rooftop solar inverters and home batteries.

1.3 Emerging minimum system load (MSL) conditions in the NEM

The success of distributed PV means it now often supplies more than half the electricity demand in some regions at certain times during sunny periods. This has required increasing active management capabilities to allow AEMO and NSPs to manage the power system during these times.

The continued contributions of distributed PV and storage help provide 'resource adequacy' – one of the overarching requirements identified in AEMO's 2022 *Engineering Roadmap to 100% Renewables*[4]. This effectively means the ability to provide the right amount of energy to match consumption at every moment and at every location across the grid. Among many other requirements is the ability to maintain a secure and reliable power

[4] At https://aemo.com.au/initiatives/major-programs/engineering-roadmap.

system under all conditions – including within challenging events like extreme weather, network or generator faults, or cybersecurity threats – and the ability to restart the system quickly in the event that a widespread blackout occurs.

System security is a key part of these requirements, relating to the ability of the system to avoid a cascading failure following the occurrence of a credible contingency event. AEMO obligations to maintain system security are defined under the National Electricity Rules (NER).

Until recently, traditional large-scale synchronous generation units, like coal, gas and hydro power plants, have provided sufficient levels of system security services like system strength, inertia, voltage control, frequency control, ramping capability, system restart needs, and broader system resilience behaviours. Much of this was provided by the inherent physical characteristics of these units, due to the large rotating mass within the generation turbines. Inverter-based resources like PV, wind turbines and batteries inherently provide different system security characteristics. In past decades, when the contribution of inverter-based resources was low, sufficient system security was provided by synchronous generation; however, the NEM is now experiencing times of NEM-wide wind and solar contribution over 70% (see Figure 3 below). In South Australia, the contribution has exceeded 100% of local demand (made possible by the ability to export energy into Victoria).

AEMO is committed to working with NSPs and market participants to deliver other approaches to maintaining sufficient system security services, as the generation mix evolves towards more inverter-based resources. As these approaches come to fruition, this will allow the power system to operate securely at lower levels of operational demand. This could involve measures to reduce the minimum safe operating levels of essential synchronous units, or through investment in new assets that can provide essential transmission system services in other ways (such as synchronous condensers, batteries, network devices for voltage management support, and alternative sources of frequency response). The *Engineering Roadmap to 100% Renewables* outlines the transition to other ways of providing system services as coal retires, continuing to evolve use of alternative sources of essential system services that allow secure operation with fewer large synchronous generating units online, allowing the requirement for synchronous generation to reduce to zero in the long term.

1.4 The introduction of dynamic CER management

Figure 3 shows how the contribution of renewable generation in the NEM has been growing over time. The “Maximum contribution” indicates the maximum actual percentage of total NEM underlying demand met by renewable generation in each quarter, with the bars indicating the breakdown by renewable technology type in that maximum interval. Distributed PV is the single largest contributor. “Maximum potential” indicates the maximum possible percentage of underlying demand that could have been met by renewables, based on renewable generation forecasts.

Figure 3 NEM renewable energy potential and actual contributions

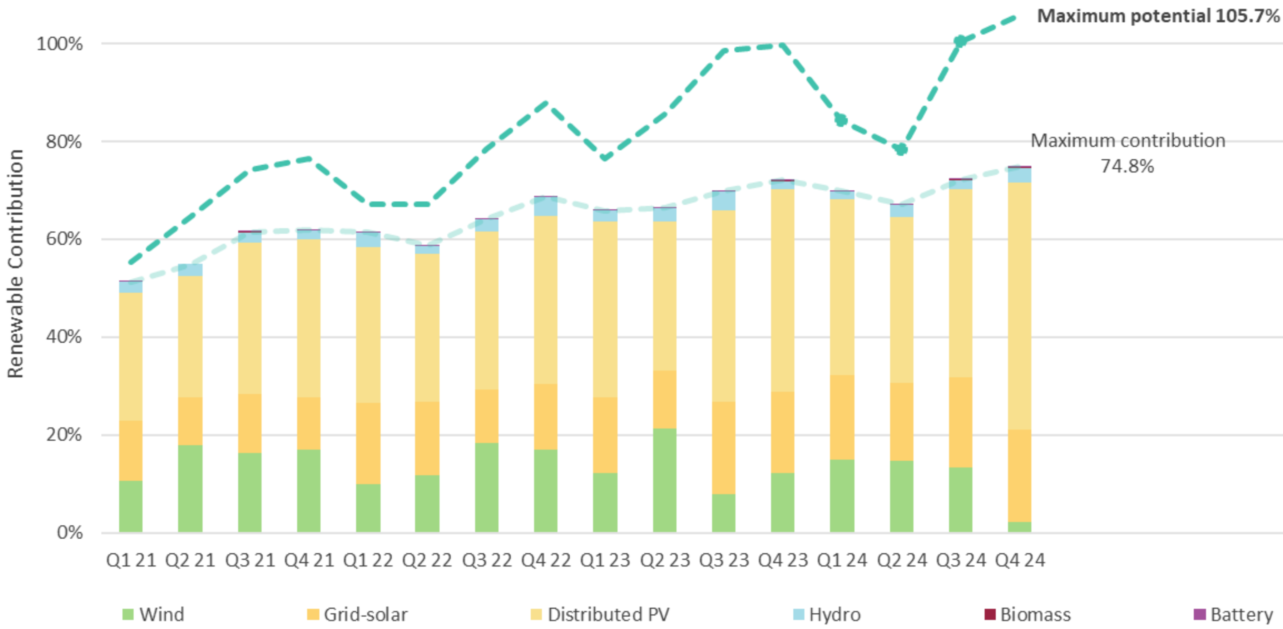


Figure 3 shows that the NEM has already experienced periods of over 100% renewables potential, however the actual peak contribution remains lower at around 75%. A significant contributor to the difference between these numbers is due to intentional curtailment of renewable energy for economic reasons (that is, large-scale wind and solar generators intentionally curtailing output due to negative wholesale prices[5]). Economic curtailment is an important feature of NEM market design that assists efficient supply-demand balancing.

To date, economic curtailment of small-scale distributed PV systems has been relatively rare. This is partly due to simplification of retail tariff structures, in which retailers absorb the volatility of market prices (often with the help of hedging products) and pass on a flat feed-in tariff, and partly due to lack of dynamic control capabilities on distributed PV.

Similarly, consumers have historically had limited flexibility to optimise their electricity usage. One exception has been controlled load tariffs, which allow the distribution network service provider (DNSP) to control the electricity supply to certain circuits – most commonly electric hot water systems – and enable them to run at off-peak times, usually at night.

This is beginning to change. Consumer investment in battery storage and EVs adds load that can soak up excess solar during the daytime and store it for use at other times. Likewise, DNSPs have begun shifting some of their controlled loads to daytime[6]. However, to be most effective, this additional load could be dynamically managed and coordinated to target times when it is most valuable. Such coordination can be provided by energy retailers or

[5] Negative wholesale prices are generally caused by oversupply of generation, partly due to generation sources such as coal-fired power, that are needed for evening peaks but are not flexible enough to ramp down during the daytime. While the replacement of these generators with flexible, grid-forming renewables and storage will eventually enable renewables contributions up to 100%, an efficient power system will always involve some level of curtailment during times of high solar and/or wind availability and low demand.

[6] See, for example, Ausgrid's revised Tariff Structure Statement (TSS) Explanatory Statement. p50, at https://www.aer.gov.au/system/files/2023-12/Ausgrid%20-%20Revised%20proposal%20-%20Att.%208.2%20-%20Our%20TSS%20Explanatory%20Statement%20for%202024-29%20-%2030%20Nov%202023%20-%20public.pdf.

aggregators, typically in VPPs which manage CER in a way that gains value from energy markets and network support services in addition to meeting the consumer's own needs.

While VPPs are a relatively nascent industry, AEMO's ISP forecasts that they will grow to play a major role in a least-cost net zero energy system. To support this growth, AEMO proposed two rule changes, which have been progressed by the AEMC: one allowing CER to be separately measured by low-cost meters, allowing differentiated VPP services for flexible and non-flexible customer resources;[7] and one allowing for VPPs to participate in market scheduling and dispatch[8]. AEMO is also collaborating with industry on various trials to progress these capabilities (such as Project Symphony[9] and Project Edge[10])

Dynamic CER management has also begun helping DNSPs offer more network capacity for solar exports. As rooftop solar deployment grows with low-voltage networks, it can in aggregate reach the capacity of the network to transport excess solar to load centres that can use it. To manage this, many networks implemented export limits on solar connections; however, these were understood to be unnecessarily restrictive in some places at some times, while being insufficient to manage constraints in many locations at peak export times.

To overcome this inefficiency, some networks, including SA Power Networks and Ergon and Energex, have begun offering dynamic export limits – also known as flexible exports, dynamic connections or dynamic operating envelopes[11]. Dynamic export limits are offered to customers to allow a greater export capacity most of the time, compared to the alternative static export limit. To make use of them, customers must install a solar inverter that connects remotely to a utility server hosted by the DNSP in order to receive regular updates of the export limits.

The increasing availability of dynamic export limits and of inverters with remote communications capabilities may reduce the barriers for take-up of VPPs or similar coordination opportunities. An example of this is the Market Active Solar Trial led by SA Power Networks[12]. In this trial, energy retailers offering VPPs are able to combine the export limits required for network management with additional economic curtailment of their customers' PV systems, for example when wholesale prices are negative. Through this, the retailers save money by avoiding the market costs of exporting and can pass on these savings in accordance with their agreements with customers.

The growth of such market-based load shifting and solar management will help reduce the frequency of operational interventions required to manage minimum system load conditions.

1.5 The National CER Roadmap

In July 2024, building on the Energy Security Board's (ESB's) earlier advice, Australia's Energy Ministers agreed to a National CER Roadmap[13], which sets out an overarching vision and plan to unlock CER at scale across Australia, and reflects the need to implement critical technical capabilities to support the continued security of the

[7] See https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading.

[8] See https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem.

[9] https://aemo.com.au/newsroom/news-updates/western-australias-project-symphony-pilot

[10] https://aemo.com.au/newsroom/media-release/project-edge

[11] SA Power Networks Flexible Exports, at https://www.sapowernetworks.com.au/your-power/smarter-energy/flexible-exports/ and Energex Dynamic Connections, at https://www.energex.com.au/our-services/connections/residential-and-commercial-connections/solar-connections-and-other-technologies/dynamic-connections-for-energy-exports.

[12] See https://www.sapowernetworks.com.au/future-energy/projects-and-trials/market-active-solar-trial/.

[13] See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

power system. Energy Ministers recognised that better coordination and optimisation of CER will put downward pressure on bills and overall system costs while reducing emissions.

The National CER Roadmap identifies measures to “unleash the full potential of CER” by establishing the required mechanisms, tools and systems. This includes reforms to increase the market participation of CER, allowing customers to respond to market-based incentives to help meet the challenges of low demand.

The roadmap priorities include:

- A national regulatory framework for CER to enforce standards, which will support governance and compliance for standards such as AS/NZS4777.2:2020, minimising further growth in risks associated with distributed PV contingencies.
- Mechanisms that incentivise customers to choose to have their CER coordinated by market actors in line with market signals and system needs. This may include enabling new market offers and tariff structures to support CER uptake and customers, increasing access to the market and incentivisation of CER to respond to market signals, including retail and network pricing, and pathways for aggregated CER to participate in the energy market.
- Mechanisms for coordinated CER to deliver automated and streamlined methods for the management of customer distributed PV systems within normal market dispatch systems.
- Redefining roles and responsibilities for market and power system operations, which will support access to and use of community batteries and EV chargers, and other distributed resources.
- Data sharing arrangements to inform planning, enable future markets, and support effective power system operation, with considerations for cyber security.
- Enabling consumers to export and import more power to and from the grid through initiatives such as fast tracking DNSP implementation of flexible exports (discussed further in Section 4.1).
- Improving voltage management across distribution networks.
- Incentivising distribution network investment in CER.
- Ensuring consumer protections and communication strategy to increase consumer trust and ensure CER benefits are understood by all consumers.

While these priorities will help increase market-based responses to minimum system load conditions, the Roadmap also recognises that emergency backstop mechanisms are required to maintain system security at times when market-based responses are insufficient. The Roadmap includes a commitment to “implement backstop capability that is robust and reliable in each jurisdiction”.

1.6 Introduction of emergency backstop mechanisms

Power system and market operators have always had the ability to control large-scale generation through market scheduling and dispatch and, when required, through control-room directions to maintain system security, while transmission network service providers (TNSPs) can apply constraints to limit generation in parts of their networks to avoid overload.

Small-scale generation, on the other hand, was simply measured as a reduction in consumer demand. Most demand is not bid into the wholesale energy market; instead, its magnitude is forecast and corresponding generation is dispatched to meet it. AEMO and NSPs therefore have little control over demand (except in extreme cases where load shedding is required), and therefore little control over CER. This arrangement was suitable when the quantity of small-scale generation was small, but is no longer adequate for managing power system security now that distributed PV represents the largest generator on the system.

Since 2017, AEMO has been working with NEM stakeholders on measures to manage secure system operation in periods with high distributed PV generation and low demand (see Appendix A1 for a list of references of work to date)[14].

In 2020, AEMO released a report highlighting the increasing system security risks during low operational demand in South Australia[15] and provided formal advice on this topic to the South Australian Government. Records for minimum operational demand had been falling year on year, due to increased solar deployment, to the point where system security could no longer be guaranteed, particularly when the South Australian region was disconnected from the rest of the NEM.

The South Australian Government responded by implementing a new requirement on distributed PV to ensure it could be remotely disconnected, by an agent representing the customer, at the direction of AEMO, when needed to manage system security[16]. Such requirements became known as emergency backstop mechanisms.

The emergency backstop is applied if other operational measures are not sufficient to keep operational demand above required levels. Those other measures include recalling planned outages, directing off non-scheduled generation and large distributed PV systems, and directing large-scale storage to ensure maximum capacity to absorb excess solar generation. When applied, the backstop remotely controls distributed PV systems to reduce generation, thus increasing operational demand to above minimum thresholds.

