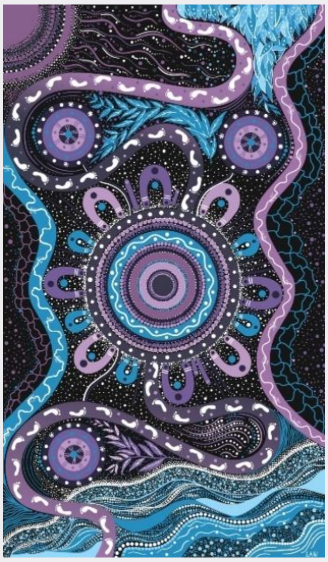
2026 General Power System Risk Review Report

July 2026

Final Report

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.

AEMO is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of 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

AEMO has prepared this 2026 General Power System Risk Review report in accordance with clause 5.20A.3 of the National Electricity Rules.

This publication is generally based on information available to AEMO as of 1 July 2026 unless otherwise indicated.

Disclaimer

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies. AEMO has made reasonable efforts to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Copyright

Executive summary

The Australian Energy Market Operator (AEMO) operates the power system to maintain a secure and reliable supply of electricity for homes and businesses across the National Electricity Market (NEM). The system continues to undergo a period of renewal as synchronous generators age and approach retirement, renewable generation and consumer energy resources (CER) continue to grow, and as technology evolves. Understanding and managing risks during this transition is essential to keep the power system secure and reliable, with new challenges continuing to emerge as the energy mix changes. Collaborative planning across the sector is key to ensuring the secure and reliable operation of the NEM into the future with consumers' interests at the centre.

Purpose of the GPSRR

Each year, AEMO collaborates with key industry stakeholders, such as network service providers (NSPs), to undertake a General Power System Risk Review (GPSRR), and publishes a GPSRR report for the NEM. The GPSRR is an annual requirement under rule 5.20A of the National Electricity Rules (NER), with the GPSRR report[1] being published on or before 31 July each year.

The GPSRR provides greater transparency of current and emerging system risks that need to be managed, and helps AEMO, NSPs, governments and market participants better understand the nature of these risks and how they can be potentially addressed. It forms part of AEMO's broader approach to identifying, assessing and managing power system security risks across the NEM. Alongside the GPSRR, AEMO publishes a range of planning and system security publications including the *Transition Plan for System Security*, which includes information on system strength, inertia and network support and control ancillary services (NSCAS), and the Engineering Roadmap. Together these measures support planning and operational strategies to maintain system security.

The purpose of the GPSRR is to support power system resilience in the NEM by reviewing:

- a prioritised set of risks comprising credible or non-credible contingency events or any other events that could lead to cascading outages or major supply disruptions under specific conditions,
- the current arrangements for managing the identified priority risks and options for their future management,
- the arrangements for management of existing protected events and consideration of any changes or revocation, and
- the performance of existing emergency frequency control schemes (EFCS) and the need for any modifications.

In addition to the identified priority risks, the GPSRR will also summarise key activities related to other power system risks that AEMO is currently undertaking.

[1] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.

Scope of the 2026 GPSRR report

The 2026 GPSRR risk assessment process has identified risks that are emerging as the NEM undergoes significant changes, requiring new arrangements for management. The NEM is seeing increasing connection of new technologies such as inverter-based loads (IBLs), impending retirements of ageing infrastructure, and the connection of new generation and transmission augmentations. The GPSRR supports the transition of the NEM, driven by the investment decisions of consumers, industry and governments.

With a focus on this objective and to meet the requirements under the NER[2], AEMO has reviewed a prioritised set of risks to the power system through the 2026 GPSRR, focusing on four priority risks. These are:

- increasing large load connections,
- non-credible system strength risks associated with unavailability of synchronous machines,
- large non-credible generation and network contingency events, and
- voltage control risks.

The recommendations made in this report aim to identify actions that will support the secure operation of the power system into the future. AEMO recognises the complexity of planning and operating a power system and that it is not possible to predict or control all risks in a rapidly changing environment. These recommendations intend to reduce the likelihood or consequence of the priority risks assessed in the 2026 GPSRR.

The four priority risks were selected by AEMO with industry input through the 2026 GPSRR approach consultation process[3]. This process considered inputs from NSPs and industry participants on potential priority risks, as well as AEMO's own operational experience, the occurrence of recent power system events nationally and globally, and any anticipated power system changes.

In addition to priority risks, the 2026 GPSRR report also contains assessment of other current and emerging risks in the NEM, an overview of stakeholder engagement and updates on previous recommendations. The 2026 GPSRR report contains the following sections to provide a broader coverage of emerging risks in the NEM:

- Section 5 sets out some of these emerging risks, which may develop into operational risks if actions are not taken in investment timeframes.
- Sections 6 and 7 provide details on the performance of existing EFCS and a review of relevant operating incidents.
- Section 8 outlines the approach to stakeholder engagement for the 2026 GPSRR.
- Section 9 provides status updates on past GPSRR recommendations.

A list of abbreviations and key terms is provided at the end of the report for reference.

---

[2] NER 5.20A outlines AEMO's obligations to review a prioritised set of risks through a general power system risk review.

[3] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-general-power-system-risk-review-approach-consultation.

2026 GPSRR priority risks

AEMO's analysis for the 2026 GPSRR has led to the findings and recommendations outlined below for the four priority risks.

Increasing large load connections

IBLs are increasing in the NEM and while the current connected capacity is still small on a system-wide scale, rapid growth is predicted in the coming years. Data centre connections are leading this growth, driven by increased demand for artificial intelligence (AI). While the increase in IBLs is expected to bring material economic and power system benefits, it can present system security challenges that must be addressed to support their integration into the NEM.

IBLs such as data centres have unique operating characteristics that must be addressed to achieve successful integration. Some of these characteristics include:

- disconnecting from the grid and switching to backup power supplies when exposed to typical voltage disturbances, or for events related to frequency, price or other operating conditions,
- the potential to ramp demand quickly, resulting in rapid increases or decreases in consumption within dispatch intervals, and
- possible contribution to oscillatory behaviour when undertaking AI training or through controller interactions, which may cause instability or impact other power system plant.

The analysis conducted through the 2026 GPSRR process highlights the potential risks that IBLs may pose to the power system if no actions are taken to support their integration.

To support successful integration, requirements such as the capability to ride through disturbances, ensuring timely active power recovery, limiting rapid demand ramping, and minimising contribution to power system oscillations must be considered.

These key findings support the measures proposed in the Australian Energy Market Commission's (AEMC's) *Improving the NEM access standards: Package 2* draft rule to implement load access standards for IBLs. These load access standards will introduce performance requirements for IBLs to minimise the adverse impacts they may present to the grid and provide greater certainty on the design specifications required for connection.

The *Improving the NEM access standards: Package 2* rule change process has made strong progress toward addressing risks related to IBLs. However, there is still further work that must be completed to continue to support the integration of IBLs. There are emerging risks that are not currently captured in the draft determination of the load access standards and are actively being considered through sub-working groups, rule change proposals, access standard reviews[4], and updates to power system stability, modelling and system strength impact assessment guidelines.

[4] An access standards review is completed every five years in obligation with NER S5.2.6A(a) to assess the need for amendments to the technical requirements outlined in Schedules 5.2, 5.3 and 5.3a.

Recommendation 1

AEMO supports the implementation of load access standards for IBLs to reduce risks related to increasing large load connections.

Actions:

AEMO will continue to monitor emerging risks related to IBLs and collaborate with industry and relevant stakeholders to support successful integration.

Non-credible system strength risks associated with unavailability of synchronous machines

The operational landscape of the NEM is changing with the ongoing retirement of synchronous generation. Assessments under the GPSRR have been undertaken to investigate the resilience of the system to withstand low likelihood events if they were to occur during infrequent operating conditions where the system is operating close to its system security limits. Forward-looking assessments of these low probability risks strengthens AEMO's ability to maintain reliability and security.

Fault level assessments have been undertaken to determine the operational actions required to meet minimum fault levels in New South Wales and Victoria[5] under the following scenario:

- post retirement of the Eraring and Yallourn power stations,
- prior planned or forced outages of up to three large synchronous units in New South Wales or Victoria, and
- the occurrence of a power system event resulting in the non-credible loss of an additional two large synchronous units.

Sensitivity studies were also completed with and without the delivery of additional synchronous condensers and network augmentations to understand their expected contribution to system strength.

Following the non-credible loss of the two large synchronous units[6], the operational actions required to resecure the power system were assessed. This involved determining the combination of fast-start units that could be brought online, or other operational actions required, to restore fault levels above the secure level.

Key findings from the analysis are detailed below.

New South Wales

- **On time delivery of synchronous condensers and network augmentations in New South Wales enables the operational management of multiple outages.** The delivery of planned synchronous condensers and network augmentations is expected to provide significant system strength benefits in New South Wales to support operations post-retirement of Eraring. It was observed that it is possible to maintain adequate fault levels without further operational actions[7] for the non-credible loss of two synchronous units under scenarios with three prior outages of large synchronous units.

[5] New South Wales and Victoria were selected for assessment due to the expected retirement dates of Eraring power station and Yallourn power station as per information available at the publication of the 2026 GPSRR Approach Paper. General recommendations from these assessments should also be considered for other upcoming synchronous generation retirements.

[6] To date in FY25-26 there have been three incidents involving the loss of two large synchronous units – Yallourn 3 and 4 on 16 October 2025, Callide C3 and C4 on 15 January 2026, and Vales Point on 2 February 2026.

[7] Assuming secure pre-contingent operation which may require directions for system strength under certain operating conditions.

- **If system strength solutions in New South Wales are delayed, this may lead to operational challenges under multiple outage scenarios.** The system strength solutions in New South Wales improve system strength significantly. However, there may be operational challenges if these solutions are not delivered before the retirement of Eraring. As highlighted in the 2025 *Transition Plan for System Security* (TPSS), the absence of synchronous condensers and network augmentations will introduce operational complexity. The 2026 GPSRR demonstrates that additional operational actions will need to be taken in conjunction with bringing on fast-start units to resecure the system for certain non-credible contingency events during multiple planned or unplanned outage conditions. The potential increase in operational complexity highlights the importance of the timely, planned system strength solutions to facilitate secure operation even for low probability events occurring under multiple outage conditions.
- **Timely delivery of planned system strength solutions should be prioritised as further synchronous generation retires in New South Wales.** While the currently planned solutions adequately support the retirement of Eraring if delivered on time, further system strength support measures will be needed to support future synchronous generation retirements or other scenarios resulting in unavailability of synchronous machines. This highlights the importance of the timely progression of ongoing system strength support measures through the current system strength framework. The consideration of additional synchronous condensers, grid-forming (GFM) battery energy storage systems (BESS)[8] or other alternative solutions, such as those explored through AEMO's TPSS or the 2025 Thermal Audit[9], will continue in a timely manner to support system strength in the NEM.

Victoria

- **Delivery of synchronous condensers in Victoria in time for the retirement of Yallourn would improve the capability to resecure for multiple outage conditions.** Once delivered, the Hazelwood synchronous condenser will support operational outcomes post-Yallourn retirement, but there will remain some operational challenges in managing low likelihood, multiple outage conditions. For three large synchronous units on prior outage, the additional non-credible loss of two synchronous units may require eight fast-start units to be brought online to resecure the system. This would be difficult to achieve within 30 minutes and may require additional operational actions to be taken to resecure within desired timeframes.
- **The scale of operational actions required increases further if Yallourn retirement occurs before synchronous condensers are delivered.** Operational actions to manage multiple outages become more challenging without synchronous condensers post-Yallourn retirement. Even in the unlikely scenario assessed for this analysis, where a non-credible loss of two units occurs when three large units are on prior outage, it is important to consider measures to improve resilience for these types of tail risk conditions.
- **Additional measures can be taken in Victoria to manage risks related to low likelihood multiple outage conditions.** There are a number of actions that could be considered to further support power system security in Victoria post Yallourn retirement. This could be achieved through improved coordination of planned outages to reduce the period of time that multiple units are on outage concurrently. This coordination should occur with appropriate advance notice to avoid significant impacts to timing or cost. Operational procedures could also be extended to consider specific

[8] GFM BESS may be capable of providing system strength support for voltage waveform stability in the near term. Contribution of GFM BESS to meet protection fault level requirements will require continued work to achieve. AEMO is proposing to procure Type 2 Transitional Services (Trial Services) to demonstrate GFM inverters' capabilities in providing protection-quality fault current.

[9] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf.

non-credible contingency events. These procedures could specify post-contingent actions such as inverter-based resource (IBR) curtailment or de-energisation of network elements, or pre-contingent actions such as ensuring fast-start units are prepared to come online in short time frames through appropriate staffing or other measures. The use of GFM BESS for system strength support related to voltage waveform stability could also be considered.

Actions to support system strength

There are a number of actions that are currently being progressed to support system strength to mitigate risks related to the unavailability of synchronous machines. These actions include:

- **Transmission network service providers (TNSPs) are progressing the delivery of measures that will support system strength such as synchronous condensers, network augmentations and the use of contracted services.** The timely delivery of these measures will support system strength as synchronous machine availability decreases. These measures include the deployment of synchronous condensers to provide fault current and voltage support, and the construction of new network augmentations that reduce network impedances and improve system strength at key locations. In the near term, TNSPs are also utilising contracted services from existing synchronous generators to support minimum fault level requirements while permanent solutions are delivered.
- **AEMO is continuing to support the evolution of system strength provision in the NEM through its Engineering Roadmap and Type 2 Transitional Services.** These will contribute to the evidence base of how specific GFM inverters behave in specific grid conditions. As part of this, AEMO is proposing to procure Type 2 transitional services to undertake a GFM inverter protection-quality fault current trial. This trial assesses the viability of inverter-based technologies providing fault current of sufficient magnitude, duration, and composition suitable for the reliable operation of power system protection systems.
- **TNSPs and AEMO are already considering GFM inverter technology as a potential solution to several challenges facing the NEM during its transition away from synchronous generation.** GFM inverters have demonstrated capabilities to improve system stability and provide synthetic inertia and are now being deployed at utility scale in the NEM. TNSPs are considering this technology as an alternative to synchronous machines to meet the stable voltage waveform component of system strength requirements.

Recommendations

Proactive measures will continue to be considered by AEMO and TNSPs to reduce the operational impacts if these low probability scenarios occur. This preparation will improve system resilience even for low probability high impact events related to multiple outages post synchronous generation retirement.

Recommendation 2

AEMO's assessments in the 2026 GPSRR reinforces the importance of prioritising the delivery of system strength support measures to maintain system strength amidst the retirement of synchronous generation in the NEM. To enable the efficient and timely delivery of system strength, AEMO also supports the need for system security framework enhancements to meet ongoing system security needs[10].

[10] See https://www.aemc.gov.au/rule-changes/security-framework-enhancements

Actions:

AEMO and TNSPs should extend operational documentation to further support the ability to resecure the system for low probability non-credible contingency events, considering options such as:

- specifying post-contingent actions required to resecure for non-credible contingency events that may present increased risk, and
- taking actions to maximise fast-start unit availability for multiple outage conditions.

AEMO will continue to progress system strength and transition point studies as outlined in the TPSS. AEMO will also continue to support the evolution of system strength in the NEM through its Engineering Roadmap and Type 2 Transitional Services[11].

TNSPs to continue to prioritise the delivery of planned system strength support measures such as synchronous condensers (conversion of existing plant, or new installations), network augmentations and the use of contracted services. The timely resolution of any identified shortfalls will support ongoing system security.

The risks highlighted are present during multiple large synchronous unit outage conditions. Where possible, actions should be taken to coordinate outages and reduce the likelihood of three or more large synchronous units being on outage concurrently.

Recommendation 3

AEMO has identified that multiple planned or unplanned prior outages may contribute to operational complexity for the occurrence of non-credible contingency events. Improved coordination of generation and network outages, or other suitable actions, should be considered to reduce risk during these periods.

Actions:

AEMO will consider the appropriate approach to reducing the likelihood or impacts of multiple prior generation and network outages while minimising impacts to participants. This may include:

- potential for regulatory change to improve generator and network outage coordination,
- procedural updates to current processes to support improved coordination without regulatory change, or
- other appropriate mitigation measures as determined by AEMO.

Large non-credible generation and network contingency events

Power systems are planned and operated to maintain system security for credible contingency events. One of the key objectives of the GPSRR is to support the resilience of the power system outside of this framework, particularly in regard to the consideration of high impact low probability (HILP) events, including non-credible contingencies. This involves forward assessment of actions required to reduce the likelihood or consequence of risks in the unlikely event they were to occur. Under the 2026 GPSRR process, the impacts of large non-credible generation and network contingency events have been

[11] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial

assessed, considering the loss of multiple power system assets that result in the disconnection of large quantities of generation or critical transmission infrastructure. The loss of multiple power system elements simultaneously does not occur frequently, but it is important to understand conditions where elevated risks may be present and identify if mitigation measures are required.

Non-credible contingency events can occur for a range of reasons, such as a result of extreme weather conditions, inadvertent operation of protection systems, or the failure of power system plant or components. This priority risk considers the likelihood and consequences related to large non-credible generation and network contingency events in the NEM. These are assessed both in the current and future system to understand how the risk profile may change over time.

AEMO's analysis in the 2026 GPSRR finds that the risks related to non-credible contingencies are expected to change into the future. Some factors will improve power system resilience, such as fast frequency response (FFR) capability provided by BESS or new generation, or the addition of network augmentations that strengthen connections between regions. Other factors may increase risks such as operating lines at higher transfers or connecting large quantities of generation behind double circuit lines.

AEMO assessed the resilience of the current and future systems through power system studies. For the 2026 GPSRR, AEMO completed power system studies assessing the consequences of a range of non-credible contingencies in the current system. For each region, AEMO applied increasing contingency sizes to the system under various dispatch scenarios to identify a range of contingencies that could result in major supply disruptions. This information could then be compared to historical events and the current potential non-credible contingencies to understand the current risk profile.

It was found that while a number of factors increase power system resilience over future years, the NEM may still be susceptible to large contingency events that occur under infrequent operating conditions. One of the risks that is expected to persist is instability on the Queensland – New South Wales Interconnector (QNI) for large generation contingencies south of Queensland when QNI is operating close to its south transfer limits. The resilience of the system would be tested for the unlikely occurrence of a large non-credible generation contingency under these conditions.

Power system resilience in the NEM can be supported through a number of ongoing measures that can be taken, including:

- **Implementing remedial action schemes (RASs) where specific contingency events are likely to result in severe consequences** – a RAS may be the most appropriate solution where the risk is present for large periods of time, but only if the implementation of a scheme is simple, and if it does not introduce significant maloperation or interaction risks.
- **Declaring a protected event or using the indistinct events framework where specific conditions could result in severe consequences** – a protected event was utilised for South Australia[12] where interconnector flows were limited during periods of destructive winds. Using the market actions allowed through protected events may be a more suitable solution when a risk is only present for short periods of time, so that any constraints or other limitations do not have a significant market impact. These short term conditions may arise under specific dispatches, weather conditions or operating scenarios, where the likelihood or consequences related to non-credible contingency risks justify pre-emptive controls. In some instances, the use of a protected event may remove the need for a RAS entirely, avoiding the associated costs and complexity. In other cases, it may simplify the requirements for a RAS and assist in managing risks for boundary cases. The indistinct events framework is another potential approach that can be used to reclassify non-credible contingency events when abnormal conditions are present that increase the likelihood of a non-credible

[12] See https://www.aemc.gov.au/sites/default/files/2019-06/Information%20Sheet%20-%20final%20determination%20-%20REL0069.pdf.

contingency occurring. However, the indistinct events framework manages increased likelihood of occurrence, but does not take into account scenarios where an increased consequence may be present.

- **Ensuring that EFCS such as under frequency load shedding (UFLS) and over frequency generation shedding (OFGS) are maintained and available.** It would not be economical to implement specific mitigation measures to protect against every possible non-credible contingency event. Due to this, EFCSs such as UFLS or OFGS are used as a broad measure to arrest cascading failures in the event of an unexpected non-credible contingency event that has severe frequency impacts. AEMO is currently progressing additional measures to maintain UFLS and OFGS schemes in the NEM. This includes the NEM UFLS adequacy review which involves the detailed evaluation of the regional UFLS bands and assesses the performance and adequacy of the current UFLS schemes. There are also updates related to OFGS presently underway across multiple regions in the NEM.

Analysis in the 2026 GPSRR report has highlighted that protected events may be able to play a larger role in power system resilience in future, particularly situations such as QNI instability where a number of different large contingencies could result in severe consequences. For specific operating conditions where risks of cascading failures have been identified through system studies, it is proposed that protected events could support power system resilience through taking actions such as:

- procurement of additional frequency control ancillary services (FCAS) or other ancillary services,
- reducing interconnector flows during high risk conditions, and
- constraining generation that is concentrated in high risk areas.

The declaration of a protected event may be best suited for high consequence risks where the necessary operating conditions are only present for short periods of the year.

Recommendation 4

AEMO has demonstrated the emerging risks related to large non-credible generation and network contingency events. Operating conditions will change materially with new augmentations and generation retirements, influencing risk outcomes.

Actions:

AEMO will continue to monitor conditions that may present an increased likelihood or consequence of cascading failure or major supply disruptions. If the duration of these conditions is observed to be increasing beyond tolerable limits, **AEMO** will consider the appropriate implementation of protected events or identify the need for RASs through the GPSRR to support power system resilience.

TNSPs to continue to support the assessment of power system resilience for large non-credible contingency events, particularly supporting the consideration of protected events, RASs, EFCS or identifying the need for reclassification.

Voltage control risks

On 28 April 2025, the Iberian Peninsula[13] experienced a widespread blackout following a rapid and uncontrolled rise in system voltage and the subsequent loss of effective voltage control. This international incident demonstrated the consequences that insufficient voltage control can have on power systems. One of the key objectives of the GPSRR is to

[13] See https://www.entsoe.eu/publications/blackout/28-april-2025-iberian-blackout/.

reduce the likelihood or consequences of risks that may result in cascading failures or major supply disruptions. With recent international examples to reference, it was determined through the GPSRR consultation process that it would be appropriate to review the root causes and identify learnings for the NEM to understand any mitigation measures required to improve power system resilience.

The review of voltage control risks in the 2026 GPSRR found that the NEM already has a number of requirements and procedures in place to reduce the likelihood of cascading voltage events occurring. However, there may be certain operating scenarios or conditions where significant non-credible contingency events could cause voltage control challenges. The NEM would benefit from studies confirming the extent of voltage control challenges that may arise under non-credible contingency events occurring in low likelihood operating conditions. This will further support the understanding of non-credible risks in the NEM and provide the opportunity to implement mitigation measures if determined to be necessary.

Recommendation 5

AEMO recommends that existing studies on voltage control risks are extended to consider the impacts of non-credible contingencies in operating conditions that may present an elevated risk of voltage control related cascading failures.

Actions:

AEMO will consider the inclusion of detailed voltage control risk studies for a future GPSRR, particularly during minimum system load conditions, low fault levels or other periods of low dynamic reactive power availability. This may include consideration of:

- non-credible generation contingency events such as the loss of multiple synchronous generating units that are absorbing reactive power,
- the non-credible disconnection of multiple loads and the potential impact on system voltages,
- stability of IBR when absorbing close to the reactive limit of the plant, or
- other voltage control risks identified through the GPSRR consultation process.

TNSPs and distribution network service providers (DNSPs) to provide inputs to AEMO on any identified conditions or events related to voltage control risk studies that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.

Recent reports from international incidents have identified that oscillations can contribute to events leading to cascading voltage failures. The contribution of oscillations is notable as small signal stability risk is an area of increasing consideration in the NEM. This is particularly important due to the topological changes occurring with new augmentations, the retirement of synchronous generation and associated power system stabilisers, and the addition of new synchronous condensers. Recommendations and learnings from international events related to oscillations should be considered in the NEM context.

Recommendation 6

AEMO recommends that power system oscillation risks are considered as a priority risk for a future GPSRR or through the TPSS. This is intended to highlight potential consequences, identify appropriate mitigation measures and drive action to address this risk. AEMO is intending to consider small signal stability through the 2026 TPSS, which will further contribute to identifying emerging security gaps related to power system oscillations.

Actions:

AEMO will consider the inclusion of power system oscillation risks for a future GPSRR or through the TPSS. This may include consideration of:

- operational procedures for power system oscillations,
- source location and detection of forced oscillations,
- assessment of the impacts of changing network topology and generation retirements on inter-area modes,
- impacts of increasing IBR on small signal stability,
- power system oscillation monitoring and benchmarking challenges, and
- other power system oscillation risks identified through the GPSRR consultation process.

TNSPs and DNSPs to provide inputs to AEMO on any identified conditions or events related to power system oscillations that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.

2026 GPSRR recommendations

Table 1 lists the key recommendations from the analysis that was completed for the 2026 GPSRR.

Table 1 2026 GPSRR recommendations

	Recommendations	Priority risk
1	AEMO supports the implementation of load access standards for IBLs to reduce risks related to increasing large load connections. **Actions:** **AEMO** will continue to monitor emerging risks related to IBLs and collaborate with industry and relevant stakeholders to support successful integration.	Increasing large load connections
2	AEMO's assessments in the 2026 GPSRR reinforces the importance of prioritising the delivery of system strength support measures to maintain system strength amidst the retirement of synchronous generation in the NEM. To enable the efficient and timely delivery of system strength, AEMO also supports the need for system security framework enhancements to meet ongoing system security needs[14]. **Actions:** **AEMO and TNSPs** should extend operational documentation to further support the ability to resecure the system for low probability non-credible contingency events, considering options such as: • specifying post-contingent actions required to resecure for non-credible contingency events that may present increased risk, and • taking actions to maximise fast-start unit availability for multiple outage conditions. **AEMO** will continue to progress system strength and transition point studies as outlined in the TPSS. AEMO will also continue to support the evolution of system strength in the NEM through its Engineering Roadmap and Type 2 Transitional Services. **TNSPs** to continue to prioritise the delivery of planned system strength support measures such as synchronous condensers (conversion of existing plant, or new installations), network augmentations and the use of contracted services. The timely resolution of any identified shortfalls will support ongoing system security.	Non-credible system strength risks associated with unavailability of synchronous machines
3	AEMO has identified that multiple planned or unplanned prior outages may contribute to operational complexity for the occurrence of non-credible contingency events. Improved coordination of generation and network outages, or other suitable actions, should be considered to reduce risk during these periods.	Non-credible system strength risks associated

[14] See https://www.aemc.gov.au/rule-changes/security-framework-enhancements

<table>
<tr><th></th><th>Recommendations</th><th>Priority risk</th></tr>
<tr><td></td><td>Actions:
AEMO will consider the appropriate approach to reducing the likelihood or impacts of multiple prior generation and network outages while minimising impacts to participants. This may include:
• potential for regulatory change to improve generator and network outage coordination,
• procedural updates to current processes to support improved coordination without regulatory change, or
• other appropriate mitigation measures as determined by AEMO.</td><td>with unavailability of synchronous machines</td></tr>
<tr><td>4</td><td>AEMO has demonstrated the emerging risks related to large non-credible generation and network contingency events. Operating conditions will change materially with new augmentations and generation retirements, influencing risk outcomes.
Actions:
AEMO will continue to monitor conditions that may present an increased likelihood or consequence of cascading failure or major supply disruptions. If the duration of these conditions is observed to be increasing beyond tolerable limits, AEMO will consider the appropriate implementation of protected events or identify the need for RASs through the GPSRR to support power system resilience.
TNSPs to continue to support the assessment of power system resilience for large non-credible contingency events, particularly supporting the consideration of protected events, RASs, EFCS or identifying the need for reclassification.</td><td>Large non-credible generation and network contingency events</td></tr>
<tr><td>5</td><td>AEMO recommends that existing studies on voltage control risks are extended to consider the impacts of non-credible contingencies in operating conditions that may present an elevated risk of voltage control related cascading failures.
Actions:
AEMO will consider the inclusion of detailed voltage control risk studies for a future GPSRR, particularly during minimum system load conditions, low fault levels or other periods of low dynamic reactive power availability. This may include consideration of:
• non-credible generation contingency events such as the loss of multiple synchronous generating units that are absorbing reactive power,
• the non-credible disconnection of multiple loads and the potential impact on system voltages,
• stability of IBR when absorbing close to the reactive limit of the plant, or
• other voltage control risks identified through the GPSRR consultation process.
TNSPs and DNSPs to provide inputs to AEMO on any identified conditions or events related to voltage control risk studies that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.</td><td>Voltage control risks</td></tr>
<tr><td>6</td><td>AEMO recommends that power system oscillation risks are considered as a priority risk for a future GPSRR or through the TPSS. This is intended to highlight potential consequences, identify appropriate mitigation measures and to drive action to address this risk. AEMO is intending to consider small signal stability through the 2026 TPSS, which will further contribute to identifying emerging security gaps related to power system oscillations.
Actions:
AEMO will consider the inclusion of power system oscillation risks for a future GPSRR or through the TPSS. This may include consideration of:
• operational procedures for power system oscillations,
• source location and detection of forced oscillations,
• assessment of the impacts of changing network topology and generation retirements on inter-area modes,
• impacts of increasing IBR on small signal stability,
• power system oscillation monitoring and benchmarking challenges, and
• other power system oscillation risks identified through the GPSRR consultation process.
TNSPs and DNSPs to provide inputs to AEMO on any identified conditions or events related to power system oscillations that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.</td><td>Voltage control risks</td></tr>
</table>

Contents

Tables

Figures

Part A: Priority risks for review

1 Increasing large load connections

This section covers the following key points:

- Increasing large load connections may bring opportunities and benefits to the NEM but require ongoing system security challenges to be addressed.
- IBLs may introduce risks due to their operational characteristics, requiring analysis and actions to support their successful integration.
- Actions to mitigate some of these risks are currently underway, but further action is required.

A growing number of new large IBLs are expected to connect to the NEM in the coming years. This is evident from forecast data centre growth, with data centre energy consumption expected to reach 12.0 terawatt hours (TWh) by 2029-30 under the *Step Change* scenario[15]. These connections are expected to bring material economic activity with up to $135 billion dollars in Australian construction investment by 2035[16]. Power system benefits may also be realised such as the ability to offer demand response, FCAS or additional demand in minimum system load (MSL) conditions. However, the benefits of these new connections will only be realised if system security needs are met.

There are emerging challenges associated with the rapid increase in IBLs that must be addressed to support their successful integration. These include improving the performance of IBLs in withstanding voltage and frequency disturbances on the grid. The operational characteristics of IBLs must also be considered, such as the impacts of rapid demand ramping or forced oscillations.

Analysis undertaken as part of the 2026 GPSRR supports the requirements currently being considered in the AEMC's *Improving the NEM access standards – Package 2* rule change[17] and AEMO's *Operational integration and visibility of large inverter-based loads rule change request*[18]. Among other measures, these proposed changes would introduces load access standards that require IBLs to ride through voltage disturbances, as well as address the operational challenges arising from the increased number of large IBL connections. The implementation of these proposed measures would reduce system security risks related to requirements within the scope of the proposed rule changes.

1.1 Inverter-based loads are increasing in the NEM

1.1.1 The NEM is seeing rapid growth in inverter-based load connections

Data centre connections are increasing rapidly, supporting growth in inverter-based loads associated with AI demand. Inverter-based load connections in the NEM are increasing as new data centres are developed to meet the rising demand

[15] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf.

[16] See Clean Energy Finance Corporation, *Getting The Balance Right Data Centres And The Energy Transition*, *Investment and capacity projections*, page 13, at https://www.cefc.com.au/document?file=/media/hs5ner3s/getting-the-balance-right-data-centres-and-the-energy-transition-full-report.pdf.

[17] See https://www.aemc.gov.au/rule-changes/improving-nem-access-standards-package-2.

[18] See https://www.aemc.gov.au/rule-changes/operational-integration-and-visibility-large-inverter-based-loads.

for AI. At present, this growth is largely concentrated in the Melbourne and Sydney central business districts, due to the close proximity to existing infrastructure and skilled workforce. However, it is expected that all regions will see increases in IBL connections in future.

Data centre demand as a percentage of NEM total demand is still small, but expected to increase. AEMO estimates that data centres consumed approximately 2% of NEM demand in 2024-25. This is forecast to increase in future years, up to approximately 6% by 2029-30 under the *Step Change* scenario. Current forecasts from the 2025 *Electricity Statement of Opportunities* (ESOO)[19] for the NEM predict that maximum data centre demand is expected to increase materially in future years, with up to 6 gigawatts (GW) of data centre demand present in the system by 2035.

The NEM is at the beginning of this IBL transition. The relatively low current connection volumes provide an opportunity to plan the pathways required to support successful future integration. This requires consideration of the technical, operational and planning factors to maintain system security without introducing unnecessary limitations. By agreeing on an approach that satisfies system requirements while meeting the needs of data centre proponents and customers, a sustainable pathway can be established to support the effective integration of data centres into the future power system.

1.1.2 Expected benefits of new data centre connections

Data centres are expected to deliver material economic and power system benefits, provided that emerging system security challenges are effectively managed. Some of the benefits data centres may be able to contribute include investment in construction and grid infrastructure, employment opportunities and flexibility in power system operations.

In recent analysis conducted by Baringa, it is forecast that data centre investment in Australia will reach values between $85 billion and $135 billion[20] and create employment across construction, operations, digital and information and communications technology (ICT) roles. A report from Mandala[21] highlights that data centres are also expected to contribute directly to grid infrastructure, with an expected $7.2 billion of grid infrastructure investment predicted over the next five years. Of this amount, the report states that $1.1 billion is predicted to be over and above data centre connection needs and available for public use.

From a power system perspective, data centres may also provide benefits. Additional load from data centres may help in managing MSL conditions by facilitating the operation of synchronous machines above their minimum stable operating levels with reduced need to take actions to manage MSL conditions, such as the use of emergency backstop mechanisms. Potential benefits could also arise where on-site batteries or backup generation participate in contingency or emergency demand response or ancillary service arrangements. Stable demand from data centres may also assist in meeting minimum levels of demand for adequate operation of UFLS.

Connected data centres have also supported investment in renewable generation projects. Mandala's report estimates that in 2025 around 40% of data centre electricity consumption was offset through power purchase agreements, underwriting new renewable generation and on-site solar installations.

[19] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf.

[20] See https://www.baringa.com/globalassets/insights/low-carbon-futures/australia-data-centre-growth-report/getting-the-balance-right-data-centres-and-the-energy-transition-full-report.pdf.

[21] See https://mandalapartners.com/uploads/Data-Centres-as-Enabling-Infrastructure.pdf.

To realise the benefits data centres can bring, potential power system security and reliability challenges must be addressed. The Federal Government's *Expectations of data centres and AI infrastructure developers*[22] highlighted that new data centres and AI should positively contribute to Australia's energy transition.

1.1.3 Inverter-based loads have the potential to impact system operations

Without appropriate controls, IBLs such as data centres may impact system operations due to different operating characteristics, large scale of connections and geographic concentration compared to other typical power system loads. Data centres operate differently to typical power system loads due to a range of different factors. One of the most significant factors is that their power electronic equipment is sensitive to voltage disturbances, yet their uptime is highly prioritised for their customers. Due to this, if a data centre experiences voltages outside its allowable limits, it may disconnect from the grid and switch to back-up generation to maintain reliability of supply.

In the absence of voltage ride-through standards, the performance for data centres or other IBLs may align with the Information Technology Industry Council (ITIC) thresholds[23]. These thresholds outline the typical voltage and durations that most information technology (IT) equipment can withstand without damaging equipment or operating unexpectedly.

These thresholds are restrictive for undervoltages, where a voltage less than 0.7 per unit (p.u.) for more than 20 milliseconds (ms) will result in the disconnection of the equipment. Clearance times for transmission faults is typically between 80 ms and 220 ms, and these faults will often reduce voltages below 0.7 p.u. when they occur. Data centres adhering to the ITIC curve would be seen to disconnect for many typical voltage disturbances.

Data centres are expected to be geographically concentrated and may have similar settings. Based on experience in the NEM, data centre connections are typically concentrated around central business districts. The common location of these connections means that a single voltage disturbance will affect many connections at once. If these connections operate with similar settings, the impact to the power system will be a coincident response of many individual data centres. This has the potential to have significant impacts if large numbers of data centres disconnect for a voltage disturbance.