The 2020 ESOO for the NEM also recommended urgent actions to introduce backstop capabilities in Victoria and Queensland, and the 2021 ESOO reported that security issues in low demand periods could arise for the NEM mainland as a whole by 2025 in the Central scenario, or as early as 2024 in some scenarios. This is consistent with projections in the latest 2024 ESOO[17]. As the system security risks became increasingly clear, similar emergency backstop requirements followed in Queensland for new distributed PV systems larger than 10 kilovolt amperes (kVA) in February 2023,[18] and for all new distributed PV systems in Victoria from October 2024.[19] AEMO has also worked with Energy Policy WA and Western Power to implement emergency backstop capability for Western Australia's South West Interconnected System[20].

[14] AEMO has also worked with Energy Policy WA and Western Power to ensure suitable management measures are in place for the South West Interconnected System. For more information, see https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

[15] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

[16] See https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes.

[17] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf?la=en.

[18] See https://www.energyandclimate.qld.gov.au/energy/types-of-renewables/solar-energy/emergency-backstop-mechanism.

[19] See https://www.energy.vic.gov.au/households/victorias-emergency-backstop-mechanism-for-solar.

[20] For more information, see https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

The value of the emergency backstop mechanism was demonstrated most significantly during the November 2022 separation of South Australia following severe weather[21]. During a week of islanded operation, the South Australian emergency backstop was used almost daily to varying degrees. The system nevertheless peaked at over 90% wind and solar energy and averaged over 60% during the week. Emergency backstops in this case helped ensure there was no repeat of the 2016 black system event[22], and instead underlined the progress of the South Australian transition by demonstrating the highest contribution of inverter-based renewable energy to a gigawatt (GW)-scale island grid that AEMO is aware of.

1.7 Structure and context for this report

Despite the progress described above in implementing emergency backstops to help manage low demand periods, the risks continue to grow, with minimum demand forecast to further decrease in the coming years. This report aims to highlight those risks and provide the technical basis for further actions to address them. It focuses on articulating the technical power system needs, and the technical solutions required, as a basis for collaboration with stakeholders on the broader measures required to introduce those technical capabilities.

This report complements related AEMO reports published or planned for publication in 2024, including:

- The 2024 ISP,[23] which plans the investment required in the NEM to meet Australia's target for net zero emissions by 2050.
- The *NEM Engineering Roadmap FY25 Priority Actions Report*[24], which outlines priority actions towards meeting the requirements of a system capable of operating with 100% renewable energy.
- The 2024 ESOO[25], which highlights the reliability outlook for the NEM to signal where investment is needed.
- The *Transition Plan for System Security*[26], due to be published in December 2024, which identifies actions to maintain system security through key events such as the planned retirement of synchronous generation units currently operating in the NEM, as well as the continued growth of CER.

Chapter 2 of this report describes these risks in further detail, along with mitigations including the operational measures that are applied within MSL procedures.

Chapter 3 then quantifies the low demand challenges with respect to NEM-wide operational demand thresholds, both in system normal conditions and in foreseeable outage scenarios. These projections have been analysed with respect to different levels of compliance with emergency backstops and coverage of emergency backstops across the NEM.

[21] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf.

[22] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[23] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[24] At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/nem-engineering-roadmap-fy2025-priority-actions.pdf?la=en&hash=E934DFFF6D4544B9F117BAF6A6E4088D.

[25] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf?la=en.

[26] See Chapter 3 of the *Engineering Roadmap FY25 Priority Actions Report* for a description of the proposed approach for the *Transition Plan for System Security*.

Chapter 4 breaks down the projections for each individual NEM region.

Chapter 5 describes emergency backstop experience to date in South Australia and Queensland, including details of different mechanisms, rates of compliance and lead times for implementation.

Chapter 6 concludes the report with recommendations for governments, NSPs and AEMO.

2 Measures to support secure operation with high levels of distributed resources

2.1 System security risks in low demand periods

There are three main power system security issues related to low demand periods which are known at this time. Table 2 summarises these issues and some options available to mitigate these risks.

Table 2 System security risks in low demand periods and mitigation tools

Risks to security	Mitigation options	References
NEM-wide low demand Sufficient essential services, including system strength, voltage control, reactive power management, inertia, frequency control, and ramping management, must be delivered at all times. With the present operational toolkit, to ensure sufficient provision of these services, a minimum number of units need to be in operation, including a number of large synchronous units. These units need to operate above their minimum safe operating levels, which can be significant for some synchronous units. Some technologies (such as synchronous condensers and batteries) can deliver many of these services with low or zero minimum safe operating levels, but these are only available to a limited degree at present.	To balance supply and demand across the NEM, it will be necessary to do one or more of the following: • **Reduce the amount of generation that needs to remain online to provide essential services** – this can be done by reducing the minimum safe operating levels of essential units, or through investment in new assets that can provide system services in other ways (such as synchronous condensers, batteries, and/or reactors)[A]. These assets take time to develop, and other operational levers are required for operational management when gaps arise. • **Increase demand** – demand response capability to move consumption of energy from other periods to daytime periods. Practical options to increase responsive demand may evolve over time, but are operationally very limited at present. • **Store energy** – deep storage can help move energy from daytime periods to other periods. This capability is very limited at present. • **Decrease distributed PV generation** – along with reducing generation from non-essential generating units (scheduled, semi-scheduled, and non-scheduled), it is essential that sufficient operational levers are available under high-risk conditions to curtail distributed PV, as an emergency backstop to maintain system security when the above options are insufficient.	Section 3
Regional security issues Some NEM regions are already at or beyond thresholds where under some conditions it is no longer possible to maintain interconnector flows within the required secure export limits, and also maintain online the minimum units required to deliver local essential security services, operating above their minimum safe operating levels. Under network outage conditions, issues within regions can arise sooner as interconnector limits may be reduced. Regions may also need to operate securely as a synchronous island (separated from the rest of the NEM), or at credible risk of separation (which reduces interconnector limits and increases local service requirements). These risks can mean it is increasingly challenging to find suitable periods to undertake planned outages necessary to complete essential network maintenance. This may escalate the risk of unplanned outages.	The possible mitigation options are similar to those noted for NEM-wide low demand (above), but the need for these arises earlier in some regions, and needs to be delivered locally.	Section 4

Risks to security	Mitigation options	References
Distributed PV contingencies (DPVC) A large proportion of distributed PV generation can "shake-off" (disconnect) in response to a transmission network fault[B]. This can occur coincident with the trip of a large generating unit, such that the largest credible contingency in a region becomes the size of the generating unit that trips, plus the amount of distributed PV generation that shakes off[C].	Options to maintain power system security include: • **Improve CER disturbance ride-through capabilities** – continuing improvement in compliance with inverter standards (AS/NZS4777.2:2020)[D] to improve disturbance ride-through capabilities for new distributed PV installations and limit further escalation in contingency sizes. • **Reduce size of the largest generating unit** – this can be achieved by moving to a smaller unit combination, or dispatching the unit at lower levels if possible. • **Increase frequency response capabilities** – increasing the amount of reserves and the capabilities of those reserves to respond to larger contingency events can assist with managing larger credible contingencies. Fast Frequency Response (FFR) from Battery Energy Storage Systems (BESS) can be particularly helpful, as well as increasing conventional inertia from synchronous units or synchronous condensers. • **Decrease distributed PV generation** – in some cases, the only option available to maintain system security may be to curtail distributed PV to reduce the total contingency size down to a level that can be managed within network limits and with available frequency reserves. This can be particularly the case when operating a region such as South Australia as a synchronous island where frequency reserves may be limited.	Section 4.1

A. The *Engineering Roadmap to 100% Renewables* outlines the transition to other ways of providing system services as coal retires, allowing the requirement for synchronous generation to eventually reduce to zero: https://aemo.com.au/initiatives/major-programs/engineering-roadmap.
B. See AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.
C. Net of anticipated load shake-off in response to the same fault.
D. AEMO (December 2023) *Compliance of Distributed Energy Resources with Technical Settings: Update*, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

2.2 Emergency backstop capability

As noted above, there are a range of tools that are, or may become, available to address the identified risks in low demand periods. This report focuses on the urgent need for establishment of an 'emergency backstop capability' to decrease distributed PV generation, to allow confidence that power system security can be maintained while other options come to fruition.

Defining emergency backstop capability

"Emergency backstop" capability refers to operational measures to reduce aggregate distributed PV generation if required for system security, when other options have been exhausted.

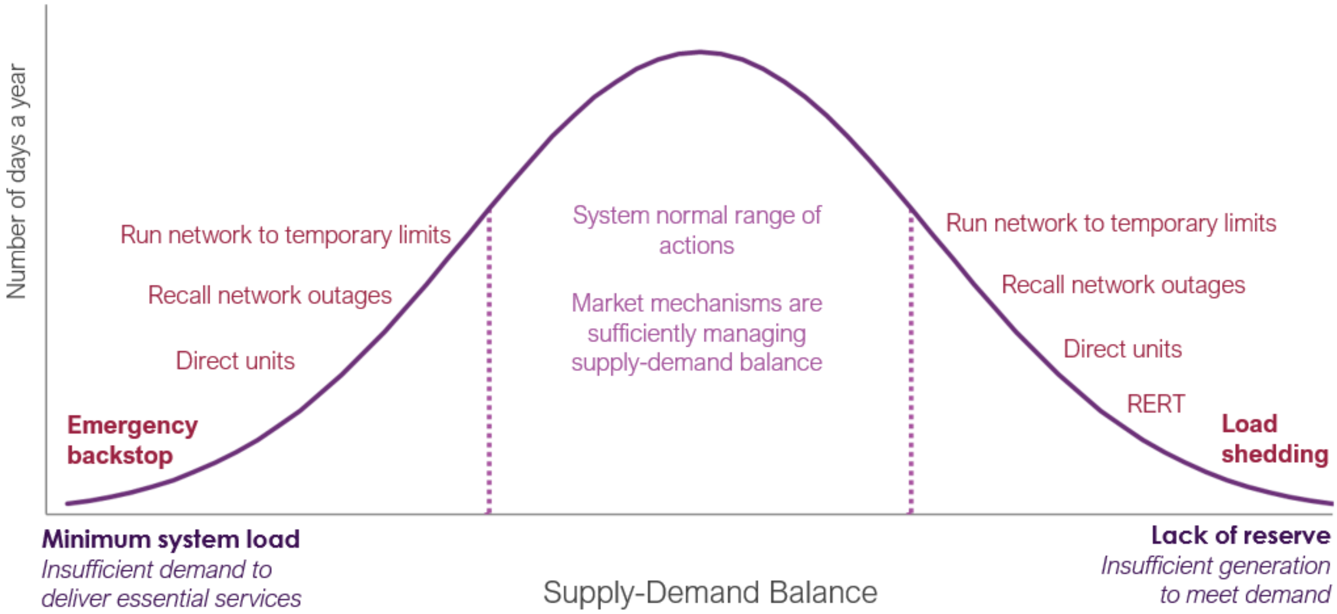
This is a critical last-resort tool to keep the power system secure under emergency conditions.

Achieving this means that all new distributed PV installations should be capable of both remote reduction to zero active power and of remote disconnection.

Growing availability of other options to maintain system security (outlined above in Table 2) will limit the instances where emergency operational levers need to be used, but does not replace the need for these tools to exist.

Figure 1 illustrates the spectrum of options used to manage emergency conditions, needed for managing periods of both low and high demand.

Figure 4 Emergency backstop to be used when other options have been exhausted



RERT refers to the Reliability and Emergency Reserve Trader, an NER mechanism for AEMO to contract capacity electricity reserves when a reserve shortfall is projected up to nine months in advance.

Section 2.3 below outlines the NEM's existing and forecast emergency backstop capabilities (based on existing regulatory requirements), with regional assessments provided in Section 4.

2.2.1 Risks if the backstop is not sufficient

As system security thresholds are approached, there is a rapidly escalating risk of power system conditions where there are insufficient available operational tools to maintain security, especially if unplanned outages occur. If emergency backstop capability is not available at the scale required, DNSPs will need to resort to options that have an increasingly high impact on customers. These options could include:

- Distribution voltage management – this involves increasing distribution voltages to outside the normal range, to deliberately trip or curtail distributed PV (based on the high voltage response settings in the individual distributed PV inverters). DNSPs have advised this method of increasing operational demand is a high risk control and its adoption can have significant impact on customers, including failure of customer equipment or network, tripping of customer load, and reduction in equipment life. It also may compromise delivery of system services from distribution-connected resources, including where these are aggregated to provide a response via a VPP.
- Shedding of reverse flowing feeders – this involves shedding whole distribution feeders (tripping all the distributed PV on the 11 kilovolts (kV) or 22 kV circuit, as well as all the customer load on the circuit). Tripping distribution circuits that are operating in reverse flows contributes to an overall increase in operational demand. Customers that are connected to feeders that are shed will have no electricity supply during these periods.

This approach requires shedding large amounts of customer load to achieve a small increase in regional operational demand, so has a very high impact on households and businesses. At present, this is the only form of control available to increase operational demand in many areas of the NEM.

If these more extreme tools are exhausted, this could mean the NEM is operating insecure for extended periods, outside the permissible range specified in the NER. A credible disturbance at such times could lead to cascading failures and reliance on emergency control schemes to prevent system collapse.

As elaborated in Chapter 3 and Chapter 4, scenarios where there are insufficient operational tools to manage the conditions emerging in the NEM are foreseeable and anticipated, possibly as early as spring 2025. Urgent actions are required to implement suitable emergency backstop capabilities, and minimise these risks.

2.3 Minimum system load (MSL) framework

To manage conditions of low system demand, AEMO collaborated with NSPs to introduce the MSL framework in 2021[27]. This aims to mirror the lack of reserve (LOR) framework[28] (used when approaching conditions of inadequate supply to meet demand), providing transparency to the market on emerging low demand conditions when actions may be required to maintain system security. The actions taken at MSL1, MSL2 and MSL3 levels are outlined in Table 3. Demand falling below these thresholds may be identified in forecast timeframes (week ahead, day ahead or hours ahead), or could arise suddenly in response to a contingency event or unplanned outage. If management actions are required, these will be directed at the latest time to intervene, so decisions can be based on the latest available forecast. Aligned with standard practices, AEMO will provide market notices to inform market participants if these conditions are forecast or occurring[29,30].

Table 3 MSL framework

Condition	Actions
MSL1	Notify the market, monitor the situation.
MSL2	Take preparatory actions required to land satisfactory and return to secure within 30 minutes following a credible load contingency. This might include: • Recalling transmission line outages. • Moving to synchronous unit combinations which facilitate a lower combined minimum safe operating level to deliver essential system services. • Constraining or directing any non-essential generating units to decommit (including scheduled, semi-scheduled, non-scheduled and exempt generators), if they have not already self-curtailed in response to low or negative market prices. • Ensuring availability of adequate frequency reserves. • Preparing necessary measures to ensure the system can be resecured within 30 minutes following a credible contingency.
MSL3	• System security violations related to low demand are occurring or forecast to occur at this level. • Direct NSPs to restore and maintain regional demand above the thresholds required. This may require use of emergency backstop capabilities.

27 AEMO (Sept 2021), *AEMO's new market signal to improve transparency and system security*, https://aemo.com.au/newsroom/media-release/aemos-new-market-signal-to-improve-transparency-and-system-security.

28 AEMO (28 November 2023) Fact sheet: Lack of Reserve (LOR) notices, https://aemo.com.au/en/learn/energy-explained/fact-sheets/lack-of-reserve-notices.

29 AEMO, Managing Minimum System Load, https://wa.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/managing-minimum-system-load

30 AEMO (November 2024) Victorian Minimum System Load Procedure Overview, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2024-11-01-vic-msl-procedure-factsheet_final.pdf?la=en.

Conditions that require management of the largest credible contingency related to distributed PV shake-off are referred to as distributed PV contingency (DPVC) conditions. These apply in South Australia only at present. Similar preparatory actions to manage these conditions (such as reducing the size of the largest credible contingency) are taken as DPVC1, DPVC2 and DPVC3 levels are reached, with market notices to advise the market of these conditions.

2.4 Demand definitions

All minimum demand projections in this report are presented as operational demand[31], "as generated" (including generator auxiliaries), for the lowest minimum demand in the year (regardless of season when it occurs), presented by calendar year (annual minimum daytime demand typically occurs during the October to December period in most NEM regions). This provides the closest demand definition to the "regional demand" terms used by AEMO's control room for defining thresholds and managing MSL conditions in the NEM.

[31] AEMO (June 2024) Demand Terms in the Electricity Market Management System (EMMS) Data Model, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

3 Current and emerging risks for NEM-wide low demand

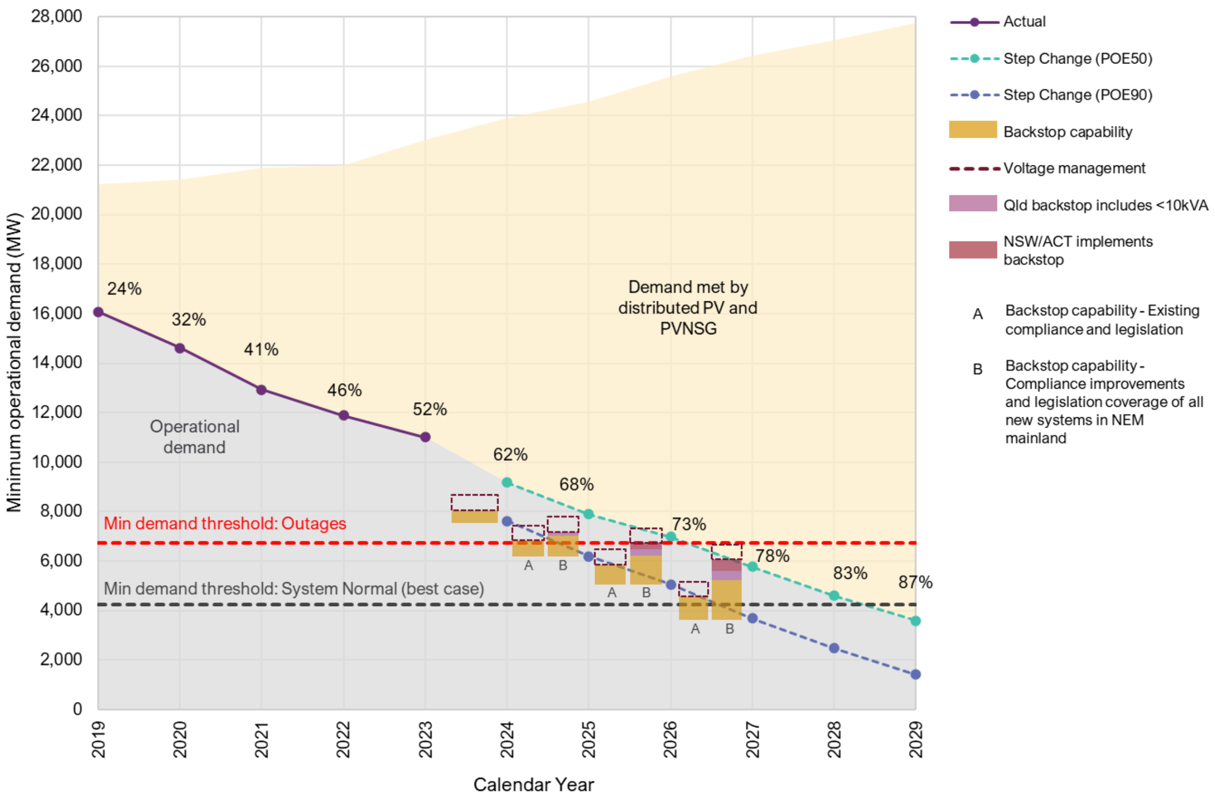
The NEM experienced a record minimum operational demand of 10,073 MW at 11:30 on 26 October 2024. In this half-hour interval, distributed PV supplied 58% of the underlying demand in the NEM. Minimum demand in the NEM has been falling on average more than 1.2 GW per year, and is projected to continue on this trajectory given anticipated continued growth in distributed PV.

3.1 Imminent operational risks

To support the minimum generation levels of units providing required essential services across the NEM, with the present operational toolkit, AEMO estimates that a minimum of ~4.3 GW of operational demand is required in the NEM. In the event of unplanned network or unit outages, this could increase to as high as ~6.8 GW.

Figure 5 shows these thresholds, compared with projections of coincident minimum operational demand in the NEM.

Figure 5 Minimum demand in the NEM



Note: POE50 and POE90 values represent NEM minimum outcomes from regional 50% probability of exceedance (POE) and 90% POE traces respectively. Forecast NEM minimum demands were calculated for 14 historical reference years. The POE50 value shown represents the mean value across reference years, and the 90POE value represents the minimum value across reference years. The POE90 value represents historically observed weather and solar insolation patterns leading to low demand conditions, as well as the modelled coincidence of minimum demand conditions across NEM regions, and is used to quantify design needs for emergency mechanisms that maintain system security under high-risk conditions. The amount of backstop capability during the minimum NEM demand period is scaled based on the modelled coincidence of minimum demand conditions across the NEM.

AEMO's forecasts indicate that NEM-wide demand could fall below 6.8 GW by as early as October 2025. It is assumed that in these periods, all non-essential generation will already be self-curtailed in response to very low market prices (likely at market price floor) or will be decommitted if necessary.

Security issues arising due to NEM-wide low demand conditions as early as 2025

Under emergency conditions (involving unplanned outages), activation of NEM-wide emergency backstop capabilities may be required as a last resort to maintain power system security by as early as 2025.

Figure 5 also indicates the total amount of backstop capability available to increase operational demand in the NEM if necessary to above the thresholds required to maintain power system security, based on best estimates from DNSPs:

- The yellow boxes indicate the amount of backstop capability available in the NEM based on present regulatory requirements.
- The 'A' scenario indicates a lower bound estimate of the backstop capability available, based on existing legislation and with persistence of present levels of compliance.
- The 'B' scenario indicates an upper bound estimate of the backstop capability available, if compliance rates improve[32] and Queensland, New South Wales and the Australian Capital Territory expand regulatory frameworks to require backstop capability from all new distributed PV installations[33] (shown in purple and red bars respectively).
- The dashed boxes indicate the further capability available to increase demand via distribution voltage management, which is considered a high impact measure not recommended for regular use.

By 2026, under some conditions, these available tools (based on existing levels of compliance and legislation, as shown in the 'A' scenario) may not be adequate to maintain power system security. The quantity of backstop capability required for managing foreseeable emergency conditions grows rapidly beyond this date, with the shortfall in 2027 potentially exceeding 1 GW.

Furthermore, as elaborated further in Section 4, there are already shortfalls in backstop capability within some NEM regions for managing regional-specific system security issues.

Emergency backstop capability may become insufficient from as early as 2026

If no further action is taken, the capability of backstop mechanisms for managing NEM-wide low demand conditions could become insufficient from 2026.

[32] Assumed compliance rates improve under existing regulatory frameworks from present levels to 55% by 1 October 2025.

[33] Assumed Queensland introduces regulatory requirement for backstop capability from all distributed PV systems from 1 January 2025, and New South Wales/Australian Capital Territory introduce a regulatory requirement for backstop capability from all new distributed PV systems from spring 2025.

If sufficient backstop capability is not available, the NEM may be operating insecure for extended periods, and therefore be operating outside of the risk tolerances specified in the NER. This places customers at elevated risk beyond the levels defined as acceptable in the NER, where reliance on emergency control schemes is needed to prevent system collapse following a single transmission or generation outage. The ability to restore the system following a black system event may also be compromised at times of very high distributed PV generation.

Implementation of robust backstop capabilities at operational scale is complex. In regions where backstop implementation has begun, DNSPs have encountered implementation challenges (elaborated in Section 5.1). Substantial work programs are required to bring backstop compliance and performance to the necessary levels.

Significant urgency around developing sufficient emergency backstop capability

To maintain system security, all mainland NEM regions (South Australia, Queensland, Victoria and New South Wales/Australian Capital Territory) need operationally effective emergency curtailment backstop capabilities as soon as possible.

This includes extending backstop application to all distributed PV systems in Queensland, implementing a backstop mechanism in New South Wales/Australian Capital Territory, and implementing effective monitoring and enforcement regimes to increase compliance in all regions.

More detailed recommendations to address this growing shortfall in NEM-wide backstop capability are summarised in Chapter 6.

3.2 Risks emerging in system normal conditions

AEMO's forecasts indicate that total NEM demand could fall below approximately 4.3 GW by 2027. Below this threshold, with the present operational toolkit, activation of emergency backstop capabilities could be required even in system normal conditions (with no outages) to maintain power system security.

Urgency around foundational reforms and alternative sources of system services

Activation of emergency backstop mechanisms could be required to maintain system security in system normal conditions (with no outages) as early as 2027[34]. This indicates urgency around foundational reforms and investment in capability to support more efficient management of the system and market in low demand periods, suitable for regular use in system normal conditions. These reforms could be required at operational scale by as early as 2027.

These reforms and resources do not replace the need for emergency backstop capabilities. Rather, they are complementary tools, with these reforms and resources minimising the proportion of periods where emergency backstop tools need to be utilised.

[34] In individual NEM regions, the need for emergency backstop under system normal conditions will likely emerge earlier than this date (see Chapter 4).

4 Regional projections

The following sections provide more detail on backstop capabilities and requirements in each region.

4.1 South Australia

South Australia has experienced a record minimum 30-minute operational demand of -205 MW, occurring at 13:00 on 19 October 2024 due to mild temperatures, clear skies and an ongoing large load outage. In this interval, distributed PV supplied approximately 114% of the underlying demand in the region, with exports into Victoria via interconnectors.

Minimum demand in South Australia has been falling on average more than 100 MW per year, and is projected to continue on this trajectory.

The SA Government, working closely with SA Power Networks, has taken comprehensive steps to build significant curtailment capacity. Already, this has been relied upon to maintain energy security and has provided key learnings for other jurisdictions as they do likewise.

4.1.1 Operational demand thresholds

Table 4 summarises operational thresholds in South Australia (based on the present operational toolkit). These will continue to change over time as the power system evolves, as AEMO's ability to model the power system under these novel conditions continues to improve, and as the operational toolkit expands.