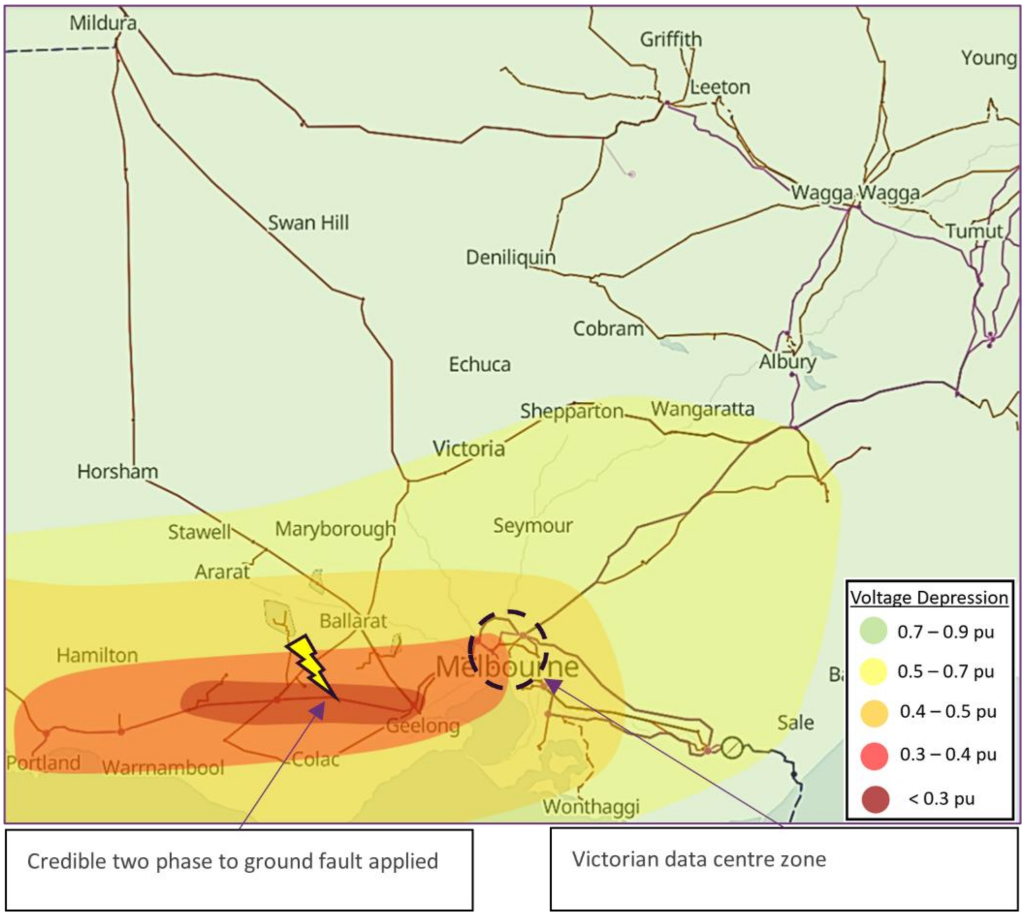
Voltage disturbances can propagate widely through the transmission network, affecting data centres even for remote faults. Voltage disturbances applied to the high voltage transmission network can be experienced across wide geographic areas due to the low impedance transmission lines. The same properties that allow for the transmission of power over long distances also mean that when a voltage disturbance occurs, this may propagate to locations that are distant from where the fault occurred. This may mean that even faults occurring in remote locations may impact the operation of IBLs located close to major cities.

Figure 1 illustrates this, demonstrating the modelled propagation of a two phase to ground fault in South West Victoria. It can be seen that the network surrounding the Melbourne central business district (CBD) would experience a voltage drop below 0.5 p.u. This would result in the disconnection of all data centres that experienced this disturbance if only complying with the ITIC curve.

[22] See https://www.industry.gov.au/publications/expectations-data-centres-and-ai-infrastructure-developers.

[23] See https://voltage-disturbance.com/voltage-quality/itic-curve/.

Figure 1 Voltage disturbance propagation for a two phase to ground fault in the Victorian transmission network



The load profiles of data centres may also have operational impacts outside of disconnection. In addition to introducing potential system security issues for disconnection, data centres can also exhibit operational characteristics that may impact power system operations. These include the ability to ramp their demand rapidly within dispatch intervals or introduce forced oscillations into the network.

1.2 Integration challenges are being addressed

IBLs such as data centres have unique operating characteristics that must be addressed to achieve successful integration. To support this integration, requirements regarding the capability to ride through disturbances, ensuring timely active power recovery, limiting rapid demand ramping, and minimising contribution to power system oscillations must be considered.

1.2.1 Improved inverter-based load disturbance ride-through supports system security

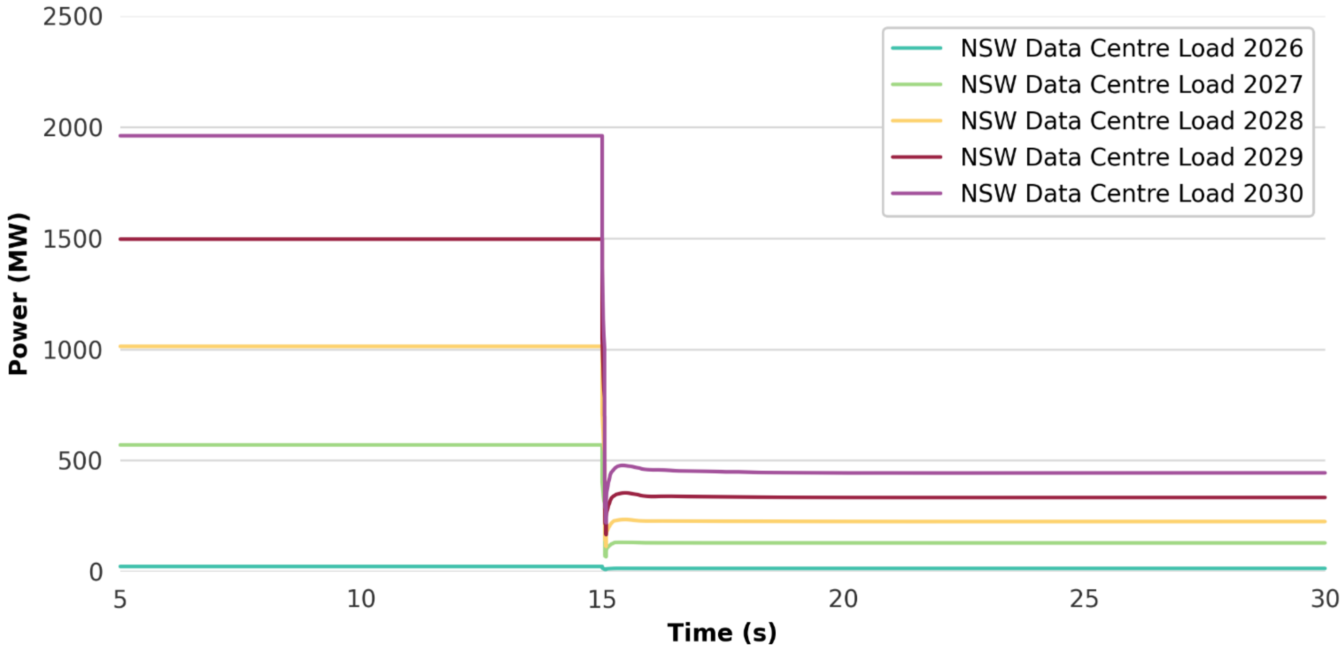
IBLs that ride through typical voltage disturbances will better support system security. The power system is planned and operated on the basis that a voltage disturbance and the loss of one element of the power system may reasonably occur at any time. If any voltage disturbance or the loss of one element occurs, this must not result in the system landing in an unsatisfactory state. To ensure the system is secure, AEMO will implement constraints or procure ancillary services to ensure the system will land satisfactory for any credible contingency event such as a voltage disturbance or loss of a single element. If the largest credible contingency size increases due to data centre disconnections, more restrictive actions may need to be taken by AEMO to ensure the system remains secure, potentially increasing costs to consumers.

Increasing contingency sizes

Disconnection of data centres for voltage disturbances could significantly increase credible contingency sizes in the NEM. If data centres do not ride through voltage disturbances, any credible contingency and an associated voltage disturbance could result in the loss of a significant number of data centres. This would increase the largest credible load continency in each region by the quantity of data centre load that would disconnect.

As more data centres connect, there will be a larger total of potential data centres that would disconnect for a voltage disturbance. Consider **Figure 2** below, outlining scenarios regarding data centre growth in New South Wales.

Figure 2 New South Wales data centre disconnections in the absence of ride through access standards following a credible contingency (MW)



By the year 2030, if all new data centre connections do not adhere to the proposed access standard, the application of a two phase to ground fault on the 330 kilovolts (kV) network near Sydney West could result in the disconnection of approximately 1,500 megawatts (MW) of data centre load[24]. If more data centres were to connect to the network without suitable voltage ride-through requirements, this value would increase further.

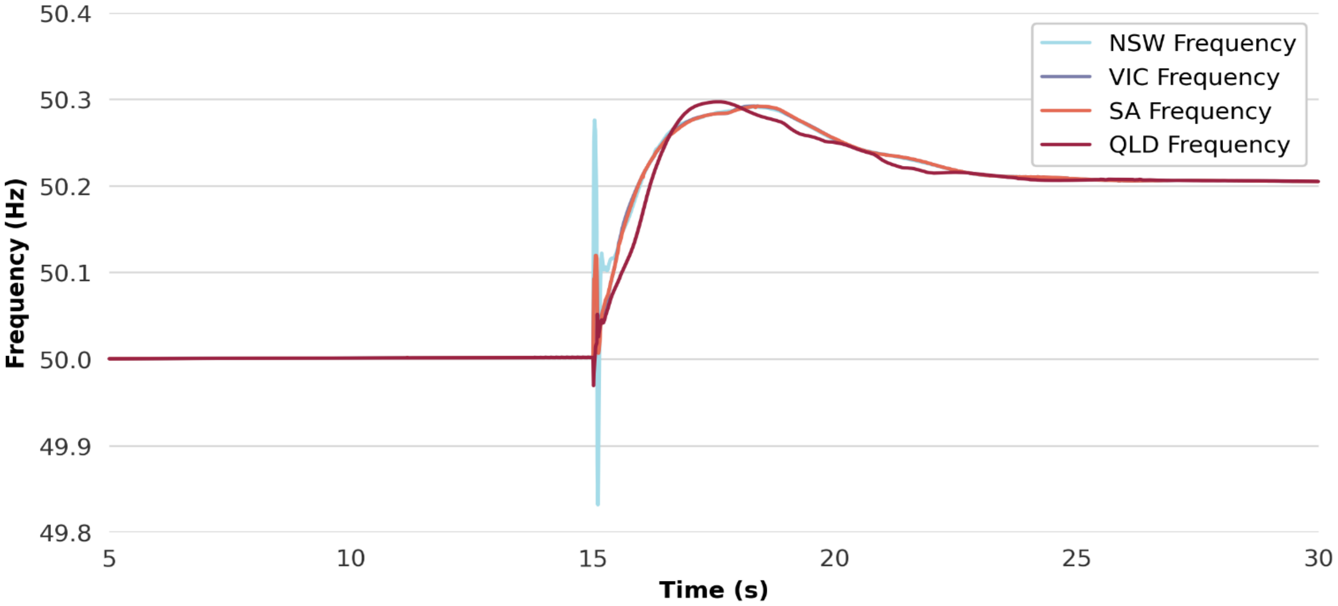
Frequency impacts

The loss of large quantities of load can also impact system frequency. Increasing load contingency sizes could also result in more severe frequency impacts on the system. An increased maximum load contingency will result in larger frequency excursions, and therefore a requirement to carry more FCAS lower services. If more data centres connect without requiring

[24] Based on AEMO forecasts of data centre load growth in the 2025 ESOO.

disturbance ride-through, the frequency impacts would increase for each new connection. This would require the continual re-evaluation of FCAS requirements to account for the impacts of each new connection. An example of potential frequency impacts related to data centre disconnections is shown in **Figure 3**, which demonstrates the impact on frequency for a disconnection of 1,500 MW in the New South Wales region in 2030. **Figure 3** shows the impacts for a single voltage disturbance in 2030, but the frequency impacts could be even more severe in future years, for the coincident trip of a major industrial load or during low inertia conditions.

Figure 3 Frequency impacts of data centre disconnections (hertz [Hz])



Impacts on power transfers

IBLs disconnecting for credible contingencies would also impact internetwork transfer capability. Interconnector constraints can be implemented to maintain power system security for major system events such as large load contingencies. These constraints are intended to limit the flows on the interconnectors such that the loss of the largest credible load within a region will not result in instability over the interconnectors. If this largest load contingency size in a region increases, this will require recalculation of limits and likely a reduction in interconnector transfer capability.

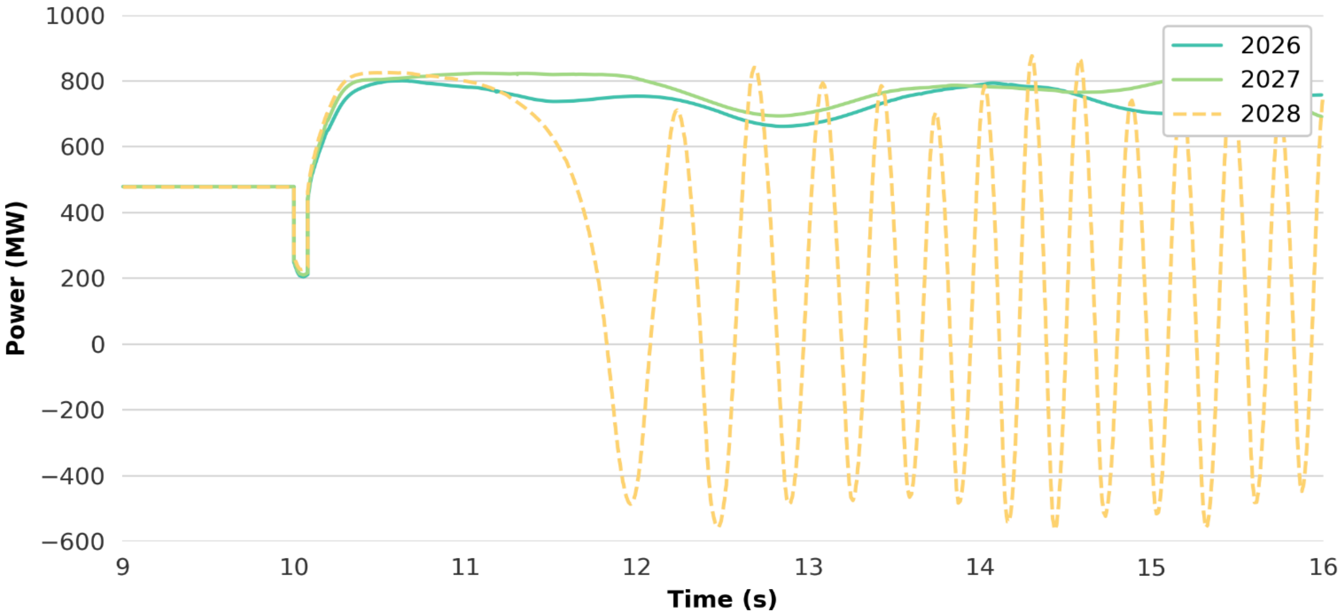
The impact of increasing contingency sizes on Victoria – New South Wales Interconnector (VNI) stability is shown below in **Figure 4.** It was observed that the additional data centre disconnections resulted in system instability when operating close to interconnector limits. These cases were set up identically, except that each case has the 2025 ESOO forecast quantity of data centre demand that relates to the year listed in **Table 2**. To assess the response of the system, a 500 kV fault was applied in South West Victoria with an initial 530 MW load disconnecting to represent a significant load contingency in Victoria. An additional quantity of data centre load was also observed to disconnect due to disturbance ride through behaviour.

In the 2026 and 2027 cases assessed, the modelling indicates that the system can withstand the trip of the additional data centres for this scenario due to the capacity of data centres remaining within the safety margin of the constraint. However, projected data centre capacity reaches a critical point in 2028. System instability is observed because the largest load contingency now far exceeds the level assumed in system planning and security assessments. Any increases in the largest load contingency size in a region will impact system security requirements and the procurement of ancillary services, ultimately resulting in increased costs. The system may also reach instability earlier than demonstrated for more severe contingency events or other dispatch scenarios.

Table 2 Summary of forecast Victorian data centre demand (MW) – 2025 ESOO

Year	Demand (MW)
2026	66
2027	312
2028	594
2029	815
2030	1,910

Figure 4 Victoria – New South Wales Interconnector active power transfer: Murray – Upper Tumut (MW)



Cumulative impact of smaller loads

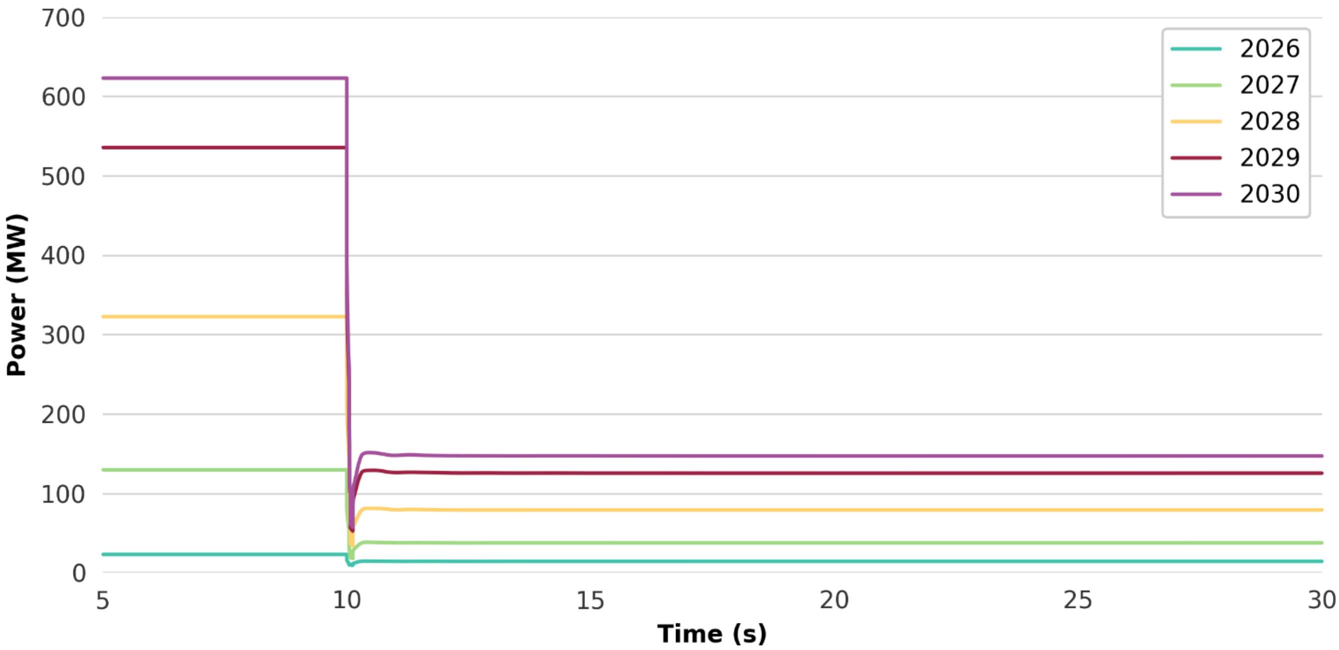
The aggregate response of multiple small IBLs could have similar impacts to individual large connections. Smaller IBLs may also impact power system operations if ride-through performance is poor and there are many individual connections that operate with similar settings. In the simulations shown above in **Figure 4**, an increase of around 500 MW in load contingency size in Victoria was enough to result in voltage collapse. This indicates that a similar contingency size as a result of the aggregation of smaller data centre connections could have similar system security impacts.

The potential contingency sizes associated with smaller data centre connections are shown below in **Figure 5**, demonstrating a hypothetical scenario where a credible fault is applied in New South Wales but data centre loads below 40 MW[25] have no ride-through requirement. It can be seen that for the 2030 case, data centre load reduces from around 620 MW to less than 150 MW, an approximate 470 MW decrease.

[25] Note that the analysis using a threshold of 40 MW was conducted prior to the publication of the draft rule with a proposed large IBL threshold of 30 MW. However, similar conclusions can be drawn from these results and applied to the 30 MW threshold.

It can be seen that this increase in contingency size is of the same magnitude that caused instability in the previous example. This demonstrates the importance of considering the aggregate impacts of data centres for all sizes. If there are concerns regarding data centres 100 MW or greater, there should be equal consideration given to the cumulative impacts of small data centres that can reach similar sizes.

Figure 5 Contingency sizes associated with less than 40 MW data centre connections without access standards (MW)



AEMO supports the need for ride-through requirements for IBLs to reduce the impacts on system security. Ride-through requirements should be applied to IBLs that may materially impact system security, whether this is for large individual connections or the aggregate response of multiple smaller connections.

Inverter-based loads must be able to ride through typical protection clearance times as a minimum

To minimise impacts to the power system, IBLs should be able to ride through voltage disturbances that last for typical protection clearance times. Typical voltage disturbances can occur on the transmission network, and there are minimum clearing times specified in the NER that outline how quickly circuit breakers must operate to clear the fault. Voltage disturbances that are applied at voltages at 100 kV and above are more likely to propagate further in the transmission and distribution networks.

This places a high priority on the capability of IBLs to ride through protection clearance times that align with these rows in **Table 3** below. A voltage disturbance that propagates further in the network is more likely to be seen at the point of connection for multiple IBLs. As voltage levels reduce, the likelihood of the disturbance reaching multiple connections is less. Voltage disturbances less than 100 kV are more likely to only affect connections in close proximity to the disturbance. This should only result in a limited number of disconnections.

Table 3 National Electricity Rules fault clearance times reproduced from table S5.1a.2

Voltage level	Near end clearing time (ms)	Remote end clearing time (ms)	CBF clearing time (ms)*
400 kV and above	80	100	175
At least 250 kV but less than 400 kV	100	120	250
More than 100 kV but less than 250 kV	120	220	430
Less than or equal to 100 kV	As necessary to prevent plant damage and meet stability requirements		

Note: see https://energy-rules.aemc.gov.au/ner/756/29929.
* The occurrence of a circuit breaker failure (CBF) event is considered to be non-credible.

AEMO supports the need for ride-through requirements to align with typical protection clearing times in the NEM. The AEMC's *Improving the NEM* access *standards: Package 2* draft rule has proposed a voltage disturbance ride-through requirement with an automatic access standard (AAS) of 240 ms and a minimum access standard (MAS) of 140 ms, noting that DNSPs have some discretion on the application of these standards to IBLs less than 100 MW.

Preliminary assessments indicate that compliance with the proposed disturbance ride-through automatic access standard provides significant benefits compared with the minimum access standard

Power system studies were conducted to assess the difference in performance for IBLs connecting in compliance with the voltage disturbance ride-through AAS or MAS. A Victorian transient stability export limit study has been conducted to assess the possible impact of proposed data centres and other large IBLs. Sensitivity of the export limit was assessed with the IBLs represented at the proposed AAS and MAS for voltage disturbance ride-through. The following NEM study case dispatch conditions were assessed:

- system loading and generation aligned with recent typical conditions under which the Victorian transient export limit was binding, and
- 2030 forecast total data centre load of 1,910 MW added across four proposed sites in western metropolitan Melbourne.

Studies were completed with the following transmission network configurations:

- existing transmission network plus Project EnergyConnect (PEC) Stage 2, and
- planned augmentations to 2030, excluding Victoria – New South Wales Interconnector West (VNI West).

Preliminary results indicate that the AAS reduces the impact on transient export limits when large quantities of IBLs connect. The study identifies the possible impact of data centre IBL compared with general mixed customer load at the same size and location. This was achieved by adding a total of 1,910 MW of data centre load at four sites, and adjusting the percentage of load that has under-voltage tripping behaviour as specified in the AAS, in the MAS, or as represented via a typical voltage dependent static load model without under-voltage tripping. The Victorian transient export limit was then determined for each of these sensitivities by adjusting interconnector transfer levels and applying a Hazelwood to South Morang 500 kV line fault.

Preliminary study results demonstrate the following possible impacts of connecting data centre IBLs in metropolitan Melbourne for the dispatch scenario and specific fault assessed:

- Up to approximately 1,900 MW of IBL may be connected at the proposed AAS for voltage ride-through without materially affecting the Victorian transient export limit.
- Connecting more than approximately 1,100 MW of IBL at the proposed MAS for voltage ride-through may materially reduce the Victorian transient export limit.

These results demonstrate the potential difference in performance that is provided through compliance with the AAS as opposed to the MAS for the particular conditions studied. Additional network augmentations or support may facilitate the connection of IBLs greater than the numbers specified above. However, while performance aligned with the AAS is expected to minimise the potential system security impacts of large IBLs, negotiation of performance standards should consider commercial, technical and locational factors and should remain fit-for-purpose and proportionate to the risks associated with both individual and aggregate impact.

Frequency disturbances

IBLs should also be required to ride through frequency disturbances. It would be particularly important for IBLs to ride through over frequency events, because the disconnection of load for over frequency would result in further increases in the frequency. This would have potential to push the frequency into ranges that could result in generator protection operating.

The capability of IBLs to ride through frequency disturbances is expected to be sufficient. IBLs are expected to be more resilient in remaining connected for frequency disturbances than traditional synchronous generation. Due to this, it should be sufficient for IBLS to ride through frequency disturbances in line with the requirements for generators as specified in the NER.

> AEMO supports frequency ride-through requirements for IBLs to align with those specified for generators in the NER. This has been proposed in the AEMC's *Improving the NEM access standards: Package 2* draft rule.

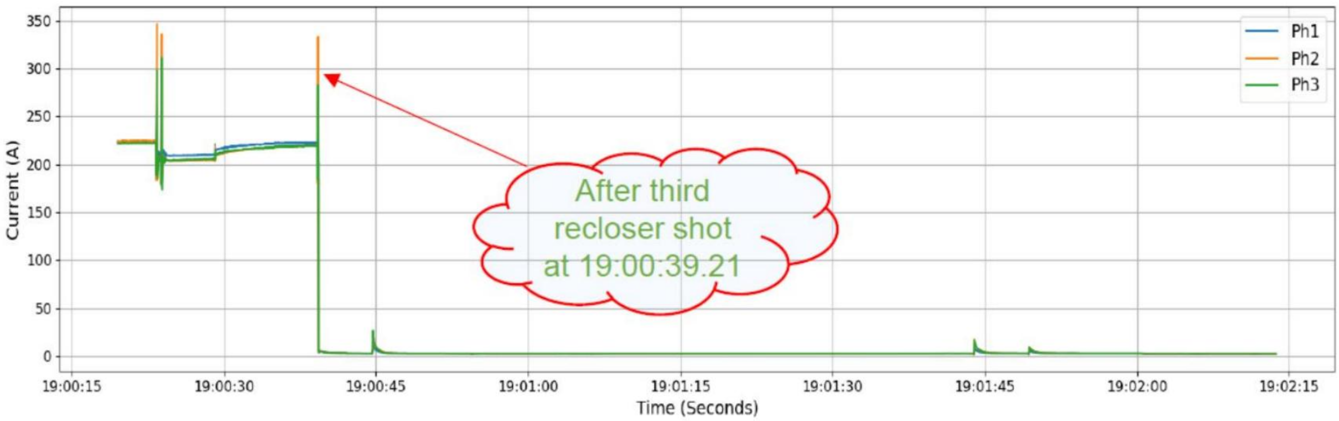
Settings that automatically disconnect for multiple disturbances should not be implemented as default

IBLs may have common protection settings that automatically disconnect the load from the grid in the event of multiple disturbances. These settings are typically implemented by IBLs to protect equipment, or to maintain reliability for end users in the event of grid instability. Multiple disturbance ride-through protection typically counts the number of disturbances that are experienced within a pre-defined timeframe and will disconnect the plant if its threshold is exceeded. However, if this threshold is too low and many IBLs share the same settings, this act of disconnecting from the grid when multiple disturbances occur has the potential to impact power system security. As outlined in the North American Electric Reliability Corporation's (NERC's) *Characteristics and Risks of Emerging Large Loads*[26] report, there have been known instances where data centres have shared the same multiple disturbance ride-through settings and have disconnected simultaneously for a typical grid event. This is demonstrated in **Figure 6**, which shows the disconnection of approximately 1,500 MW of primarily data centre load due to multiple disturbances.

[26] See page 23 of https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf.

Multiple disturbance ride-through settings for IBR contributed to the South Australian black system in 2016. One of the key conclusions in AEMO's *Black System South Australia 28 September 2016* report[27] was *"It was the action of a control setting responding to multiple disturbances that led to the black system".* Wind farms successfully rode through grid disturbances, but it was the presence of a disturbance counter setting that resulted in the disconnection of many wind farms. IBLs have similar disturbance counters, and it should be ensured that they will not contribute to similar impacts as was seen for the South Australian black system event.

Figure 6 Data centre load disconnections due to multiple disturbance ride-through settings in the Eastern Interconnection (United States)



Other grid operators internationally have proposed multiple disturbance ride-through requirements. As outlined in ESIG's *Large Load Performance Requirements: Current practices and recommendations* report, there are a number of grid operators internationally that are already considering multiple disturbance ride-through requirements for IBLs. It is recommended that this risk is also considered in the NEM.

Table 4 Summary of international multiple disturbance ride-through requirements

Network	Requirement
Fingrid	Require large loads to ride through 10 bolted faults of 100 ms each within a 90-second period.
TenneT	Require large loads to ride through three low voltage ride-through events within 30 minutes and five high voltage ride-through events within 30 minutes.
AESO	Specify that the minimum ride-through durations are applicable to one or multiple faults in a 10-second window.
ATC	Require large loads to sustain three ride-through events over a period of 10 seconds (s).

Note: see page 12 of https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf.

AEMO supports the requirements in the AEMC's *Improving the NEM access* standards draft rule, proposing that IBLs do not implement protection that disconnects the facility from the grid based on disturbance counters.

[27] At 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.

1.2.2 Active power recovery delays should be minimised

IBLs may need to temporarily disconnect from the grid during disturbances. While it is important that IBLs can ride through voltage disturbances, it may not be possible for them to remain connected continuously under severe fault conditions. For IBLs such as data centres, if the voltage drops below 0.7 p.u., it may be necessary for the data centre to temporarily block the flow of power to its inverters until the voltage returns within the acceptable limits of its equipment. This temporary disconnection cannot be avoided without the risk of maloperation or unexpected shutdowns of the plant. However, to ensure that data centres minimise the power system impacts, it is necessary that they reconnect to the grid as soon as possible.

Table 5 Summary of international active power recovery requirements

Network	Requirement
Electric Reliability Council of Texas (ERCOT)	Large electronic loads (approved after or on 14 November 2025) must return to 90% pre-disturbance consumption within one second [A].
Fingrid	Data centres 10 MW and greater must return to 90% active power level that existed prior to the fault within 0.5 s [B].
EirGrid and SONI	Following clearance of the fault the demand facility should return to at least 90% pre-fault demand within 500 ms [C].
TenneT	Pre-fault active current must be restored after fault clearance [D].
American Transmission Company (ATC)	Active power must be fully restored within three cycles after the fault is cleared without shifting to back-up or UPS, otherwise detailed studies are required [D].
Energinet	80% of pre-disturbance power must be restored within 5 s (±2% difference allowed). 90% of pre-disturbance power must be restored within 20 s (±2% difference allowed). 95% of pre-disturbance power must be restored within 30 s (±2% difference allowed) [D].
Alberta Electric System Operator (AESO)	Default active power recovery time is 1 s, configurable to 10 s depending on system strength [D].

A. See https://www.ercot.com/files/docs/2025/11/14/282NOGRR-01-Large-Electronic-Load-Ride-Through-Requirements-111425.docx.
B. See https://www.fingrid.fi/globalassets/dokumentit/fi/palvelut/kulutuksen-ja-tuotannon-liittaminen-kantaverkkoon/2025-06-05-kjv2026-main-requirements-draft-for-stakeholders.pdf.
C. See https://cms.eirgrid.ie/sites/default/files/publications/MPID345-Large-Demand-Facility-Fault-Ride-Through-Issue-and-Proposed-Solutions-EirGrid-and-SONI-Information-Paper-November-2025.pdf.
D. See https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf.

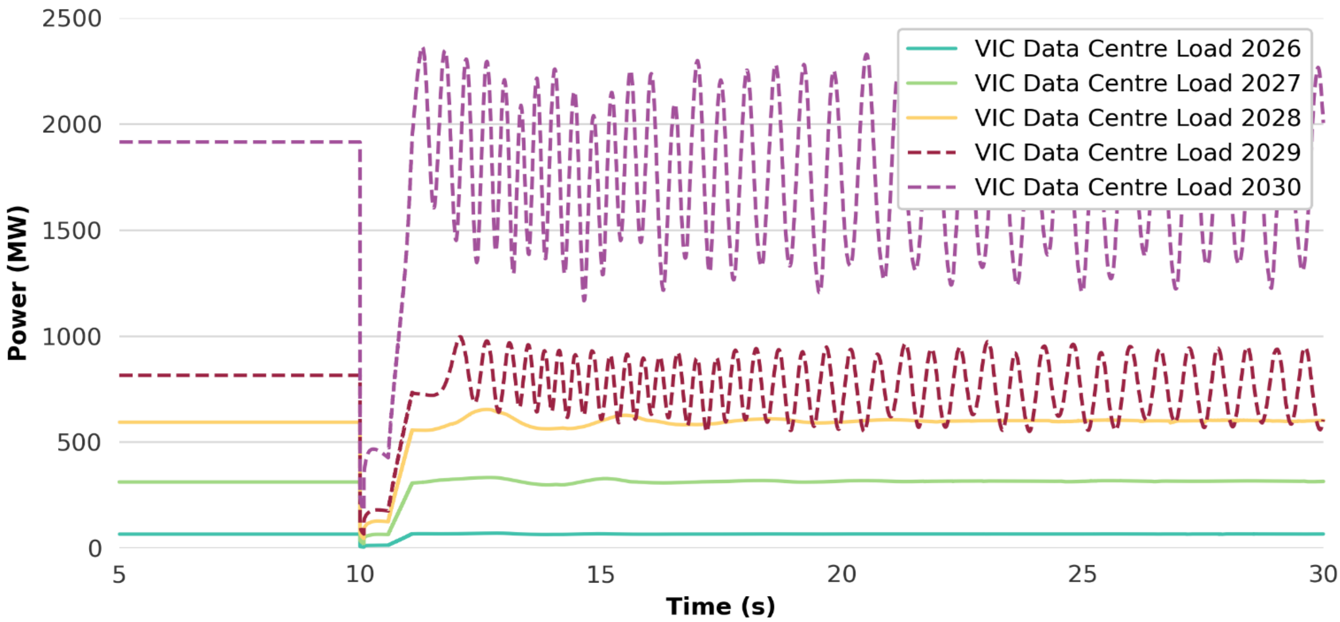
Temporary disconnections will have a similar effect to increased contingency sizes but at a smaller magnitude. In the same way that increasing contingency sizes impact power system security, delayed active power recovery during a fault will have the same effect. This temporary disconnection results in an absence of load on the system for the period of time that it takes for the data centres to reconnect. For the system, this is equivalent to a load contingency, except that it is only temporary. This means that while it will have transient impacts, these impacts will increase as more data centres connect. The impact of active power recovery is influenced by the delay time as well as the quantity of load. The impact of delayed active power recovery is shown below in **Figure 7** and **Figure 8**:

- **Figure 7** demonstrates the impacts of increasing data centres given a fixed active power recovery time.
- **Figure 8** demonstrates the impacts of an increasing active power recovery time given a fixed size of data centre connections.

Note that the outcomes of these studies demonstrate the impacts for a specific operating condition. However, as these outcomes could occur as a result of a credible contingency event, they must be considered for system security assessments which will directly impact power transfers and the requirements for ancillary services.

Increasing quantity of data centre load increases the transient energy surplus. There is an increase in the energy surplus the grid experiences during a disturbance when there are more data centres that temporarily disconnect. This is demonstrated in **Figure 7**, where active power recovery time is kept constant at 1,000 ms but the number of data centres increases over time.

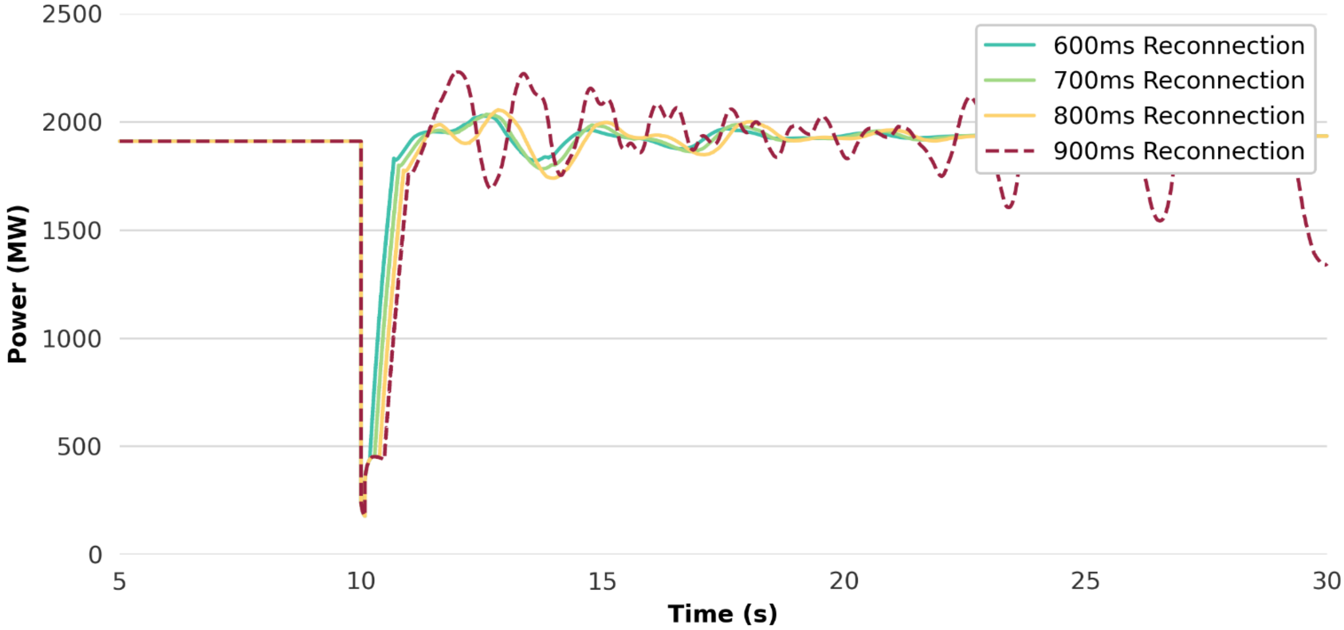
Figure 7 Impacts of increasing data centre connections and delayed active power recovery on interconnector instability (MW)



Increased active power recovery time also increases the transient energy surplus. A similar impact can be seen for a fixed number of data centres and an increasing active power recovery time. As the recovery time increases, the energy surplus in the system increases, driving the system closer to instability. In the case shown below in **Figure 8**, for all data centres operating with a 900 ms recovery time, this was long enough to result in interconnector instability for the dispatch scenario that was studied.

Active power recovery delays will have an impact on power system operations. It may not be possible for data centres to reconnect to the grid with no delay and as such there will always be some impact on the system due to delayed active power recovery. Even in an optimistic scenario where all data centres return to their pre-disturbance active power within 500 ms after a disturbance, there will still be an energy surplus during this 500 ms period. If the number of data centres increases significantly, this may have material impacts requiring recalculation of limits or procurement of additional FCAS. While it is not possible to completely mitigate the impacts of delayed active power recovery, minimising it where possible should be targeted.

Figure 8 Impacts of increasing active power recovery time on interconnector stability (MW)



AEMO supports the need to minimise active power recovery delays for IBL ride-through. Active power recovery delays should be as low as possible and should not be longer than 1,000 ms. The AEMC has proposed a draft load access standard requiring active power recovery delays to be minimised with an AAS of 500 ms and a MAS of 1,000 ms.

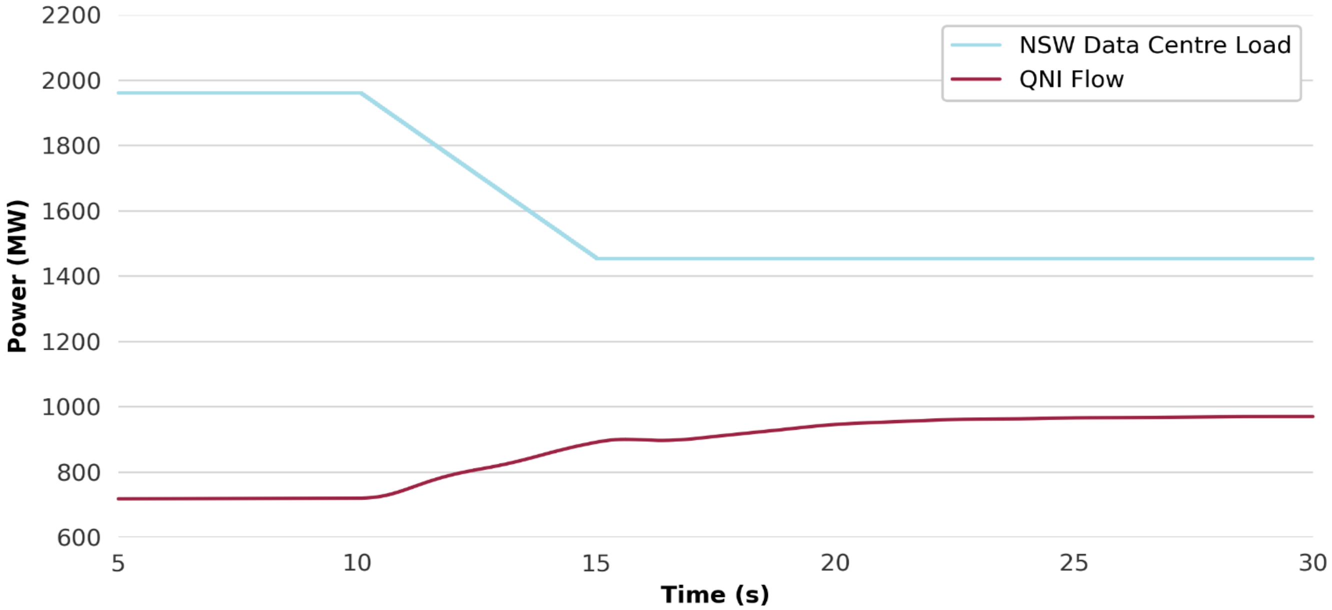
1.2.3 Limits on demand ramping may be required to prevent interconnector drift and impacts to ancillary services

Data centres may impact power system security or operations due to rapid demand ramping. Data centres have the ability to rapidly ramp their demand. This may occur in response to changes in market price, increasing or decreasing user demand, or any number of other signals. For large data centres, this change in demand could be hundreds of megawatts within a trading interval, which has the potential to significantly impact power system operations. For example:

- Rapid demand ramping within a dispatch interval can impact the accuracy of short-term forecasting, resulting in the over or under procurement of energy and ancillary services. This may impact the system from both a security and economic perspective.
- Large increases or decreases in demand in one region may result in interconnector drift[28] if the surplus or deficit in demand is balanced across regions. This may result in interconnectors operating above their secure limits, or reductions in system transfer capacity if the system has to be operated more conservatively to allow for this.

[28] Interconnector drift refers to the unintended change in interconnector power flows over time, driven by regional demand or generation imbalances.

Figure 9 Demonstration of potential impacts of data centre load ramping on interconnector flows (MW)



There is no current maximum ramp rate limit specified for loads in the NEM. This means unscheduled[29] data centres could ramp from minimum output to their maximum capacity at any time within a dispatch interval. To mitigate this risk, the implementation of maximum ramp rate limits should be considered so demand changes within dispatch intervals are limited to known acceptable values. The management of risks related to ramp rates was not included in the draft rule change for *Improving the NEM access standards - Package 2*, however, this risk has been highlighted in AEMO's submission on the draft rule and is currently being considered via other workstreams. More details on workstreams currently underway are described in Section 1.3.

Other system operators have specified maximum ramp rate limits for IBLs. There are ramp rate limits specified in load performance requirements in other networks such as Fingrid, Energinet, American Transmission Company (ATC) and Alberta Electric System Operator (AESO)[30]. These typically range from 10 MW per minute to a maximum of 60 MW per minute.

AEMO supports the need to specify maximum ramp rates for IBLs. This topic was raised in AEMO's submission on the *Improving the NEM access standards - Package 2* rule change and is included in AEMO's *Operational integration and visibility of large inverter-based loads* rule change request. The management of ramp rates may be addressed in accordance with the ECMC process recommendations (see Section 1.3 below), or through a separate rule change process.

[29] Unscheduled load is electricity demand that is not registered with AEMO and therefore does not submit dispatch bids, receive dispatch targets, or have its consumption directly controlled through central dispatch.

[30] See https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf.

1.2.4 Improved visibility and flexibility of inverter-based loads will be required to support price formation, forecasting and reserve assessments

Limited visibility of load behaviour and flexibility can degrade forecasting and real-time operational decision-making. Where large loads are not required to provide timely and accurate operational data, system operators may face challenges in anticipating demand variability and preparing appropriate dispatch and reserve levels. This can lead to inefficient generation dispatch and increases the risk of over- or under-procurement of reserves. Visibility limitations also affect longer-term planning by obscuring the true demand profile and its variability. The issue is compounded where flexible load response occurs outside market mechanisms or without direct operator coordination. Unobserved demand changes, including price-responsive behaviour, can introduce additional uncertainty into both dispatch and planning processes.

Demand flexibility has the potential to reduce system costs and improve operability but introduces new complexities if not integrated effectively. Flexible demand can support the efficient integration of renewable generation by shifting consumption toward periods of high renewable availability, reducing peak demand, and improving utilisation of existing network and generation assets. This can defer augmentation, lower wholesale costs, and reduce emissions by reducing reliance on firming generation. It can also provide a rapid response capability during system stress events, improving resilience to supply disruptions. However, flexibility that is not observable or coordinated with system operators can increase short-term forecasting uncertainty and degrade operational control. Uncoordinated demand response may increase the risk of dispatch inefficiencies and, in extreme cases, contribute to more severe power system outcomes. The benefits of demand flexibility are therefore conditional on adequate visibility, coordination, and integration within existing operational frameworks.

AEMO supports the need for improved visibility and flexibility for IBLs. AEMO is currently progressing the development of a Market Visibility Framework[31] for price-responsive resources and has submitted the *Operational integration and visibility of large inverter-based loads* rule change request. Across these two measures, it is intended to establish requirements for the visibility, forecasting integration and operational use of flexible load behaviour.

1.2.5 Oscillation monitoring and detection will be required to manage the potential for forced oscillations

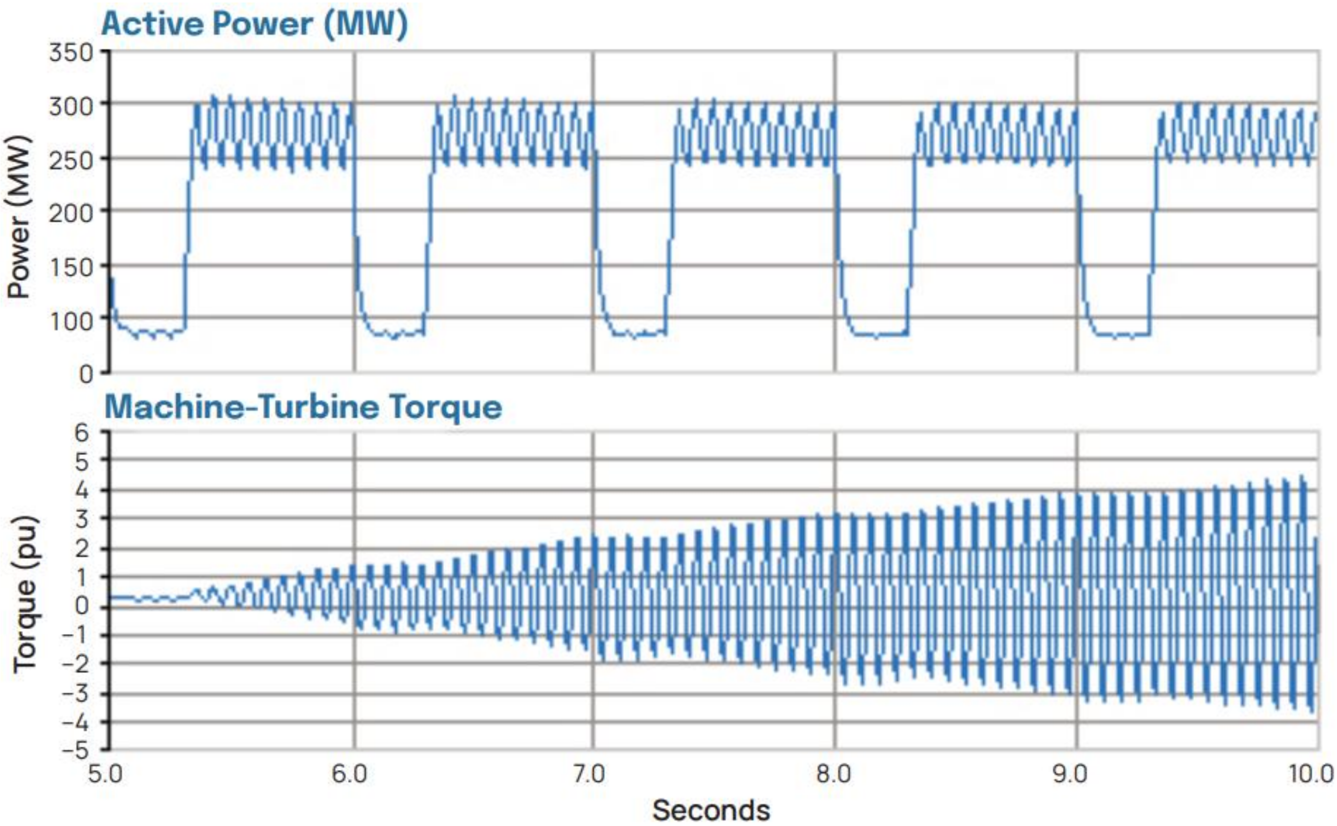
IBLs may introduce forced oscillations due to cyclical demand profiles. Some data centres are known to operate with cyclical load profiles, particularly when operating with AI training loads where graphics processing unit (GPU) usage can ramp up and down in a regular pattern. These are described as forced oscillations in the power system, where the data centre active power oscillates in a cyclical pattern, varying by up to 60% of the facility rating within seconds[30]. The major concerns around forced oscillations occur when the oscillations are at frequencies near existing modes in the network. These oscillations may exacerbate inter-area oscillations, damage equipment or result in unexpected protection operation.

These oscillations can impact the power system at known frequency ranges. There are known frequencies of oscillation in power systems where forced oscillations are more likely to result in increased risk of adverse power system outcomes. These frequencies typically are:

[31] See https://www.aemo.com.au/consultations/current-and-closed-consultations/market-visibility-framework-consultation

- **Less than 1 hertz (Hz)** – oscillations within this frequency range may excite inter-area modes where large groups of generators within a region oscillate against generators in another region. Excitation of these modes can result in increasing oscillations in interconnector power flows between regions, which could lead to interconnector instability.
- **Between 5 Hz and 35 Hz** – oscillations within this frequency range may interact with power system plant through sub-synchronous control interactions (SSCI) or sub-synchronous torsional interactions (SSTI).
  - SSCI are interactions with IBR, IBLs, or other power electronic based devices that could result in unexpected operation of controls or operation of protection to disconnect the devices.
  - SSTI are interactions with the shafts of synchronous generating units. If the frequency aligns with the natural resonant frequency of the turbine shaft, the oscillations could create growing vibrations in the shaft that will lead to long term damage or protection operation of the generating unit. As shown in **Figure 10** below, Energy Systems Integration Group's (ESIG's) *Large Load Performance Requirements: Current practices and recommendations* report demonstrates how a forced oscillation at 14 Hz from a data centre training load can align with the natural resonant frequency of a turbine shaft. The level of interaction could result in shaft damage or protection operation.

Figure 10 Study-based sub-synchronous torsional interactions example: cycling load profile and resultant interactions



Note: see https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf.

The frequencies discussed above occur in known ranges where there may be risks. However, there could be other frequency ranges that result in the unexpected operation of equipment or long-term damage. To limit the impacts of forced oscillations on the grid, there must be some measure to limit variations in the demand from data centres or ensure that they do not oscillate at frequencies of concern.

IBLs may also present risks of controller interactions. Active front-end converters for IBLs are structurally similar to the voltage source converter interfaces commonly used in inverter-based generation and high voltage direct current (HVDC) systems. They typically rely on a phase-locked loop (PLL) to track grid phase angle and frequency to maintain synchronism. In weak-grid conditions, the PLL and associated control loops can have reduced stability margins, particularly during disturbances or faults. This can manifest as PLL instability or converter-driven oscillations, including poorly damped or unstable small-signal interactions between converter controls and the network. These behaviours are primarily relevant for IBLs with actively controlled front-end interfaces and may not apply to passive rectifier interfaces that do not rely on PLL-based synchronisation control.

AEMO supports the need for oscillation monitoring and detection requirements for large IBLs, as well as the capability to disconnect units for instability. The AEMC's draft *Improving the NEM access standards – Package 2* rule change proposes requirements for large IBLs to monitor and detect instabilities in voltage, reactive power and active power and be capable of disconnecting units for instability via a remote trip signal if requested by AEMO or the NSP.

1.3 The integration of large loads is already underway, with a number of workstreams addressing risks currently in progress

While potential risks have been identified with the projected increase in IBLs on the power system, there are actions underway to begin to address some of the challenges. Some current workstreams progressing IBL integration work are:

- The *Improving the NEM access standards - Package 2* rule change, led by the AEMC, has received inputs from AEMO, NSPs, data centre proponents, equipment original equipment manufacturers (OEMs) and wider industry. One of the key outcomes from the rule change is a new draft rule that:
  - creates a tiering system for applying access standards to large load connections in distribution networks,
  - introduces new voltage and frequency ride-through access standards for large IBLs, and
  - updates and improves other access standards that are relevant to large loads.
- The Energy and Climate Change Ministerial Council (ECMC)[32] has tasked the Department of Climate Change, Energy, the Environment and Water (DCCEEW) to lead a sub-working group to investigate the impacts of data centres on Australia's energy system. The ECMC has endorsed a number of recommendations to support the integration of data centre growth into Australia's energy systems. These recommendations include the consideration of:
  - managing system security challenges,
  - streamlining the connections process,
  - data collection and forecasting,
  - market operations,
  - registration, and

[32] See 14 March 2025, 15 August 2025, and 8 May 2026, at https://www.energy.gov.au/energy-and-climate-change-ministerial-council/meetings-and-communiques.

  - demand flexibility.

- AEMO is progressing the development of a Market Visibility Framework (MVF)[33] for price-responsive resources, following recommendations from the NEM Wholesale Market Settings Review and direction from Energy Ministers. The MVF is intended to address gaps in the visibility of flexible load and distributed resources by establishing fit-for-purpose arrangements for the provision and use of information on price-responsive behaviour, including its incorporation into operational forecasting and, where appropriate, participation in dispatch. AEMO has been tasked to develop the framework in consultation with industry and provide recommendations on its detailed design, including visibility modes, thresholds for participation and implementation pathways. To enhance consumer outcomes, the framework seeks to improve:
  - wholesale price formation and forecasting accuracy,
  - AEMO's ability to operate the power system securely and efficiently, and
  - market participants' ability to manage risk and make efficient investment and operational decisions.
- Since the publication of the draft 2026 GPSRR report, AEMO has proposed the *Operational integration and visibility of large inverter-based loads* rule change[34], which seeks to establish a consistent and proportionate framework for the operation of large IBLs in the NEM. This rule change proposes to address outstanding challenges associated with IBLs, including ramp rate limits and improved communication and monitoring systems. The proposal seeks to:
  - establish consistent monitoring and communication arrangements across NSPs and jurisdictions,
  - introduce clear, staged implementation of preferred rule amendments, considering potential options for large IBLs such as registration requirements, new access standards, NSP obligations, large IBL obligations, and new guidelines and procedures,
  - streamline and align the registration requirements for back-up generation systems,
  - improve visibility of significant changes in demand to support efficient planning, dispatch and investment decisions,
  - manage the rate of demand changes from large IBLs to reduce adverse impacts on the power system, and
  - improve the management of power system events via enhanced communication channels and operational coordination capabilities and requirements for large IBLs to respond to instructions and directions issued by networks or AEMO or networks to maintain power system security and reliability.
- An access standards review is completed every five years in obligation with NER S5.2.6A(a) to assess the need for amendments to the technical requirements outlined in Schedules 5.2, 5.3 and 5.3a. Emerging issues related to loads may be considered under this process.
- AEMO is developing a large IBL interim guideline, so proponents can be better prepared when the *Improving the NEM access standards – Package 2* rule change is finalised. This will also provide assessment and modelling guidance ahead of changes to the power system model guidelines.

[33] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/mvf-consultation/mvf---approach-to-policy-framework-development.pdf.

[34] See https://www.aemc.gov.au/rule-changes/operational-integration-and-visibility-large-inverter-based-loads.

- The system strength impact assessment guidelines (SSIAG) are proposed to be updated to consider the system strength impacts of IBLs. There will also be a number of other changes including those related to withstand short circuit ratio (SCR), system strength remediation scheme (SSRS) and system strength charges.
- An update of other guidelines will also be progressed, including the update of AEMO's power system stability guidelines and power system modelling guidelines. These will be updated to consider stability and modelling requirements for IBLs.

1.4 Integration work must continue to address risks and emerging issues

The work that has been completed to date or is already underway addresses some of the more pressing challenges related to IBLs. However, there is still more work required to continue the integration of large IBLs into the NEM. This work includes addressing new issues that arise as more experience is gained in the operation of these loads.

Some of the current and emerging issues that will need consideration into the future include:

- **Rapid demand ramp rates** – rapid ramping from data centres within a trading interval may introduce system security risks. The implementation of maximum ramp rate limits or other appropriate measures will be considered to mitigate potential risks.
- **Visibility and remote monitoring provision** – it is necessary to have visibility of large IBL operations to ensure power system security is maintained. Large IBLs will require remote monitoring and control equipment to receive and transmit the quantities that AEMO requires for its market and power system security functions.
- **Enhancement of oscillation monitoring and detection** – a future area of development in oscillation detection is expanding requirements to include the capability to detect the source of instability. While this capability may only be emerging, having information pertaining to whether a plant is actively contributing to or providing damping for the oscillation would deliver valuable inputs to determine the correct hierarchy of actions when oscillations are present. Note that this is a broader area for development and is not unique to IBLs.
- **Consideration of registration requirements for backup generation** – the registration requirement for backup generation associated with large IBLs is a topic of further consideration. Some backup generation will not be electrically connected to the NEM and therefore will not require full assessment under the NER Schedule 5.2 access standards. However, appropriate registration requirements will be considered for generation, BESS or uninterruptible power supply (UPS) systems associated with IBLs that are intended to interact with the grid.
- **Short-term forecasting** – an appropriate level of short-term forecasting visibility will need consideration to ensure non-scheduled IBLs do not have unintended impacts on the availability of energy and ancillary services. This may require increased visibility of expected load profiles, advance notice of expected sudden changes in demand or other appropriate actions that are determined to be suitable.
- **Ability to receive instructions or directions** – in some instances, AEMO may need to instruct or direct data centres in the interests of power system security and reliability. To enable this, there may be additional requirements such as the provision and maintenance of a telephone facility for the purposes of operational communications between the IBL's responsible operator and AEMO's control centre.
- **Modelling capability** – the modelling capability and understanding related to IBLs continues to develop across the industry, addressing a need that is critical to accurately determine power system security limits. Modelling requirements

will continue to be considered to find an appropriate balance of modelling detail that is proportional to the size, complexity and potential system security impacts that IBLs may present.

1.5 Recommendations

AEMO supports the introduction of load access standards for large IBLs to provide explicit requirements that will support power system security and the successful integration of IBLs.

The 2026 GPSRR has identified that, if not proactively addressed, the forecast growth in IBLs has the potential to impact power system security. This is primarily due to their sensitivity to voltage disturbances but also considers the potential for oscillatory behaviour, rapid demand ramping or protection settings. The AEMC draft determination for Package 2 recognises these system security challenges and proposes a clearer framework and new access standards to manage disturbance ride-through and instability risks in a proportionate manner.

Further work is still required to address emerging risks outside of the load access standards.

The GPSRR also notes that while the *Improving the NEM access standards – Package 2* rule change materially progresses key elements of IBL integration risk management, additional measures will still be required as understanding matures and as connection volumes increase. The GPSRR identifies further needs such as ramp rate limits, improved visibility and supervisory control and data acquisition (SCADA) provision and forecasting requirements that will need to be progressed. AEMO has recently proposed the *Operational integration and visibility of large inverter-based loads* rule change to address these risks. The complementary measures included in this proposal are intended to support operational readiness and enhance the effectiveness of disturbance-related performance standards in practice.

Recommendation 1

AEMO supports the implementation of load access standards for IBLs to reduce risks related to increasing large load connections.

Actions:

AEMO will continue to monitor emerging risks related to IBLs and collaborate with industry and relevant stakeholders to support successful integration.

2 Non-credible system strength risks associated with unavailability of synchronous machines

This section covers the following key points:

- The changing landscape of the NEM may result in less operational flexibility in maintaining system strength around outage conditions.
- In rare scenarios where multiple synchronous units are on prior outages, the unlikely occurrence of a non-credible contingency and loss of two synchronous units may result in challenges to resecure the power system within standard timeframes.
- A number of actions can be taken to support resilience to manage these conditions such as improved coordination of outages, extension of procedures to include specific non-credible events and the consideration of GFM BESS in limit advice to provide a stable voltage waveform. .

The operational landscape of the NEM is changing with the increasing unavailability of synchronous generation through retirement, decommitment or planned and unplanned outages. There are currently 15 operational coal-fired power stations across the NEM, with a combined capacity of approximately 21 GW. Excluding Queensland, the average age of the NEM's coal generation fleet is 40 years, with generator owners declaring planned retirements that are on average only 10 years away[35]. Based on announced closure dates, all remaining coal-fired generation is scheduled to exit the system by 2051. However, under AEMO's *Integrated System Plan* (ISP) optimal development path, two-thirds of the remaining fleet would close by 2035, with all due to retire by 2049. This may have significant implications for how the power system is planned and operated.

While large coal units offer significant power system reliability and security benefits, it may not be economic to extend their lifetime beyond a certain age. The average age for retired coal generators in the NEM is 44 years, which the remaining coal fleet across New South Wales and Victoria is now approaching. These units provide system strength throughout the NEM while they are still operational, but their transition to retirement must be managed. The introduction of synchronous condensers or other measures is required to support system strength management and manage the orderly retirement of coal generation. If lifetime extensions are relied on too heavily, the ageing coal fleet may be exposed to increased age-related reliability risks, elevating the likelihood of unplanned outages and power system security challenges.

AEMO has assessed system strength risks associated with synchronous machine withdrawals by examining the impacts of non-credible contingency events across multiple outage conditions. These assessments identify the operational actions required to manage low-probability, unplanned outage scenarios involving major coal generation and transmission assets. Undertaking forward-looking assessments of these low-probability risks strengthens AEMO's ability to maintain power system reliability and security throughout the energy transition.

[35] See https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-integrated-system-plan-isp.pdf.

Fault level assessments have been undertaken to understand the operational actions required to meet minimum fault levels[36] across New South Wales or Victoria under the following non-credible contingency scenario:

- post-retirement of Eraring and Yallourn power stations,
- prior outages of up to three large synchronous units in New South Wales or Victoria, and
- the occurrence of a power system event resulting in the non-credible loss of an additional two coal units, or a double-circuit transmission line.

Sensitivity studies were also completed with and without the delivery of additional synchronous condensers and network augmentations to understand their expected contribution to system strength.

Following the non-credible loss of the two large synchronous units, the operational actions required to resecure the power system were assessed. This involved determining the combination of fast-start units that could be brought online, or other operational actions required, to restore fault levels above the secure level.

The assessment of system strength for non-credible contingencies determined that:

- **After the delivery of synchronous condensers and new augmentations, New South Wales is not exposed to significant operational risks related to system strength.** It was determined that the addition of synchronous condensers and new augmentations provide sufficient system strength benefits to offset the retirement of Eraring. Even with three large synchronous units on prior outage, the additional loss of two coal units can be managed operationally.
- **If system strength solutions in New South Wales are delayed, this may lead to operational challenges under multiple outage scenarios.** If Eraring retires before synchronous condensers and augmentations are in place, there will be insufficient units available to resecure the system for the loss of two Vales Point units if three large synchronous units are on prior outage. There may also be other operational challenges related to the non-credible loss of other large synchronous units depending on dispatch conditions. Concurrent outages should be minimised where possible to reduce the impact non-credible contingencies could have. The timely delivery of planned synchronous condensers should also continue to be prioritised to ensure they are operational when Eraring retires.
- **Delivery of synchronous condensers in Victoria prior to the retirement of Yallourn improves the capability to resecure the system following non-credible contingencies, yet there are still challenges.** The delivery of synchronous condensers in Victoria significantly improves system strength management, but there may still be some difficulties resecuring the system in the event of non-credible contingencies. With synchronous condensers in place, the loss of two Loy Yang units when three coal units are on outage may still require up to eight fast-start units to resecure, which could be difficult to achieve within 30 minutes.
- **The scale of operational actions required may increase further if Yallourn retirement occurs before synchronous condensers are delivered.** Delays in the expected delivery of synchronous condensers in Victoria would require additional actions or procedures to manage risks related to multiple outages. When operating with three coal units on outage, the loss of two Loy Yang A units could require 16 available fast-start gas units to resecure the system. This may not be possible to achieve within 30 minutes. The extension of procedures to define operational actions for these

[36] AEMO assesses and publishes annually the regional requirements for system strength to allow subsequent delivery and maintenance by the system strength service provider in each region. These requirements cover the minimum three phase fault level to ensure power system security.

scenarios would contribute to improved resilience. The occurrence of multiple unit outages should also be minimised where possible.

- **Additional measures can be taken in Victoria to manage risks related to low likelihood multiple outage conditions.** There are a number of actions that could be considered to further support power system security in Victoria post Yallourn retirement. This could be achieved through improved coordination of planned outages to reduce the period of time that multiple units are on outage concurrently. Operational procedures could be extended to consider specific non-credible contingency events. These procedures could specify actions such as IBR curtailment, ensuring fast-start units are prepared to come online in short timeframes, or de-energisation of network elements. The use of GFM BESS for system strength support related to voltage waveform stability could also be considered.

2.1 Synchronous machine withdrawals will change the NEM's operational landscape

The retirement of major synchronous machines across the NEM may influence a significant shift in power system behaviour and operational dynamics. Large synchronous generators have been relied on for system security and reliability for many years, and their withdrawal reshapes how the power system is operated. Coal-fired plant has accounted for approximately 28% of installed grid-scale generation capacity, yet this particular generation type has supplied 51.9% of total energy generated in the NEM in 2025[37], highlighting the extent of the system's reliance on these assets and their availability. This reliance is increasingly concentrated on the remaining generators as further synchronous units are withdrawn from the NEM.

Victoria and New South Wales are set to experience significant synchronous generation withdrawal in the NEM with the retirement of Yallourn and Eraring. The planned retirement of Yallourn power station (1,480 MW) in Victoria and Eraring power station (2,880 MW) in New South Wales in 2028 and 2029 respectively will result in a considerable reduction in synchronous generation capacity in both regions, and in the pool of major units available to provide system strength[38]. This may increase operational challenges during both planned and forced outage conditions for major generating units and transmission network elements, including non-credible contingency events. As a result, the secure operation of the power system may increasingly depend on the availability and dispatch of alternative synchronous resources to address system strength shortfalls identified in the operational timeframe, and future system strength-supporting assets installed on the power system, such as synchronous condensers and new transmission network augmentations.

2.1.1 Ageing synchronous generation fleets may result in increased forced outage rates

Emerging risks may arise as major synchronous power stations reach end of life. The continued operation of synchronous power stations may introduce the risk of declining reliability of these power stations near the end of their technical life. As synchronous power stations approach end-of-life, asset management plans implemented by generator owners may reduce investment in plant maintenance as the station prepares for shut down. This results in limited capital investment, with a greater focus on extending the life of critical items rather than their replacement. This may contribute to a reduction in

[37] See https://www.aemo.com.au/-/media/files/electricity/nem/national-electricity-market-fact-sheet.pdf.

[38] System strength, as defined by AEMO, is the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.

overall plant availability, with potential increases to both forced and partial outages[39]. Alternatively, this may result in reduced operational flexibility as plants implement measures to extend lifetimes and reduce unavailability.

The reliability of synchronous generation has been observed to decline significantly once plant age exceeds approximately 40 years[40]. A substantial proportion of the synchronous generation fleet in the NEM is planned to continue operating well beyond this 40-year age threshold. Beyond this threshold, synchronous unit reliability trends indicate a non-linear decline in unit availability. This may imply that forced outages and non-credible contingencies could occur more frequently for units that approach their planned retirement dates.

There have been several incidents involving forced outages of synchronous generation across the NEM in the past year. In some cases, these events have resulted in the non-credible disconnection of multiple generating units at a single power station, including:

- trip of Yallourn 'W' power station units 3 and 4 in October 2025[41],
- trip of Callide 'C' power station units 3 and 4 in January 2026[42], and
- trip of Vales Point power station units 5 and 6 in February 2026[43].

While the current power system prior to the retirement of Eraring and Yallourn has generally remained resilient to such contingencies in terms of system strength, the retirement of multiple synchronous units materially reduces this resilience. Under these conditions, system strength headroom is reduced and less operational actions are available to maintain power system security.

2.1.2 Planned outage requirements may be more onerous

Generator owners often concentrate outages in autumn and spring to avoid peak demand periods. Synchronous generators typically schedule maintenance outages in autumn and spring, when demand is lower and reliance on large units for power system reliability is reduced. While this supports higher unit availability during peak demand periods, it can result in coincident outages, reducing the number of units available to provide centralised system strength. These challenges are further exacerbated if TNSPs also plan transmission network outages, which can significantly affect the delivery of system strength to key parts of the power system for some high-impact outages.

Prior to retirement of Eraring and Yallourn, there are planned periods with up to four major synchronous units concurrently on outage in New South Wales, and up to three in Victoria. This has been determined for the next two-year period via Medium Term Projected Assessment of System Adequacy (MT PASA) runs[44]. While this is prior to the impending retirement of Yallourn and Eraring, it demonstrates the state of the existing synchronous generation fleet in Victoria and New South Wales and their planned outage needs. It is expected that similar coincident outage numbers may extend

[39] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-elical-assessment-of-ageing-coal-fired-generation-reliability.pdf.

[40] See https://www.climatecouncil.org.au/wp-content/uploads/2025/01/CC_LightsOut_Final.pdf.

[41] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2025/trip-of-yallourn-w-power-station-unit-3-and-unit-4.pdf.

[42] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2026/trip-of-callide-c-power-station-unit-3-and-4.pdf.

[43] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2026/trip-of-vales-point-unit-5-and-unit-6.pdf.

[44] As of January 2026.

beyond the respective retirement of Eraring and Yallourn. As these generation assets continue to age, maintenance requirements will increase to manage the increasing unreliability rates. Planned outages of major units are often inflexible, as they are driven by the time required to complete key maintenance activities, offering limited scope to shorten outage durations once underway. This can become particularly challenging if forced outages occur on remaining available units. Of 25 planned major unit outages across the NEM in the next two-year period:

- 11 outages are expected to exceed 30 days of duration, and
- six outages are expected to exceed 60 days of duration.

Historical data indicates that planned outages of synchronous generation units frequently extend beyond scheduled durations. This increases the risk of overlapping outages for major units and periods of heightened vulnerability to major contingency events.

Hydro and gas generators also have scheduled outages during autumn and spring to maximise availability during peak demand periods. In some cases, gas power stations comprising multiple smaller units plan coincident outages across all units at a single station. System security management increasingly relies on hydro and gas facilities to address system strength gaps within the operational timeframe. Due to this, the unavailability of key units under certain outage conditions may require sub-optimal dispatch to manage localised system strength shortfalls. As hydro and gas units are typically used to provide fast-start capability, their pre-contingent dispatch reduces the availability of fast-start resources for subsequent power system security actions following contingency events.

2.2 System strength requirements post synchronous generation retirement

The retirement or unavailability of synchronous generation could increase the difficulty in meeting minimum system strength requirements in the absence of system strength mitigation measures, including synchronous condensers. System strength is required for many aspects of power system security, yet it will become increasingly difficult to manage without additional support from synchronous condensers and other appropriate solutions.

2.2.1 Adequate system strength is crucial to secure power system operation

Minimum system strength levels must be met to support stable and compliant power system operation. Many plant connected to the power system rely on a minimum level of system strength to operate as designed. Where this minimum is not met, adverse power system impacts may arise following network disturbances. While synchronous three-phase fault levels provide a proxy to define the strength at different locations of the power system[45], the adequacy of system strength comprises multiple interrelated characteristics, including:

- adequate magnitude and quality of fault current contribution during fault events, preventing:
  - mal-operation or non-operation of protection systems, and
  - more widespread voltage depressions and delayed post-disturbance voltage recovery,
- sufficient robustness of the power system voltage waveform to magnitude and angle perturbations, preventing:

[45] These locations are defined as system strength nodes, each having a minimum three-phase synchronous fault level requirement to ensure secure operation of the power system.