Table 4 Regional demand thresholds: South Australia (as of July 2024)

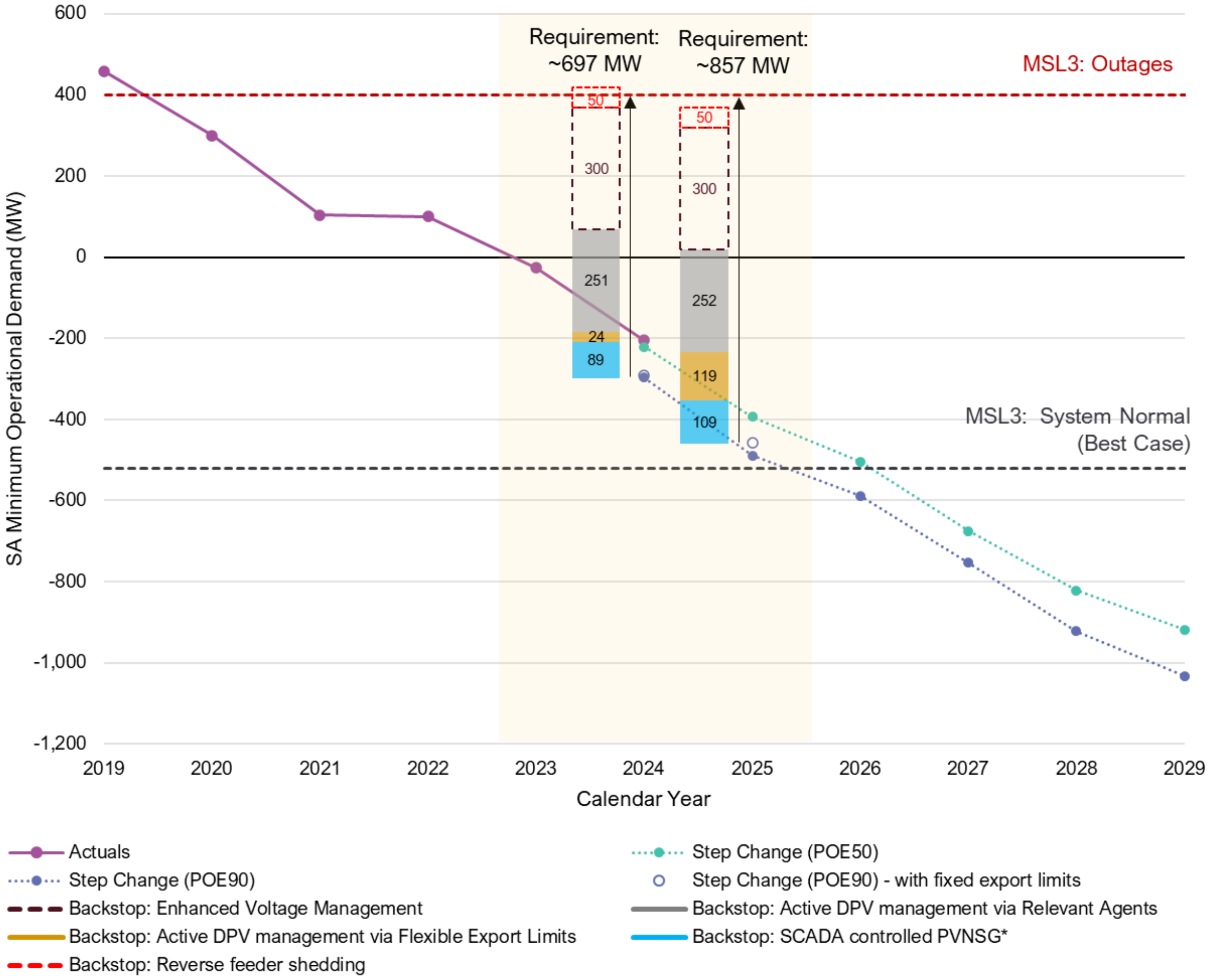
System conditions	Threshold	Level of regional demand required for secure operation, based on present operational toolkit (MW)	Details
Interconnected to rest of NEM	MSL3	-520 MW to 400 MW	• Defined by the level of regional demand in South Australia where SA->VIC interconnector export violations start to occur. • Depends on the minimum safe operating levels of the minimum generating units required for essential system services in South Australia, and any network outages that affect interconnector limits. • The lowest threshold (-520 MW) assumes the smallest possible unit combination online to deliver essential services, no outages affecting interconnector limits, and allows for a small operating margin. • The highest threshold (400 MW) could occur in the case of multiple coincident outages including outages of Murraylink, other network equipment that significantly reduces Heywood interconnector export limits, the four synchronous condensers, and multiple generating units, such that a large unit combination must operate to deliver essential system services. This is an unlikely but plausible operating scenario, for which AEMO must ensure suitable plans and operational tools available.

System conditions	Threshold	Level of regional demand required for secure operation, based on present operational toolkit (MW)	Details
South Australia at credible risk of separation	PTP (permission to proceed) with planned outages	250 MW	• AEMO does not provide permission to proceed (PTP) with planned network outages that put South Australia at credible risk if operational demand is forecast to go below 250 MW during the outage window. Demand forecast below this level is within uncertainty margins of requiring use of emergency backstop to maintain interconnectors within secure limits, if the outage were to proceed. • Defined by interconnector limits that apply when at credible risk of separation, which include terms to manage distributed PV shake-off impacts on contingency sizes.
SA Island	MSL3	400 MW	• Defined by the level of operational demand required for secure operation of the South Australia island, avoiding violation of supply-demand balance and frequency control ancillary services (FCAS) requirements. • Depends on the minimum safe operating levels of minimum generating units required for essential system services, including voltage management capability. • The level of regional demand required for secure operation, based on present operational toolkit is 600 MW, however latest analysis accounting for evolving minimum unit requirements in South Australia shows that this can reduce to 400 MW under some conditions.
	DPVC3	400 MW	• Defined by need to maintain total maximum credible contingency size to within available frequency reserves. • Depends on the availability of frequency reserves (including conventional FCAS, very fast FCAS and inertia), the limits defined in the Frequency Operating Standards, minimum safe operating level of the largest unit operating, and the amount of distributed PV and load shake-off that could occur if there is a severe fault at that location. This is influenced by the compliance of distributed PV with the disturbance ride-through requirements in AS/NZS4777.2:2020. • The level of regional demand required for secure operation, based on present operational toolkit varies depending on system conditions, but can be as high as 900 MW. However, accounting for the introduction of the very fast FCAS market, increasing availability of fast frequency response from Battery Energy Storage Systems (BESS), and improving compliance of distributed PV with the disturbance ride-through requirements in AS/NZS4777.2:2020 can reduce this limit to 400 MW under some conditions.

Figure 6 compares the MSL3 interconnected system thresholds with the minimum demand actuals and forecasts in South Australia. The maximum amount of backstop capability available in South Australia in 2024 and 2025 is shown, based on advice from SA Power Networks, indicating whether it is likely to be possible to achieve the necessary operational thresholds if required under various conditions.

As shown in Figure 6, minimum demand has already been experienced in South Australia below MSL3 interconnected system outage thresholds. This means that use of emergency backstop is already required in South Australia under certain circumstances, especially if South Australia is operating as an island or at credible risk of separation, or if there are outages materially affecting interconnector export limits.

Figure 6 South Australia: Minimum demand thresholds, projections and estimated backstop capabilities



A proportion of new distributed PV connections choose a fixed export limit of 1.5 kilowatts (kW) in preference to the SA Power Networks Flexible Exports offering. The minimum demand levels forecast in the ESOO do not consider the impact of these fixed export sites on minimum demand. SA Power Networks estimates this could increase the minimum demand in 2024 by ~7 MW, and increase minimum demand in 2025 by ~33 MW, compared with the ESOO forecast levels. This is shown in the figure above as the alternative "Step Change (POE90) forecast - with fixed export limits". The amount of emergency backstop distributed PV curtailment capability available is indicated in bars originating from this adjusted level.
* Further to PVNSG curtailment, there may be other non-scheduled generation (ONSG) in SA Power Networks' network which can also be curtailed, noting these systems may self-curtail during minimum demand periods due to low prices, and the more binding security threshold in South Australia tends to be distributed PV contingency management.

Emergency backstop capabilities have already been needed and used operationally on several occasions in South Australia, including:

- 13-19 November 2022[35] – South Australia operated as an island for a week following storm damage to the Heywood interconnector. During this week, with high levels of distributed PV generation, AEMO instructed SA Power Networks to maintain regional demand above 715-855 MW to maintain contingency sizes within the required ranges. This required curtailment of 400-600 MW of distributed PV. On several days, the amount of capability required represented the full extent of SA Power Networks' abilities.

[35] AEMO (May 2023), *Trip of South East – Tailem Bend 275kV lines on 12 November 2022*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf?la=en&hash=A89F330CF6C979E52EF15EB86E5CF058.

- 15 February 2024 – following storm damage and failure of six 500 kV towers between Heywood and Moorabool on 13 February 2024[36], South Australia operated at credible risk of separation for several days, and distributed PV curtailment was necessary on 15 February to prevent violation of interconnector limits affected by the credible contingency size.

The minimum demand thresholds in South Australia for managing island and credible risk of separation conditions account for the following developments, all of which help to support the secure operation of the power system under low demand conditions:

- Commissioning of the ElectraNet synchronous condensers.
- Reduction in the minimum unit requirements in South Australia for maintaining essential system services.
- Increasing understanding of transmission voltage management requirements in South Australia under low demand conditions.
- New battery energy storage systems (BESS) in South Australia, delivering additional fast frequency response capability.
- Introduction of the new Very Fast frequency control ancillary services (FCAS) market.
- Recent improvements in compliance of new distributed PV installations with AS/NZS4777.2:2020[37], reducing DPVC risk.

From 2026, the 90% probability of exceedance (POE) regional demand in South Australia is projected to fall below thresholds where backstop will be required in system normal conditions with no outages. Project EnergyConnect will increase the export capability from South Australia, and will therefore affect these regional thresholds. However, by the time this interconnector is fully commissioned, all NEM regions may simultaneously be experiencing low demand, which limits the ability to export excess generation from South Australia.

Table 5 presents estimates of the amount of emergency backstop needed in South Australia to provide reasonable confidence of an ability to operate a secure system under most foreseeable conditions, based on the information available at the present time. This is based on needing to restore South Australian regional demand to at least 400 MW to maintain system security under some circumstances such as unplanned outages. Minimum demand records typically occur on weekends and public holidays in the October to December period, so requirements are presented as the maximum amount that may be required by this period each year (but this capability could also be required and has been called on during other periods).

Table 5 Emergency backstop capability required in South Australia (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
Emergency backstop required	~426 MW	~697 MW	~857 MW

[36] AEMO (February 2024), *Preliminary Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

[37] AEMO (December 2023), *Compliance of Distributed Energy Resources with Technical Settings: Update*, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

4.1.2 Backstop capability available

South Australia has the following mechanisms available to deliver emergency backstop capabilities:

- **Curtailment of SCADA-controlled PV non-scheduled generation (PVNSG) sites** – since 2017, distributed PV sites with export capacity larger than 200 kilowatts (kW) must have Supervisory Control and Data Acquisition (SCADA) control installed on SA Power Networks' network, providing the ability to be curtailed to 0 MW if necessary. As of February 2024, there was a total installed capacity of 204 MW of SCADA-controlled PV non-scheduled generation (PVNSG) generation in South Australia[38]. In low demand periods, these units typically generate less in response to low market prices.
- **Relevant Agents** – the Smarter Homes regulations[39] have been applicable to all distributed PV systems installed in South Australia since 28 September 2020. These regulations require that all new electricity generating plants connecting to the distribution network in South Australia must be capable of being remotely disconnected (and later reconnected) by a "relevant agent".
- **Flexible Export Limits (FELs)** – SA Power Networks has also introduced the Flexible Exports mechanism[40]. This new connection option is offered to new or upgrading solar customers as an alternative to fixed export limits, and on agreement by the customer, allows the customer to export at higher levels most of the time unless network or security limits require a lower export limit in that interval. SA Power Networks is then able to utilise the technology put in place for the Flexible Export mechanism to deliver backstop capability on direction in MSL or DPVC conditions. The increased sophistication of the mechanism allows improved tracking and monitoring of commissioning and compliance. Flexible Exports has been offered to a growing base of SA Power Networks' customers from July 2023, targeting offering to 100% of customers from January 2025.
- **Enhanced voltage management (EVM)** – SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that distributed PV systems can generate. When using EVM, SA Power Networks increases or decreases the voltage levels at key distribution zone substations (within safe limits). A side-benefit of EVM is that at certain higher voltage levels, a subset of distributed PV systems trip, disconnecting from the system. This method of disconnecting distributed PV can be used as a last resort when required to maintain system security. This is only suitable for use in rare emergency conditions; it is not recommended for regular use since if used regularly it may risk damage to customer equipment.

Table 6 outlines estimated levels of the total capability available to SA Power Networks via these various methods to deliver emergency backstop capabilities, as a last resort if required to maintain power system security. Uplift in compliance to curtailment signals under the Relevant Agent and FELs functions is required for operational effectiveness in restoring demand to levels required for system security. SA Power Networks has a considerable work program underway to improve backstop compliance (discussed further in Section 5.1.1).

[38] Further to PVNSG curtailment, there may be other non-scheduled generation (ONSG) in SA Power Networks' network which can also be curtailed, noting these systems may self-curtail during minimum demand periods due to low prices, and the more binding security threshold in South Australia tends to be distributed PV contingency management, which is only alleviated by curtailment of distributed PV at risk of shake-off.

[39] Government of South Australia, Energy & Mining, Remote disconnect and reconnection of electricity generating plants, https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/remote-disconnect-and-reconnection-of-electricity-generating-plants.

[40] SA Power Networks, Flexible Exports, https://www.sapowernetworks.com.au/industry/flexible-exports/.

Table 6 Emergency backstop capability available in South Australia (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
SCADA-controllable PVNSG	~ 42 MW	~ 89 MW	~ 109 MW
Flexible Export Limits	~ 0 MW	~ 24 MW	~ 119 MW
Relevant Agents	~ 206 MW	~ 251 MW	~ 252 MW
Enhanced Voltage Management	~ 300 MW	~ 300 MW	~ 300 MW
Total backstop available*	**~ 548 MW**	**~ 665 MW**	**~ 780 MW**
Backstop requirement	~ 426 MW	~ 697 MW	~ 857 MW
Shortfall	-	~ 32 MW	~ 77 MW

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

As shown in Figure 6 and Table 6, South Australia does not have sufficient backstop capability available at present, with a shortfall of ~33 MW anticipated for plausible emergency conditions that could be experienced as early as this spring (October 2024). The shortfall is growing over time. Improvement in compliance with backstop capabilities is an urgent priority.

4.1.3 Actions and recommendations

Table 7 summarises the recommended short-term actions, all of which are underway at present.

Table 7 Short-term actions required: South Australia

SA Power Networks	• Full rollout of Flexible Exports mechanism. • Implement systems for monitoring, maintaining and enforcing high levels of compliance with: – Emergency backstop requirements. – Disturbance ride-through requirements in AS/NZS4777.2:2020. • Implement systems to minimise delay between AEMO instruction and delivery of backstop (ideally achieving confidence in delivery in <10 minutes).
ElectraNet	• Ensure suitable transmission voltage management capabilities for low demand periods, including for management of plausible fringe/outage conditions. The outcome of the Voltage Control Regulatory Investment Test for Transmission (RIT-T) is the investment in additional reactors in South Australia*. • Planning assessments of alternative approaches for delivery of essential system services in MSL periods, including consideration of operability in fringe/outage conditions. • Commissioning of Project EnergyConnect.
AEMO	• Determine operational MSL thresholds for system normal, and revise AEMO's operational MSL procedures. • Update thresholds and procedures for operation of an SA island & SA at credible risk of separation from the rest of the NEM.