  - wide-area, poorly damped voltage and power oscillations,
  - degradation of generator and IBR fault ride-through (FRT) performance, and
  - generator and dynamic reactive plant control instability, and
- limited sensitivity of voltage magnitude, preventing:
  - large voltage step changes associated with fixed reactive support and transmission line switching,
  - localised or widespread voltage instability, and
  - increased incidence of temporary overvoltages (TOV) following fault clearance.

2.2.2 System strength management in the NEM is becoming a more dynamic process

System strength across the NEM is largely considered on a regional basis and traditionally involves monitoring the operation of major synchronous units and their availability. A sufficient number of these major units is required online to satisfy system strength requirements specified in limit advice prepared by TNSPs. Historically, active management of system strength has not been a major concern for power system security management, as synchronous generators typically operated continuously to supply the power system's baseload. As a result, the number of synchronous units online at any given time commonly exceeded regional system strength requirements by a significant margin.

2.3 AEMO has assessed future system strength risks following non-credible contingency events

AEMO undertook studies to assess the post-contingent impacts on system strength following non-credible contingency events. Fault level studies were performed to assess power system conditions in Victoria and New South Wales following the retirement of Yallourn and Eraring, with the objective of quantifying impacts at key fault level nodes under major generation and network non-credible contingencies. The existing set of system strength nodes (SSNs) and their synchronous three-phase fault level requirements were assumed to remain consistent for the post-Yallourn and Eraring scenarios assessed.

AEMO's assessment comprised two phases:

1. evaluation of present-day system strength non-credible contingency risks associated with synchronous generation retirements, and
2. assessment of how these risks are expected to evolve as a result of synchronous condenser installations and planned network augmentations.

Across both phases, AEMO's studies considered the potential impacts related to low probability non-credible contingency events occurring under multiple outage conditions. This provided assessment of tail risks to better understand the state of power system resilience, considering:

- low-demand conditions with various combinations of synchronous generation units online sufficient to meet minimum fault level requirements,

- coincident planned outages of multiple major synchronous units, with system strength support provided by gas and hydro generation,
- transmission network outage conditions,
- sensitivities to future transmission network augmentations, and
- sensitivities associated with the delivery of planned synchronous condenser installations.

AEMO's present-day studies assessed power system risks associated with synchronous generation retirements before synchronous condensers or key augmentations are delivered. Scenarios reflected the current network configuration, excluding Eraring and Yallourn, and assumed commissioning of PEC, including synchronous condensers at Buronga and Dinawan, as well as operation of the Ararat synchronous condenser in western Victoria. System strength in neighbouring regions was assumed to remain secure under all conditions.

Future-looking assessments investigated system strength risks when synchronous condensers and key augmentations are delivered on time, demonstrating the importance of timely delivery of network assets and upgrades. Several network projects expected to be delivered between 2026 and 2030, such as PEC Stage 2, HumeLink and other network augmentations as per AEMO's *Transmission Augmentation Information*[46] timing, were incorporated to assess their potential to materially improve system strength management across New South Wales and Victoria. AEMO also undertook electromagnetic transient (EMT) studies to assess IBR stability under non-credible contingencies, highlighting increased risks during conditions with reduced synchronous generation availability due to multiple planned or forced outages.

This enabled AEMO to explore the impacts of non-credible contingency events through:

- the potential challenges in maintaining secure fault levels in New South Wales and Victoria following major synchronous generation retirements during non-credible contingency events with multiple network and/or generator outages,
- the magnitude of system strength shortfalls that may arise following major non-credible generation and network contingency events,
- the scale of operational actions that could be required to return the power system to a secure operating state following large non-credible contingencies,
- the potential impact that gas supply constraints could have on particular fast start unit operation to re-secure the power system,
- the benefits of future network augmentations and synchronous condenser delivery in supporting system strength management across New South Wales and Victoria for low probability events occurring under multiple outage conditions, and
- the key stability challenges that may be faced by IBR plant and the wider power system following major non-credible contingency events under low system strength conditions.

[46] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

2.4 Outages of synchronous machines before delivery of synchronous condensers may reduce system strength management options

As has been assessed in the TPSS, minimum fault levels can still be met after the retirement of Yallourn and Eraring before synchronous condenser installations in Victoria and New South Wales. However, while minimum fault levels could be met, operational flexibility to manage system strength declines as more units are on outage or when high impact transmission outages are taken. An overview of the system strength challenges posed in Victoria and New South Wales is provided in the sections below, highlighting the potential increase in requirements as more outages are present in the system.

2.4.1 Victoria may heavily rely on Loy Yang A and B units to meet system strength requirements prior to delivery of synchronous condensers

Victoria has operated with at least six major coal units online for approximately 85% of the time over the past two years. Following the retirement of Yallourn, only six major coal units will remain available in Victoria, all located at Loy Yang A and B power stations. Approximately one-third of currently accepted secure unit combinations for system strength include at least one Yallourn unit. As a result, Yallourn's retirement places increased reliance on the remaining Loy Yang units to maintain secure operating conditions.

Operating with multiple outages can result in a greater dependence on gas and hydro units. Loy Yang will be central to meeting system strength requirements after Yallourn retires in the absence of synchronous condenser replacements. However, when Loy Yang units are on outage there may be an increased reliance on gas and hydro generation to meet system strength requirements. This dependence on gas and hydro generation is observed to increase as more coal units are on outage. Under these conditions, the combinations in **Table 6** are required to satisfy Victoria's system strength requirements according to existing unit combinations specified by VicGrid in Victorian limit advice.

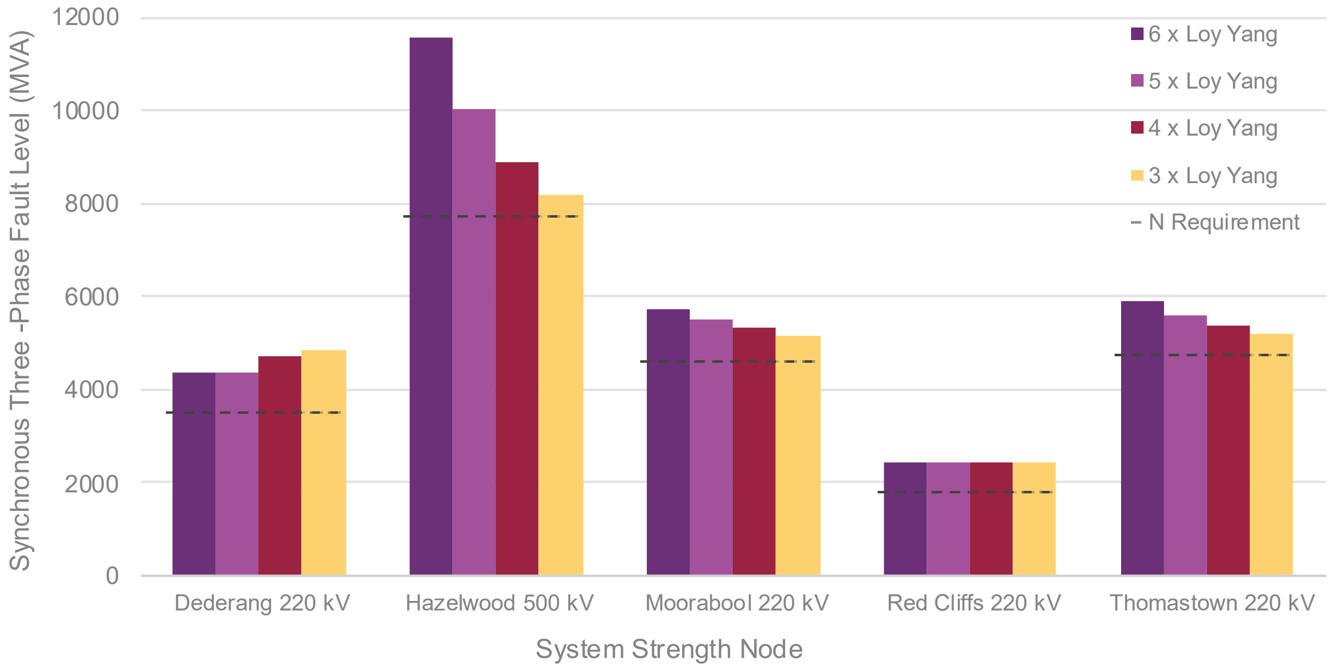
Table 6 Summary of supplementary units required for Victorian system strength management

Major units	Additional system strength requirement to ensure secure operation
Six (6) Loy Yang A/B units	System strength sufficient
Five (5) Loy Yang A/B units	One hydro or small gas unit (for example, Jeeralang, Valley Power, or Murray 2 unit)
Four (4) Loy Yang A/B units	Either: • one large gas unit (for example, Newport or Mortlake unit), or • two small hydro or gas units (for example, Jeeralang, Valley Power, Murray 2, Dartmouth, or Bogong units)
Three (3) Loy Yang A/B units	Either: • one large gas unit and combination of three small hydro or gas units, or • a combination of between four and eight small hydro and gas units, assuming operation of the Ararat synchronous condenser.

System strength margins decrease as more units are on concurrent outages. While all unit combinations comprising between three and six Loy Yang A/B units summarised in **Table 6** are secure, system strength margins reduce as fewer synchronous units are online, exacerbating post-contingent impacts following major contingencies.

This is illustrated in **Figure 11,** which demonstrates outcomes if the delivery of further system strength-supporting assets in Victoria is delayed. Following the closure of Yallourn and as the number of Loy Yang units online reduce, there is a corresponding reduction in operating margin above the secure fault level requirement (dashed line) at the Hazelwood, Moorabool, and Thomastown SSNs. The Red Cliffs SSN remains largely unaffected due to its electrical distance from the eastern Victorian network, where coal units are progressively substituted by hydro units in the north-east and gas units in the south-east of the region. The increase in fault levels at the Dederang SSN is attributed to the increasing number of proximal hydro units required to be online.

Figure 11 Victorian system strength margin reduces with fewer available Loy Yang units (megavolt amperes [MVA])



Note: Unit combinations depicted in this figure are labelled by the number of Loy Yang units online, but are approved unit combinations that are supported by other smaller hydro and gas generators not listed.

2.4.2 New South Wales system strength management relies on high coal unit availability

New South Wales has operated with at least eight major coal units online for approximately 98% of the time since the retirement of Liddell power station in 2023. The retirement of Eraring will reduce the number of available major coal units in New South Wales to eight, at Bayswater, Mount Piper, and Vales Point power stations. This highlights the shift in operational requirements if synchronous condensers are not delivered on time.

Secure operation of the New South Wales region requires the equivalent of 6.97 major synchronous units online. Under Transgrid's system strength limit advice, all coal units in New South Wales are treated as offering an equivalent contribution to system strength, which adopts a coefficient-based approach to ensure secure fault levels are met. Under this framework, each coal unit in New South Wales contributes 0.97 equivalent units. Satisfactory operation under intact conditions requires a cumulative total of 6.0 equivalent units, with the secure requirement increasing to 6.97 equivalent units to allow for the credible loss of one major unit. As a result, meeting this secure level using coal generation alone requires full availability of the remaining eight coal-fired generating units, as only seven units provides a total contribution of 6.79 equivalent units, which is insufficient to meet the regional system strength requirement.

When coal units are unavailable, the number of smaller units required to meet system strength may increase. Under conditions of coal unit unavailability, gas and hydro generators in New South Wales are required to support system strength. As more coal units are out of service, the requirements may increase significantly, with five coal unit operation requiring between nine and 16 additional units to meet the required 6.97 equivalent units, as **Table 7** shows.

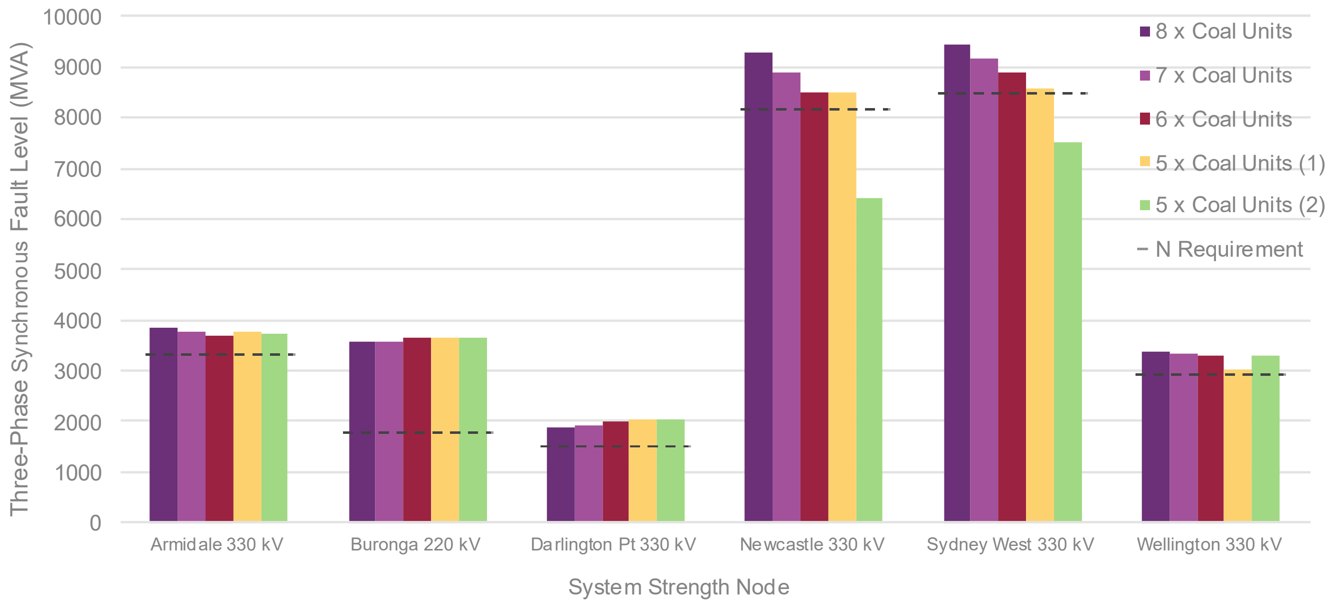
Table 7 Summary of supplementary units required for New South Wales system strength management

<table>
<tr><th>Major units</th><th colspan="2">Additional system strength requirement to ensure secure operation</th></tr>
<tr><td>Eight coal units</td><td colspan="2">Sufficient system strength</td></tr>
<tr><td>Seven coal units</td><td colspan="2">0.18-unit equivalents – for example, 2 x Kangaroo Valley hydro units</td></tr>
<tr><td>Six coal units</td><td colspan="2">1.15-unit equivalents, for example:
• 2 x Kangaroo Valley hydro units, and
• 4 x (Lower) Tumut 3 units</td></tr>
<tr><td>Five coal units</td><td>2.12-unit equivalents, for example:
• 2 x Kangaroo Valley hydro units, and
• 6 x (Lower) Tumut 3 units, and
• 1 x Hunter gas unit</td><td>Or, for example:
• 2 x Kangaroo Valley hydro units, and
• 6 x (Lower) Tumut 3 units, and
• 4 x (Upper) Tumut 2 units, and
• 4 x Murray units</td></tr>
</table>

As system strength margins decrease, unit coefficients may not translate to meeting fault levels for all SSNs. While these unit combinations are sufficient to meet the minimum equivalent unit requirements for system strength, AEMO's assessments indicate that the minimum three-phase synchronous fault levels may not be satisfied under all conditions at all SSNs. This shows that when operating with a reduced number of units, the relationship between number of units online and fault level may become more complex.

This is illustrated in **Figure 12,** which demonstrates outcomes if synchronous condensers and key network augmentations are not delivered on time.

Figure 12 New South Wales system strength margin reduces with fewer available coal units (MVA)



Note: Unit combinations depicted in this figure are labelled by the number of Loy Yang units online, but they satisfy limit advice through the support of other smaller hydro and gas generators not listed.

The two options outlining five coal unit operation show the difference in fault level at the Newcastle SSN may be significant, and the second option does not meet the minimum fault level requirements despite meeting the unit equivalent requirement in the limit advice. This also highlights the complexity associated with modelling system strength impacts, particularly for purposes such as a regulatory investment test for transmission (RIT-T). Consideration of fault levels and system strength in each region will continue to assess impacts such as this to ensure system strength is adequate to maintain system security.

2.4.3 Maintaining system strength during network outages may require enablement of additional units

System strength requirements may increase under transmission network outage conditions. Some high-impact transmission outages may require further units to be synchronised to manage power system security. This is most evident in New South Wales during operation with reduced coal unit availability. AEMO completed this sensitivity by considering operating conditions in Victoria and New South Wales that satisfy minimum fault level requirements at all SSNs and determining the sensitivity of several major single line outages in the region. It was assumed that synchronous condensers and future network augmentations were not yet delivered for this sensitivity. AEMO identified the following:

- **Victoria:**
  - Minimum fault level requirements are satisfied for all single high-impact outages when four or more Loy Yang units are online.
  - With only three units Loy Yang units operational, a minor shortfall occurs at the Moorabool 220 kV SSN for a Moorabool 500/220 kV transformer outage. This can be resolved by synchronising one additional hydro unit (for example, Bogong or Murray 2).
- **New South Wales:**
  - With seven coal units online, the system is generally tolerant to high-impact outages, with only a minor breach identified for a Liddell – Newcastle 330 kV line outage, which can be resolved by synchronising one additional gas unit.
  - With five coal units online, at least five high-impact outages do not meet minimum fault level requirements, increasing to at least nine when the two Vales Point units are offline. The most severe shortfall could be mitigated by synchronising three additional gas units, in close proximity to the Newcastle SSN; however, gas supply constraints may limit the feasibility of sustained multi-unit operation in some instances.

2.5 Timely delivery of synchronous condensers and network augmentations provides significant system strength benefits to support synchronous generation retirements

AEMO's analysis demonstrates that the planned system strength solutions in New South Wales and Victoria are key to improving operational outcomes to restore power system security. If delivered in full and on schedule, these planned assets materially mitigate system strength risks and support their ongoing management across the NEM. In New South Wales, it is observed that delivery of synchronous condensers and network augmentations removes the need to take any operational actions for the loss of two large synchronous units when there are three large units on prior outage. In Victoria, the on-time delivery of synchronous condensers improves operational outcomes, but further supplementary actions may be required to support system security under the same non-credible contingency scenarios.

2.5.1 The synchronous condensers planned in New South Wales and Victoria significantly contribute to system strength to facilitate the retirement of Eraring and Yallourn

TNSPs across the NEM have undertaken RIT-T processes to identify optimal options for the ongoing procurement of system strength. Based on the preferred portfolios for Victoria and New South Wales, the first tranche of synchronous condensers in these respective regions have been included in AEMO's assessment of system strength risks:

- two synchronous condensers[47] delivered at Hazelwood terminal station in Victoria, assumed to have a connection point voltage of 220 kV, and
- five synchronous condensers[48] delivered across five key sites in New South Wales – Newcastle, Kemps Creek, Armidale, Wellington, and Darlington Point 330 kV transmission substations. In September 2025, the New South Wales Government directed Transgrid to deliver synchronous condensers at the first five substations across New South Wales as a Priority Network Infrastructure Project (PNIP). This has accelerated the timeframe for the delivery of units to these first five sites.

Studies conducted by AEMO for the 2026 GPSRR have confirmed that the addition of these synchronous condensers will provide significant system strength and operational benefits. The ability to resecure the system for non-credible contingencies under multiple outage conditions is vastly improved in cases after synchronous condensers are installed. The key findings are:

- In Victoria, the addition of synchronous condensers reduces operational actions required for a non-credible contingency under conditions with three large synchronous units on outage. In the scenarios assessed, the number of fast-start units required reduces from 16 to eight.
- In New South Wales, the addition of synchronous condensers was observed to significantly improve system strength for a non-credible contingency under conditions with large synchronous units on outage. The system can now be resecured with the synchronisation of four fast-start units, when previously it was not possible to resecure the system using fast-start units alone. If network augmentations such as Central West Orana (CWO) renewable energy zone (REZ) and HumeLink are also delivered within this timeframe, this eliminates the need to make any post-contingent direction for system strength for this condition following Eraring's retirement.

2.5.2 Synchronous condenser delivery in Victoria remains a priority

The delivery of the first pair of synchronous condensers at Hazelwood terminal station materially reduces the impact of non-credible contingencies in Victoria. For many of the non-credible generation contingencies assessed, the largest system strength impact, in terms of fault level, occurs at the Hazelwood 500 kV SSN. The integration of the first pair of synchronous condensers most effectively supports this SSN, reducing the post-contingent fault level shortfall by approximately 1,500 megavolt amperes (MVA), relative to operating conditions without synchronous condenser installations.

For a non-credible contingency with three units on outage, the addition of synchronous condensers reduces the number of fast-start units from 16 to eight. Under the non-credible trip of two Loy Yang A units while operating with only three large synchronous units online pre-contingently, fault levels at the Hazelwood SSN fall to approximately 6,350 MVA. In this

[47] One equivalent synchronous condenser in Victoria is assumed to offer 1,100 MVA of fault level at its point of connection.

[48] One equivalent synchronous condenser in New South Wales is assumed to deliver 1,050 MVA of fault level at its point of connection.

condition, a direction to nine gas-fired units (for example, Valley Power and Jeeralang) is required to restore fault levels above the secure operating level.

Other actions, such as improved coordination of outages, could further reduce risks under multiple outage conditions. While there should be sufficient fast-start units available to execute these actions, the scale of directions may pose operational challenges in returning the power system to a secure operating state within 30 minutes. Other courses of action could proceed in parallel to reduce risks related to operations during multiple outage conditions. The primary action is to reduce the period of time where three large synchronous units are on concurrent outage. If this cannot be achieved, other post-contingent actions could be taken to help resecure the system, such as the curtailment of generation output and turbine numbers for wind farms located in south-west Victoria to manage stable operation of IBR plant.

2.5.3 New South Wales system strength impacts are largely managed with the first tranche of synchronous condensers

The addition of synchronous condensers across five key sites in New South Wales significantly improves system strength outcomes, with many of the non-credible contingencies assessed being resolved following full delivery of these assets ahead of Eraring's retirement. The synchronous condensers planned at the Newcastle and Kemps Creek 330 kV substations are of highest criticality, as they provide the greatest fault level support to the Newcastle and Sydney West SSNs, where the most severe shortfalls were identified.

Synchronous condensers materially reduce the scale of operational actions required following non-credible contingency events in New South Wales. While not all contingencies are fully remediated from a fault-level perspective, the residual system strength shortfalls following the initial phase of synchronous condenser delivery can be managed operationally. This avoids the need for widespread directions to synchronise large numbers of synchronous units, which provide increasingly limited fault level benefit to electrically distant nodes and deliver diminishing returns for system security management.

The highest non-credible contingency risk in New South Wales was identified as the simultaneous trip of both Vales Point units when the system is operating with only five coal units online, with residual system strength supplied by the new synchronous condensers in addition to hydro and gas generation. Under this operating condition, shown below in **Figure 13,** the maximum post-contingent system strength shortfall at the Newcastle SSN reduced to approximately 1,000 MVA; this was an improvement of around 1,650 MVA relative to the case without integrated synchronous condensers. In this scenario, directing four gas-fired units can be sufficient to close the remaining system strength gap. This level of operational intervention is achievable within the 30-minute timeframe required to restore the system to a secure operating state under NER 4.2.6.

2.5.4 Future transmission augmentations further support system strength

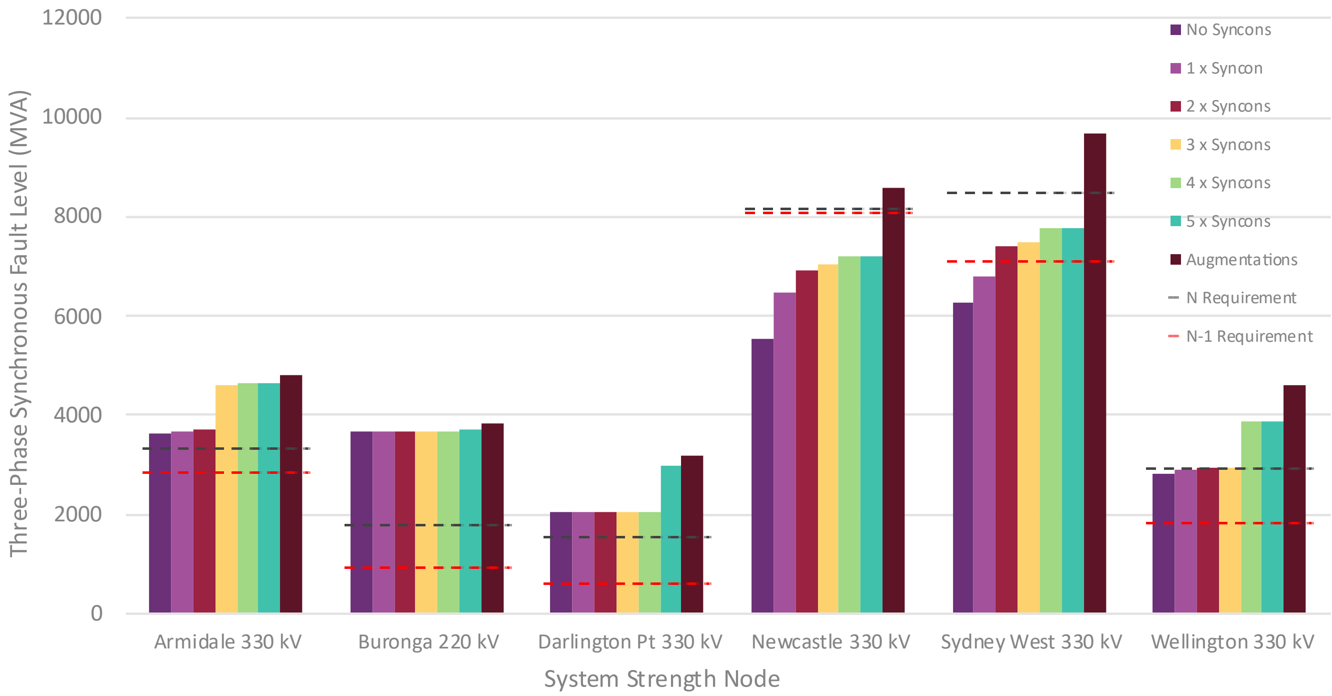
Transmission network augmentations support system strength by reducing the equivalent network impedance between system strength sources and key fault level nodes. This is particularly beneficial where augmentations improve interconnection between regions, increase transfer capability into areas with high IBR penetration, or strengthen connections to synchronous plant.

Key prospective transmission projects assessed with the potential to deliver a material system strength benefit in Victoria and New South Wales include HumeLink, CWO REZ, Western Renewables Link (WRL), and VNI West, connecting into the core Victorian network via WRL. AEMO observed that all these projects provided a material improvement to system strength in either New South Wales or Victoria.

Under the reduced large synchronous unit operating conditions assessed, the most notable improvement in New South Wales was delivered by the CWO REZ, which increased fault levels at the Newcastle and Sydney West SSNs by approximately 1,300 MVA and 1,750 MVA respectively under system normal conditions. This significant improvement is attributable to the seven proposed network-owned synchronous condenser facilities within the REZ, which provide fault level support extending beyond the REZ boundary.

In Victoria, the most significant system strength benefit was observed from the combined delivery of WRL and VNI West, increasing fault levels at the Hazelwood SSN by around 850 MVA. Approximately 250 MVA of this increase is attributable to WRL, with the remaining 600 MVA delivered through the VNI West component. The HumeLink project was also observed to provide system strength benefits across both regions, with the most pronounced impact in New South Wales through increased fault level transfer from southern hydro generation to the Sydney West SSN, delivering an additional approximately 450 MVA under system normal operation. Other future network augmentations may further improve system strength such as the connection of the Marinus Link voltage source converter (VSC) HVDC, although how its contribution is considered in limit advice will need further consideration.

Figure 13 The first tranche of New South Wales synchronous condensers and transmission augmentations significantly support New South Wales system strength management (trip of two Vales Point units during five-unit operating conditions) (MVA)



Transmission network augmentations and synchronous condensers are a critical enabler of effective system strength management in the future power system. This is consistent with the benefits observed from synchronous condenser installations across Victoria and New South Wales, with network augmentation enabling synchronous sources to deliver system strength more broadly and efficiently. If delivered on time and in full, these projects will play a central role in supporting the initial phase of synchronous generation retirements by reducing reliance on local synchronous generation and increasing the resilience of system strength outcomes under a wider range of operating conditions. This will also support the management of network and generation outages, allowing required maintenance activities to be completed to ensure reliability across the power system. However, delays to these augmentations represent a material system risk. In the absence of timely delivery, secure power system operation may increasingly depend on the remaining fleet of synchronous generators to provide fault level and voltage support, potentially increasing exposure to common-mode outages, forced deratings, and declining reliability as these assets continue to age.

2.6 Delays in delivery of synchronous condensers or network augmentations may cause operational challenges under multiple outage conditions

AEMO also studied a selection of non-credible contingencies, considering multiple coal-unit trips and double-circuit transmission faults when network augmentations and synchronous condensers were not delivered. This allowed assessment of operational actions that may be required to resecure the system under outage conditions without system strength support measures. Non-credible contingencies assessed were the loss of two large synchronous units, or double-circuit transmission outages to major 500 kV and 330 kV transmission lines across Victoria and New South Wales. All dispatch conditions satisfied the pre-contingent minimum fault level requirements across all SSNs. The result of this analysis is detailed below.

2.6.1 Without system strength support measures, non-credible contingencies that occur during outage conditions in Victoria may increasingly rely on fast-start gas units

AEMO identified a post-contingent fault level shortfall of nearly 3,000 MVA at the Hazelwood SSN when a non-credible contingency occurs in scenarios with only three Loy Yang units online. Under these conditions, resecuring the system may be dependent on the availability and timely direction or enablement of fast-start gas generation in the Latrobe Valley and metropolitan Melbourne. However, even with optimal availability of fast-start units and rapid IBR curtailment or disconnection, meeting the requirement to re-secure the system within 30 minutes is unlikely to be achievable. If synchronous condensers are not delivered on time, this may present risks of insecure or potentially unsatisfactory operation if a non-credible loss of two large units occurs when operating with only three Loy Yang units online. **Figure 14** shows the system strength shortfalls**.**

Up to 16 fast-start gas units are required to resecure the Victorian power system across Jeeralang, Valley Power, Somerton, and Laverton power stations following the trip of two Loy Yang units during three-unit operation[49]. Note that this assumes full availability for direction or enablement[50] of Victorian gas facilities. These units were selected due to their proximity to the Hazelwood SSN, where the fault level shortfall is most severe for the trip of two Loy Yang units. If gas or hydro units are on coincident outage, insufficient units may be available for synchronisation, increasing the risk that the system remains insecure for extended periods, potentially requiring more extreme operational actions to manage.

The scale of required operational actions to meet minimum fault levels is greatly reduced through increasing coal unit availability:

- three Loy Yang units – 16 units synchronised,

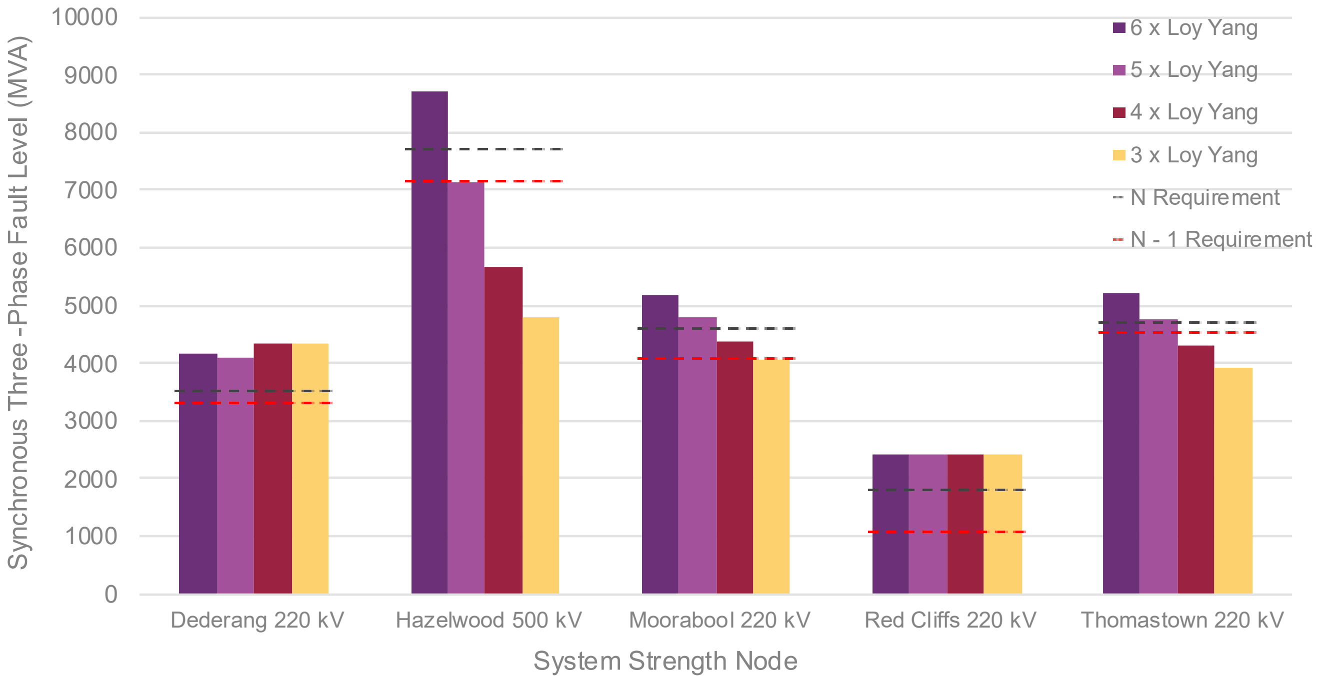
[49] Select Victorian gas units have varying fast-start capability depending on their state prior to being directed or enabled for power system security.

[50] The Improving Security Frameworks (ISF), effective in December 2025, allows AEMO to enable or schedule generating units in the operational timeframe. This framework is designed to reduce reliance on directions to manage power system security, such as system strength.

- **four Loy Yang units –** nine units synchronised (for example, Jeeralang and Valley Power units),
- **five Loy Yang units –** three units synchronised (Jeeralang), and
- **six Loy Yang units –** no immediate operational actions to meet minimum fault level requirements.

Coincident outages should be minimised where possible to reduce operational risk. While the current rules framework does not provide AEMO with a mechanism to directly coordinate planned generation outages to support power system security and reliability, this highlights the value of operating with a higher number of large synchronous units online and the opportunity to explore options to better support outage coordination. Such coordination could help minimise periods of increased vulnerability to power system security risks.

Figure 14 The loss of two Loy Yang units results in significant fault level shortfalls in Victoria (MVA)



Note: Unit combinations depicted in this figure are labelled by the number of Loy Yang units online, but they satisfy limit advice through the support of other smaller hydro and gas generators not listed.

2.6.2 Non-credible contingencies that occur during outage conditions in New South Wales may cause significant operational challenges without synchronous condensers

Locational diversity of large synchronous generation in New South Wales provides inherent system strength benefits, with generation distributed across multiple parts of the network rather than concentrated in a single area, as in Victoria. This supports broader fault level coverage across a range of operating conditions. However, system strength remains highly dependent on a subset of strategically located large synchronous units that are strongly coupled to key SSNs, increasing the impact of their non-credible loss. It was found in the analysis completed that the non-credible loss of two Vales Point units will be difficult to manage under multiple outage conditions if synchronous condensers are not delivered on time. The loss of two Vales Point units was determined to be the most onerous condition, however the loss of two other large synchronous units could also result in operational challenges to a lesser extent under certain operating conditions.

Without the delivery of synchronous condensers and network augmentations, the New South Wales power system may not be able to be resecured using the existing fleet of fast-start units alone following non-credible contingency events during multiple outage conditions. Clear examples of this risk can be demonstrated when operating with only five units online across the Bayswater and Vales Point power stations. Under these conditions, the trip of two units at either station results in the following impacts:

- **Trip of two Vales Point units** – fault levels at the Newcastle SSN may fall to approximately 5,550 MVA, around 2,650 MVA below the secure operating level. Following synchronisation of all available fast-start units in New South Wales, fault levels remain approximately 500 MVA and 400 MVA below the secure and satisfactory operating levels, respectively.
- **Trip of two Bayswater units** – fault levels at the Wellington SSN may fall to approximately 2,700 MVA, around 200 MVA below the secure operating level. Under this scenario, fault levels at the Wellington SSN remain marginally below the secure operating level following synchronisation of all fast-start units.

Under other dispatch conditions, the non-credible loss of two other large synchronous units such as the Mount Piper units can also result in operational challenges. While the shortfall is not as large as 400 MVA to 500 MVA as observed in the loss of two Vales Points units, there will still be additional operational actions required under some scenarios.

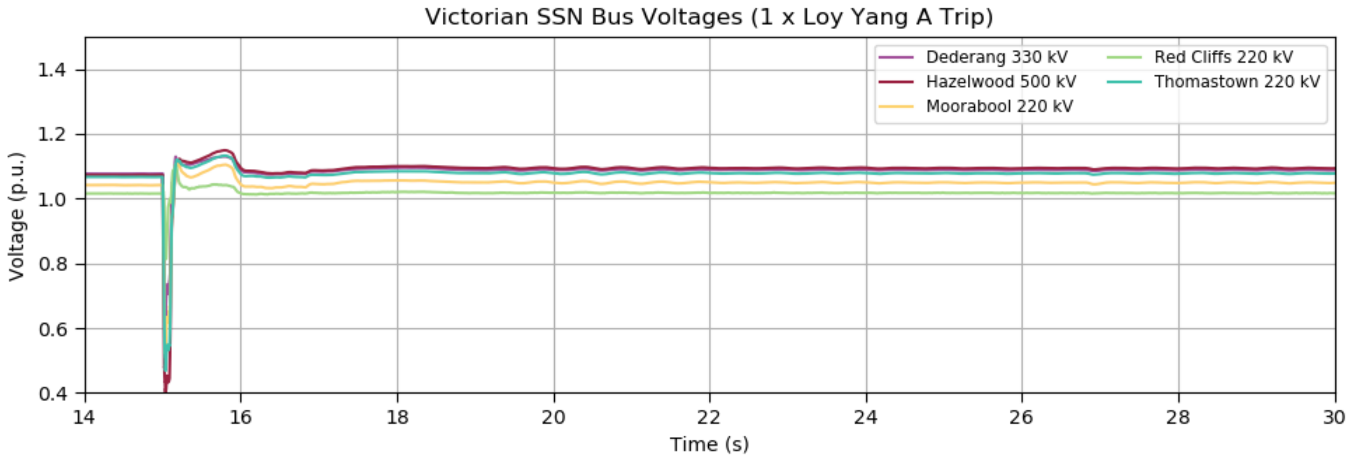
Such events may require a broad and coordinated set of operational actions to resolve, including curtailment of IBR output and inverter numbers in areas of high IBR penetration. Depending on the extent of IBR curtailment, other actions could be required to maintain the supply demand balance. In some circumstances, network protection requirements may necessitate de-energisation of network elements to manage power system security.

2.7 Non-credible contingencies may result in IBR instability under specific multiple outage operating conditions

AEMO has undertaken a series of EMT assessments for Victoria, examining operation with three Loy Yang units online, supported by gas and hydro generation to maintain secure system operation. The studies assessed whether IBR may become unstable in low system strength conditions after the loss of multiple units. While the fault level analysis in previous sections assessed how the system could be resecured from post-contingent low fault level scenarios, this section assesses whether the system would land satisfactory before the system can be resecured.

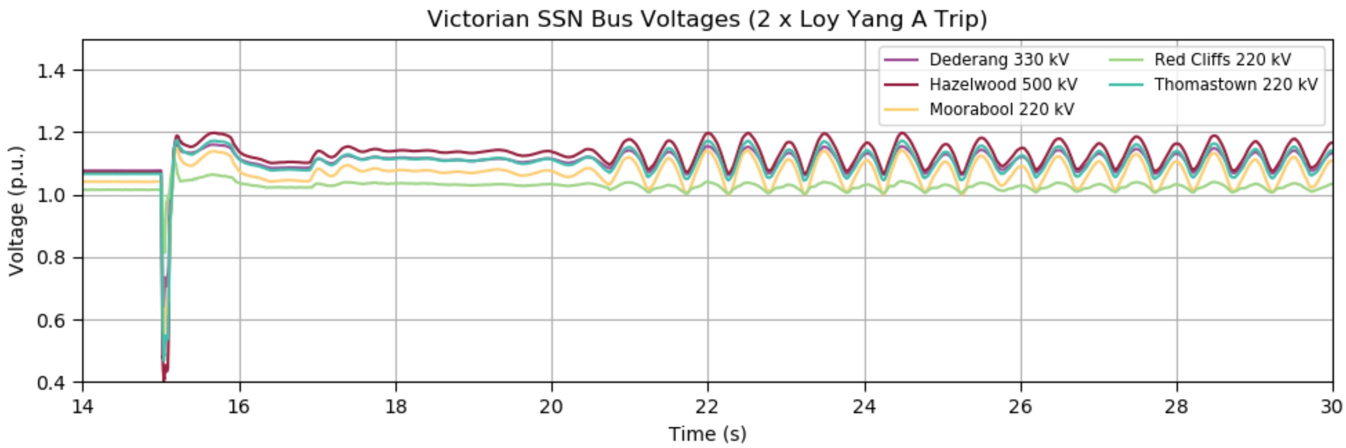
AEMO compared assessments of the credible loss of a single Loy Yang unit with the power system response to the non-credible loss of two Loy Yang units. The operating condition assessed had relatively low Victorian system demand, with high IBR generation, particularly in south-west Victoria, and high export across the Heywood interconnector from South Australia. Under these low demand conditions, system voltages across Victoria were at the upper end of the normal operating band, resulting in generator voltage control systems absorbing reactive power to limit further voltage rise. The credible contingency scenario is illustrated below in **Figure 15**, where the Victorian power system demonstrated satisfactory performance, with adequate containment of voltages and sufficient damping of post-contingent voltage and power oscillations.

Figure 15 Secure power system operation is demonstrated by the satisfactory network response following the trip of a single Loy Yang A unit (p.u.)



The non-credible loss of two Loy Yang units resulted in a pronounced deterioration in system performance, with the Victorian power system entering an unsatisfactory operating state. Illustrated in **Figure 16**, this was characterised by high-magnitude, poorly damped voltage and power oscillations. The most definite impacts occurred in south-west Victoria, which exhibited the largest voltage oscillation magnitudes of the five Victorian SSNs. This behaviour is attributed to the aggregated reactive power response of IBR following the disturbance. Low system strength conditions increased network voltage sensitivity such that reactive power injections from IBR resulted in the observed persistent voltage oscillations.

Figure 16 The impact of insufficient system strength is demonstrated by undamped voltage oscillations following the non-credible trip of two Loy Yang A units (p.u.)



AEMO observed that the following installations and operational changes improved the Victorian network's post-contingent response following the non-credible loss of two Loy Yang A units:

- **Synchronous condenser installations or other system strength support measures** – the addition of two 250 MVA synchronous condensers modelled at Hazelwood terminal station improved the Victorian network's dynamic response, reducing the peak-to-peak post-contingent voltage oscillation magnitude to approximately 2%. The addition of a third synchronous condenser at Hazelwood further improved system performance, resulting in a satisfactory post-contignent response, with observed dynamics consistent with those illustrated above in **Figure 15**.

- **IBR active power and inverter/turbine curtailment** – the curtailment of approximately 550 MW of IBR generation in south-west Victoria resulted in satisfactory damping of post-contingent voltage oscillations. Generation curtailment also included a proportional reduction in the number of turbines online.
- **Reduction of reactive power absorption by IBR** – reducing transmission-level voltages, through the switching of additional reactors (where available) or the deployment of devices such as static synchronous compensators (STATCOMs), improved the network's post-contingent response and reduced voltage oscillation magnitudes. This was most effective when implemented in close proximity to wind farms in south-west Victoria, as lower voltages reduced reactive power absorption by IBR in this part of the network and improved dynamic response following the applied non-credible contingency.

The above observations demonstrate that while there are low likelihood conditions where non-credible contingencies may present increased risk, the risk can be minimised as long as mitigation measures or procedures are considered beforehand. These observations reinforce the importance of timely synchronous condenser installations and coordination of outages, and highlight the value of decisive operational processes to maintain power system security. If the power system enters an unsatisfactory operating state, there is a heightened risk of adverse outcomes. In these circumstances, it is critical that AEMO can take effective actions to return the system to within its technical envelope as soon as practicable.

Grid-following IBR may be more susceptible to instability when absorbing reactive power

AEMO's analysis indicates that when IBR absorb reactive power, voltage sensitivity at the point of connection increases. When operating in a reactive power absorbing mode, the local network may become more sensitive to both active and reactive power changes, leading to larger voltage movements for a given change in output than would occur when reactive power is being injected. During FRT, an IBR that is undergoing a ramp increase in active power while absorbing reactive power produces larger voltage changes than if it were supplying reactive power. These increased voltage excursions make it more difficult for grid-following (GFL) inverters to re-establish stable synchronisation following fault clearance.

Additional measures may be required to support IBR stability during times of high reactive power absorption. Conditions such as MSL periods, or other lightly loaded system conditions, may result in elevated voltages and increased reactive power absorption by IBR. These effects are not captured by conventional system strength proxies, such as fault level or SCR metrics, and as such it may mean the system is more exposed to instability under certain conditions while still meeting minimum fault level requirements. This highlights the need for regular system strength assessment under IBR-dominated dispatch conditions using EMT tools to ensure unit combinations that meet minimum fault level requirements remain fit for purpose. If it is determined that there is an increased risk, additional measures such as synchronous condensers and GFM BESS could provide the required increase in system strength, or the use of reactors or other reactive plant could reduce the reactive power absorption required by the IBR.

Grid-forming battery energy storage systems present an opportunity for future system strength support

GFM BESS may present a viable option to support the stable voltage waveform component of system strength[51]. While not able to provide all the same advantages of synchronous condensers, the use of GFM BESS may assist in meeting system

[51] For the delineation between minimum fault level requirements and a requirement for stable voltage waveforms at connection points (also known as the *efficient level of system strength*), see AEMO's 2025 TPSS, Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-tpss-appendix-a2-network-requirements.pdf.

strength requirements. The benefit of synchronous condensers largely arises from their ability to deliver fault current over significant distances into the network, enabling a more centralised approach to system strength management, particularly where protection-grade fault current is required. However, for more localised system strength requirements, such as maintaining stable IBR operation at efficient system strength levels, GFM BESS can provide a material level of support. GFM BESS may be more suited to provide system strength in concentrated local areas, or the use of a sufficiently large GFM BESS may be appropriate to serve a larger area.

AEMO's assessment of GFM BESS capability indicates GFM BESS can deliver equivalent stability performance when rated at approximately double the capacity of a synchronous condenser, effective over a considerable electrical distance, dependent on network impedance and system conditions and subject to case-specific tuning. Further work will be required to support the practical implementation of GFM inverters for system security across components such as inertia, protection-quality fault current provision and system restart ancillary services. For example, real world trials such as the Type 2 Transitional Services (Trial Services) are progressing to demonstrate GFM inverters' capabilities in providing protection-quality fault current.

BESS are commonly co-located in regions where other IBR facilities are concentrated, so accounting for these benefits provides an opportunity for future system strength management during operating conditions with high IBR penetration. As conventional fault level assessments do not capture these benefits, ongoing assessments will continue through work related to the Engineering Roadmap, the TPSS and other system strength studies underway to appropriately understand the system strength support offered by the ongoing integration of GFM BESS.

2.8 Operating procedures, tools and schemes to manage system strength will continue

AEMO has demonstrated that delays to planned synchronous condenser installations may result in an increased risk related to low probability non-credible contingency events during infrequent multiple outage operating conditions. To support power system security management under these conditions, development and refinement of existing operational processes will continue, alongside enhancements to control room tools and the potential deployment of schemes to rapidly manage post-contingent system strength following major contingencies.

2.8.1 Control schemes can address locational system strength impacts, but are difficult to implement more broadly

Control schemes to manage system strength may be suitable for known network outages. In practice, locational system strength control schemes are most effective where system strength risks are well understood and linked to known network conditions, such as the outage of specific transmission lines that materially reduce fault levels at nearby SSNs. Low-SCR schemes associated with predefined transmission line trips can be used to proactively disconnect IBR in affected areas, mitigating local stability risks following these contingencies. Such schemes are currently used across the NEM to increase the volume of IBR that certain areas of the network can host under normal operating conditions, while mitigating post-contingent impacts. This approach could be further expanded to involve larger-scale actions following the loss of multiple key transmission elements. However, the applicability of such schemes is inherently limited to anticipated network configurations and does not readily extend to unplanned coincident outages of multiple major generators.

2.8.2 Inverter management is important to maintain secure power system operation

As operational reliance on IBR continues to increase, more effective and timely control mechanisms to manage locational system strength will become increasingly important. In some instances, low-SCR schemes may not be required, as targeted IBR power or inverter curtailment can be implemented and power system security managed within the permitted 30-minute operational window. However, extended periods of insecure operation have previously occurred in the NEM due to delays in inverter curtailment or disconnection in areas of low system strength. In response, AEMO is progressing the development of an Inverter Management System (IMS) to provide a more consistent and timely operational approach to managing IBR during system security events. Such capabilities are intended to improve AEMO's ability to rapidly manage inverter behaviour in response to emerging locational system strength risks, supporting secure operation of the power system following contingencies.

2.8.3 Operational contingency plans may be necessary to manage certain widespread impacts

Extension of contingency plans may be key to the management of severe system-strength shortfall events. In circumstances where fault level shortfalls cannot be resolved through bringing fast-start units online, it may be necessary to have other actions ready to resecure the system. Contingency plans could be extended to define actions to be taken for certain system strength shortfall conditions as a result of non-credible contingency events. This could include consideration of network reconfiguration, increased availability of fast start units, targeted IBR curtailment or the de-energisation of selected network elements to stabilise the power system and limit broader security impacts. While some of these actions are disruptive, they may be necessary to prevent escalating instability or protection system maloperation[52,53].

2.8.4 Improving control room visibility of system strength can support operational decision-making

Real-time visibility of system strength parameters is increasingly critical as the power system operates closer to technical limits. Enhanced real-time fault level visibility would better equip operations staff to respond effectively within operational timeframes and to validate the effectiveness of operational actions through energy management system (EMS) monitoring and assessment. This is particularly important during conditions where existing operating advice may be less applicable following major contingencies. Currently, only the Tasmanian power system has operationalised real-time fault level monitoring to support system strength management, with contractual arrangements enabling fast-start units to be brought online when shortfalls are identified. A similar approach could be implemented in mainland NEM regions, leveraging new Improving Security Frameworks (ISF) scheduler capabilities to enable appropriate units within the operational timeframe when shortfalls are identified in real time.

Current operational approaches to managing system strength are highly dependent on assumed transmission network topologies. The use of known secure unit combinations or cumulative generator coefficient methods relies on predefined network configurations, which may no longer be valid following significant network contingencies. In such circumstances,

[52] NER 4.2.2(e) defines a satisfactory operating state to include the operation of the power system such that any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.

[53] NER 4.8.2(a) states that if a Registered Participant becomes aware that any relevant protection system or control system is defective or unavailable for service, that Registered Participant must advise AEMO. If AEMO considers it to be a threat to power system security, AEMO may direct that the equipment protected or operated by the relevant protection system or control system be taken out of operation or operated as AEMO directs.

these approaches may be insufficient to restore system strength above secure thresholds, whereas real-time fault level monitoring would provide operators with immediate feedback to assess whether operational actions are achieving the intended outcome.

The locational nature of system strength presents opportunities to optimise the selection of synchronous plant to address regional shortfalls. Improved visibility of fault level contributions at individual SSNs would allow a clearer understanding of how specific synchronous units support different areas of the network. This information could inform more targeted enablement decisions, enable efficient investment planning, improve the effectiveness and timeliness of operational actions and support a faster return of the power system to a secure operating state.

2.9 Recommendations

Maintaining power system security through the transition to fewer operating large synchronous power stations will depend on the timely delivery of assets that provide equivalent system strength services. AEMO's studies have identified potential risks to power system security under major generator outage conditions if synchronous condensers at key network locations are not delivered in full and on schedule. AEMO therefore recommends that the timely delivery of synchronous condensers and associated network augmentations in Victoria and New South Wales continue to be prioritised to support future system strength management, particularly following the retirement of the Eraring and Yallourn power stations, and further synchronous generator retirements or unavailability across the NEM.

Actions to support system strength have already been considered to mitigate some of the risks related to reduced availability of synchronous machines resulting from upcoming retirements. As outlined in the TPSS, this includes:

- AEMO enabling TNSP security contracts for hydro, gas and coal, issuing directions, or directing to de-energise network assets,
- as a precautionary measure, AEMO working with relevant TNSPs to prepare a procedure on which sections of the transmission network may be de-energised under fault level shortfalls, and
- AEMO creating constraints on IBR generation as needed, based on limits advice to maintain adequate short circuit ratios to ensure IBR stability.

Where relevant, these measures should be extended further to consider the potential risks related to non-credible contingency events, particularly during multiple unit outage conditions.

Recommendation 2

AEMO's assessments in the 2026 GPSRR reinforces the importance of prioritising the delivery of system strength support measures to maintain system strength amidst the retirement of synchronous generation in the NEM. To enable the efficient and timely delivery of system strength, AEMO also supports the need for system security framework enhancements to meet ongoing system security needs[54].

[54] See https://www.aemc.gov.au/rule-changes/security-framework-enhancements

Actions:

AEMO and TNSPs should extend operational documentation to further support the ability to resecure the system for low probability non-credible contingency events, considering options such as:

- specifying post-contingent actions required to resecure for non-credible contingency events that may present increased risk, and
- taking actions to maximise fast-start unit availability for multiple outage conditions.

AEMO will continue to progress system strength and transition point studies as outlined in the TPSS. AEMO will also continue to support the evolution of system strength in the NEM through its Engineering Roadmap and Type 2 Transitional Services[55].

TNSPs to continue to prioritise the delivery of planned system strength support measures such as synchronous condensers (conversion of existing plant, or new installations), network augmentations and the use of contracted services. The timely resolution of any identified shortfalls will support ongoing system security.

Ensuring the availability of major generating units – particularly during spring and autumn periods when demand is low and multiple generators schedule maintenance – is critical to maintaining adequate resilience to contingencies that result in a significant reduction in system strength. AEMO's assessments indicate that higher levels of large synchronous unit availability under pre-contingent conditions reduce reliance on hydro and gas-fired units for system strength management during normal operation. This increases the pool of generators available to be synchronised following a contingency, provides additional operational margin, and reduces the scale of post-contingent operational actions required to maintain power system security. AEMO therefore recommends that generator and key network outages be coordinated, where practicable, to reduce the frequency of periods with concurrent outages of major units.

Recommendation 3

AEMO has identified that multiple planned or unplanned prior outages may contribute to operational complexity for the occurrence of non-credible contingency events. Improved coordination of generation and network outages, or other suitable actions, should be considered to reduce risk during these periods.

Actions:

AEMO will consider the appropriate approach to reducing the likelihood or impacts of multiple prior generation and network outages while minimising impacts to participants. This may include:

- potential for regulatory change to improve generator and network outage coordination,
- procedural updates to current processes to support improved coordination without regulatory change, or
- other appropriate mitigation measures as determined by AEMO.

[55] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial

3 Large non-credible generation and network contingency events

This section covers the following key points:

- Power system limits are designed to manage credible contingency events. Therefore, the unlikely occurrence of non-credible contingency events will always present risks of higher consequences, particularly when the system is operating close to its limits.
- General resilience to large non-credible contingency events in the NEM was observed to improve in future years due to the addition of new network augmentations and the FFR provided by new BESS and generation projects. However, increased risks related to non-credible contingencies are expected to continue to be present for short periods of time when the system is operating close to its limits or when significant non-credible contingency events are more likely.
- To manage infrequent periods of increased non-credible contingency risk, the use of protected events may be the most appropriate solution.

Power system resilience is integral to the operation of power systems, supporting the system's capability to withstand high impact, low probability events. To strengthen the understanding of resilience in the NEM, the impacts of large non-credible generation and network contingency events were assessed in the 2026 GPSRR. Large non-credible generation and network contingency events are defined as follows:

- Large non-credible generation events are the coincident loss of multiple power system assets that result in the disconnection of large quantities of generation.
- Large non-credible network events are the loss of multiple power system assets that result in the disconnection of critical transmission infrastructure such as high capacity transmission lines.

The events discussed in this section are unlikely to occur and will only result in significant power system impacts if they occur during infrequent operating conditions. The assessments completed for this priority risk investigates potential events and operating conditions that may coincide and suggests mitigation measures that could be considered if the risk is observed to increase in the future.

AEMO assessed the resilience of the current and future systems through power system studies. AEMO completed power system studies to determine a range of non-credible contingency events that could be withstood in the current system. For each region, increasing generation contingency sizes were assessed under various dispatch scenarios to determine the system limits. While these studies cannot be fully representative due to the vast permutations of potential non-credible contingency events, they do provide an indication of the resilience of the system. Future system studies were also completed to understand the impact of future augmentations, generation and storage.

Power system resilience can be supported through a number of actions. Power system resilience is expected to change over time, but it can be supported by forward-looking assessments that identify periods where the system may be more susceptible to non-credible contingency events. Under these rare conditions, there are a number of mitigation measures that can contribute to improved resilience, such as:

- the increasing uptake of BESS and generation in the system that can provide FFR and increased reactive power support,
- new network augmentations that support the transfer of power and strengthen the network for stability risks,
- the addition of synchronous condensers, contributing system strength, inertia and voltage support to the system, and
- taking actions such as:
  - implementation of protected events, permitting actions that include:
    - reducing interconnector flows during high risk conditions,
    - procurement of additional FCAS or other ancillary services, and
    - constraining generation that is concentrated in high risk areas,
  - appropriate implementation of RASs, and
  - ensuring that EFCS such as UFLS and OFGS are maintained and available.

Resilience measures will continue to support secure and reliable operation. To address the changing system dynamics, it is important that resilience measures are implemented. Ongoing enhancement of power system resilience should be considered via a number of approaches. While the use of RASs is one of the most common approaches to mitigate the risks associated with non-credible contingencies, the use of market actions associated with protected events may be required more often to procure additional FCAS, reduce interconnector flows or constrain generation during high risk conditions.

3.1 Power system resilience is essential in a rapidly changing system

As the Conseil International des Grands Réseaux Electriques (CIGRE) defined it in its 2017 CIGRE SC C4 working group[56], "*power system resilience is the ability to limit the extent, severity, and duration of system degradation following an extreme event*". Maintaining power system resilience is a core obligation under the GPSRR. This section outlines how power system resilience is considered in the planning and operation of power systems and provides background on the types of events that a resilient system will withstand.

3.1.1 Power systems are typically designed for the loss of single assets, but high impact, low probability events must also be considered

The power system is typically designed around credible contingency events. Planning and operational frameworks are designed to cater for credible contingencies, with AEMO and TNSPs planning and operating the system with several options available to mitigate the security impacts related to the loss of one asset. The impacts of credible contingencies can be managed through additional infrastructure, implementing constraints or the procurement of ancillary services. These actions are taken to ensure that the system remains in a satisfactory operation condition if a credible contingency were to occur. This supports reliability and system security for the large majority of operating conditions.

[56] See http://cigre.org/article/defining-power-system-resilience.

Non-credible contingency events are uncommon but do occur. However, non-credible contingencies involving the loss of multiple assets are known to occur, despite this being a lower likelihood event[57]. Planning and operational frameworks have a limited number of actions to manage non-credible contingencies, due to the wide ranging number and likelihoods of potential non-credible contingency events. If the system limits are designed to cater for credible contingencies, a non-credible contingency event will always present a risk if it occurs when the system is operating at its limits. However, the intention is to identify the most likely or consequential non-credible contingency events and ensure that their occurrence does not result in cascading failures or blackouts. Major system events can have significant consequences, with large economic and societal costs.

Current approaches to managing non-credible contingencies include:

- implementing emergency controls such as EFCS or RASs to significantly reduce the probability of cascading failure,
- declaring a protected event, and
- reclassifying an event under the indistinct events framework or in the presence of bushfire, lightning or under other conditions.

3.1.2 Significant events have occurred in the NEM in recent years

Large non-credible generation and network contingency events have been known to occur in the NEM, with a range of serious consequences. A few examples of major events that have occurred recently are:

- **Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024**[58] – the Moorabool terminal station (MLTS) – Sydenham terminal station (SYTS) 500 kV No. 1 and No.2 lines tripped, resulting in the loss of approximately 2,484 MW of generation and the shake-off of approximately 870 MW of net operational demand in Victoria.
- **Trip of multiple generators and lines in Central Queensland and associated UFLS on 25 May 2021** – the unexpected operation of Callide Unit C4 and eventual catastrophic failure started a chain of events that ultimately resulted in the disconnection of 3,045 MW of generation, the trip of QNI, and operation of UFLS.
- **Black system South Australia 28 September 2016**[59]**:**
  - Destructive winds damaged multiple transmission lines in South Australia, resulting in a sequence of faults in quick succession. As the number of faults in the network grew, generators began to disconnect resulting in a reduction of 456 MW of generation.
  - This reduction in generation resulted in a significant increase in interconnector flows over the Heywood Interconnector, activating a special protection scheme (SPS) that tripped the interconnector offline.
  - With the South Australian power system disconnected from the rest of the NEM, the mismatch of generation and load was too high and the system was unable to maintain a stable frequency, resulting in system collapse and a regional blackout.

---

[57] Non-credible contingency events that have occurred in the last financial year are detailed in Section 7.

[58] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/final-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf.

[59] 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.

Other non-credible contingencies of varying severity have also occurred in the NEM and are reported on by AEMO if determined to be Reviewable Operating Incidents[60]. A summary of incidents that have occurred in the last financial year is also provided in Section 7.

3.1.3 System response to extreme events is difficult to predict

Extreme events may include unexpected failures. Planning for system resilience is especially important because of the uncertainty in how extreme events could result in cascading failures. While the initial failure can be planned for and mitigated, there is always the possibility that unexpected failures or plant behaviour will arise during extreme events. This is demonstrated in the 2016 South Australia black system event, where a large quantity of generation disconnected due to common multiple FRT settings. Similarly, the trip of the MLTS to SYTS 500 kV No. 1 and No. 2 lines also resulted in the rapid ramp down of generation. Due to the extreme nature of non-credible contingency events, there may be unexpected operation of power system plant that can exacerbate the consequences or lead to further cascading failures.

Studies completed under the GPSRR provide an indication of resilience. To assess system resilience in the GPSRR, it would not be possible to determine the exact modes of failure that may occur, taking into account the potential unexpected failures of many components that make up the complex power system. However, it is possible to identify ahead of time which events would have the highest known impact, and to test this over a number of various dispatch scenarios to understand the risk profiles under different operating conditions. This can be done in the current system, and then repeated in the future system to determine whether any actions are required to be taken. The studies in the 2026 GPSRR have focused on the known modes of failures that may occur, with the understanding that instability or cascading failure may occur earlier if unexpected operation of plant, maloperation or interaction of control schemes, non-compliance or other factors are observed.

3.1.4 The 2026 GPSRR assessed a range of scenarios to understand resilience in the NEM for the current and future systems

The 2026 GPSRR undertook a number of studies to understand the impact that a range of generation contingency sizes could have on the power system. The scope of the work undertaken for the 2026 GPSRR on large non-credible generation and network contingency events was as follows:

- **Current system scenarios were investigated considering the following factors and their impact on system resilience:**
  - high interconnector flows on QNI, VNI and Heywood interconnector (HIC), with sensitivities covering different magnitudes of transfers in both directions,
  - low to medium interconnector flows to assess system resilience when the interconnectors are not close to transfer limits,
  - high and low operational demand,
  - low system inertia and system strength, and
  - increasing non-credible generation contingency sizes until instability is observed.

[60] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

- **Future system scenarios were then studied to further investigate the factors above, with the following additional considerations:**
  - Study cases were developed up to the year 2030 to understand the impact that committed, anticipated and actionable transmission augmentations would have on system resilience.
  - Committed and anticipated generation and BESS projects were included, to demonstrate their impact on supporting system resilience during extreme events.
  - It was assumed that minimum fault levels, inertia requirements and minimum unit combinations were met for all dispatch scenarios.

3.2 Current state of power system resilience

The assessment on the current state of power system resilience found the following key themes:

- The resilience of the NEM is influenced by both interconnector flow transfer levels and the size of generation at risk for certain non-credible contingency events.
- Risks of non-credible contingency events may increase during known but infrequent operating conditions.
- The use of RASs to mitigate non-credible large non-credible contingency events is not suitable for all scenarios.

These key themes are discussed in further detail in the sections below.

3.2.1 The resilience of the system is influenced by interconnector flows and contingency sizes

The system can withstand much larger contingencies when interconnectors are not the limiting factor. When there is additional operating margin available on interconnectors, the system is more likely to remain stable for large generation contingency events in the NEM. When interconnectors were sufficiently far from their limits, it was found that generation contingency sizes in the range of approximately 2,000 MW to 3,000 MW or higher could be withstood. As generation contingency sizes begin to reach within this range and beyond, the likelihood of occurrence decreases significantly.

The likelihood of instability depends on both the generation contingency size and interconnector transfer levels. Sensitivity studies were conducted to demonstrate the required contingency sizes that resulted in instability over QNI for a range of transfer levels. The results shown in **Figure 17** below are not representative of all conditions but show the relationship for a low demand case. It shows that as flows on QNI decrease down to 1,000 MW, the resilience of the system improves significantly, with a generation contingency size of over 2,000 MW able to be withstood. In this instance, a reduction of around 500 MW in flows provided approximately 1,000 MW of potential generation contingency size margin.

Larger contingencies may still cause instability when interconnectors are not at limits. While it has been discussed above that the NEM is more resilient when there is sufficient operating margin on the interconnectors, there is still potential for instability if a significantly large contingency size were to occur.

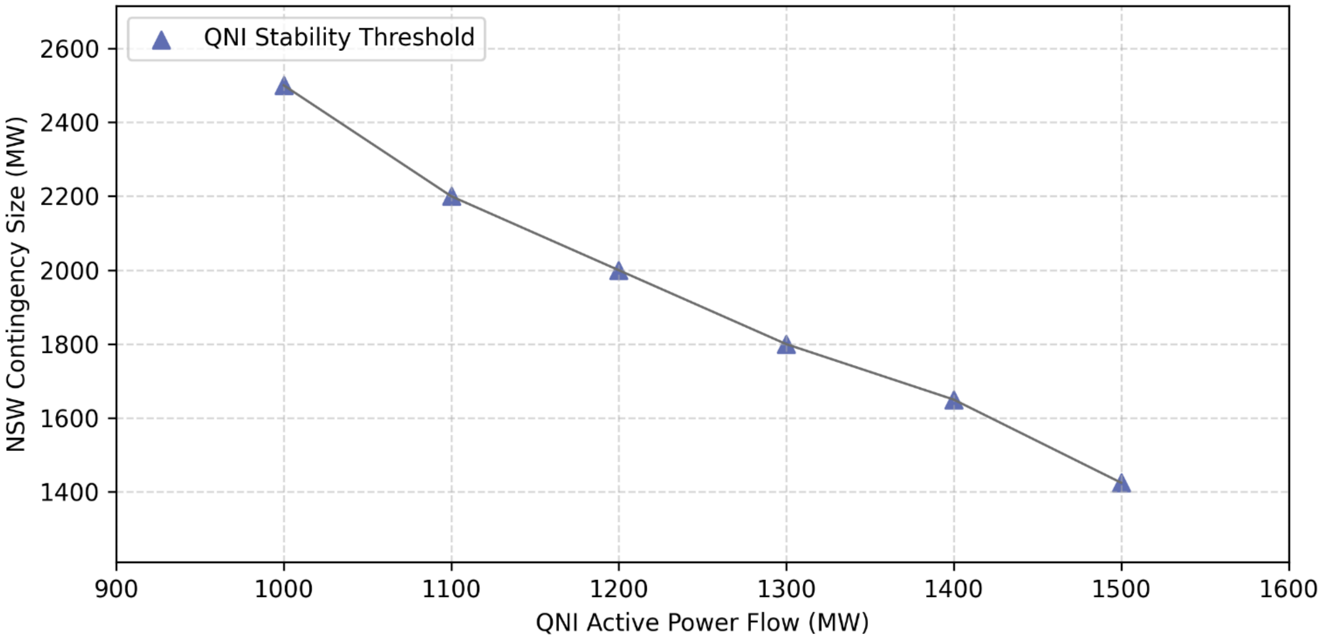
Examples of times when the NEM may be more exposed to large contingency sizes include:

- When large quantities of generation are concentrated behind common assets – this risk increases as the condition persists for longer and as the quantity of generation behind the common assets increases.

- When armed, RASs may disconnect large quantities of generation in response to a known non-credible contingency.
- When large quantities of distributed photovoltaics (DPV) or load are online, there may be a risk of significant shake-off for certain faults.

These are often known conditions that can be determined based on specific dispatch conditions. To further support power system resilience, mitigation measures can be implemented to reduce risk during conditions that may present increased risk related to non-credible contingency events.

Figure 17 Queensland – New South Wales Interconnector stability threshold relationship between Queensland – New South Wales Interconnector active power flow and New South Wales generation contingency size (MW)



3.2.2 Certain operating conditions may result in a higher likelihood or consequence of a non-credible contingency

Non-credible contingency risks are based on both the consequence and the likelihood of occurrence. The risk associated with non-credible contingencies may increase during infrequent operating conditions where a significantly large non-credible contingency may be present or have an increased likelihood of occurrence.

An example of one of these known future operating conditions is the scenario illustrated by **Figure 18**. Key details of this scenario are:

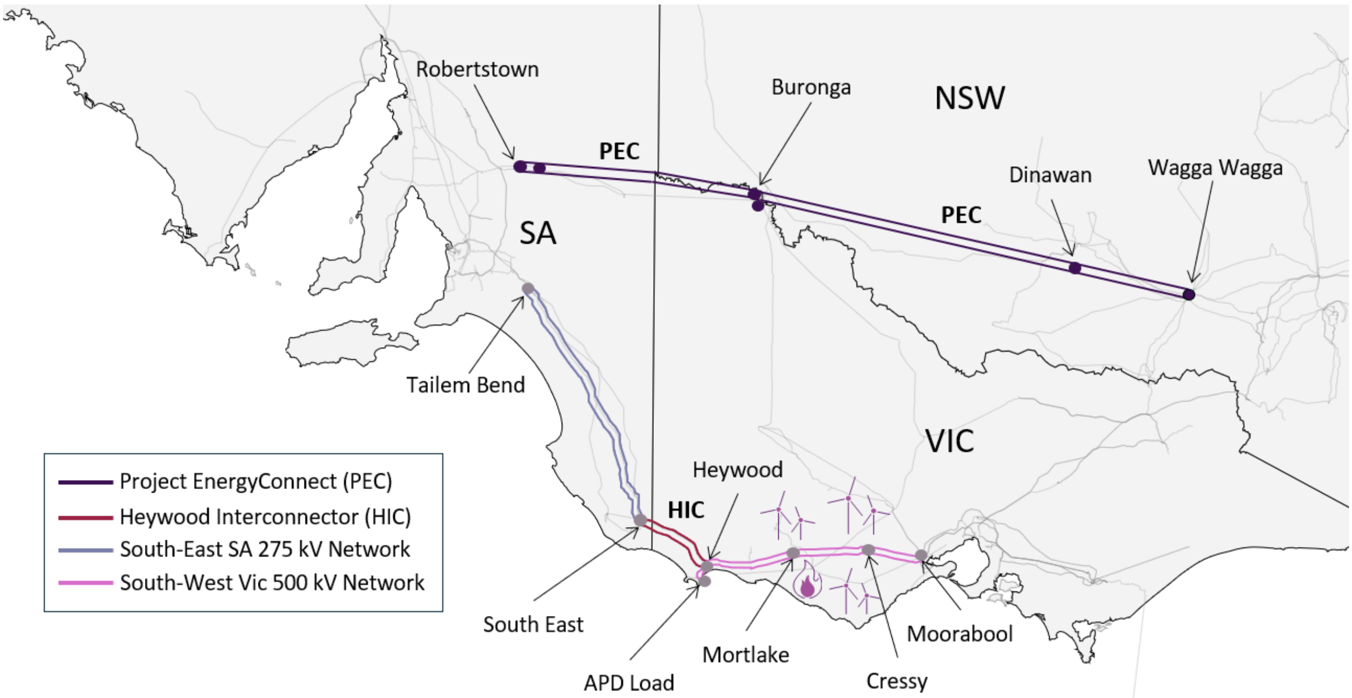
- Large quantities of generation may be connected to the 500 kV lines between Heywood terminal station (HYTS) and MLTS in South-west Victoria.
- In the event of the unlikely disconnection of both lines between HYTS and MTLS, there are RASs that will operate to disconnect generation to prevent instability on PEC or HIC.