* Electranet (May 2024), *SA Transmission Network Voltage Control: RIT-T Project Assessment Conclusions Report*, https://www.electranet.com.au/wp-content/uploads/ritt/SA_Transmission_Network_Voltage_Control_PACR.pdf.

4.2 Victoria

Victoria experienced a record minimum operational demand of 1,564 MW at 13:00 on 31 December 2023 (New Years Eve). At the time, distributed PV was contributing 66% of underlying demand in Victoria.

Minimum demand in Victoria has been falling on average almost 400 MW per year, and is projected to continue on this trajectory, as shown in Figure 7 in the following section.

4.2.1 Operational demand thresholds

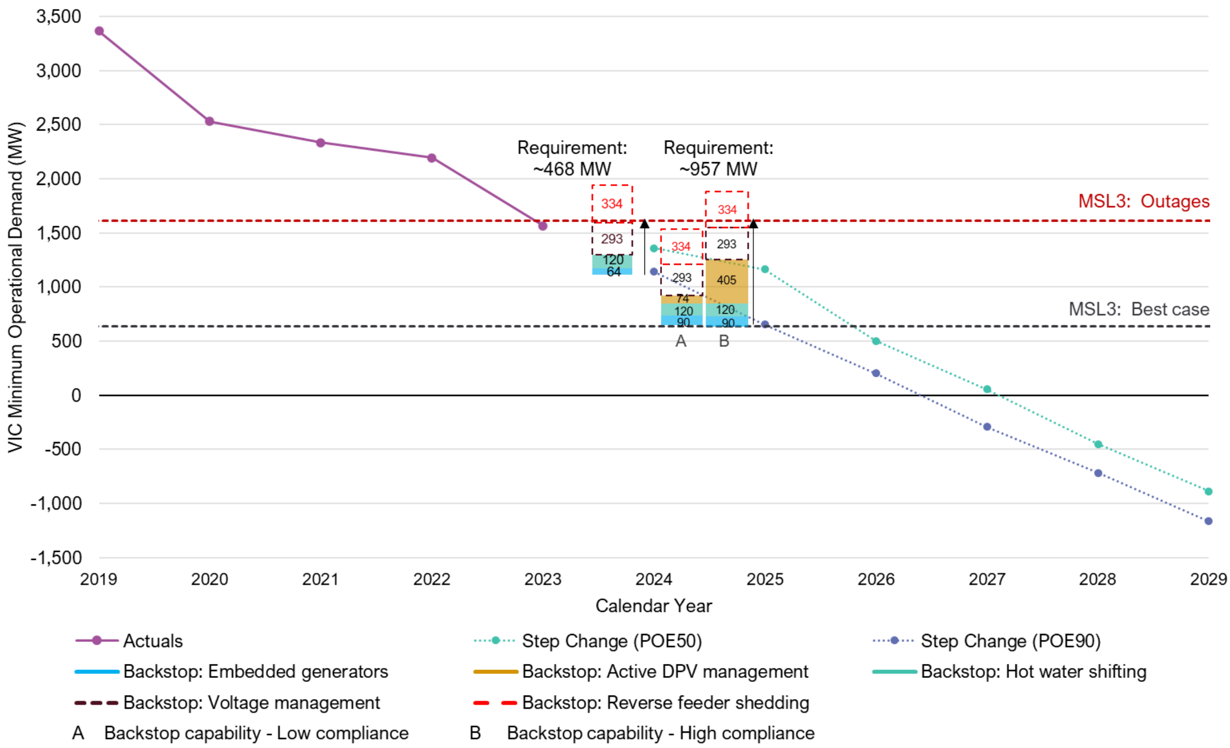
Table 8 summarises operational thresholds in Victoria (based on the present operational toolkit). These will continue to change over time as the power system evolves, as AEMO's ability to model the power system under these novel conditions continues to improve, and the operational toolkit expands.

Table 8 Regional demand thresholds: Victoria (as of June 2024)

System conditions	Threshold	Level of regional demand (MW)	Details
System normal	MSL3	~640 MW	• Defined by the requirement to keep online minimum generating units required for essential system services in Victoria and South Australia so that VIC->NSW interconnector export flow does not violate security constraints. • This lower (best case) limit assumes Basslink is in service, moderate demand conditions in South Australia, a relatively smaller number of Latrobe Valley units are required online to manage transmission voltages, and a single transmission line is switched out for voltage management (which reduces VIC->NSW export capability).
Outages	MSL3	~640 MW to ~1,610 MW	• The upper outages limit assumes Basslink is unavailable, combined with other network outages that significantly reduce VIC->NSW export limits, a relatively larger number of Latrobe Valley units are required online to manage transmission voltages, and coincident very low demand conditions in South Australia.

Figure 7 compares these operational thresholds with the minimum demand actuals and forecasts in Victoria. The total amount of backstop capability available in aggregate from Victorian DNSPs is shown, indicating whether it is likely to be feasible to increase demand to the operational thresholds that may be required under emergency operating conditions. Two estimates of backstop capability are shown for 2025 (A and B), indicating the plausible range of capability based on varying outcomes for distributed PV compliance with the new backstop requirements introduced from 1 October 2024.

Figure 7 Victoria: Minimum demand thresholds, projections and estimated backstop capabilities



A scenario: assumed initial compliance rates are similar to those observed in other jurisdictions, with 10% compliance for the first year of delivery of backstop capabilities.
B scenario: assumed considerable uplift and immediate investment in major efforts to achieve high compliance, which could increase compliance to as high as 55% for the first year of delivery of backstop capabilities. Compliance rates of >90% should be targeted as soon as possible.

In 2024 (public holidays and weekends during October-December), it is projected that minimum operational demand could fall to the level where with certain unplanned outages almost 500 MW of emergency backstop capability may be required. By spring 2025, almost 1 GW of backstop capability could be required in Victoria. These requirements are summarised in Table 9.

Table 9 Emergency backstop capability required in Victoria (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
Emergency backstop capability required	~71 MW	~468 MW	~957 MW

4.2.2 Backstop capability available

Victorian DNSPs have advised that they have the following mechanisms available to manage minimum operational demand:

- **Curtailment of embedded generation** – Victorian DNSPs have the capability to curtail some larger non-scheduled, exempt and SCADA controlled generators in their networks. In low demand periods, these units typically generate less in response to low market prices. The Victorian Department of Energy, Environment and

Climate Action (DEECA) has also introduced requirements for new, upgrading and replacement PV systems >200kW to deliver emergency backstop capability from 25 October 2023[41].

- **Hot water shifting** – some Victorian DNSPs have some ability to temporarily shift a proportion of electric hot water load into the middle of the day.
- **Active distributed PV management** – DEECA has introduced requirements for all new, upgrading and replacement PV systems ≤200 kW to deliver emergency backstop capability from 1 October 2024[42].
- **Dynamic Voltage Management System (DVMS)** – this mechanism is similar to the SA Power Networks EVM system, used to improve management of distribution voltage levels throughout the year. Increasing distribution voltages to disconnect distributed PV can be used as a last resort when required to maintain system security. This is only suitable for use in rare emergency conditions; it is not recommended for regular use because it can risk damage to customer equipment.

Table 10 outlines best estimates provided by AusNet Distribution, Jemena, Citipower, Powercor and United Energy to AEMO on the total capability available in Victoria via these various methods to deliver emergency backstop capabilities, as a last resort if required to maintain power system security.

Table 10 Emergency backstop capability available in Victoria (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
Embedded generators	~ 64 MW	~ 64 MW	~ 90 MW
Hot water shifting	~ 120 MW	~ 120 MW	~ 120 MW
Active distributed PV management	0 MW	0 MW	Under the ESOO forecast, ~740 MW of distributed PV is projected to be installed under new backstop requirements from 1 October 2024 to 1 October 2025[A]. Victorian DNSPs estimate ~301 MW of backstop capability by Oct 2025. If initial compliance rates are similar to those observed in other jurisdictions, backstop capability available in Victoria could be only **74 MW**[B]. With considerable uplift and immediate investment in major efforts to achieve high compliance, this could increase to as high as **405 MW**[B].
DVMS	~ 293 MW	~ 293 MW	~ 293 MW
Total backstop available*	~ 477 MW	~ 477 MW	With baseline compliance levels: **577 MW** With major uplift in compliance: **908 MW**
Backstop requirement	~ 71 MW	~ 468 MW	~ 957 MW
Shortfall	-	-	With baseline compliance levels: **379 MW** With major uplift in compliance: **48 MW**

A. AEMO (August 2024), *NEM Electricity Statement of Opportunities*, 2024 Forecasting Assumptions Update Workbook: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update-workbook.xlsx?la=en.
B. Based on an assumption of an upper bound compliance rate of 55%, and lower bound compliance rate of 10% for the first year of delivery of this capability. Compliance rates of >90% should be targeted as soon as possible.
* Excludes shedding of reverse flowing loads to increase regional demand.

At present, Victorian DNSPs have advised that the total capability available for this spring (October 2024) is likely to be a maximum of ~477 MW, all of which may be required under some conditions. This includes use of the

[41] Victorian Department of Energy, Environment and Climate Action (DEECA), Victoria's emergency backstop mechanism for solar, https://www.energy.vic.gov.au/households/victorias-emergency-backstop-mechanism-for-solar.

[42] Victorian Department of Energy, Environment and Climate Action (DEECA), Victoria's emergency backstop mechanism for solar, https://www.energy.vic.gov.au/households/victorias-emergency-backstop-mechanism-for-solar.

DVMS. AEMO has also recommended that Victorian NSPs should prepare schedules and procedures for efficiently shedding reverse flowing circuits, if required, as a last resort measure to increase operational demand. This will involve shedding large amounts of customer load for a small increase in operational demand, and therefore will have a very high customer impact.

By October 2025, almost 1 GW of backstop capability may be required under some circumstances. Delivery of this amount will depend on the Victorian DNSPs' ability to rollout the required backstop measures, commenced 1 October 2024, and rapidly achieve high levels of compliance. As discussed further in Section 5.1, other DNSPs have experienced serious challenges achieving high compliance rates. Considerable work programs and lead times are required to achieve effective rollout of these capabilities at operational scale.

4.2.3 Actions and recommendations

AEMO is working with Victorian NSPs to prepare for anticipated low demand periods in the present October-December 2024 period, as well as preparing for 2025. Table 11 summarises the recommended short-term actions.

Table 11 Short-term actions required: Victoria

Victorian DNSPs	• Rollout of requirements under Victoria's emergency backstop requirements mechanism. • Implement systems for monitoring, maintaining and enforcing high levels of backstop compliance with: – Emergency backstop requirements. – Disturbance ride-through requirements in AS/NZS4777.2:2020. • Implement DNSP operating procedures to deliver backstop capabilities efficiently. • Implement systems to minimise delay between AEMO instruction and delivery of backstop (ideally achieving confidence in delivery in <10 minutes). • Develop and implement additional effective backstop controls (for example, expand coverage of hot water shifting capabilities, consider expanding voltage management capabilities).
AusNet Transmission	• Develop TNSP procedures for management of MSL conditions, including efficient coordination between multiple DNSPs.
AEMO	• Investigate transmission voltage management for low demand periods. Assess appropriateness of investment if necessary. • Planning assessments of alternative approaches for delivery of essential system services in MSL periods, including consideration of operability in fringe/outage conditions. • Determine operational MSL thresholds, and revise AEMO's operational MSL procedures.

4.3 Queensland

Queensland experienced a record minimum operational demand of 3,096 MW at 13:00 on 18 August 2024. At the time, distributed PV was contributing 55% of underlying demand in Queensland.

Minimum demand in Queensland has been falling on average more than ~250 MW per year, and is projected to continue on this trajectory.

4.3.1 Operational demand thresholds

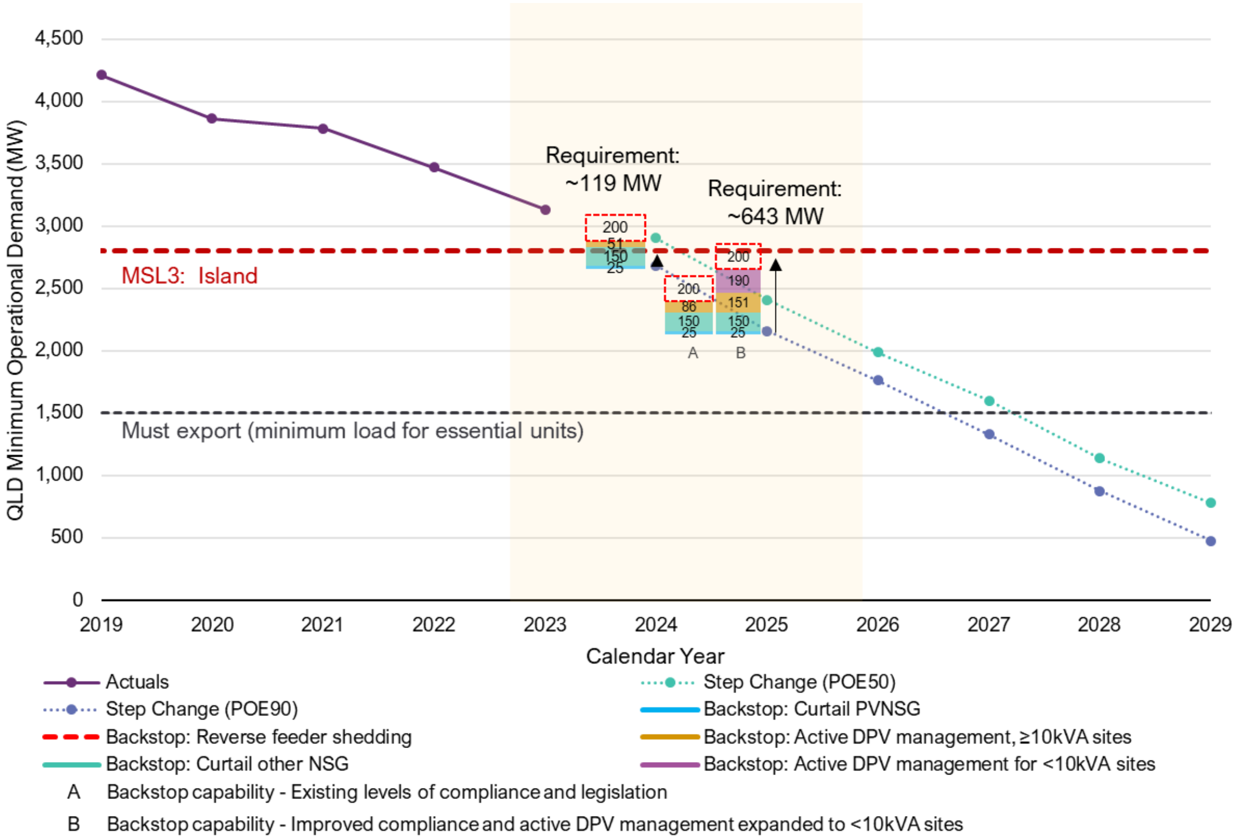
Table 12 summarises operational thresholds in Queensland (based on the present operational toolkit). These will continue to change over time as the power system evolves, and as AEMO's ability to model the power system under these novel conditions continues to improve, and the operational toolkit expands.