- If this non-credible contingency event occurs in specific operating conditions where there is high wind generation in south-west Victoria and high exports from South Australia on PEC and HIC, the operation of the RASs could result in significant quantities of generation being disconnected.
- If the conditions described above coincide with high flows on QNI or other interconnectors, it is possible that further instability will occur after operation of the RASs.

While the dispatch conditions outlined will only be present for infrequent periods of the year, it can be identified that there is increased risk related to non-credible contingency events during these times. If the duration of these conditions increases beyond the limits of tolerable risk, there are a number of actions that can be considered to enhance power system resilience and further reduce the likelihood of cascading failures or major supply disruptions.

The south-west Victorian non-credible contingency event is just one example of low likelihood but high consequence events that could result in instability. Non-credible 500 kV contingencies in south-west Victoria are one example of a known non-credible contingency with demonstrated consequences under certain dispatch conditions. As more generation connects into the network, and new high-capacity interconnectors and critical transmission corridors are operated at high flows, the number of identifiable conditions that could lead to severe consequences for a non-credible contingency event may increase. Given that many of these conditions are possible to determine in advance, it would be prudent to take pre-emptive measures to monitor the occurrence of these operating conditions and to implement mitigation measures to increase power system resilience where necessary.

Figure 18 Non-credible contingencies in South-West Victoria can separate significant generation from the Victorian network



3.2.3 Remedial action scheme complexity

The RASs that have been implemented are of critical importance to ensure PEC stability in the event of loss of two lines between MLTS and HYTS. However, as more RASs are implemented into the power system to manage credible or non-credible contingency events, the operational complexity increases, particularly for schemes with large contingency sizes and rapid operating time requirements. This has implications such as:

- **The risk of maloperation** – this risk may be present when a scheme is armed, and will be influenced by factors such as schemes controlling larger volumes of load and generation, operating across larger areas of the network, and are becoming more complicated with additional inputs and logic. As such, it is essential that development of RASs considers whether the level of risk is acceptable and the consequences of maloperation. There is currently work underway at AEMO to address this, extending the RAS guidelines into explicit requirements for the design, maintenance, modelling and testing of RASs.
- **Operation time** – the network is becoming increasingly sensitive to the operating time of these RASs, with speed playing a large role in ensuring stability is maintained. For the south-west Victorian event described in Section 3.2.2, AEMO observed that small changes in the operation time of the RAS could have material impacts on stability outcomes.
- **Testing requirements** – more complex schemes require additional testing to validate performance, such as hardware in the loop (HIL) testing, prior to implementation on the real power system.
- **Complexity of RAS design may make implementation unviable** – in some cases, the complexity of the network scenario may make a RAS unviable. RASs based on topology-based triggers, such as known circuit faults, are simpler to implement because the cause and action are known. However, when this trigger is unknown, implementation is much more difficult or may be unviable.

RASs serve an important purpose in the NEM, but are not the only solution for non-credible contingency events. In general, RASs allow infrastructure to be better utilised by removing the need for further network augmentation. However, it is important to recognise the risks associated with their implementation and the implications they may have on network resilience. As discussed in the 2025 GPSRR[61], there is ongoing work within AEMO to expand on the RAS guidelines to develop specific requirements related to the implementation of RASs. This intends to ensure appropriate implementation of RASs and reduce the risks of interaction or inadvertent operation.

3.3 Resilience is expected to change throughout the energy transition

Future system studies were conducted to understand how the changing power system may impact power system resilience. These studies consider the impacts that new augmentations, generation, storage, dispatch conditions and the retirement of synchronous generation will have on the resilience of the system. Cases were set up to consider up to 2030 to observe how system resilience changes over time. It was observed that power system resilience will be influenced by many factors, with some providing improvements and others requiring further consideration to address.

3.3.1 New generation, battery energy storage systems and augmentations provide resilience benefits

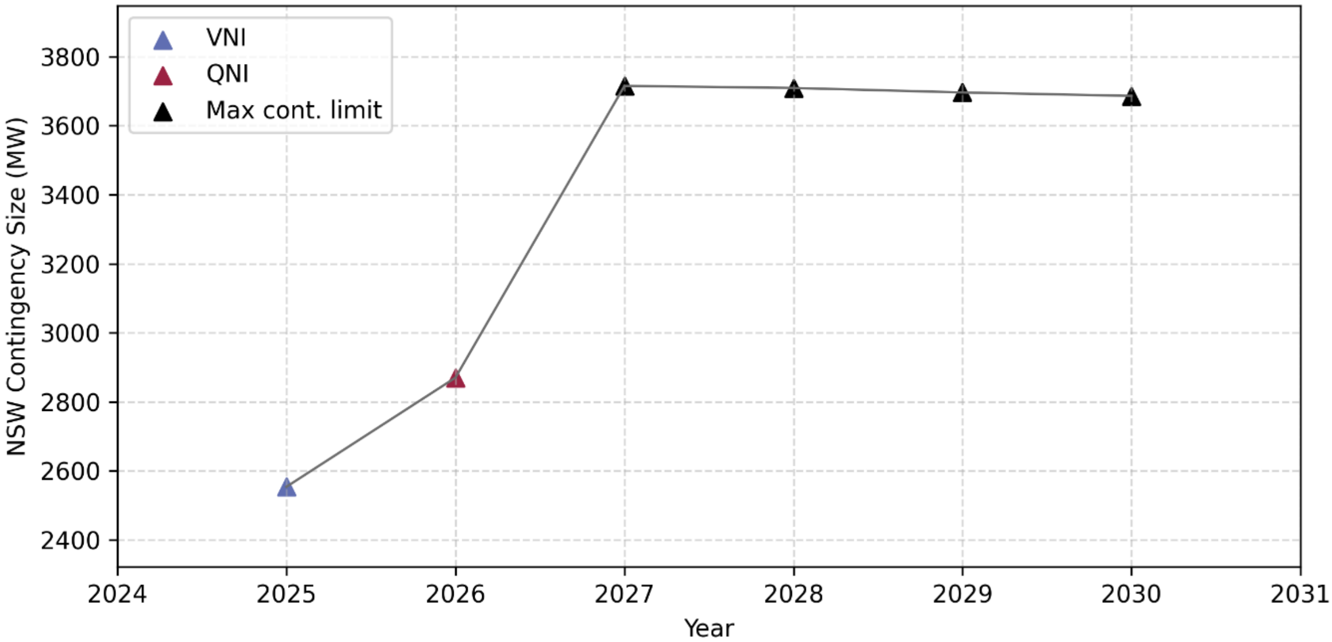
It was observed that a number of system changes provided positive impacts on the resilience of the future power system. In particular, it was observed that the addition of BESS and new generation provides FFR that assists in addressing large

[61] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

generation contingencies, reducing the stress on the system. Local response within regions also reduces the need to rely on interconnectors which improves interconnector stability for these large events. It was also observed that the addition of key network augmentations played a large role in supporting resilience in regions nearby.

Transmission augmentations provide system resilience benefits. Future study results indicate that the additional augmentations in future years – such as PEC Stage 2 and HumeLink – result in an increased capability to withstand large contingency events. These augmentations facilitate the transfer of power and support voltages during high stress events. This was demonstrated for illustrative future studies assessing VNI stability, where resilience was significantly improved for years from 2027 onwards. This trend is demonstrated in **Figure 19** for a particular dispatch with medium flows on VNI and medium flows on QNI. The initial contingency size that resulted in VNI instability in 2025 was around 2,500 MW, but this is seen to increase as augmentations and additional BESS are added to the system. In 2026, VNI is no longer seen as the first mode of instability, as QNI goes unstable for a contingency size above 2,800 MW. The strengthening of the network through the addition of PEC Stage 2, the Ararat synchronous condenser, and new BESS and generation projects supports higher transfers on VNI without resulting in instability. These benefits do not extend to QNI in the 2026 case, despite QNI having approximately 800 MW of headroom, demonstrating that instability may still be seen for very large contingency sizes.

Figure 19 New South Wales generation contingency size relationship with instability (MW)



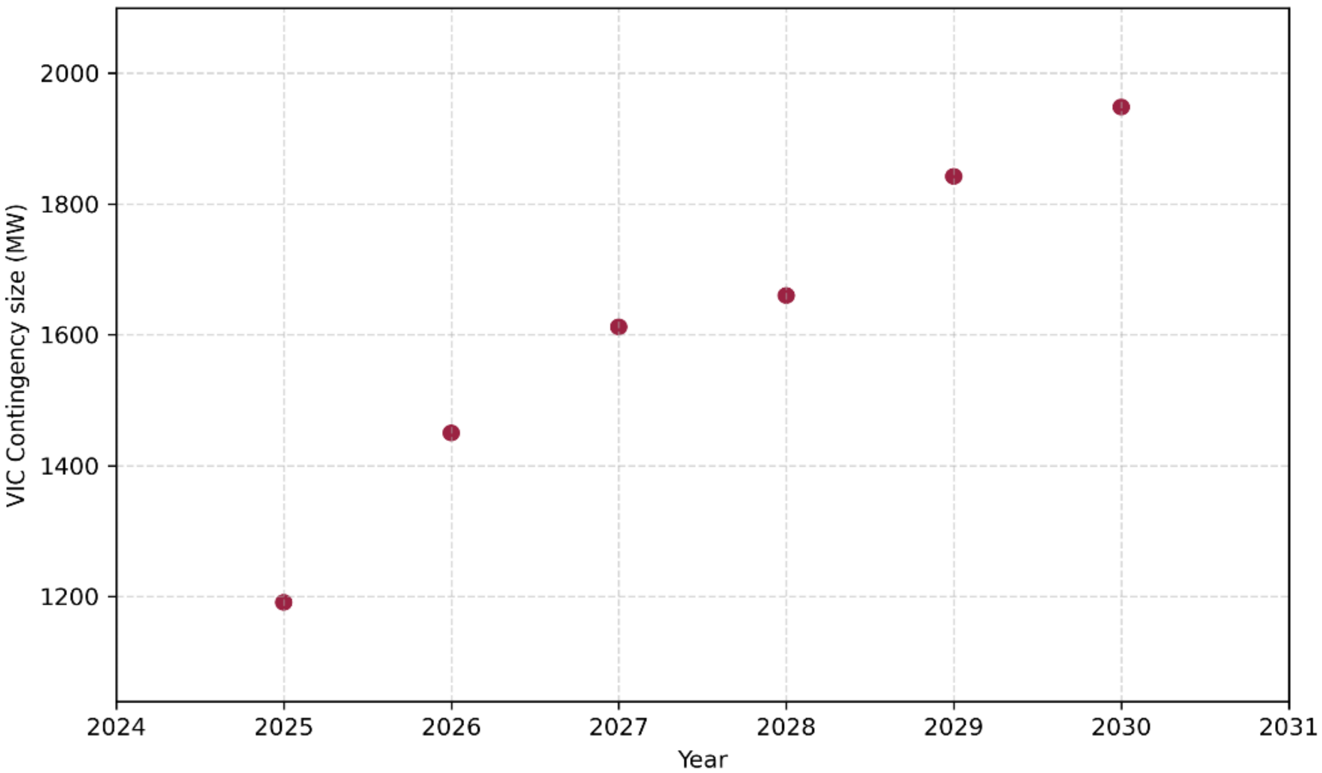
System resilience is expected to be strong in the future network when not operating close to limits. From 2027, the system resilience improves significantly, where studies were completed with contingency sizes above 3,600 MW without seeing system instability. With interconnectors away from their limits and the addition of augmentations and new BESS and generation, the ability of the system to withstand very large contingency events increases markedly. Contingency sizes above 3,000 MW are even less likely to occur and begin to reach the point where the system is achieving very high levels of resilience.

3.3.2 QNI instability risks require continued monitoring

QNI instability risks at high flows improve but may still occur for large non-credible contingency sizes. Future cases were developed to assess QNI instability when operating at high flows with additional augmentations and future BESS and generation. The results indicated that the capability of the system to withstand large contingency sizes increased gradually over the years studied, but there were no significant increases related to specific augmentations coming into the system. QNI Connect would be expected to increase the resilience of the system for instability over QNI, but this is not expected until 2033[62] or later. QNI Connect is still in the early planning stages and there is still uncertainty on whether it will proceed.

BESS and generation provide moderate improvement to QNI instability risks. The main improvements arise from the additional BESS and generation being added into the system, providing capability to provide fast active power response locally and reducing the need for inter-regional responses that will result in interconnector flow increases. **Figure 20** shows the trends in contingency size required to result in instability when QNI is operating at maximum flows. It can be seen that in 2025 and 2026, contingency sizes less than 1,500 MW could result in instability over QNI, but this gradually increases to just under 2,000 MW by 2030. This indicates that there is some improvement to this stability risk as time progresses, but if the system is exposed to contingency sizes larger than 2 GW, then the risk will still remain.

Figure 20 Victorian generation contingency size resulting in QNI instability when operating at maximum QNI flows (MW)



Risks related to QNI instability may increase if it is expected to operate close to its limits for longer durations. This risk may also increase if QNI is observed to operate at higher flows for longer periods of time. The data from AEMO's *October*

[62] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

2025 Update to the 2025 Electricity Statement of Opportunities was used to get an approximate understanding of the percentage of time that these interconnectors may be operating at their limits into the future. For QNI import and export in the year 2030, it is forecast that:

- QNI equals or exceeds 830 MW import 5% of the time, and
- QNI equals or exceeds:
  - 1,000 MW export 15% of the time,
  - 1,200 MW export 6% of the time, and
  - 1,350 MW export 1% of the time.

These forecasts predict that high flows southwards on QNI will not be a frequent occurrence, exceeding 1,350 MW for 1% of the time or less. However, there may still be risks for significantly large contingencies when flows exceed 1,000 MW. For risks such as this that are only present for short periods of time, the consideration of protected events may not have significant market impacts but could provide additional resilience through measures such as limiting interconnector flows, procuring more FCAS or limiting specific non-credible generation contingency sizes. Further monitoring will be required to understand the interconnector flows that are seen in practice to determine the risk exposure.

3.3.3 Heywood and Project EnergyConnect Stage 2 stability

Interconnector stability for South Australia is significantly improved with the addition of PEC Stage 2 due to significant increases in interconnector transfer capability. Interconnector stability was seen to improve significantly with the addition of PEC Stage 2 when considering similar flows into South Australia. For certain dispatch conditions where flows into South Australia were 640 MW, it was shown that non-credible continencies within South Australia of 1,290 MW did not result in instability over the interconnectors. The additional benefits provided by the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) were not modelled, which would add further system resilience to withstand larger contingency sizes.

Operating closer to the limits increases the risk, but the SAIT RAS already provides a measure to mitigate non-credible contingency risks. However, the additional interconnector capacity provided by PEC Stage 2 will be used and as the system operates closer to its limits, the possibility of non-credible contingency events impacting stability increases. An additional case was developed to assess stability when South Australia's interconnectors are operating at high combined import power flows over Heywood and PEC. In one dispatch where combined interconnector flows reached 1,250 MW, it was found that marginally stable undamped oscillations were observed for an initial contingency size of 954 MW. This further highlights the general trend of reduced resilience when operating close to the interconnector limits as would be expected. However, South Australia already has the SAIT RAS to mitigate the risks of non-credible contingencies, which was not included in the studies. Provided that this operates as required, South Australia's interconnectors will be even more resilient to large generation contingencies.

3.3.4 Non-credible loss of high capacity lines will need continued consideration

The addition of high capacity augmentations improves resilience when in service, but their non-credible loss at high flows introduces new potential risks. While new augmentations improve resilience generally for large non-credible contingencies, it introduces a trade-off that the non-credible loss of these new augmentations must be managed. The loss of these new augmentations may result in instability or significant generation disconnection when operating at high flows. The non-credible loss of new network augmentations is assessed under the planning process via NER S5.1.8 and where required, managing these types of non-credible contingency events is typically addressed using RASs to mitigate. However, for transmission lines with high flows, RASs may require complex designs or the tripping of very large quantities of generation and load in short timeframes.

RASs may only be suitable for certain applications to manage non-credible loss of high capacity transmission lines. An example of non-credible contingency events that require complicated remedial actions schemes and the tripping of large quantities of generation was demonstrated in South-West Victoria (discussed in Section 3.2.2). This illustrates that while the RASs are essential to ensure PEC and wider NEM stability under these conditions, their presence complicates network operations and may introduce further risks. The suitability of RASs to manage large generation contingencies will be considered in the current work underway investigating the expansion of the RAS guidelines.

Other high capacity lines outside of south-west Victoria will need consideration as they are introduced into the system and operated at higher flows. Outside of south-west Victoria, the non-credible loss of other major transmission augmentations will also need consideration. The non-credible loss of other high capacity lines is being assessed through typical planning processes which may identify a requirement for a RAS to mitigate non-credible contingency risks. If a RAS is not determined to be suitable, protected events could be considered for short term operating conditions.

3.4 Increased resilience can be supported through a number of actions

Maintaining power system resilience can be supported by a combination of approaches. Typically, non-credible contingencies are managed via three approaches:

- **Protected events** allow AEMO to treat a non-credible contingency event as credible and take actions such as implementing constraints and procuring FCAS. Protected events also allow for the creation of new or amended EFCS. Note that the indistinct events framework[63] can also be used to reclassify non-credible contingency events, but only for increased likelihood due to abnormal conditions.
- **RASs** typically will trip load or generation in fast timeframes to rebalance the system in the event that a non-credible contingency occurs. These may also be implemented under the protected event framework.
- **Managing the risk through EFCSs and inherent system resilience** – for low likelihood or low consequence non-credible contingency events, EFCS such as UFLS or OFGS are implemented as a mechanism that will provide a method of arresting cascading failures. The use of these schemes, in addition to relying on the inherent resilience of the system, is relied on to manage these non-credible contingencies in the unlikely event that they occur.

There is scope to improve the use of all three of these approaches in managing power system resilience into the future. This will be discussed in the sections below.

3.4.1 Protected events

Protected events can be recommended under the GPSRR where a non-credible contingency event is expected to result in an unacceptable likelihood or consequence of cascading failure or major supply disruptions. There has only been one

[63] See https://www.aemc.gov.au/sites/default/files/2022-03/Indistinct%20Events%20Information%20Sheet.pdf.

protected event previously, which was the South Australian protected event[64]. This protected event was invoked to manage destructive winds in South Australia that could result in loss of multiple transmission elements causing generation disconnection. It achieved this by constraining flows on HIC in the event of destructive winds in South Australia. This protected event was based primarily on likelihood factors, where large contingency sizes may be more likely to occur in the presence of destructive winds. Some other factors that could be considered for future protected events are discussed in the sections below.

Maintaining headroom on interconnectors under high risk conditions

Additional headroom on interconnectors provides additional resilience for extreme events. This was demonstrated in the non-credible contingency studies undertaken in the 2026 GPSRR and also aligns with the approach taken for the South Australian protected event. Maintaining additional headroom on interconnectors will increase the resilience of the system and could be an appropriate mitigation measure for operating conditions of increased risk.

A protected event could be used to reduce flows on interconnectors under high consequence or high likelihood conditions. There are two potential approaches that a protected event could use to address non-credible contingency risk:

- The first is as per the South Australian protected event, where interconnector flows were constrained when there is an expected increase in the likelihood of non-credible contingency events occurring.
- The second approach is to use a protected event when there is more generation at risk for a potential non-credible contingency. This could mean constraining interconnector flows if a concentrated area of the network is connected via a double circuit line and operating at 2 GW or above, as one example.

Protected events could also consider both factors. A protected event could also be considered that takes both likelihood and consequence into account. For example, if there are destructive winds in a region and there is a large quantity of generation at risk for a known non-credible contingency, this could be identified as a protected event and mitigation actions could be taken. With more qualifying conditions, this would make the implementation of a protected event more economical as it would only bind under high risk conditions. However, this would increase the complexity and would only be possible to implement if conditions can be accurately forecast ahead of time.

Increased contingency frequency control ancillary services

Procuring more FCAS is another approach that will support resilience without constraining transfers. Additional FCAS within a region, or more globally, could be used to support power system resilience when it is identified that a non-credible contingency is more likely to result in cascading failure. Additional regional FFR from BESS or other plant will reduce the support provided from other regions and lessen power swings over the interconnectors. Due to this, it may not be required to constrain interconnectors if additional levels of FCAS are shown to reduce the risk sufficiently.

FCAS may be a more economical way to manage non-credible contingency events as a first measure. The addition of new BESS in the NEM is providing low cost FCAS supply. This indicates that procuring additional FCAS may not add significant additional costs as even more BESS are added to the system, particularly if it is only procured during periods of increased risk for non-credible contingencies. Additional FCAS could be procured within a region if it is identified that a non-credible contingency could be present that may cause instability in another region. For example, if south-west Victoria is operating

[64] See https://www.aemc.gov.au/sites/default/files/2019-06/Information%20Sheet%20-%20final%20determination%20-%20REL0069.pdf.

with a non-credible contingency of over 2 GW, it may be required to procure additional FCAS in New South Wales or Victoria to prevent QNI from going unstable.

Additional FCAS is a simpler approach than complex RASs. The other benefit that procuring additional FCAS brings is that it is simpler to implement to mitigate for large non-credible contingencies, particularly if there are multiple non-credible contingency events that could result in severe consequences. With additional FCAS, the system will naturally provide a response when the frequency drops, resulting in an automated method of restoring the frequency without the need for the design of complicated RASs that rely on fast operation of load or generation tripping. Additional FCAS will also provide additional system resilience benefits for any other contingency that may occur.

Limiting non-credible contingency sizes

Non-credible contingency sizes could be limited by constraining generation output. Another measure that could be considered is limiting the non-credible contingency size through redispatch. If loss of a major generation centre or a critical transmission line may result in severe consequences, it would be possible to limit the output of generation to levels such that the non-credible contingency event could be withstood if it were to occur. This could involve limiting non-credible generation losses for pre-identified events to within levels that the system would be capable of withstanding if the event were to occur. These limits would only be imposed if high risk system conditions were identified, such as high flows on interconnectors and the presence of large non-credible contingency sizes that may result in significant consequences.

Limiting non-credible contingency sizes could consider a number of potential events. There could be a number of non-credible contingencies where a common asset failure could result in large generation contingencies resulting in cascading failure or major supply disruptions. If there is available generation at similar cost elsewhere, it may make sense to limit the output of certain generators to limit non-credible contingency sizes associated with common assets. Additional diversity will inherently increase power system resilience. Some potential constraints that could be considered include:

- the quantity of generation connected to double circuit lines,
- the quantity of generation controlled by a single power plant controller (PPC),
- generation that may be disconnected through a circuit breaker failure (CBF) event,
- generation that may trip as a result of a RAS,
- generation that may trip as a result of a busbar fault, and
- generation that may trip as a result of a three phase fault, including DPV shake-off.

Co-optimised approach to managing non-credible contingencies

A co-optimised approach could be considered, using the NEM Dispatch Engine (NEMDE) and protected events. A co-optimised approach could be taken by integrating non-credible contingency constraints into NEMDE, allowing for the least cost dispatch while also ensuring appropriate levels of FCAS, interconnector flows, or generation outputs for power system resilience. To implement these constraints, the non-credible contingency events would have to be identified under the protected event framework as significant events that could result in cascading failure or major supply disruptions. A constraint could be developed that includes interconnector flows, power outputs of identified generators, and the amount of FCAS in a region, to determine the lowest cost dispatch. This could also be enabled only when interconnector flows and generation output exceed certain values to ensure it is not binding unnecessarily.

3.4.2 Remedial action schemes

RASs may be an appropriate mitigation measure for non-credible contingencies under certain circumstances. RASs are appropriate to implement provided that the scheme is simple to design, maintain and operate and that it does not introduce unacceptable interaction or maloperation risks. In instances such as this, where the implementation is not overly complex, the least cost and most reliable option may be the implementation of a RAS.

Known risks that are present for long periods of time may require RASs over other solutions. RASs may be best suited for scenarios where a known contingency is being mitigated, and where it would be uneconomical to implement infrastructure-based solutions or take market actions that may impose additional costs for large periods of time. A known contingency may be easier to design a scheme for, particularly if the scheme can be topology based. This will simplify the design and operating times of the scheme. Additionally, if the risk is present for large periods of the year, constraining flows or generation output may come at an excessive cost to the system. To prevent excessive reductions in transfer capacity for long periods of time, or significant procurement of FCAS throughout the year, it may be more cost-effective to develop a scheme that can be active at all times.

Implementation of schemes should consider the uplift work highlighted in the 2025 GPSRR to minimise additional risk. However, as mentioned in the 2025 GPSRR, the development of schemes is dependent on ensuring they do not introduce unacceptable maloperation or interaction risk. There is a project underway at AEMO intending to uplift RAS design, operation, maintenance and testing in the NEM and improve system resilience regarding the application of RASs as a solution.

3.4.3 Managing the risk through emergency frequency control schemes and inherent system resilience

While protected events and RASs are typically implemented to mitigate scenarios where non-credible contingencies may have an increased consequence, events that do not meet this classification criteria are typically captured through reliance on UFLS or OFGS. It is not possible to protect against every non-credible contingency event and at some point there must be a delineation between events that have active mitigation and those where the risk is accepted. However, while not all events can be addressed individually, there are some actions that can be taken to further improve general resilience in the power system to improve the likelihood of withstanding unexpected non-credible contingencies.

Increased BESS distributed evenly across regions with appropriate settings

Additional BESS adds system resilience for large generation contingency events. As shown in the future studies in Section 3.3.1, the addition of new BESS improves system resilience generally. As more BESS connect to the system, the FFR provided will offset the large generation contingency sizes experienced. This will naturally increase resilience to these types of contingency events.

Even distribution of BESS is required to prevent risks of concentrated fast active power response resulting in instability. As shown in studies conducted in the 2025 GPSRR, it must be noted that an appropriate distribution of BESS across regions will be required to reduce the likelihood of a concentrated response resulting in interconnector instability. Provided that BESS are adequately balanced between regions, they appear to bring a net positive to power system resilience.

Additional voltage support close to interconnectors

Additional voltage support can improve resilience. In studies assessing instability over QNI, it was found that voltages on the interconnectors contribute significantly to the active power transfer levels that can be maintained during a disturbance. It was found that raising voltages on QNI by 5% at high flows could result in an increased ability to withstand large generation contingency sizes. An increase of approximately 300 MW in contingency size that could be withstood was observed for cases at maximum QNI flows.

Operation of reactive plant could be changed to improve resilience for certain contingencies. Similarly, it was found that reactive power support near the interconnectors also contributed strongly to interconnector stability. When studying QNI stability, the operating points of the Armidale, Tamworth and Dumaresq static var compensators (SVCs) were important to provide reactive power in the event of increased active power flow over the interconnector. These are typically operated at approximately 0 megavolt amperes reactive (MVAr) when operating at high flows to maintain sufficient dynamic reactive power headroom in either direction. However, it is possible to switch in static reactive plant nearby, such as capacitor banks, so the SVCs are absorbing reactive power. This could be considered via an automatic scheme that switches capacitor banks or reactors for non-credible increases in active power over the interconnector.

Review of appropriate UFLS or OFGS settings

Ongoing measures to improve operation of UFLS and OFGS will continue. To support system resilience, it is also important that mechanisms such as UFLS or OFGS have appropriate settings and are still fit for purpose in a changing power system. As detailed in Section 6, there are a number of current and future OFGS and UFLS projects underway to improve the ability to arrest frequency when it significantly exceeds the normal operating band.

3.5 Recommendations

Assessment on the most appropriate measures to manage risks related to non-credible contingencies will continue. While the implementation of RASs, UFLS and OFGS are used to mitigate the majority of non-credible contingency risks in the NEM, there may be an emerging need for protected events to manage high impact, low probability events in the NEM where these existing measures may not be appropriate. This emerging need relates to events such as QNI instability, where a large non-credible contingency occurring anywhere south of Queensland can result in instability. It is difficult to implement a RAS to reduce this risk due to the large number of potential contingency events that could cause this. Relying on UFLS may also be insufficient to maintain system stability due to the size of the generation contingency and the expected timeframe in which instability may occur.

Protected events may be a preferable solution. Events that can result in cascading failure could be declared as protected events and constraints could then be implemented to mitigate the risk. With appropriate design, these constraints for non-credible contingencies should only impact the market when the specific risk conditions are present. If these conditions are present, the constraint could consider the procurement of regional FCAS, constraining generator outputs or constraining flows on interconnectors to reduce the risk. NEMDE will then choose the most cost-effective method to reduce the risk.

This process would be repeatable for any number of non-credible contingency events that have been demonstrated via studies to be likely to result in cascading failures or major supply disruptions. This approach is well suited to "tail risk" type events, where the consequence may be significant but the risk conditions are only present at certain times. For risks where the risk conditions are only present for a small percentage of the year, the constraint will not bind often, resulting in a reduced impact to costs, but improved resilience if the event were to occur.

Recommendation 4

AEMO has demonstrated the emerging risks related to large non-credible generation and network contingency events. Operating conditions will change materially with new augmentations and generation retirements, influencing risk outcomes.

Actions:

AEMO will continue to monitor conditions that may present an increased likelihood or consequence of cascading failure or major supply disruptions. If the duration of these conditions is observed to be increasing beyond tolerable limits, **AEMO** will consider the appropriate implementation of protected events or identify the need for RASs through the GPSRR to support power system resilience.

TNSPs to continue to support the assessment of power system resilience for large non-credible contingency events, particularly supporting the consideration of protected events, RASs, EFCS or identifying the need for reclassification.

4 Voltage control risks

This section covers the following key points:

- An example of cascading failure and major supply disruptions occurred in the Iberian Peninsula. This incident was reviewed as part of the GPSRR to identify key learnings relevant for the NEM.
- Through the review of the incident and via consultation with NSPs, it was determined that a number of measures reduce the likelihood of cascading failures related to overvoltages in the NEM. However, there may still be risks related to non-credible contingency events for short periods when the system is operating close to its limits.
- Oscillations also played a major contributing factor to the Iberian Peninsula incident. Further assessment of oscillations in the NEM will continue to address this emerging risk.

On 28 April 2025, the Iberian Peninsula experienced a widespread blackout following a rapid and uncontrolled rise in system voltage and the subsequent loss of effective voltage control. While the NEM is generally more resilient for voltage control risks, there may still be risks present in certain infrequent operating conditions and the Iberian Peninsula offers key learnings for the treatment of voltage control risk in Australia.

The Iberian Peninsula event occurred under conditions of multiple coincident system stresses such as low system demand, high IBR dispatch operating using power factor control, and the presence of pre-incident oscillations. As voltages began to rise, generators began tripping on overvoltage protection settings, leading to further generator output disconnections and the eventual cascading loss of supply across the Iberian Peninsula.

The NEM already has a number of requirements and procedures in place to reduce the likelihood of a similar incident to this occurring. However, it was determined through the GPSRR consultation process that the NEM would benefit from a review of potential scenarios or risks that could result in similar outcomes. This approach of applying lessons learned from events internationally will support the continued resilience of the NEM so proactive mitigation measures can be identified and implemented if required.

The European Network of Transmission System Operators for Electricity (ENTSO-E) published the expert panel's final report on the Iberian Peninsula blackout, *Grid Incident in Spain and Portugal on 28 April 2025*[65], on 20 March 2026. This report outlines the root causes that were determined to contribute to the cascading failure of the Iberian Peninsula and makes key recommendations that should be implemented to prevent similar events from occurring in the future.

The incident demonstrated a potential mode of cascading failure resulting from a lack of voltage control, and the consequences that can arise. It is difficult to arrest a cascading event linked to uncontrolled voltage rise, as the operation of UFLS may result in a system with increased voltages due to lightly loaded transmission lines. The difficulty of interrupting the cascading event once it begins highlights the importance of having sufficient dynamic reactive power margins and operational procedures and requirements in place to reduce the risk of it occurring.

The following sections contain:

[65] See https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/2025/iberian-blackout/Final%20Report%20on%20the%20Grid%20Incident%20in%20Spain%20and%20Portugal%20on%2028%20April%202025.pdf.

- **A summary of the root causes identified in the Iberian Peninsula incident** – these have been broadly grouped into key themes to discuss in relevance to the NEM.
- **Discussion of the modes of failure in the Iberian Peninsula with identification of factors that may support resilience in the NEM** – while the NEM is more resilient for voltage control risks due to a number of factors, there may still be risks present in certain infrequent operating conditions. Other contributing factors such as power system oscillations or the operation of UFLS during overvoltage events may present potential learnings for the NEM.
- **Review of potential risks in the NEM that may need further assessment to improve power system resilience** – this discusses potential risks in the NEM that are relevant to those experienced in the Iberian Peninsula, highlighting areas for continued investigation.

4.1 Root causes identified in the Iberian Peninsula incident

The *Grid Incident in Spain and Portugal on 28 April 2025* report identified a number of root causes that contributed to the cascading failure of the system. While not all of the root causes are relevant for the NEM, a subset of these have been summarised and categorised into key themes that will be discussed as outlined below.

- **Insufficient dynamic reactive power** – a lack of dynamic reactive power support was a significant factor that contributed to the voltage control challenges experienced in the Iberian Peninsula. This included:
  - insufficient dynamic reactive power output from synchronous generation during the incident,
  - lack of regulation or penalties for synchronous generation that did not provide sufficient dynamic reactive power,
  - renewable plants not providing dynamic reactive power support due to operation in power factor control mode,
  - design of voltage control of local generation networks not aligned with system needs,
  - no limitation on ramping for generators with fixed power factor, and
  - manual operation of shunt reactors, requiring decision-making and processing time.
- **Overvoltage protection settings were set too close to normal band of operation** – low operating margin between normal operational conditions and protections setting thresholds increased exposure to contingency events resulting in plant disconnection. Contributing factors were:
  - overvoltage disconnection protection settings may not have been aligned with system needs, and
  - the Spanish 400 kV grid is operated at a wider voltage range than in other European Union countries.
- **Oscillatory behaviour** – the presence of oscillations in the network required operational actions that contributed to increasing voltages. Oscillatory impacts included:
  - two oscillatory episodes occurred in Iberian Peninsula incident, the first a forced oscillation of 0.63 Hz, and the second an inter-area oscillation of 0.2Hz, and
  - disconnection of DPV due to oscillations triggering inverter protection.

- **EFCS** – UFLS delayed the collapse of the system but was ultimately unable to interrupt the cascade of overvoltage disconnections and prevent the total collapse of the Spanish and Portuguese power systems. The disconnection of loads absorbing reactive power increased the overvoltages.

The following sections will review factors that contributed to the Iberian Peninsula with reference to conditions in the NEM. The NEM has a number of mitigation measures already implemented that reduce the exposure to the cascading failures seen in the Iberian Peninsula. However, it will be beneficial to investigate the potential for increased risk under certain circumstances or operating conditions.

4.2 Discussion of risks in the Iberian Peninsula and the NEM

International power system events provide insights into how cascading impacts can develop when the system is operating close to key voltage and reactive power limits. While conditions and system characteristics differ between jurisdictions, the NEM has several design and operational factors that support resilience to events such as those seen in the Iberian Peninsula. This section discusses root causes identified in the Iberian Peninsula and the factors in the NEM that may contribute to a reduced vulnerability to widespread voltage instability and cascading failures. Other aspects that may require further investigation to understand the risks present in the NEM will also be considered.

4.2.1 Reactive power support and voltage control

One of the major contributors to the Iberian Peninsula incident was a lack of available dynamic reactive support. When the system was operating close to its limits, this lack of dynamic reactive support meant that significant changes in reactive power required by the system could not be easily met and pushed the system beyond the limit of satisfactory operation. While this was an issue in the Iberian Peninsula, the NEM already has greater reserves of dynamic reactive power capability, which reduces the likelihood of being exposed to this risk when this reactive support is available.

Voltage control mode

Renewable energy sources in the Iberian Peninsula were not required to provide dynamic reactive support. In the Iberian Peninsula, renewable energy sources operated in power factor control mode, meaning each generator only provides a fixed quantity of reactive power that is proportional to the active power it is producing. This means there was no requirement for generators to absorb or supply additional reactive power in the event of a disturbance or change in voltages in the system. In the Iberian Peninsula, this mode of operation was noted to exacerbate the issues further. For generators that were already absorbing reactive power to keep voltages down, as any reduction in their active power resulted in a proportional reduction in reactive power to maintain the same power factor. This resulted in further impacts to the voltage whenever active power changed.