Table 12 Regional demand thresholds: Queensland (as of July 2024)

System conditions	Threshold	Level of regional demand (MW)	Details
Queensland island	MSL3	~2,800 MW	• Defined by the level of regional demand needed to operate minimum units for essential services when operating a Queensland island, with necessary frequency reserves, and allowing for possible unit unavailability. • Depends on the minimum safe operating levels of the minimum generating units required for essential system services in Queensland when operating as an island. Unit outages may increase this level.
Must export	Threshold below which Queensland must export to other regions	~1,500 MW	• Depends on the minimum safe operating levels of the minimum generating units required for essential system services in Queensland under system normal conditions in addition to sufficient load being available in other regions to accept export.
System normal	MSL3	Under analysis	• Analysis is underway at present.

Figure 8 compares projected minimum demand levels with these thresholds. In the present October-December 2024 period, Queensland is projected to fall below thresholds where backstop capability would be required to maintain power system security if the region is operating as an island. By spring 2025, the amount of emergency backstop capability required to securely operate Queensland as an island (if there is an unplanned outage of the Queensland – New South Wales interconnector [QNI]) grows to more than 600 MW. These requirements are summarised in Table 13.

Figure 8 Queensland: Minimum demand thresholds, projections and estimated backstop capabilities



A scenario: assumed backstop continues to apply to ≥10 kVA systems only, and existing compliance rate persists (16%).
B scenario: assumed regulatory requirement expands to cover all new distributed PV systems with backstop capability from 1 January 2025, and compliance rate for all new distributed PV systems improves linearly from 16% of systems in October 2024 to 75% of systems in October 2025.

Table 13 Emergency backstop capability required in Queensland (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
Emergency backstop capability required	-	~119 MW	~643 MW

4.3.2 Backstop capability available

Energex/Ergon Energy Networks has the ability to curtail non-scheduled generation (NSG) in their network. Historical generation patterns suggest that at times where MSL may be a concern, approximately 25 MW of PVNSG and 150 MW of other NSG will be available to be curtailed.

In addition, from 6 February 2023, all new distributed PV systems installed in Queensland with aggregated capacity of 10 kVA and above have been required to be fitted with a generation signalling device (GSD)[43]. The GSD can be activated via Energex/Ergon Energy Networks' audio frequency load control (AFLC) network.

At present, smaller distributed PV systems continue to be installed without any regulatory requirement to deliver emergency backstop capability. Furthermore, for systems 10 kVA or larger, poor rates of compliance with

[43] Queensland Government, Department of Energy and Climate, Emergency Backstop Mechanism, https://www.energyandclimate.qld.gov.au/about/initiatives/emergency-backstop-mechanism#:~:text=The%20emergency%20backstop%20mechanism%20will%20apply%20only%20to%20new%20and,residential%20and%20commercial%2Findustrial%20customers.

backstop capabilities are being observed, with site audits identifying that only 16% of systems have been correctly configured with the GSD and performing as designed (discussed further in Section 5.1.2). These two factors significantly limit the amount of active distributed PV management capability available.

Table 14 summarises Energex/Ergon Energy Networks' estimates of the total capability available to deliver emergency backstop capabilities, as a last resort if required to maintain power system security. Based on these estimates, there is a shortfall in capabilities emerging from next spring (October 2025).

Table 14 Emergency backstop capability available in Queensland (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
SCADA-controlled PVNSG		~ 25 MW	~ 25 MW
SCADA-controlled other NSG		~ 150 MW	~ 150 MW
Active distributed PV management	-	~51 MW	With continuation of present compliance and legislation: **86 MW*** With major immediate uplift in compliance and expansion of coverage to <10kVA systems: **341 MW***
Total backstop available**	-	~ 226 MW	With continuation of present compliance and legislation: 261 MW With major immediate uplift in compliance and expansion of coverage to <10kVA systems: 516 MW
Backstop requirement	-	~119 MW	~ 643 MW
Shortfall	**-**	**-**	With continuation of present compliance and legislation: **382 MW*** With major immediate uplift in compliance and expansion of coverage to <10kVA systems: **127 MW***

* This range is estimated based on projected installations ≥10 kVA in Queensland. The lower bound assumes a continuation of the present 16% compliance rate, and the upper bound assumes expansion of distributed PV backstop legislation to include <10kVA sites, with compliance improving linearly from 16% in October 2024 to 75% by October 2025.
** Excludes shedding of reverse flowing loads to increase regional demand.

Energex/Ergon Energy Networks is escalating a program of work to improve compliance of its active distributed PV management mechanism. Depending on the success of this program, the amount of backstop capability could grow to the range of 86-151 MW[44] by October 2025 (assuming that backstop requirements continue to apply only to systems ≥10 kVA). If regulatory requirements are expanded to include coverage of <10 kVA systems under backstop from 1 January 2025, up to 190 MW of further capability could be available by October 2025.

Depending on actions taken, the possible shortfall in backstop capability could be in the range of 127-382 MW by October 2025. This could mean that if there is an unplanned outage of the Queensland – New South Wales interconnector and Queensland needs to operate as an island through periods of high solar insolation and low demand, it may be operating insecure for an extended period, placing customers at escalated risk of system black events beyond the risk tolerances specified in the NER.

4.3.3 Actions and recommendations

Table 15 summarises the recommended short-term actions in Queensland.

[44] This range is estimated based on projected installations ≥10 kVA in Queensland. The lower bound assumes a continuation of the present 16% compliance rate, and the upper bound assumes expansion of distributed PV backstop legislation to include <10 kVA sites, with compliance improving linearly from 16% in October 2024 to 75% by October 2025.

Table 15 Short-term actions required: Queensland

Queensland Government	• Expand requirement for backstop capability to cover all new distributed PV installations (including new <10 kVA installations). • Explore opportunities to incentivise curtailment capability or retrofit of backstop mechanisms to legacy distributed PV systems (for example, for large commercial and industrial (C&I) installations and institutions). • Work with Energex/Ergon Energy Network to explore potential benefits and limitations of additional options for backstop capabilities (for example, the possibility of enabling voltage management capabilities). • Adjust regulations to allow for regular periodic remote testing of the backstop mechanism at scale, to support compliance improvements.
Energex/Ergon Energy Network	• Implement systems for monitoring, maintaining and enforcing high levels of compliance with: – Emergency backstop requirements. – Disturbance ride-through requirements in AS/NZS4777.2:2020. • Pending government mandate, prepare for rapid rollout of backstop requirements for all distributed PV (including new <10 kVA installations). • Consider approaches to retrospectively address distributed PV systems that are non-compliant with backstop requirements where appropriate. • Pending relevant regulatory support, undertake regular periodic testing of emergency backstop capability.
Powerlink	• Escalate further investigation of transmission voltage management and other transmission system limits for low demand periods and assess appropriateness of investment if necessary[A], including consideration of operability in fringe/outage conditions[B]. • Explore alternative approaches for delivery of essential system services in MSL periods, to minimise use of backstop mechanisms.
AEMO	• Determine operational MSL thresholds for system normal, and revise AEMO's operational MSL procedures. • Update thresholds and procedures for operation of a Queensland island and Queensland at credible risk of separation.

A. Powerlink, *Managing voltages in South East Queensland,* https://www.powerlink.com.au/managing-voltages-south-east-queensland.
B. This may require review of network Planning Criteria across the NEM under outage scenarios.

4.4 New South Wales and the Australian Capital Territory

The combined New South Wales and Australian Capital Territory region experienced a record minimum operational demand of 3,121 MW at 13:00 on 26 October 2024. At the time, distributed PV was contributing 61% of underlying demand in New South Wales.

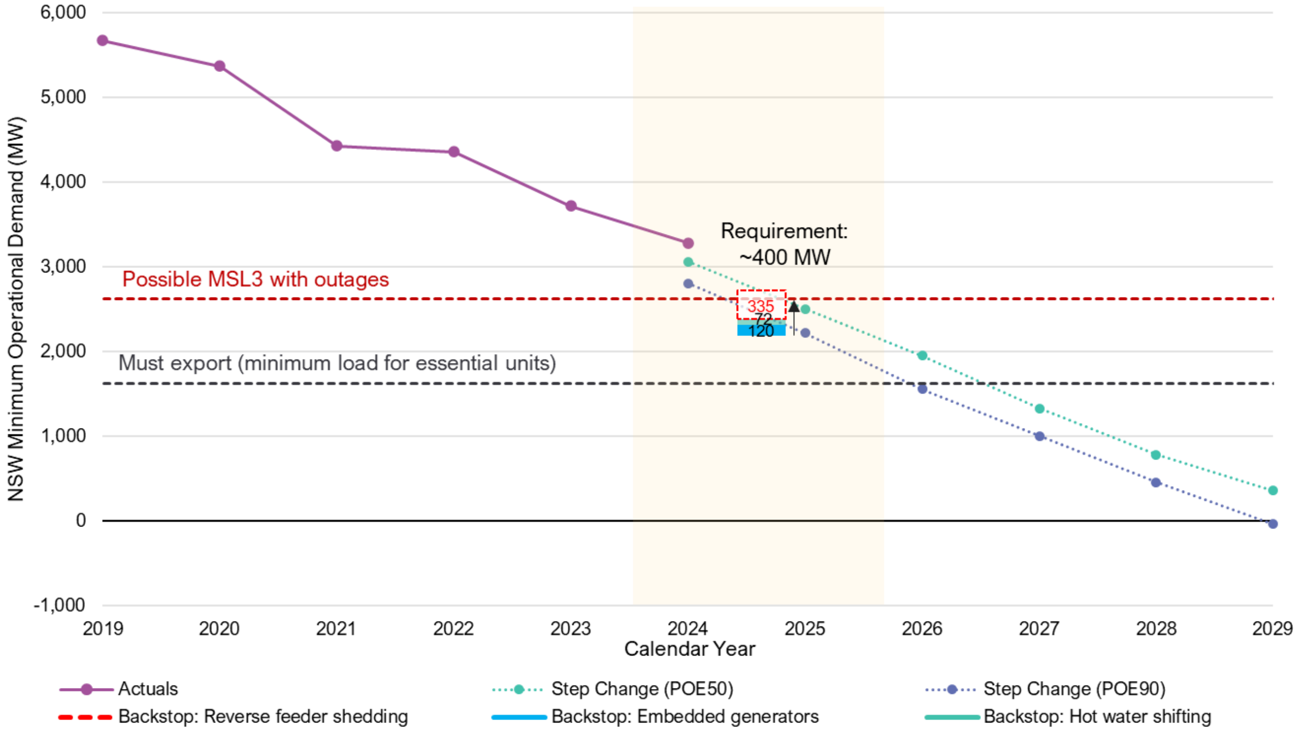
Minimum demand in New South Wales and the Australian Capital Territory has been falling on average around 500 MW per year, and is projected to continue on this trajectory, as shown below in Figure 9.

4.4.1 Operational demand thresholds

With the present operational toolkit, New South Wales/Australian Capital Territory requires at least 1.5-2 GW of operational demand to maintain online the minimum synchronous units required for essential services. However, challenges will arise much earlier than this threshold under conditions of outages. Unplanned outages can occur at any time, and there needs to be adequate operational tools available for managing these conditions. Extrapolating from studies in Victoria, outages can push thresholds ~1 GW higher.

Figure 9 shows the projections for minimum operational demand for New South Wales/Australian Capital Territory, compared with these thresholds. The potential requirements for backstop capability are shown in Figure 9, based on needing to reach an operational demand threshold of ~2.6 GW under conditions of outages. This indicates possible issues could emerge in New South Wales/Australian Capital Territory as early as 2025 if emergency conditions occur in extreme low demand periods. The amount of backstop capability required could be in the order of ~400 MW from October 2025.

Figure 9 New South Wales/Australian Capital Territory: Minimum demand thresholds and projections



4.4.2 Backstop capability available

AEMO is engaging with Governments and NSPs on introduction of an emergency backstop capability in New South Wales and the Australian Capital Territory. At present, there is no requirement for distributed PV systems to have active management capabilities in New South Wales or the Australian Capital Territory.

DNSPs in this region estimate they can curtail some embedded and non-scheduled generators in their network, delivering a total estimated response of ~120 MW. Some DNSPs estimate that they can also shift hot water loads delivering a total estimated response of ~72 MW. Beyond these options, DNSPs have indicated that at present, they have limited ability to respond to an instruction from AEMO to increase operational demand if necessary.

If adequate operational tools are not available to manage these emerging conditions, reverse feeder shedding may be required to maintain operational demand above secure limits. New South Wales and Australian Capital Territory NSPs have indicated that their present systems may require uplift to deliver this efficiently.

4.4.3 Actions and recommendations

Table 16 summarises the recommended short-term actions in New South Wales and the Australian Capital Territory.

Table 16 Short-term actions required: New South Wales and Australian Capital Territory

New South Wales and Australian Capital Territory Governments	• Introduce framework for requiring backstop capability for all new distributed PV installations. • Ensure coverage of all new distributed PV systems. • Ensure frameworks to incentivise and enforce high backstop compliance, and allow for periodic aggregate remote testing.
New South Wales and Australian Capital Territory DNSPs	• Pending regulatory frameworks, prepare for rapid rollout of active distributed PV management requirements for all new systems, and existing systems where feasible. • Implement systems for monitoring, maintaining and enforcing high levels of compliance with: – Emergency backstop requirements. – Disturbance ride-through requirements in AS/NZS4777.2:2020. • Implement DNSP operating procedures and systems for efficient delivery of backstop capabilities.
TransGrid	• Escalate further investigation of transmission voltage management and other transmission system limits for low demand periods and assess appropriateness of investment if necessary, including consideration of operability in fringe/outage conditions. • Explore alternative approaches for delivery of essential system services in MSL periods, to minimise use of backstop mechanisms.
AEMO	• Determine operational MSL thresholds, and introduce suitable MSL operational procedures.

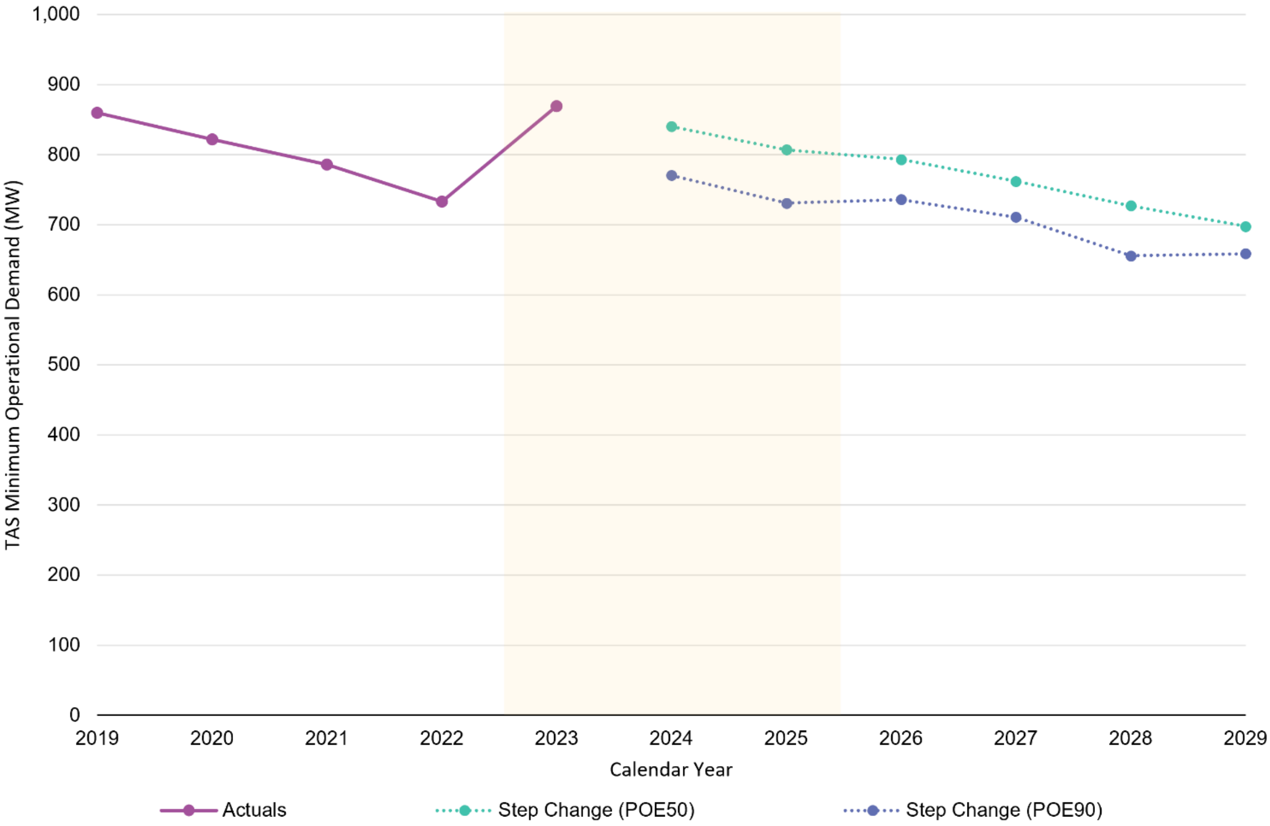
4.5 Tasmania

Tasmania experienced a record minimum daytime demand of 733 MW at 10:00 on 14 October 2022. At the time, distributed PV was contributing 13% of underlying demand in Tasmania[45].

Figure 10 below shows the daytime minimum demand actuals and forecasts for Tasmania. Minimum demand is projected to remain above historical daytime minimum levels until 2028. Tasmanian demand has a large component associated with industrial customers, which are relatively less affected by growth in distributed PV. Distributed PV also operates at lower capacity factors in Tasmania than in other NEM regions.

[45] The minimum demand in Tasmania is 732 MW on 21 March 2013 at 21:30 hrs.

Figure 10 Tasmania: Minimum daytime demand projections



Tasmania is a relatively small synchronous island, and can therefore experience challenges with managing frequency in the island, even for relatively small contingency sizes. This could mean that emergency backstop capability is required in Tasmania for managing more novel types of risks that could become apparent over time. This could involve management of type-faults or other common modes of failure (such as cyber risk) that could lead to a large proportion of distributed PV tripping. AEMO therefore recommends that Tasmania begin preparations to implement backstop capability as a precautionary measure. Technology and processes implemented for backstop capability can be leveraged alongside opportunities to deliver broader distributed resource capabilities.

4.6 Summary of regional projections

Table 17 summarises estimates of the total capability available to DNSPs in each region to deliver emergency backstop capabilities, as a last resort if required to maintain power system security.

Under some possible outage conditions in Spring 2025, South Australia, Victoria, Queensland and New South Wales may be exposed to regional shortfalls in the ability to deliver backstop capability required for management of severe emergency outage conditions. This means that use of high customer impact mechanisms (discussed in Section 2.2.1) may be required in some circumstances.

Table 17 Summary of backstop status in each NEM region

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

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

Implementation of backstop capabilities with high levels of compliance is an urgent priority. The identified shortfalls can be addressed by improvements to compliance with existing backstops, expansion of backstop and other complementary measures in a timely manner, as well as full implementation of the National CER Roadmap recommendations.

At present, New South Wales and the Australian Capital Territory have no regulatory requirements for distributed PV systems to have active management capabilities, and Queensland has no requirement for inverters <10kVA. It is recommended that pathways are put in place for effective emergency backstop mechanisms to be developed and implemented as soon as possible in these regions. For Tasmania, it is recommended that work commences on development of a backstop capability consistent with other NEM regions as a precautionary measure.

5 Implementing emergency backstops

5.1 NEM experience to date implementing backstop capabilities

5.1.1 Experiences in South Australia

SA Power Networks has been working to implement an emergency backstop mechanism in South Australia since 2020. Use of the mechanism during a power system incident in 2022[46] revealed that compliance rates were very low, with less than 30-40% of distributed PV systems responding correctly. Non-compliance was primarily associated with devices never being connected to their relevant control platform. Proper commissioning could not be automatically verified with the simple “no frills” technology used in this initial phase.

Since July 2023, SA Power Networks has introduced a Flexible Export Limits (FELs) capability. Customers installing a new distributed PV system in an area eligible for FELs are offered the choice of FELs[47] or a Fixed Export limit of 1.5 kW. The FELs mechanism involves the following aspects which support improved compliance:

- Use of Common Smart Inverter Profile – Australia (CSIP-Aus)[48] to enable communications loss failsafe behaviour (devices default to a 1.5 kW export limit if communications are lost for an extended period of time) and automated compliance checking through device telemetry.
- A compliance program which automatically prevents new applications from solar retailers who do not meet a threshold level of compliance.
- Extensive support and engagement with installers and solar retailers to help them correctly implement the new requirements.
- Extensive engagement with original equipment manufacturers (OEMs) and technology providers to help them understand and implement the new requirements.

This has led to a greater proportion of FELs systems being correctly commissioned, and this is steadily continuing to increase over time as the industry gains familiarity. As such, where emergency backstop capability used by SA Power Networks leverages the same technology, response and compliance is also improved. During the use of this newer system on 15 February 2024[49]:

- SA Power Networks records show that of the installed sites that chose FELs, 75% were correctly commissioned by the installer.
- Independent analysis found that of those correctly commissioned FELs sites:

[46] AEMO 2023, *Trip of South East – Tailem Bend 275kV lines on 12 November 2022*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf?la=en.

[47] Under FELs, customers can export up to 10 kW per phase, with export limits reducing to zero if required due to network or security constraints.

[48] The CSIP-Aus ‘Common Smart Inverter Profile – Australia’ was developed by the DER Integration API Technical Working Group to promote interoperability amongst DER and DNSPs, and leverages the IEEE 2030.5-2018 specification, and the Common Smart Inverter Profile (CSIP): https://arena.gov.au/knowledge-bank/common-smart-inverter-profile-australia/.

[49] Emergency backstop was used in South Australia two days after the power system incident on 13 February: https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

- 75% responded fully to the curtailment signal and reduced export to close to 0 kW at each site. This represents a substantial improvement since November 2022, when much of the measured response was likely related to use of enhanced voltage management.
- 10% correctly delivered the "loss of communications" 1.5 kW fallback export limit, which minimised the impact of these systems having lost communications on system security outcomes.

These steps represent important improvements, but considerable further work is required to improve compliance to the levels required for operational effectiveness. Of the ~16 MW of installed capacity of distributed PV that was eligible for FELs from 1 July 2023 to 14 Feb 2024[50], ~5 MW of demand increase was successfully delivered following the curtailment signal. SA Power Networks is targeting full rollout of the FELs mechanism by January 2025, and compliance continuing to improve throughout 2025.

Some of SA Power Networks' work to address the factors which have impacted backstop compliance in South Australia over the last four years will be transferable to other states, including through the growing availability of CSIP-Aus compatible inverters, working through teething issues associated with OEMs' initial implementation of CSIP-Aus, and the development of an innovative approach for DNSPs to manage distributed PV compliance. However, other areas will require local investment, such as working with local installers to understand the new requirements, and implementing the internal systems required to efficiently manage curtailment instructions. DNSPs in other regions should plan adequate resourcing for the work required.

5.1.2 Experiences in Queensland

Energex/Ergon Energy Networks have similarly encountered challenges with compliance. From 6 February 2023, distributed PV inverters ≥10 kVA were required to be installed with a Generation Signalling Device (GSD). Energex/Ergon Energy Networks have found that installer compliance has been far lower than expected. Site audits conducted in the past 12 months indicate that only 60% of installations have a GSD installed, and only about a quarter of those with a GSD installed are functioning as required to deliver backstop capabilities. This means that only about 16% of all installations are estimated to be performing as designed, which is significantly lower than required.

Extrapolating from these initial audit compliance rates, of the ~350 MW total distributed resource inverter capacity that should have a GSD installed (as of June 2024), there may only be a maximum effective total distributed resource curtailment response of ~51 MW. Significant further work is required to improve compliance and achieve an operationally effective backstop mechanism in Queensland.

5.1.3 Allowance for long lead times before capabilities are operational at scale

Experience to date shows that the process of implementing backstop capabilities at operational scale is complex and challenging, and needs to be commenced early to allow significant time to "learn by doing" and work through teething issues. Based on DNSP experiences to date, assuming a high level of business focus and availability of appropriate skills and resourcing, DNSPs should plan for the following indicative timeframes:

[50] Including sites that were eligible for FELs but chose a 1.5 kW Fixed Export limit instead.

- 1-2 years to implement basic curtailment capability for a proportion of the distributed PV fleet (which may involve some level of manual processes).
- 2-5 years to:
  - Achieve a high level of operability through building streamlined internal control systems.
  - Achieve high levels of compliance through uplifting local solar industry capability, and developing processes to monitor and manage compliance.

Long lead times mean it is crucial that work begins immediately to implement operationally effective backstop capabilities in all NEM mainland regions as an urgent priority.

5.2 Key considerations in implementing emergency backstop capabilities

Based on learnings to date and recent NEM incidents where backstop was used, Table 18 highlights some key factors to consider in the implementation of emergency backstop capabilities.

Table 18 Factors to consider in designing a program to implement emergency backstop capabilities

	Factors to consider
Compliance	Ensure suitable mechanisms and frameworks for managing backstop compliance, both during initial commissioning and maintained over time. For example, consider approaches utilising feedback loops, such as: • Capability testing: a test triggered by installers at the time of commissioning to check that a site is set up and responding to emergency backstop triggers correctly. • Increased incentives – requirements for capability test response in order to enable export, and potential penalties for installers that consistently fail to install systems with compliant backstop capabilities. • Periodic testing – in development of regulatory frameworks, jurisdictions should make explicit allowance for periodic testing of the mechanism in aggregate, so that compliance can be assessed and enforced.
Robustness under emergency conditions	Consider the robustness of the technical approach applied, especially under conditions where communications networks may be compromised and there may be widespread power outages (due to flooding, bushfires, storm damage, or other reasons). These types of conditions may coincide with challenging grid conditions where emergency backstop capabilities are more likely to be required.
Fallback settings for communications outages	Distributed PV systems should be configured with local “fall-back” or “fail-safe” behaviours that support system security (such as fallback generation or export limits on distributed PV), in case of connectivity issues (with the communication network for the curtailment mechanism) for an extended period.
Cybersecurity needs	Consider cybersecurity frameworks and obligations, for internet-connected distributed PV devices.
National consistency	Target consistency of approach across jurisdictions where possible (leveraging work done to date on standards such as IEEE 2030.5 CSIP-AUS and leveraging prior experience and existing systems where feasible). This should simplify implementation for DNSPs and equipment manufacturers.
Consider broad need of backstop capability	Backstop capabilities are intended to be the last resort measure to allow AEMO to manage power system security in a wide range of circumstances. The security issues highlighted in this report represent only those issues that are known at this time, but many other potential security issues could arise and require backstop capabilities, such as: • Management of cybersecurity threats. • CER control system interactions (which could occur even if systems are curtailed to 0 MW but remain connected to the system). • Possible use to facilitate a system restart process. For these reasons, AEMO recommends that backstop capabilities include the ability to completely disconnect the system if required, in addition to the ability to curtail generation to 0 MW.