Generators in the NEM typically operate under voltage droop control mode rather than power factor control mode. The majority of generators in the NEM operate in voltage droop control mode, which supports voltage operation at specified set points. If voltages deviate from the setpoint, all reactive plant in the area operating in voltage droop control mode will proportionally change their reactive power consumption to bring the voltage back to the setpoint. This is a system-focused approach that prioritises maintaining the specified voltages in the system rather than prioritising a set ratio of active power to reactive power for each individual plant. One of the recommendations made in the *Grid Incident in Spain and Portugal on*

28 April 2025 report was to prioritise voltage control mode over fixed power factor operation. This is already the accepted practice for most generators in the NEM.

Switching of reactive plant

Reactors in the Iberian Peninsula were switched manually. Reactors were manually switched out prior to the event due to low voltages seen during oscillations. Due to the manual nature of switching, the reactors did not automatically switch back in when voltages were high. This increased the operational difficulty in maintaining voltages during an incident that required multiple operator actions. The additional responsibility for operators to monitor and operate manual switching of reactive plant in a timely manner was not possible during a cascading voltage event.

Volt ampere reactive (VAr) dispatch scheduler (VDS) operates in the NEM to automatically send reactive power targets to reactive plant. AEMO manages transmission network voltages in the NEM using the VDS, an automated system that determines the dispatch of reactive power devices to meet voltage setpoints. The VDS uses inputs such as reactive device availability, voltage limits, desired voltage profiles, and voltage violations identified through AEMO's real-time contingency analysis to determine the appropriate reactive dispatch. The VDS then automatically publishes the reactive dispatch to TNSPs, generators or integrated resource providers, allowing coordinated changes to reactive plant. AEMO operational staff monitor and verify the issued instructions and coordinate with network operators where adjustments are required, providing a structured approach to voltage control that reduces reliance on manual interventions. Some TNSPs in the NEM have also implemented emergency voltage response schemes that will automatically switch reactive plant on set voltage thresholds.

4.2.2 Overvoltage protection setting risks

Generator connection agreements

Generators in the Iberian Peninsula had varied requirements based on date of connection. As identified in the *Grid Incident in Spain and Portugal on 28 April 2025* report, generators had different overvoltage ride-through requirements based on the date of their connection to the grid. Connections prior to 2019 had more lenient requirements that permitted disconnection for voltages greater than 435 kV. Newer connections had stricter requirements as per Order TED/749/2020, which requires generators in Spain to withstand 440 kV for at least 60 minutes without disconnection, and up to 480 kV on a transient basis[66]. The number of older connections presented risks of disconnecting, with potential to result in increasing voltages to ranges that may begin to impact generators with more strict requirements.

Non-compliance of generators with ride-through requirements

Generators in the Iberian Peninsula disconnected below their required withstand thresholds. The final *Grid Incident in Spain and Portugal on 28 April 2025* report (Table 3-3) lists generation that disconnected up until 12:33:19 in the Iberian Peninsula. Of the 19 generation disconnections in the table, only four are listed as confirmed to align with their required withstand thresholds. Nine generators were confirmed to have tripped below their thresholds, while the remaining six were

[66] See https://d1n1o4zeyfu21r.cloudfront.net/WEB_Incident_%2028A_SpanishPeninsularElectricalSystem_18june25.pdf.

unknown or could not be determined based on the information available. This indicates that non-compliance with ride-through requirements was a major contributing factor to the early portion of the incident.

Operational voltage margin

Operational voltages in Spain were permitted to reach 435 kV (1.088 p.u), leaving minimal margin between operating conditions and potential overvoltage protection settings for older generators. Older generators were only required to withstand voltages up to 435 kV, which was at the limit of the normal operating band. While this requirement was not intended to imply that generators should disconnect at 435.01 kV, it was observed that some plants disconnected close to 435 kV or below. This did not leave sufficient operating margin for error in a system that was already lacking in dynamic reactive reserves.

Non-compliances or grandfathered connections in the NEM

In the NEM, generators are expected to ride through overvoltages as per the requirements in NER S5.2.5.4. The risk that the NEM is exposed to in this regard is related to the connection agreements for generators in each region, and the percentage of generators that align with the latest minimum or automatic access standards.

In the NEM, the minimum access standards require that generators ride through:

- 1.15 p.u. to 1.2 p.u. for at least 0.1 seconds (s), and
- 1.1 p.u. to 1.15 p.u. for at least 0.9 s.

The automatic access standard for generators in the NEM specifies ride-through requirements of:

- over 1.3 p.u. for at least 0.02 s,
- 1.25 p.u. to 1.3 p.u. for at least 0.2 s,
- 1.2 p.u. to 1.25 p.u. for at least 2 s,
- 1.15 p.u. to 1.2 p.u. for at least 20 s, and
- 1.10 p.u. to 1.15 p.u. for at least 20 minutes.

There are instances of grandfathered connections and non-compliances in the NEM. While it is expected that generators should be compliant with the requirements above as per their specific connection agreements, it is difficult to determine the extent of unknown non-compliances or the exact capability of generation connected under grandfathered connection agreements. As detailed in Section 5.7, there are also growing instances of non-compliances in the NEM, which have been observed as the total number of plant connected to the system increases. The majority of these are identified and resolved through the connections assessment and commissioning process, but others can arise through commercial operations due to a range of different factors. As non-compliances increase, the aggregate impact of these non-compliances may interact in unexpected ways. There is also the potential for generators that have grandfathered connection requirements as the NER evolve over time. However, the commissioning process in the NEM does verify protection settings, with signal injection test reports that consist of voltage and frequency trip thresholds and associated time delays to confirm their compliance with the access standards.

Operating margins in the NEM may be sufficient, provided that a non-credible contingency does not take the system from secure to a material overvoltage scenario. Understanding the risk posed to the NEM will require further assessments determining if there are any operating conditions or contingency events that could take the system from a secure operating state to an overvoltage that breaches any of the thresholds above. If a multiple contingency event occurred that breaches the automatic access requirements, this could result in disconnection of generators that see the voltage increase. However, a contingency event that only breaches the minimum access standards may only affect a subset of generators. Advice from TNSPs in the 2026 GPSRR process indicated that voltage disturbances that exceed the automatic access standard requirements could result in multiple disconnections, as settings were not actively coordinated outside of the NER requirements. However, it is unlikely for events such as this to occur. A non-credible contingency event that resulted in the disconnection of over 500 MW of load in Tasmania[67] only resulted in a voltage increase up to 1.14 p.u. for a brief period of time. To reach voltages that exceed the automatic access standards would likely require a significant event to occur.

4.2.3 Oscillatory behaviour

In the Iberian Peninsula, it was found that converter-driven instability interacted with other generators. It is suspected that an inverter-based generator induced a forced oscillation into the Iberian power system which impacted other generators online. This presented risk to the system due to the potential for frequency and voltage to fluctuate significantly. Due to the oscillations being converter-driven, the typical actions taken to reduce the impact of inter-area modes were not as effective. This includes changing the control mode of an HVDC link, reducing interconnector flows, and switching in additional lines.

Forced oscillations require targeted mitigation measures. The typical measures for managing oscillations in the Iberian Peninsula only had a minor impact on forced oscillations that were present. The *Grid Incident in Spain and Portugal on 28 April 2025* report identified that forced oscillations require targeted mitigation measures such as activating or deactivating controls, changing unit setpoints, or disconnecting the sources of forced oscillations. It was recommended that oscillation monitoring and detection should be improved in the system to manage forced oscillations.

DPV was observed to disconnect as a result of oscillations. Based on the analysis in the *Grid Incident in Spain and Portugal on 28 April 2025* report, a significant quantity of DPV units disconnected during the incident. These units were observed to disconnect both during times of high voltage ramps and during periods of oscillations. This impacted the load flow in the transmission network and affected voltages. The NEM has high penetration of DPV, and high voltages or oscillations could potentially result in similar disconnections.

Inter-area oscillations were mitigated by operational actions but resulted in increased voltages. There were also inter-area oscillations present in the system due to a lack of damping. These oscillations had potential to impact the operation of power system plant due to fluctuations in voltage and frequency. Operational measures were taken such as changing the control mode of an HVDC link, reducing interconnector flows, and switching in additional lines. This effectively mitigated the oscillations, but had the secondary impact of increasing system voltages and contributed to system conditions that resulted in cascading failure.

Several methods of recommended damping of inter-area oscillations were identified. The *Grid Incident in Spain and Portugal on 28 April 2025* report identified several methods that could be used to reduce the likelihood of future inter-area oscillations without the need to take operational actions that could have secondary impacts. Suggested actions include the installation and tuning of power system stabilisers (PSSs), installation of additional synchronous condensers, and the use of

[67] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/final-report--three-phase-fault-at-sheffield-and-trip-of-load-in-tasmania-on-12-april-2024.pdf?

STATCOMs or voltage source converters with power oscillation dampers. These are all relevant considerations for the NEM as retirement of coal generation proceeds and the damping in the system has potential to change significantly.

The evolution of oscillation management in the NEM should consider these learnings. The NEM is undergoing significant changes with the retirement of synchronous generation, installation of new synchronous condensers, and the uncertain impact that IBR may have on small signal stability. There are bodies of work underway to improve oscillation monitoring and detection, as well as uplifting modelling capability. This work should consider the learnings from the Iberian Peninsula incident related to oscillation management to further improve resilience in the NEM.

4.2.4 Operation of under frequency load shedding did not arrest system failure

The operation of UFLS was not a mitigation measure to prevent cascading failure under overvoltage conditions. UFLS is designed to prevent cascading failures related to a significant deficit in generation that results in rapidly falling frequency in the system. Automatic load shedding is implemented to reduce demand and restore the balance between generation and load. In the Iberian Peninsula incident, it was identified that the contribution of load shedding was not sufficient to preserve stability. The reduction in load was not designed to address the issues related to overvoltages in the system.

Voltages continued to rise as a result of the UFLS operation. While the disconnection of load did assist in balancing the system frequency, it was not capable of interrupting the cascading failure due to the continual increase in system voltages. The disconnection of load via the UFLS relays increased voltages due to two contributing factors. The first was due to the reduced loading of the transmission network resulting in capacitive contribution from lightly loaded transmission lines. The second factor was the subsequent disconnection of generation on overvoltage protection settings due to increasing voltages. The further disconnection of generators reduced voltage control and reactive power absorption capability, resulting in additional voltage increases.

UFLS is not designed to interrupt the cascading overvoltage mechanism. In the event that an overvoltage cascading failure occurred in the NEM, UFLS would not address the root cause of the issue. While UFLS would keep the system stable longer by supporting the frequency balance as designed, it would not take specific actions to reduce the increasing voltage. Disconnecting loads would be likely to exacerbate the voltage rise, as seen in the Iberian Peninsula. In the NEM, the focus is currently on ensuring overvoltage cascading failures do not occur rather than having emergency schemes to prevent system collapse for rising voltages.

4.3 Review of resilience measures being investigated in the NEM

To support the ongoing resilience of the NEM, inputs were sought within AEMO and from NSPs to identify potential scenarios or contingency events that could lead to cascading failure based on the learning from the Iberian Peninsula incident. While not all risks identified below will be material risks in the NEM, the purpose is to raise awareness of potential issues and identify the highest priority actions to progress. If further analysis confirms any of the below as significant risks, then mitigation actions could be proposed.

4.3.1 Oscillations

Oscillations were a contributing factor to the pre-conditions of the Iberian Peninsula incident, resulting in large variations in voltages and frequency. To mitigate these variations, operational actions were taken that contributed to increased voltages. The NEM may be exposed to risks related to oscillations, for example:

- **The changing topology of the NEM may pose a greater risk for oscillations to impact operations.** It is currently uncertain whether the retirement of synchronous generators, addition of new synchronous condensers, and the unknown impact of IBR on small signal stability may result in oscillations that are a more significant issue in the future NEM. The impacts that oscillations can potentially have in the system are highlighted in the Iberian Peninsula incident. Actions to improve monitoring and modelling of oscillations in the NEM will continue to support a better understanding of the risk profile.
- **Oscillations may result in unexpected operation of protection settings.** System oscillations result in undervoltage and overvoltage swings that may contribute to units tripping on voltage or frequency protection settings. As seen in the Iberian Peninsula, there is a risk that DPV may shake off as a result of oscillations, which is a growing concern due to the large quantity of DPV in the NEM and decreasing MSL. It is also possible that other plants could disconnect or operate in unexpected ways as a result of oscillations.
- **Unknown plant contribution to oscillations may increase complexity of determining appropriate operator actions.** A future area of development in oscillation detection for all plant could consider the capability to detect the source of instability. While there is not current industry consensus on how this is achieved, having information pertaining to whether a plant is actively contributing to or providing damping for the oscillation would deliver valuable inputs to determine the correct hierarchy of actions when oscillations are present.
- **Oscillations may be more likely during periods of high reactive power absorption such as MSL**. As mentioned in Section 2.7, studies conducted by AEMO have found that oscillations related to insufficient system strength are more likely to occur for IBR that are absorbing close to their reactive absorption capability limit. This further highlights the potential risks when operating during MSL conditions. IBR may be more susceptible to instability, which could result in their disconnection and the loss of their active and reactive power contributions.
- **Operator actions for oscillations could be assessed and defined in more detail to prevent unintended consequences.** There is a risk that without well-defined actions for oscillations, the NEM could be exposed to unintended consequences that haven't been studied or assessed. Often the action to reduce oscillations is a reduction in transfer, but this may have secondary impacts such as increasing voltages. It should also be noted that actions taken to mitigate inter-area oscillations may not be effective for forced oscillations. Detailed assessment outlining the preferable actions for certain scenarios would improve resilience in this area.

Actions being taken or required

Assessment of small signal stability risks is of increasing importance in the NEM due to large system changes that may impact the risk profile. AEMO will continue the investigation of small signal stability risks across various workstreams and consider assessment as a priority risk in a future GPSRR. This could include consideration of high speed monitoring, control room visibility with appropriate tools, investigation of the capability to identify the source of oscillations and the development of procedures for different types of oscillation events (inter-area modes, local modes, and converter-driven oscillations from IBR due to factors such as low system strength and forced oscillations).

4.3.2 Coordination of overvoltage protection settings

As discussed previously, there is typically a reasonable operating margin between the voltages at which the system normally operates and the voltages at which generation overvoltage protection settings are set in the NEM. However, while it is unlikely that the system will see voltages that result in overvoltage protection settings operating, there is potential for significant consequences if it were to occur. Potential risks related to this are highlighted below:

- **Uncertainty regarding coordination of overvoltage settings** – overvoltage settings on DPV, IBR, transformers, synchronous generators, reactive plant or large loads could contribute to risk conditions if there is poor coordination in settings. Overvoltage protection settings for generators are commonly set close to the limits for the automatic access standard, meaning that exceedance of these limits could result in multiple plant disconnections. Risk may be present if overvoltage protection is set at the "minimum must-withstand" requirement rather than actual plant capability.
- **DPV disconnections could result in large active and reactive power changes in the system** – similarly, for DPV, the overvoltage threshold for all DPV disconnection is 1.18 p.u. for two seconds as per AEMO's *PSS®E composite load and distributed PV model updates*[68]. A significant voltage excursion could result in multiple disconnections if it were to occur.

Actions being taken or required

To better understand the risks related to a lack of coordination of overvoltage protection settings, system studies could be undertaken to apply significant contingencies and observe the response of the system. If the voltages approach the limits of overvoltage protection settings for a reasonably possible contingency, mitigation measures may need to be implemented. This may be considered in a future GPSRR. If this is identified as a potential risk, an audit of overvoltage protection settings for plant in the NEM could also be considered to understand the extent of the risk.

4.3.3 Lack of reactive reserve under certain conditions

The NEM has multiple factors that support reactive power reserves in normal operating conditions, such as generators operating in voltage droop control model, the operation of the VDS, and the large quantities of BESS in the network. However, maintaining power system resilience requires identifying conditions where risk may be elevated and reducing the likelihood that contingencies could result in cascading failures or major supply disruptions. These are examples of potential scenarios where the NEM could have reduced reactive power reserves:

- **Generators may not provide the expected reactive support during a severe contingency event.** Generators may not provide reactive support for a range of reasons. These could include a lack of headroom, certain plant operating in different control modes, or capability diagrams not being accurate for different system conditions (for example, not at 1 p.u. voltage).
- **MSL or night time dispatches could result in low reactive margin.** Voltages may be high in the system when lines are lightly loaded due to high DPV online or lack of demand. If operating with low demand, the number of synchronous units online is likely to be reduced, which could result in larger impacts in the event of a non-credible contingency. Night time cases may also cause issues for reactive power due to the disconnection of solar farms that may typically provide reactive power support during the day.
- **Non-credible contingencies could result in significant reductions in reactive power that are not considered under planning or dispatch.** The system is planned and operated to withstand the loss of a single asset, but non-credible

[68] PSS®E: Power System Simulator for Engineering. See https://www.aemo.com.au/-/media/files/initiatives/der/2024/report---psse-composite-load-and-distributed-pv-model-updates_.pdf?rev=ac5b72d32a124e028c170a1a76d29f04&sc_lang=en.

contingencies are known to occur. The loss of two synchronous units during MSL conditions could have a significant impact on the ability to control voltages, particularly in the future NEM when further synchronous plant is unavailable.

- **Voltages in the system are sensitive to active power changes.** Reactive reserves in the system could change within dispatch intervals if rapid ramping of large loads, BESS or variable renewable energy occurs in short timeframes. This could potentially erode reactive margin in the system and create conditions where a credible or non-credible contingency could have larger impacts. Quick changes in system conditions could also outpace static voltage control devices such as shunt capacitors and reactors.

Actions being taken or required

To better understand the risks related to certain operating conditions with reduced reactive margin, system studies could be undertaken to apply significant contingencies and observe the response of the system. If the voltages approach the limits of overvoltage protection settings for a reasonably possible contingency, mitigation measures may need to be implemented. This may be considered in a future GPSRR. The addition of synchronous condensers, new BESS and generation projects will continue to add plant with reactive capability. These additions will improve the resilience of the system and the available reactive margin.

4.3.4 Distributed PV/consumer energy resources risks

The NEM has high penetration of DPV, and the uptake of other types of CER such as residential batteries and electric vehicles are increasing rapidly. As observed in the Iberian Peninsula incident, the disconnection of large quantities of distributed resources can have material impacts at the transmission level. The following potential risks were identified as relevant consideration for the NEM:

- **High DPV conditions such as MSL could be a precondition where the NEM is exposed to voltage control risks**. Voltages will be elevated due to a lightly loaded system, and there may not be the same quantity of reactive power reserves available if minimum units are online. The unlikely occurrence of the loss of two or more units could be a trigger event for a high impact event.
- **High DPV penetration and quick weather changes could lead to quick changes in generation conditions.** Cloud cover could lead to rapid ramp up or down of DPV, which may change system conditions rapidly. This could result in interconnector drift and potentially changes in voltages as loadings of interconnectors and transmission lines are affected.
- **DPV may trip on overvoltage settings before transmission-connected generation**. DPV may contribute to pre-conditions that could pose voltage control risks by tripping at elevated voltages or due to other unexpected behaviour. This could then push voltages into regions where transmission connected generation begins to disconnect, as seen in the Iberian Peninsula incident.
- **DPV behaviour in response to oscillations is unknown**. There could be potential for oscillations in the system to result in unexpected tripping of DPV, which could have a significant impact in high DPV conditions. Further understanding of DPV behaviour is required in combination with developing oscillation mitigation methods for forced and natural oscillations.
- **Unexpected impact of backstop mechanisms**. DNSPs using voltage raise in response to MSL for emergency backstop could have secondary impacts. This would be co-incident with low UFLS availability on the distribution network due to large amounts of DPV.

- **Rapid behaviour of virtual power plants (VPPs) could have unexpected consequences**. Rapid or unexpected behaviour of aggregated resources could result in significant changes in power system conditions. There could be a risk of a VPP or a price-responsive CER responding to a price signal during a high voltage event and causing issues.
- **In the Iberian Peninsula, some of the Transmission–Distribution interface points exhibited highly capacitive behaviour.** The injection of uncompensated reactive power by distribution networks further contributed to increases in system voltage. As more CER, generation and large loads connect to the distribution network, the potential for impacts between the transmission and distribution networks will increase.

Actions being taken or required

Further studies may be required to assess the impacts associated with the unlikely occurrence of a non-credible contingency event under MSL conditions. The loss of multiple generators, loads or transmission lines should be assessed to understand the risks of cascading failure. Understanding of DPV response to oscillations could also be investigated to support better understanding of potential risks. With such high DPV penetration in the NEM, it is important to understand how sensitive it may be to oscillations. See Section 5.1 for more details on actions currently underway regarding distributed energy resources (DER) risks.

4.3.5 Non-compliances

Several instances of suspected non-compliances contributed to the cascading failure in the Iberian Peninsula. This included synchronous generators not providing their required reactive power and generators tripping on overvoltage when they were required to ride through. As discussed in more detail in Section 5.7, non-compliances are a growing issue in the NEM. While it is rare for a significant event to occur as a result of non-compliances in the NEM, as the number of open non-compliances increases, the risk present in the system may grow. The identified risks are:

- **Non-compliances are an ongoing issue in the NEM.** The number of non-compliances has increased with time. Non-compliances could impact the ability of generators to provide their required reactive power or may result in unexpected disconnections.
- **Enforcing rectification of non-compliances is difficult.** There is typically limited incentive for plant owners with open non-compliances to rectify issues once they have achieved full commercial operation, unless AEMO has imposed an associated restriction. There may also be complexities in resolving a non-compliance. Restrictions may be applied if significant risks are identified.

Actions being taken or required

AEMO will continue to track and manage non-compliances and work with participants to rectify known non-compliances. If any significant risks related to non-compliances are identified from detailed voltage control studies, or other risks assessed in the GPSRR, audits or reviews of plant compliance may be recommended as a proactive mitigation measure.

4.3.6 Under frequency load shedding increased overvoltages in the Iberian Peninsula

While the operation of UFLS assisted in delaying the collapse of the system in the Iberian Peninsula, there was no true mechanism implemented to arrest a cascading overvoltage. The operation of UFLS further contributed to rising voltages, due to capacitive effects of lightly loaded lines and further disconnection of generators due to the subsequent overvoltages.

Potential risks related to UFLS in the NEM include:

- **UFLS adequacy may be less than expected.** A review is currently underway to assess the adequacy of UFLS in the NEM. Under this review there have already been instances where loads were required to be part of the UFLS scheme but were not compliant.
- **UFLS adequacy may not be sufficient in high DPV conditions.** Lack of under frequency load to trip due to higher penetration of DPV on feeders may result in inadequate load shedding or uncertainty of performance if a low probability high impact frequency event were to occur.
- **UFLS operation during low demand may result in overvoltages.** UFLS events at times of low demand could result in widespread overvoltages as load is disconnected from the system.
- **Trip of multiple generators during MSL could result in excessive rate of change of frequency (RoCoF).** There could be a risk of excessive RoCoF in scenarios with light system conditions such as MSL where minimum units are online. In the event of loss of multiple units, it may be possible that excessive RoCoF results in failure of UFLS to arrest the frequency.

Actions being taken or required

The UFLS adequacy review is underway and will continue to identify if any further loads need to be added to UFLS. Dynamic arming is also underway in the NEM to restore UFLS adequacy under high DPV conditions. This is already underway in South Australia and is under consideration for other regions.

4.3.7 Network service provider input on voltage control risks in the NEM

To further support the review of voltage control risks in the NEM, AEMO contacted NSPs and requested input on voltage control risks in their networks. They were given the opportunity to provide feedback on any potential voltage control risks, particularly in reference to the voltage control failures observed in the Iberian Peninsula. The general response from NSPs was that voltage control was well understood in the NEM and that it was unlikely then NEM would see a similar cascading event as occurred in the Iberian Peninsula. NSPs are actively considering voltage control in the NEM to support mitigation of risks.

Some of the key themes identified in the responses are discussed below.:

- **Coordination of voltage trip settings for reactive plant** – voltage trip settings for reactive plant are typically coordinated by time delay, with trips commonly initiated at voltage levels exceeding 115% of nominal. These settings are generally designed to ensure that TOV limits specified in NER S5.1a.4 are not exceeded. Time-based coordination enables faster response to mitigate voltage changes, such as through capacitor bank tripping if voltage increases progress through higher thresholds. However, while the timing of actions is coordinated, the voltage thresholds themselves may not be, and could be applied inconsistently across different NSPs' jurisdictions.
- **Generator and synchronous condenser voltage protection** – generator overvoltage and undervoltage protection is generally set to meet the AAS under NER S5.2.5.4, unless plant design limitations prevent compliance. Synchronous condensers typically incorporate equivalent overvoltage protection to provide comparable voltage support capability and protection performance.
- **Reactive power exchange at the distribution–transmission interface:**

- Reactive power exchange at the distribution-to-transmission interface is most pronounced during low demand periods, particularly in the early morning when demand is minimal and DPV inverters have not yet energised and are therefore unable to provide Volt/VAr support. AusNet has also observed similar behaviour during mid-day periods of high DPV output. While distribution-level power factors during peak demand are trending closer to unity, some residual inductive demand remains. In contrast, during low demand periods, power factors are often capacitive, resulting in reactive power flows toward the transmission network.
- SA Power Networks (SAPN) is progressing a regulatory investment test for distribution (RIT-D) to address increasing capacitive power flows from the distribution network into ElectraNet's transmission network. Reactive power trends at ElectraNet–SAPN connection points have increasingly shifted in the reverse (capacitive/leading) direction over at least the past decade. ElectraNet has observed that these elevated capacitive flows cause SVCs to operate outside their intended range, limiting their availability for dynamic voltage support during disturbances and compromising system security.
- Potential mitigation options could include the installation of reactors or STATCOMs, as well as customer-level solutions leveraging smart inverters, energy management systems, and coordinated household DER control to manage capacitive behaviour.

- **Common drivers of overvoltage conditions** – NSPs identified several event types that could lead to overvoltage conditions, although it was noted that these events were unlikely to result in major cascading failure. The examples provided included:
  - loss of the largest generator (or multiple generators) absorbing reactive power during MSL or other lightly loaded/high-voltage conditions, potentially leading to reactors, transformers, generators, or DPV reaching overvoltage trip thresholds,
  - loss of large loads (or multiple loads) during already high-voltage conditions, including temporary disconnection of major customers such as data centres,
  - loss of reactive support from inverter-based generation due to outages or reduced system strength following generation or network contingencies, and
  - operation of UFLS, OFGS, or other RASs.
- **Reactive power variability during renewable transitions** – large variations in reactive power requirements are observed during day–night transitions, as solar systems shut down and restart daily. AEMO and TNSP controllers manage these changes through established operational practices to prepare the system for subsequent operating conditions. Variability in renewable generation output due to cloud cover or wind fluctuations also affects reactive power demand, as changes in active power flows materially alter system reactive losses. This is actively managed in real time through the switching of reactive plant, such as capacitor banks and reactors.
- **Voltage control challenges during MSL and low demand periods –** MSL conditions and low-demand early-morning periods were consistently identified as the most challenging times for voltage control across jurisdictions.
- **Risks associated with dynamic reactive plant** – potential risks associated with dynamic reactive plant that were identified include:
  - controller tuning not suited to weaker grid conditions, leading to instability or oscillatory behaviour,

  - insufficient dynamic reactive capability at critical locations,
  - inappropriate response prioritisation, such as IBR tripping before providing reactive support, and
  - because controller tuning is typically designed for credible contingencies, performance under non-credible events may be less well understood.
- **Need for reactive power reserves at minimum demand** – there is an increasing requirement for reactive power reserves to manage high-voltage conditions during minimum demand periods. In several cases, transmission–distribution interface transformers are approaching tap limits during high DPV output scenarios. This is often attributable to transformer designs optimised for voltage boosting during high-demand conditions, with limited capability to buck voltage during very low demand periods.
- **Transformer tap coordination and timing** – transmission transformer tap changers are typically configured to operate more quickly than those on the distribution system to avoid control interactions or "hunting". Initial delays are often relatively long, followed by faster tap operations if further voltage correction is required. Several NSPs reported delay times of approximately 15 s for initial TNSP transformer actions, with a further 15-second delay before corresponding DNSP transformer operations commence.
- **Voltage oscillation risks** – additional voltage control risks related to voltage oscillations were specifically noted for South Australia. There are multiple events of voltage oscillations currently under investigation by AEMO and ElectraNet. This provides further support for the need to improve oscillation monitoring, detection and modelling capabilities.
- **Protection, control, and stability risks under extreme conditions** – observed voltage control risks include failure or malfunction of protection and control schemes during contingencies under lack of reserve (LOR) or MSL conditions, or the failure to enable available schemes during bushfire events. Contributing factors include the increasing distance between new IBR generation and load centres following synchronous generator retirements, growing reliance on exports, potential increases in oscillatory behaviour, loss of PSS functionality, and limitations in small-signal modelling maturity for IBR and IBLs. Regular review of RASs and systematic incorporation of lessons learned from past events can be used to address these risks.

4.4 Recommendations

The review of voltage control risks in the NEM has provided an increased understanding of potential risks that the NEM may be exposed to. For typical events, the operating margins and voltage control management processes currently in place reduce the likelihood of cascading failures related to a lack of voltage control. However, there may still be risks for extreme events occurring in particular operating scenarios. Further assessment will be required to determine if mitigation measures are required to manage these low likelihood conditions. The review of the Iberian Peninsula incident also identified the importance of addressing risks related to oscillations. Further work should be undertaken in the NEM to reduce risks related to small signal stability.

4.4.1 Voltage control risks

While the NEM is resilient to voltage control risks in normal operating conditions, there may be certain operating conditions or high impact non-credible contingencies that could pose an increased level of risk for short periods of time. Due to the potential consequences if a cascading overvoltage incident were to occur, it is recommended that detailed assessment is undertaken to further understand voltage control risks for non-credible contingencies under certain operating conditions.

Recommendation 5

AEMO recommends that existing studies on voltage control risks are extended to consider the impacts of non-credible contingencies in operating conditions that may present an elevated risk of voltage control related cascading failures.

Actions:

AEMO will consider the inclusion of detailed voltage control risk studies for a future GPSRR, particularly during minimum system load conditions, low fault levels or other periods of low dynamic reactive power availability. This may include consideration of:

- non-credible generation contingency events such as the loss of multiple synchronous generating units that are absorbing reactive power,
- the non-credible disconnection of multiple loads and the potential impact on system voltages,
- stability of IBR when absorbing close to the reactive limit of the plant, or
- other voltage control risks identified through the GPSRR consultation process.

TNSPs and DNSPs to provide inputs to AEMO on any identified conditions or events related to voltage control risk studies that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.

4.4.2 Oscillations

Small signal stability risk is an ongoing focus in the NEM, particularly considering the significant changes that may impact this risk in the near term. The Iberian Peninsula incident has highlighted how oscillations can contribute to cascading failure events and the importance of implementing oscillation monitoring, detection and operational procedures. It is recommended that small signal stability is considered as a priority risk for a future GPSRR in light of its relevance and importance to system resilience.

Recommendation 6

AEMO recommends that power system oscillation risks are considered as a priority risk for a future GPSRR or through the TPSS. This is intended to highlight potential consequences, identify appropriate mitigation measures and to drive action to address this risk. AEMO is intending to consider small signal stability through the 2026 TPSS, which will further contribute to identifying emerging security gaps related to power system oscillations.

Actions:

AEMO will consider the inclusion of power system oscillation risks for a future GPSRR or through the TPSS. This may include consideration of:

- operational procedures for power system oscillations,
- source location and detection of forced oscillations,

- assessment of the impacts of changing network topology and generation retirements on inter-area modes,
- impacts of increasing IBR on small signal stability,
- power system oscillation monitoring and benchmarking challenges, and
- other power system oscillation risks identified through the GPSRR consultation process.
- **TNSPs and DNSPs** to provide inputs to AEMO on any identified conditions or events related to power system oscillations that should be considered in future GPSRRs. Where risks are identified, these inputs should be provided through the 2027 GPSRR consultation.

Part B: Other risks

5 Current and emerging system operator risks

In addition to the priority risks considered in the GPSRR, the report provides a brief overview of other current and emerging risks. This section provides context on emerging issues that are being experienced in the NEM and would be relevant to other power systems across the world. It gives an overview of each risk and any actions that are currently being progressed. These risks may be considered in more detail as priority risks in future GPSRRs if they are assessed to be high priority.

5.1 Distributed energy resources risks

5.1.1 Incidence of minimum system load events

AEMO continues to strengthen arrangements to support MSL conditions. From 1 November 2025 to 10 April 2026, South Australia has had 21 actual MSL1 conditions and six actual MSL2 conditions, and Victoria has had three actual MSL1 conditions. AEMO continues to work towards improved integration of BESS into MSL thresholds and is also progressing Transitional Services contracts to support MSL conditions[69].

5.1.2 Operational demand increase actions (Emergency backstop)

AEMO's current outlook on operational demand increase capability is supported by ongoing DNSP implementation testing. AEMO reported on MSL and operational demand increase capabilities in the NEM in the TPSS published in December 2025[70], and on learnings from industry implementation of emergency backstop mechanisms for distributed resources in July 2025[71]. This advice remains current.

Some additional information is also now available on DNSP testing of the Victorian Backstop Mechanism (VBM), which uses the Common Smart Inverter Protocol – Australia (CSIP-AUS[72]). These tests are in line with the Ministerial Order Specifying Licence Condition 2025[73]:

- Citipower, Powercor and United Energy (CPUE) ran a series of at-scale tests in Q4 2025, with the latest test on 10 December 2025 conducted simultaneously for backstop enabled solar systems across all of CPUE's network. The test ran for 60 minutes and aimed to test for potential CSIP-AUS server loading challenges across CPUE and OEM systems. CPUE reports that more than 90% of all backstop enabled sites successfully responded to the curtailment signal during the test, delivering a combined 54 MW of response.

[69] AEMO 2026, Provision of Minimum System Load Transitional Services, at https://www.aemo.com.au/consultations/tenders/provision-of-minimum-system-load-transitional-services-nem-wide.

[70] AEMO 2025, 2025 TPSS, at https://www.aemo.com.au/energy-systems/major-publications/transition-plan-for-system-security-tpss/2025-transition-plan-for-system-security. Analysis of MSL outlook for each region is found in Appendix A3, MSL Regional Assessments, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-tpss-appendix-a3-msl-regional-assessments.pdf?rev=475bfa4a721e4acdb03b30367e617226&sc_lang=en.

[71] AEMO 2025, Learnings from industry implementation of emergency backstop mechanisms for distributed resources, at https://www.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/learnings-from-industry-implementation-of-emergency-backstop.pdf?rev=5e261f83f11b426cb086069ac86e8cee&sc_lang=en.

[72] More information on CSIP-AUS is at https://www.csipaus.org/about.

[73] Victoria Government Gazette S553, 9 October 2025, at https://www.gazette.vic.gov.au/gazette/Gazettes2025/GG2025S553.pdf.

- Jemena conducted an at-scale test of its backstop mechanism in March 2026, in four blocks of 15-minute tests, and reported that across the blocks, 88% of sites successfully commissioned on the VBM responded. Jemena reports that some OEMs appeared to have timeout issues, and that it worked with the OEMs to rectify these.
- Ausnet has plans to conduct an at-scale test in 2026.

5.1.3 AS4777.2:2020 compliance

Compliance with AS4777.2:2020 ('the 2020 Standard') continues to improve due to voluntary actions from OEMs. 80-90% of newly installed DER inverters[74] are correctly configured aligning with inverter requirements from the 2020 Standard, AS 4777.2:2020. These improvements have largely been driven by voluntary actions by inverter OEMs, including the removal of legacy standards from product menus.

A large portion of the 200 kilowatts (kW) to 5 MW PV non-scheduled generation (PVNSG) fleet remains non-compliant. Current assessments indicate that up to 50% of the 200 kW to 5 MW PVNSG fleet remains non-compliant with the standard, particularly with respect to ride-through requirements. This non-compliance increases the likelihood of adverse system outcomes during disturbances, including inappropriate disconnection or active power reduction across these systems in response to disturbances.

AEMO continues to track compliance progress through various initiatives and stakeholder engagement. The most recent compliance status update highlights that remediation activities are ongoing. Further details are available in the latest compliance update report[75], which provides an overview of compliance trends and remaining risks.

5.1.4 Increasing size of operational demand swings

Operational demand (OD) swings associated with DPV and composite load behaviour are a real physical phenomenon and increase in magnitude as DPV generation rises. They occur because underlying demand typically recovers faster following a disturbance than DPV recovers after momentary cessation, producing sharp post-fault OD spikes and associated power swings across interconnectors and other transmission and distribution lines. Studies show that these swings can materially affect post-disturbance system response and reduce transient stability margins, particularly in high-DPV conditions. At the same time, PEC Stage 2 improves overall transient performance, including faster voltage recovery, reduced Heywood flow excursions and better-damped rotor-angle response, although it does not remove the underlying OD swing mechanism and can increase the instantaneous positive OD peak.