	Factors to consider
	To appropriately manage customer impacts, a first tier of response could involve curtailment of site exports to 0 MW, but it is also important that the full ability to curtail ***all generation*** on site to 0 MW is also available and tested (potentially reserved to a later tier of response), to ensure a sufficient suite of tools available to manage plausible emergency conditions.
Communications	Consider programs for customer and installer engagement to ensure sufficient understanding of requirements, benefits and impacts. Systems for communication of emergency backstop usage may be required to avoid it being interpreted as system faults.

6 Recommendations

As discussed in other forums and reports, AEMO continues to recommend work with high priority on complementary measures that will limit the need to use emergency backstop capabilities. These include:

- **AS/NZS4777.2:2020 compliance** – target high rates of compliance with the disturbance ride-through requirements in AS/NZS4777.2:2020 for all new distributed PV installations (with recommendations outlined in detail in AEMO's other reports[51,52]). This aims to limit further growth in distributed PV contingency sizes, which can become a significant driver of a need to use backstop mechanisms. This will be supported by the implementation of a national regulatory framework for CER to enforce standards, as identified in the National CER Roadmap.
- **Alternative sources of system services** – implement suitable transmission network planning processes to continuously assess alternative sources of essential system services, and implement these where appropriate. This will help limit the need to use backstop mechanisms. This includes:
  - Planning processes to analyse near and medium term operational scenarios and explore novel options for delivery of essential system services (as outlined in the *Engineering Roadmap to 100% Renewables*[53]).
  - Ensuring planning processes and network Planning Criteria consider management of "fringe" operating scenarios such as combinations of possible unplanned outages and plausible extreme low demand scenarios.
- **Reform towards efficient market integration of distributed PV and CER** – escalate work programs to implement reforms that will support greater market integration of distributed PV and other types of CER, including:
  - Market systems and strong incentives for customers to participate in markets and have access to wholesale market price signals.
  - Removing barriers and encouraging investment in deep storage and responsive demand.
  - Automated and streamlined methods to manage the generation of customer distributed PV systems within normal market dispatch systems.

While the above reforms and resources are necessary and are being pursued as complementary measures to reduce the frequency of emergency backstop usage, they do not replace the need for emergency backstop capability as a last resort measure to maintain system security. In addition to these workstreams, establishment of a NEM-wide emergency backstop mechanism is required. The overarching outcome required is:

- Operationally effective emergency backstop distributed PV curtailment capabilities implemented immediately in all NEM mainland regions.

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[51] AEMO (December 2023) Compliance of Distributed Energy Resources with Technical Settings: Update, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

[52] AEMO (April 2023) Compliance of Distributed Energy Resources with Technical Settings, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en&hash=FC30DF5A3B9EF853093709012242D897.

[53] At https://aemo.com.au/initiatives/major-programs/engineering-roadmap.

- Required by spring 2025, in line with the National CER Roadmap agreed by Energy Ministers.

Table 19 summarises recommended short- and medium-term actions, with an indication of the status of each by region. It is anticipated that parallel reform programs will be implementing suitable approaches to give customers improved access to the market and improved incentives for market participation, and other mechanisms to minimise the need to utilise backstop systems. Table 19 focuses on the measures required to implement suitable backstop capabilities to maintain system security while these more sophisticated reform processes evolve and mature over time.

Table 19 Recommendations and present capabilities on emergency backstop curtailment capability

Parties	Actions required	Existing capability				
		SA	VIC	QLD	NSW/ACT	TAS
Governments and/or Regulatory bodies	• Implement suitable regulatory frameworks to require backstop capability. • Ensure coverage of all new distributed PV systems.	●	●	◑	○	○
	• Regulatory frameworks to incentivise and enforce high backstop compliance. • Allowance for periodic aggregate remote testing of the mechanism.	●	◔	○	○	○
DNSPs	• Implement backstop capabilities, with: – Periodic testing of the system at operational scale. – Capability to estimate distributed PV generation available for curtailment and verify actual curtailment in real time and post event.	◕	◔	◔	○	○
	• Implement systems for monitoring, maintaining and enforcing high compliance to backstop	◑	○	○	○	○
	• Develop DNSP operating procedures for efficient delivery of backstop. • Systems to minimise delay between AEMO instruction and delivery of backstop (ideally achieving confidence in delivery in <10 minutes).	◕	◑	◕	○	○
TNSPs	• Develop TNSP operating procedures for use of backstop.	◕	◑	◕	○	○
	• Analysis of transmission system needs in low demand periods: – Reviewing limit advice to AEMO for suitability in high distributed PV periods. – Identifying and procuring new services or investments where suitable, including options to minimise need to utilise backstop capabilities. – Ensure suitable operational options available for management of outages, (including combinations of outages) and extreme fringe scenarios*.	◑	◔	◑	◔	◔
AEMO	• Determine thresholds where backstop will be required.	◕	◕	◔	◔	○
	• Develop AEMO procedures for use of backstop, ensuring all other available actions are taken prior.	◕	◕	◑	◔	○

Key - capability assessment

○ ◔ ◑ ◕ ●

Not in place ← Partially met → Fully in place

* This may require review of network Planning Criteria across the NEM under outage scenarios.

AEMO looks forward to collaborating with NSPs, industry and governments towards establishing effective CER and distributed PV integration across the NEM. Delivery of these recommendations will provide a key underpinning towards successful operation of a secure and reliable power system that can accommodate much higher levels of distributed PV generation and other consumer assets.

A1. Previous work on minimum system load security challenges

AEMO has been working with stakeholders on measures to manage secure system operation in periods with high distributed PV generation and low demand since 2017. A summary of references is provided in the table below.

Table 20 Activity and advice relating to emergency backstop capabilities in the NEM

Date	Activities	References
2017 to 2019	AEMO analysis highlighted emerging challenges in South Australia. AEMO collaborated with SA Power Networks to explore possible mitigation measures.	-
Apr 2020	AEMO published a detailed Appendix as part of the Renewable Integration Study, focused on high penetrations of distributed PV. Bulk system challenges were discussed, and the report recommended mandating minimum device level requirements to enable generation shedding capabilities for new distributed PV installations in South Australia with other NEM regions and Western Australia encouraged.	AEMO (April 2020) *Renewable Integration Study Stage 1*, Appendix A: High Penetrations of Distributed Solar PV: https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en&hash=0E635FBFF96859AC012F189BCC6EEBA4.
May 2020	AEMO published advice to the South Australian Government on minimum operational demand thresholds in South Australia. This report outlined the system security challenges emerging in low operational demand periods, and recommended introduction of a backstop mechanism.	AEMO (May 2020), *Minimum operational demand thresholds in South Australia* – Technical Report – Advice prepared for the Government of South Australia: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/minimum-operational-demand-thresholds-in-south-australia-review.pdf?la=en&hash=BBB27149A93B9259C63B47A8ECDB0B6E.
2020	Accepting the recommendations in AEMO's advice, the South Australian Government promptly introduced the Smarter Homes framework, which introduced a requirement for backstop capability for all new distributed PV systems installed in South Australia from 28 September 2020.	South Australia Government, Regulatory changes for smarter homes: https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes.
Aug 2020	AEMO's ESOO included an extensive chapter on the challenges and opportunities of low operational demand, highlighting a growing need for active distributed resource management, and recommending urgent actions in Victoria and Queensland (in addition to the actions already underway in South Australia).	AEMO (August 2020) *Electricity Statement of Opportunities*, Section 7: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.
Nov 2020	AEMO's *South Australian Electricity Report* included a chapter on challenges and opportunities in a high renewables environment, including substantial sections highlighting specific challenges in low demand periods, and the need for new capabilities to actively manage distributed PV when necessary.	AEMO (November 2020) *South Australian Electricity Report*, Section 8: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/2020-south-australian-electricity-report.pdf?la=en&hash=E323BB3271C041904CF0D0334F5511C8.
July 2021	Release of the ESB's Post 2025 Market Design final advice to Ministers, which included the need for jurisdictions to put in place emergency backstop measures to ensure AEMO has the tools necessary to manage system security issues associated with minimum system load.	ESB (July 2021) Post 2025 Market Design final advice to Ministers.
Aug 2021	AEMO's ESOO included a comprehensive status update on minimum system load challenges and recommended actions. This update indicated that security issues in low demand periods could arise for all NEM mainland regions (Queensland, Victoria, New South Wales/Australian Capital Territory and South Australia) by 2025 in the Central scenario, or as early as 2024 in some scenarios. This is consistent with present projections.	AEMO (August 2021) *Electricity Statement of Opportunities*, Section 6.1 and Appendices*.

Date	Activities	References
Oct 2021	The Energy National Cabinet Reform Committee agreed to a recommendation by the ESB that emergency backstop measures be adopted as an immediate reform to support system security during times of minimum system load (Recommendation 8 of the NEM 2025 Reform Program).	AEMO (July 2022) Declared NEM Project – NEM 2025 Reform Program, Draft report and determination: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/declared-nem-project/draft-report-and-determination.pdf?la=en
Aug 2022	The Queensland Government announced requirements for all new distributed PV systems installed in Queensland with aggregated capacity of 10 kVA and above to deliver emergency backstop capabilities from 6 February 2023.	Queensland Government, Department of Energy and Climate, Emergency Backstop Mechanism: https://www.energyandclimate.qld.gov.au/about/initiatives/emergency-backstop-mechanism#:~:text=The%20emergency%20backstop%20mechanism%20will%20apply%20only%20to%20new%20and,residential%20and%20commercial%2Findustrial%20customers.
Sept 2022 – Jan 2023	Ergon Energy Network and Energex carried out industry consultation on the emergency backstop mechanism implementation in Queensland.	Energex/Ergon Energy Networks, Emergency Backstop Mechanism: https://www.talkingenergy.com.au/emergencybackstop .
Oct 2023	The Victorian Department of Energy, Environment and Climate Action (DEECA) announced requirements for all new distributed PV systems to deliver emergency backstop capabilities: • Stage 1: From 25 October 2023 – requirements for large systems (greater than 200 kW). • Stage 2: From 1 July 2024 (subsequently delayed to 1 October 2024) – requirements for small and medium systems (equal to and less than 200 kW).	Victorian Department of Energy, Environment and Climate Action (DEECA), Victoria's emergency backstop mechanism for solar: https://www.energy.vic.gov.au/households/victorias-emergency-backstop-mechanism-for-solar. Victoria Government Gazette, No. S 542 Wednesday 11 October 2023: https://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S542.pdf.
Oct 2023 – Oct 2024	Victorian NSPs carried out industry consultation on the emergency backstop mechanism implementation in Victoria.	-
Feb 2024	Release of the ESB's final report provided to Energy and Climate Change Ministerial Council (ECMC) in 2023 regarding the critical priorities to support CER and the transformation of the NEM included a priority for 'backstop capability that is robust and reliable in each jurisdiction to provide an emergency response improving operational security for all consumers'.	ESB (2023) Consumer Energy Resources and the Transformation of the NEM: https://www.energy.gov.au/sites/default/files/2024-02/ESB%20report%20-%20CONSUMER%20ENERGY%20RESOURCES%20AND%20THE%20TRANSFORMATION%20OF%20THE%20NEM.pdf.
July 2024	Energy and Climate Change Ministerial Council agreed to, and published, the National CER Roadmap, which highlights to backstop mechanisms to be in place by end 2025.	ECMC (2024) National CER Roadmap: https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.
Aug 2024	Release of the Engineering Roadmap implementation report highlighting key steps and AEMO engagements with governments and DNSPs on the implementation of backstops and improvements with compliance.	-

* See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf?la=en&hash=D53ED10E2E0D452C79F97812BDD926ED.

Abbreviations

Acronym	Definition
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AFLC	Audio Frequency Load Control
BESS	battery energy storage system
C&I	commercial and industrial
CER	Consumer Energy Resources
CSIP-Aus	Common Smart Inverter Profile - Australia
DEECA	Victorian Department of Energy, Environment and Climate Action
DNSP	Distribution Network Service Provider
DPVC	Distributed PV Contingency
DVMS	Dynamic Voltage Management System
ECMC	Energy and Climate Change Ministerial Council
EMMS	Electricity Market Management System
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
EVM	Enhanced Voltage Management
FCAS	frequency control ancillary services
FELs	Flexible Export Limits
GSD	Generation Signalling Device
GW	gigawatt/s
IEEE	Institute of Electrical and Electronics Engineers
kV	kilovolt/s
kVA	kilovolt-ampere/s
LOR	Lack of Reserve
MSL	Minimum System Load
MSL1	Minimum System Load – Threshold 1
MSL2	Minimum System Load – Threshold 2
MSL3	Minimum System Load – Threshold 3
MSOL	Minimum Safe Operating Level
MW	megawatt/s
NEM	National Electricity Market
NER	National Electricity Rules
NSP	network service provider
NSW	New South Wales
OEM	original equipment manufacturer
POE	probability of exceedance

Acronym	Definition
PTP	Permission to Proceed (with a network outage)
PV	photovoltaics (solar panels)
PVNSG	PV non-scheduled generation
QLD	Queensland
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SCADA	supervisory control and data acquisition
TAS	Tasmania
TNSP	transmission network service provider
VIC	Victoria
VPP	virtual power plant