Operational demand swings should be treated as a medium-term operational issue requiring broader reassessment. Recent analysis indicates that no spurious tripping of South Australian synchronous units was observed in the relevant high-DPV studies, and that the more material emerging concern at high DPV levels is worsening voltage stability rather than protection maloperation. The dynamic studies indicate that the representative high-DPV case remained stable under conditions broadly consistent with a future South Australian spring scenario, while more extreme cases became unstable, with supporting voltage stability analysis indicating deteriorating voltage stability margin as DPV increases. These findings suggest that OD swings should be treated as an emerging medium-term operational issue requiring further reassessment

[74] Based on available information on systems installed in Q1 and Q2 in 2024.

[75] At https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/compliance-of-der-with-technical-settings.

under broader future-case conditions, rather than as evidence of an immediate need to revise inverter ride-through settings or current operating frameworks.

5.1.5 Lack of clarity regarding system strength in distribution networks

There is limited clarity regarding how system strength should be defined and assessed in distribution networks. Unlike transmission networks, where established estimation methods such as SCR for IBR connections and synchronous fault levels are available, distribution networks currently lack a clear framework, agreed metrics, and validated methods to characterise the conditions seen by DPV inverters at low-voltage points of connection. Transmission-style metrics alone do not fully represent distribution-level inverter conditions. Existing upstream SCR screening metrics at distribution substation level are useful, but they do not directly quantify the weak-grid conditions experienced by rooftop PV inverters at their point of connection, where additional feeder impedance, local voltage behaviour, and inverter control interactions materially influence performance.

Improved understanding and quantification of distribution-level system strength is becoming increasingly important as DPV penetration rises. Recent work indicates that inverter behaviour under weak-grid conditions can vary materially across devices and operating conditions, and that acceptable performance cannot be assessed on SCR alone. A more practical distribution system strength framework is therefore needed, including clearer metrics, assessment methods, and planning and operational criteria that better reflect how large populations of inverters behave in weak-grid distribution environments.

Priority actions include targeted research and the development of appropriate metrics, supported by continued collaboration with key stakeholders, inverter manufacturers, and research institutions to improve understanding and implementation of effective mitigation measures.

5.1.6 Emerging evidence of weak-grid inverter interactions and oscillatory behaviour

There is growing evidence that weak-grid conditions in distribution networks can contribute to low-frequency oscillatory behaviour involving DPV inverters. Recent bench testing and field observations indicate that DPV inverters are a credible contributor, although the available evidence does not support the conclusion that they are the sole or universal cause in all cases. The observed behaviour does not reflect a single unique inverter signature. Rather, it forms a part of a broader spectrum of oscillatory modes whose severity and dominant frequency vary with SCR, network R/X, inverter power output, rapid output changes, and wider system operating conditions.

Control behaviour also appears to be an important part of the risk. Testing indicates that oscillatory response can worsen materially under weak-grid conditions when voltage-control functions are active, with the volt-var loop emerging as the dominant control contributor, while volt-watt does not appear to be the main driver.

Priority actions therefore extend beyond further system strength definition alone, and include targeted investigation of the operating states in which oscillations materially worsen, improved monitoring in high DPV areas, and longer-term development of weak-grid inverter requirements and a practical distribution system strength framework.

5.2 Small-signal stability

Small-signal stability deals with the ability of a power system to maintain synchronism when subjected to small disturbances, such as minor load or generation changes or network switching events. The importance of small-signal stability has been increasingly highlighted by recent power system events, including the April 2025 Iberian Peninsula event, where power oscillations were reported prior to widespread outages.

Growing IBR penetration in the NEM, and the impending installation of synchronous condensers to support otherwise declining levels of system strength and inertia, has made small-signal stability a critical topic requiring further investigation.

AEMO is currently considering the following aspects related to small-signal stability and its analysis:

- **The impact of changing system dynamics on small-signal stability.**
  - The NEM is undergoing a significant energy transition, characterised by the development of major transmission network projects and the proposed retirement of ageing coal-fired generation. These retiring synchronous generators are increasingly being replaced by renewable generation, supported by energy storage systems. Such fundamental changes to the generation mix and network topology are expected to alter system dynamics and may impact the small-signal stability characteristics of the NEM as traditionally understood.
  - While AEMO has historically focused on synchronous plant models in small-signal stability assessments, the impact of IBR models is of increasing uncertainty. Key areas of investigation are:
    - alignment of state-space small-signal modelling with operational measurements through Oscillatory Stability Monitor (OSM),
    - assessment of the impact of IBR, both GFL and GFM, on small-signal stability, and
    - fit-for-purpose approaches and tools to assess damping performance at the plant and system level, considering model availability and tool efficacy.
- **Deployment of synchronous condensers in the NEM is introducing new challenges for inter-area oscillation damping.**
  - Synchronous condensers are intended to offset system strength reductions associated with coal generation retirements, necessitating assessment of their impact on small-signal stability. While synchronous condensers provide clear benefits through system strength and inertia contributions, their impact on inter-area oscillatory modes can be adverse, a result of typically absent damping controllers and different dynamics relative to synchronous generators. As a result, greater use of synchronous condensers could negatively affect damping of inter-area modes.
  - This highlights the need for investigation into the impacts of upcoming synchronous condenser installations, including consideration of PSS applications on these devices. In addition, ongoing changes to the power system may shift the frequency of inter-area oscillatory modes, reducing the effectiveness of existing power oscillation dampers (PODs) and PSSs relative to their original design conditions, requiring a future re-tune of these devices in the NEM.
  - Under the Engineering Roadmap priority action FY26_27[76], AEMO is undertaking preliminary analysis of damping trends and needs in a scenario where synchronous condensers are the dominant rotating masses in the power system. AEMO has undertaken an initial comparative assessment of inter-area oscillatory stability under future high IBR with synchronous condensers and GFM BESS deployed as new system strength solutions. AEMO plans to publish a report that will describe the assessment approach and findings, technology sensitivities and a proposed pathway for stakeholders to progressively monitor and assess damping as power-system characteristics evolve.

[76] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf.

- **Effective transitioning and benchmarking of small-signal analysis and monitoring tools.**
  - The potential transition from previously used tools such as *Mudpack* to a more appropriate long-term approach is actively being considered. Improving modelling capability for small-signal stability across a consistent platform remains necessary to understand the risks in the NEM.
  - In addition to modelling complexities, benchmarking against existing small-signal stability monitoring tools such as the OSM is an important task to continue progressing. Such benchmarking is essential for validating internetwork testing outcomes, small signal limits, power oscillations dampers tuning and improving confidence in the small-signal stability models.
  - Another critical aspect is the quality of data supplied to online small-signal monitoring tools, which primarily rely on phasor measurement unit (PMU) inputs. AEMO has identified data quality as a key area requiring ongoing focus to ensure reliable and meaningful small-signal stability assessment.

AEMO is progressing a range of ongoing initiatives to address and mitigate the identified small signal stability related risks:

- **Completion of the Small Signal Analysis Tool (SSAT) model for the current system is well underway**, including benchmarking against other established power system analysis tools. This is being progressed as a short-term measure to assess small signal stability related to the commissioning of PEC Stage 2.
- **Benchmarking of the OSM is underway**, with completion targeted by the end of 2026. Additional small signal stability monitoring tools will be benchmarked progressively as part of the ongoing validation program.
- **Further assessment of inter-area oscillatory modes is planned**, including consideration of synchronous generator retirements and the performance and adequacy of existing PODs.

5.3 Remedial action scheme complexity and inadvertent operation

A growing number of new RASs are being proposed as a means of managing credible and non-credible contingency risks in the NEM. Such schemes can deliver material benefits by improving system resilience to non-credible contingency events, reducing overall costs and delaying or avoiding investment in additional infrastructure. However, with the growing number of RASs, the complexity of the system increases, as does the potential risk of unexpected operation or interaction.

These are recent examples of large RASs that were considered for the NEM:

- **A RAS was initially proposed to manage the non-credible loss of HumeLink's 500 kV lines.** The initial design requirements proposed that a significant quantity of generation and load would be rapidly disconnected to manage power system stability, introducing significant RAS complexity with many inputs. Subsequent studies have indicated that a simpler scheme, or alternative mitigation measures, may be sufficient to reduce the likelihood and consequence of this contingency. While a large scheme may not be required in this instance, the potential for other major augmentations to necessitate complex and fast-acting schemes remains an ongoing risk if alternative measures cannot be found.
- **A complex control scheme uses the Waratah Super Battery (WSB) to implement a system integrity protection scheme (SIPS).** This control scheme continuously monitors power flows on multiple lines, arms when system conditions are met, and automatically injects power from WSB and runs back selected generators to relieve post-contingent line overloads.

Line monitoring is performed across 36 circuits, with 18 of these circuits normally enabled to trigger the WSB SIPS operation.

- **New schemes are proposed in Victoria and South Australia to manage the risk of Heywood or PEC interconnector instability** for the non-credible trip of two interconnecting circuits under certain operating conditions. The growing complexity and number of schemes in this region will require coordinated testing and modelling to identify and manage unexpected interactions and operational risks.

Under the 2025 GPSRR, AEMO considered the risk of unexpected operation or interaction of protection systems and control schemes, highlighting the importance of establishing key actions to support the ongoing use of RASs in the NEM. There are several actions currently underway to investigate the risks related to RASs and reduce risks related to their implementation. AEMO is initiating a program of work that will include modelling, assessment frameworks, approach to improving compliance to the standard and reviewing interactions in more detail.

5.4 Emergency contingency plans may be required to manage extended forced outages

Following a non-credible trip of major synchronous units, affected generators may remain unavailable for extended periods, depending on the nature and severity of the contingency. Where such events are associated with significant generator reliability impacts, prolonged outages of major units are possible. Even if the power system can be adequately secured using the available fleet of fast-start units, it may remain vulnerable to subsequent contingencies until major generators return to service. Sustained operation under these conditions introduces additional risks, including gas supply adequacy constraints, particularly if forced outages extend from shoulder seasons into periods of higher demand.

Power system resilience includes consideration of the long-term impacts from extreme events. The long-term impacts related to non-credible contingency events must also be considered, such as the catastrophic failure of critical equipment that could lead to long-term outages (for example, the failure of Callide Unit C4 that occurred on 25 May 2021[77], after which the unit was unavailable until August 2024, more than three years following the initial incident). The analysis conducted in the 2026 GPSRR has shown the significant impacts that concurrent outages can have on system strength. Catastrophic failures of large synchronous units could add further complexity, with additional outages to manage. This could also persist for long periods, depending on the severity of the damage, or result in early retirement in extreme cases where it is no longer economical to repair failed units.

Additional resilience measures could be implemented to support resilience for long-term impacts of high impact low probability events. While the Callide example did not have significant consequences for the long-term reliability or security of supply in Queensland, due to the availability of other generation, this could be an emerging concern as the NEM progresses through the energy transition. As more thermal generation retires, additional resilience measures may need to be considered if HILP events such as this occur, where the system may need to operate without critical infrastructure for long periods of time.

The 2023 GPSRR recommended the development of region-specific emergency reserve contingency plans to mitigate this risk. As recommended in the 2023 GPSRR, the implementation of region-specific emergency reserve and system security

[77] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf.

contingency plans would improve power system resilience, particularly in addressing high impact, low probability events that result in long-term outages of generation or critical transmission infrastructure. These plans should be reviewed and updated regularly to ensure timely activation when required. They would define the required reserve capacity for each region and include details on appropriate site locations, equipment availability, procurement strategies and lead times, generation technology options, connection points and arrangements, fuel supply adequacy, environmental considerations, and construction and commissioning timelines.

5.5 System restart risks

System restart ancillary services (SRAS) are provided by generators with the ability to start, or remain online, without drawing electricity from the grid. SRAS providers restart the power system by providing energy and stability to support the incremental return-to-service of transmission lines, other generators, and loads following a major blackout.

SRAS have historically been provided by synchronous generating units, since these units can output active power consistently and provide inertia and system strength to maintain stability. Additionally, the historical restart philosophy has been to prioritise energisation paths to other synchronous machines to further strengthen restarting islands. Due to the current reliance on thermal units to provide SRAS, the limited pool of existing system restoration units is decreasing with generation retirements, restricting the black-start capability and reducing the options to establish restart pathways. This along with the reducing availability of stable load along some restart paths increases the risk of delayed restoration.

5.5.1 Current and future system restart ancillary services-related risks in the NEM

There is a limited pool of SRAS providers in some NEM regions, and some are potentially less capable of effectively commencing the process of restoring the power system. Overall, there are challenges related to the provision of SRAS services, and limited incentives for the development or construction of new dedicated restart-capable plants. While some types of SRAS providers such as gas or hydro generally provide some restart flexibility, others, such as coal units, require significant minimum levels of load to commence the restart process. In regions where there are limited SRAS providers available, there may be additional difficulty in finding stable load to commence restart. In recognition of these challenges, the Reliability Panel[78] has updated the system restart standard to provide greater flexibility in the procurement of black-start and restoration-support services.

AEMO is progressing SRAS locational assessments to signal the locations within each region that are most suitable for black start capability. AEMO has undertaken a forward-looking, screening-level assessment of the relative suitability of selected NEM network locations for future black-start-capable SRAS sources. This aims to provide stakeholders with transparency on the locational characteristics that may support efficient system restoration without determining SRAS eligibility or procurement outcomes. AEMO intends to publish further details on this work in the 2026 *Enhanced Locational Information* report.

Lack of system strength during restart prevents most IBR from participating in the early stages of restart paths, but there may be future solutions. Some BESS may be capable of providing early voltage and frequency support under certain conditions, and restoration support services may provide an incentive to reserve headroom for this purpose. However, the system strength required to energise the large interfacing transformers can often reduce their utility in current system

[78] See https://www.aemc.gov.au/market-reviews-advice/review-system-restart-standard-0.

conditions. The intermittency of other IBR sources also limits the ability to use IBR more broadly during early restoration stages. Synchronous condensers may provide a future source of system strength for restart purposes, despite having no active power capability. These units generally require auxiliary supply to accelerate them to synchronised, a process that can be assisted with variable frequency drives to limit the impact to the restarting network and to allow the condensers to accelerate without necessarily reaching standstill initially. AEMO is currently seeking to enable new SRAS sources, such as through the inclusion of IBR. Market engagement is currently ongoing for the Type 2 Transitional Service to trial black-start capability from IBR. AEMO intends to use Type 2 Transitional Services contracts to engage IBR plants, new or existing, that can provide or be upgraded to provide black-start services. The trial would help build industry confidence, inform future SRAS procurement, and guide technology development.

The risk of DPV impacts on system restart continue to grow, and the effect of home batteries is unknown. This directly affects the viability of restart paths at certain times of the day and year. Sufficient stabilising demand is required for system restart, but conditions with higher DPV generation introduces significant load variability and load erosion. If the existing DPV management processes are ineffective in restart scenarios, there may not be sufficient demand to restart the system until night time or low DPV operating conditions, which may delay restart times significantly. It is also unknown how home battery installations may operate under restart conditions. AEMO is actively progressing work to address the risks that increasing DPV penetration may pose to system restart. This includes industry engagement and a targeted System Restart under High DPV Conditions trial[79] under Type 2 Transitional Services to assess potential mitigation options and improve understanding of system restart performance under high DPV scenarios.

Public behaviour during restart may drive atypical load characteristics. In black system conditions, many people may leave commercial or industrial workplaces to return home, driving unpredictable demand. SRAS paths are developed assuming historical network loadings, but this may deviate from what is experienced in a black system event.

The system restart path across NEM regions is moving with the changing generation mix, and restart sources are often a long distance from major load centres. The NEM's increasing dependence on long electrical paths and weak system conditions further constrains restoration options. Although system restart path testing is valuable, it has a significant market impact and there are limited testing opportunities. AEMO will continue to progress work supporting future system restart planning in the NEM. The 2026 TPSS will include more details on this.

5.5.2 Actions taken to mitigate system restart risks

There are several actions currently underway to manage risks associated with SRAS in the NEM. These include:

- working to revise regional system restart plans to ensure pathways remain fit for purpose with the changing network, generation mix and load profiles, while also providing sufficient guidance on alternative switching paths where they exist,
- conducting regular system restart training with NSPs and seeking improved and accurate information from generators, TNSPs and DNSPs to input into restart plans,
- working to encourage and enable extended network testing,
- undertaking procurement of Restoration Support Services to provide stable load blocks during system restart,

[79] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.

- investigating the use of GFM inverters and the possibility of utilising BESS during early stages of system restoration, including broader assessment of IBR through Type 2 Transitional Services focused on black-start capability from IBR,
- investigation of emergency back-stop mechanisms which may be used to facilitate the availability of stable demand during system restart, including mechanisms to support restoration under high DPV operating conditions, and
- a review of the system restart standard (set by the Reliability Panel) which has now concluded, with AEMO progressing implementation activities and updates to supporting guidelines. The Reliability Panel also recommended the development of proposed rule changes to enhance testing frameworks, local black system procedure provisions and planning transparency.

5.6 Communications-related risks

Communication systems are becoming more important as the size and complexity of the power system increases. There is a growing relationship between power system security and the reliability of communication systems, because so many of the functions required to operate a complex and modern power system rely heavily on communications infrastructure. Specific communications-related risks being considered by AEMO include:

- **Communications failures within a generating system have the potential to result in plant shutdown.** Plant connecting to the NEM that are larger than the largest credible contingency may be configured with multiple transformers and multiple PPCs to improve resilience to local equipment failures. However, an internal communications system failure for 30 s or two separate events within one hour requires the automatic initiation of a shutdown sequence for the entire plant in accordance with AEMO's Communication System Failure Guidelines[80]. This is currently being reviewed and potential modifications to reduce communications-related risks will be considered.
- **Common mode communications failures that affect multiple plants could result in large contingency sizes.** A single communications failure may result in the controlled shutdown of a single or multiple resources with a capacity larger than the largest credible contingency size in the network, leading to a contingency that the network is not explicitly operated to withstand under all conditions. This risk is partially mitigated by the shutdown command being implemented as a controlled ramp-down rather than an instantaneous trip. The ramp-down is intended to avoid sudden changes in active power, reactive power, or voltage at the connection point, reducing the sudden impact on the network. AEMO is monitoring the growth of large, multi-PPC plant configurations and is assessing whether current procedures and ramp-down behaviours remain appropriate as plant sizes continue to increase.

Reviewable operating incident reports on recent communications-related power system incidents are:

- 23 March 2026 – market suspension in New South Wales[81],
- 17 March 2023 – market suspension in New South Wales[82],

[80] See https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/stage-6/communication-system-failure-guidelines.pdf.

[81] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2026/preliminary-report-nsw-market-suspension-on-23-march-2026.pdf.

[82] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2023/final-report---nsw-market-suspension-17-march-2023.pdf?la=en.

- 22 April 2023 – market suspension in Victoria[83], and
- 29 June 2023 – loss of SCADA and line protection at Keilor terminal station[84].

5.7 Generator non-compliance

As the number of connected generators increases, managing compliance with generator performance standards (GPS) is becoming more complex. The volume of new connections in the NEM continues to increase, with recent connection activity highlighting both the scale and pace of this growth, reflected in a steady volume of new applications, approvals, and projects reaching commissioning[85]. In total, 56 GW of projects are currently progressing through various stages in the connections process, half of them being battery storage projects[86]. While non-compliance affecting a small number of generators can often be addressed on an individual basis, the cumulative effect of non-compliances across a growing and increasingly diverse generation fleet is more difficult to manage and can pose broader system-level risks. The majority of these individual non-compliances are identified and resolved through the connections assessment and commissioning process, while other sources of non-compliances can arise during commercial operations due to equipment unavailability, settings updates or physical limitations of plant that may not be limited to the connection assessment. The analysis of system incidents may also identify non-compliances as system interactions become more complex, introducing system conditions that may not be assessed under the connection process. This increase in non-compliances is especially challenging if non-compliances start to accumulate more quickly than they can be resolved.

An aggregate view of generator compliance issues may benefit the non-compliance risk evaluation process. For every new instance of generator non-compliance, a risk assessment is completed that determines the risk that the compliance issue may present to operation of the power system. In many instances, the individual risk presented by any one generator is typically low. If many generators present similar compliance issues, then in aggregate these could manifest to become a large risk to the power system, especially if the non-compliance across many facilities is similar in nature. Across the NEM, a limited number of OEMs supply equipment for IBR projects, and any issue affecting one OEM that arises operationally could impact all plants using that technology. As new IBR connections involve complex control systems, which may not always be correctly configured and are interacting with a rapidly changing environment, this can pose significant risks in aggregate when implemented across multiple IBR plants. To support the mitigation of this risk, AEMO has introduced a voluntary process – the Early Assessment Framework – which seeks to provide certification of models before they are included in connections projects, which intends to address systemic model issues. An OEM register is also utilised to track model issues and solution pathways that can be leveraged across projects. More accurate modelling and understanding of plant behaviour will provide greater confidence in real power system performance.

Active power control and reactive power capability continue to be the generator performance clauses with the highest rate of non-compliance, as specified under NER S5.2.5.14, S5.2.5.13 and S5.2.5.1. During major contingency events, inadequate generator performance (particularly deficiencies in active and reactive power control or capability) may lead to adverse and unforeseen system impacts. This level of risk increases as the number of generators with unresolved

[83] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2023/preliminary-report-vic-market-suspension.pdf?la=en.

[84] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf?la=en.

[85] See https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/connections-scorecard/2025/december-2025.pdf.

[86] See https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-integrated-system-plan-isp.pdf.

non-compliances grows. This risk is further exacerbated where performance issues are not adequately captured in power system models, as modelling used to assess post-contingent system behaviour may overestimate the capability delivered in practice by an aggregation of generators, resulting in optimistic assessments of the power system's ability to remain within the technical envelope following network contingencies.

Changes in plant operation due to changing energy and market dynamics may result in unintended performance outcomes. AEMO is aware of instances where plant changes, implemented to improve flexibility in response to changing energy and market dynamics, have led to unanticipated performance outcomes. To reduce the impacts of plant changes on power system security, the following should be considered:

- ensuring all generator performance standards impacts are reviewed – this should include a review of the impacts on overall performance and how the generator performance standard maps to controls and logic, and
- assessing all changes at a detailed level, including control logics – legacy logic that may not have been activated at previous operating conditions, for example minimum and maximum active power levels, should also be reviewed.

5.8 Network interface boundary risks

Network augmentation and connection assessment is often completed within a single NSP's study boundary. This can be efficient, but it may miss impacts that emerge at neighbouring network interfaces. These risks are most acute where connection requirements, operating limits, or study assumptions differ across adjoining networks.

5.8.1 Aggressive primary frequency response (PFR)

Fast tuned IBR response can create operational and protection challenges if not well-coordinated. The 2025 GPSRR identified that fast-acting IBR can, under some conditions, contribute to instability or overload on key transmission circuits if settings are not appropriate. A wide allowable range for droop settings means active power response can vary materially between projects. For large IBR or BESS connections in concentrated areas, aggressive droop settings could drive large and rapid changes in power flows. This may impact voltage or transient stability and or contribute to unintended protection operation, including through transient fault current contributions driven by the speed and magnitude of response. This risk is managed through connection studies and performance standards, but if the impact is in a neighbouring network, it may not be identified.

5.8.2 New connections on single line configurations

Increases in the largest generator or load contingency size within a region may have further impacts in neighbouring regions. There has been increased interest in the NEM to connect large plant on a single circuit at sizes above the current largest generator or load contingency size within a region. While allowing larger contingency sizes minimises the cost of infrastructure required to connect to the network, there will be additional costs related to the impact on internetwork transfer limits or the procurement of ancillary services. When NSPs consider allowing a larger contingency size, studies are typically undertaken within the local network to confirm no adverse impacts. However, an increased contingency size may impact neighbouring networks that are not consulted under normal procedures. This creates a risk where a contingency size acceptable within one network may not be tolerable on an adjoining network, particularly for connections located close to interconnectors. If unmanaged, this could lead to credible contingencies that exceed the capability of neighbouring networks and could introduce internetwork risks that require mitigation.

5.8.3 Frequency control ancillary services response under N-1 constrained conditions

Aggressive FCAS response may contribute to security risks under N-1 conditions. Section 3.2.4 of the 2025 GPSRR[87] highlighted risks associated with constrained operation on radial networks with multiple connections. It discussed how the loss of a single line could require significant reduction in generation output to ensure the system remained secure for the loss of the other line. A related issue under N-1 conditions is that while BESS or other generation may be constrained following the first credible contingency, they may still be enabled or expected to provide FCAS. The interaction between network constraints and FCAS response under N-1 conditions is not yet fully characterised, in particular the system outcome when a constrained plant responds to a frequency event remains uncertain in some scenarios. If unmanaged, the consequence can be exceedance of post-contingent network limits. This risk is currently being monitored as part of ongoing connection assessments and operational experience.

5.9 Emerging technologies in the NEM

The influence of BESS in the system is expected to increase due to the large quantity of projects currently in the connection pipeline. As the number of BESS connections increases, their potential to impact power system operations will also become more significant. There are a number of factors that should be considered with the emerging rise of BESS in the NEM. These are discussed in the sections below.

5.9.1 Rapid battery energy storage system uptake in the NEM is forecast to continue

Utility-scale BESS are among the fastest-growing technologies being integrated across the NEM. This growth reflects the wide range of services BESS can provide to power system operation, including rapid injection or absorption of active and reactive power during network events, short-duration energy storage to manage supply demand variability, and the emerging provision of additional services enabled by GFM converter controls. This growth is further supported by declining battery costs. Approximately half of the BESS projects in the NEM's existing connections pipeline are proposed to operate with GFM capability.

AEMO's 2026 ISP indicates that the forecast uptake of utility-scale storage has increased substantially relative to previous expectations. Utility-scale BESS capacity in the connections pipeline has grown sharply, increasing from approximately 3 GW in September 2022 to approximately 26 GW in 2025. This increase is expected to continue, with a significant portion of future growth forecast to occur between 2028 and 2030, and New South Wales projected to accommodate the highest level of BESS during this period.

5.9.2 Battery energy storage systems may lack dynamic performance during local disturbances

The dynamic performance of GFL BESS may not support FCAS delivery under all grid disturbance conditions. While BESS typically exhibit superior FFR capability compared to other generation technologies and frequently dominate fast FCAS markets, AEMO has observed instances where local grid disturbances have adversely impacted this response, resulting in a reduced capability to deliver 1-second raise and lower FCAS services.

[87] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

Performance data indicates that a significant proportion of the current BESS fleet exhibits FFR delays of approximately 500 ms to 1 s. This behaviour is due to the configuration of FRT controls, which are often optimised for market operation instead of fast support to the power system. This has been observed to occur during network disturbances where a voltage depression is seen at the point of connection of BESS. In these instances, FRT control logic may sustain pre-fault active power levels following fault clearance, with limited response to the underlying frequency excursion. This condition may persist for 500 ms up to 1 s in some instances. This delayed response reduces the effectiveness of these BESS in reducing RoCoF and limiting the magnitude of frequency excursions.

FFR delays are typically observed for BESS with GFL control. This behaviour has been observed for BESS facilities configured with GFL controls, whereas GFM-configured BESS have generally delivered the expected active power response following fault clearance. However, note that there may be some instances where in-fault performance of GFM BESS may have an adverse impact on system frequency. In conditions where there is a coincident aggregate disconnection of DPV systems, which is typical during MSL conditions, these BESS response delays further exacerbate overall system frequency performance.

BESS FFR capability is currently tested using pure frequency events. This current test approach does not reflect real-world operating conditions where voltage disturbances are often a trigger for a system response leading to frequency excursions. This method overlooks the interaction between FRT behaviour and FFR performance. To account for this interaction and confirm BESS capability to provide FFR, AEMO is considering a realistic test scenario that simulates the activation of BESS FRT performance schemes during FFR testing for FCAS registration. AEMO is also considering the following potential options:

- **introducing dynamic performance standards** for new BESS integrated into the NEM,
- **creating incentive mechanisms** to encourage existing systems to upgrade control and FRT schemes, and
- **prioritising fast-responding or GFM BESS for future deployments** to ensure adequate performance during operating conditions with higher DER and IBR penetration.

5.9.3 Monitoring of battery energy storage system response to remote frequency events will continue

The 2025 GPSRR found that risks associated with regional concentration of BESS were manageable under the forecast connection outlook at the time of assessment. AEMO's assessment in the 2025 GPSRR identified that high concentrations of BESS within a single region could lead to stability challenges across alternating current (AC) interconnectors and other key transmission lines. It was found that the projected distribution of new BESS connections across the NEM was sufficiently dispersed to avoid over-concentration within any single mainland region. Internetwork stability was also observed to improve with the development of more diverse interconnector pathways, including the commissioning of PEC and other prospective future internetwork augmentations.

The 2025 GPSRR recommended that continued monitoring of BESS integration across the NEM is required to manage emerging system security risks associated with the scale and control of connected BESS. This monitoring should consider not only regional installed capacity, but also BESS frequency control settings that influence dynamic performance during disturbances. As an increasing proportion of GFM BESS are integrated, there is also a need to monitor inertial control settings in addition to frequency droop parameters. This will ensure aggregated GFM BESS behaviour continues to provide effective RoCoF suppression and frequency containment following network faults and frequency events, without resulting in a disproportionate frequency response from any single NEM region.

Additional BESS capacity monitoring may be necessary in New South Wales and Queensland. For New South Wales, increased focus may be required due to the forecast BESS capacity growth exceeding that of other NEM regions. However, the system security risk associated with increased BESS concentration in New South Wales may not be significant given its central location in the NEM, with multiple interconnector pathways to other regions compared with radially connected regions such as Queensland. Queensland's AC connection to the rest of the NEM remains solely via the double circuit QNI and therefore continues to represent a more vulnerable interconnection, particularly given the stability challenges observed across the QNI corridor as discussed in Section 3.3.2.

5.9.4 Market aggregators of distributed battery energy storage systems could present risks at large scales

The aggregation of large quantities of distributed BESS may begin to present material risks. The integration of smaller distributed BESS facilities, including behind-the-meter and community-scale installations, is increasing across the NEM. In some instances, these facilities are aggregated to operate as a VPP, allowing large numbers of small units to be coordinated through a centralised controller. Aggregator control strategies are typically designed to optimise market revenue for asset owners, with dispatch decisions informed by factors such as five-minute spot prices, pre-dispatch prices, and BESS operating constraints. These strategies do not generally explicitly consider the broader power system impacts of aggregated responses and may be open-loop in nature, presenting maximum discharge rates during high price periods and maximum charging during low price periods.

Some aggregators have exhibited step changes in active power operating points driven by revenue-optimisation algorithms. Aggregators have already been observed operating via step changes at the beginning of trading intervals in the NEM. This behaviour contrasts with scheduled and semi-scheduled generators in the NEM that operate via ramping between operating targets at the commencement of a new trading interval. Under certain spot price conditions, aggregator operation may result in rapid variations in BESS from full charge to full discharge, or vice versa. While such behaviour does not impose material impacts on power system frequency at a small scale, the aggregation of increasing volumes of BESS under common controls has the potential to present emerging system-level risks. There are currently limited obligations on aggregators governing the nature or rate of their response to spot market outcomes, which may require further consideration or assessment as aggregated distributed BESS capacity meets certain thresholds.

5.10 Extreme weather conditions

Extreme weather conditions are a major cause of non-credible contingencies, particularly related to the loss of transmission lines. Bushfires, cyclones, storms and lighting can all have significant impacts on the power system when major transmission lines are affected. Data available to AEMO's forecasting teams suggests that the extreme end of weather conditions being experienced today is very similar to what was experienced five years ago. However, there are trends indicating a future increase in the severity of some factors such as temperatures, winds speeds and humidity, as well as changes in the geographic distribution of weather events over the typical life of assets being planned in the NEM. The power system is also becoming increasingly dependent on weather due to more geographically dispersed network infrastructure, as well as significant growth in the number of generators that rely on wind, solar and hydro for power generation.

5.10.1 Changing weather patterns across the NEM

Weather conditions have been observed to be changing across the NEM. Research indicates that climate change is expected to influence the atmospheric conditions that are conducive for severe thunderstorms, including supercells and convective downbursts[88], however major uncertainties remain regarding how their frequency, intensity and spatial distribution will change in the future. This is an active area of research within the Bureau of Meteorology, CSIRO and the Australian Climate Service.

Under a warming climate, the distribution of tropical cyclones may shift further from the equator, which poses increased risk for parts of the NEM that have rarely experienced these conditions, especially if older network infrastructure there was not designed to withstand these conditions. Despite a slight decline in the total number of tropical cyclones in the Australian region, evidence suggests that a higher proportion are reaching Category 3 or above, indicating an increase in cyclone severity. Additionally, the intensity of extreme rainfall events from cyclones and storms is increasing, which can result in certain disruptions, such as to the operation of coal mines.

Typically, the majority of severe weather events are very localised and particularly difficult to forecast, with most modern tools only capable of flagging wider high-risk areas. Unpredictable and highly localised weather events, such as convective downbursts, can locally influence power system behaviour and provide operational challenges.

Historically, temperature has been the key driver of demand. There is a slight trend of increasing temperatures with summers becoming hotter, although the impacts of other climate drivers like the El Niño–Southern Oscillation are giving stronger year-on-year variability than the underlying growing trend in temperatures. Winters are also becoming warmer. Significant cold spells are still present, but are becoming less common. Extreme heat events have increased in frequency, and this trend is expected to continue, resulting in increased energy demand. There has been an increase in extreme fire weather, and a longer fire season across large parts of the country. This trend is expected to continue, with subsequent risks to transmission operations.

5.10.2 The power system is becoming more dependent on weather

The uptake in renewable energy sources may result in a power system that is more dependent on weather conditions. This is experienced primarily through solar and wind, but there are other ways weather may impact the operation of the NEM, as outlined in the sections below.

Distributed PV

Any wide-scale changes that DPV encounters will have significant impacts on the power system. This can be seen when unexpected cloud cover shades a large portion of DPV in a region, leading to rapid changes in operational demand. However, there are some factors that are reducing correlation with weather. While DPV capacity is increasing across the NEM, its impact is becoming less correlated or independent of weather conditions as additional measures are implemented, for example:

- Emergency backstop capability implementation is underway and will provide a mechanism to reduce DPV output irrespective of weather conditions.

[88] See https://www.bom.gov.au/weather-and-climate/past-weather-and-climate/state-of-the-climate-2024/report-at-a-glance#bom-anchor-list__item-key-points-australia and https://reg.bom.gov.au/state-of-the-climate/2024/documents/2024-state-of-the-climate-references.pdf.

- Consumers are responding to price signals from the market, where DPV exports may be more closely linked to price rather than weather conditions specifically.
- Some NSPs are implementing dynamic export limits, which will restrict solar exports during distribution network congestion.

Large-scale wind and solar

Increasing temperatures are expected to have an impact on large-scale wind and solar farms. These types of plant typically have cut-out maximum operating temperatures to preserve the safety of the plant during extreme weather conditions. This creates an operational issue where wind and solar farms can disconnect and result in operational challenges.

Strong wind may also cause wind farms to cut out for safety reasons should they reach their designed maximum wind speed limit. As storm fronts move through an area, it may affect several wind farms in the vicinity and cause significant generation ramping.

Other weather-based impacts

There are other weather-based impacts on the power system, such as:

- Solar eclipse – this will impact solar generation for no longer than a few hours, and should be more predictable to prepare for due to the certainty of timing, provided sufficient generation is available to support the grid during this period.
- Supercell and convective downbursts – supercell thunderstorms can produce large hail and tornadoes and may result in convective downbursts. However, convective downbursts do not only occur during supercell thunderstorms and may occur in less organised storms. While giant hail may be a risk to solar panels, the affected area is typically very localised, and the most significant risk is from the extreme wind caused by these weather phenomena. Frequency and distribution of severe storms may shift in the future, but this is highly uncertain and is an active area of research.
- Cyclones – tropical cyclones can produce destructive wind gusts which can threaten transmission assets. Intense rainfall and associated flooding can hamper recovery efforts and disrupt coal mining. Cyclone distribution may shift southwards as the climate warms, potentially bringing risks to areas that have not historically been subject to cyclones.
- Droughts – hydro generation and storage levels may be reduced, as may the availability of cooling water for thermal power plants. Furthermore, the accumulation of dirt, salt spray and industrial contaminants can build up on power line insulators during dry periods. These may lead to leakage currents and surface electrical discharge when combined with moisture from fog, dew, or light rain.
- Warmer temperatures – with climate change, the chance of bushfires or extended heatwaves may be increasing, which can impact the operation of transmission lines. This could lead to lower transmission line capacities where dynamic line ratings are utilised. HVDC or other thermal limits would be reached faster. There was a scenario that occurred in Victoria in January 2026 where a line was derated from 500 MVA to 70 MVA due to high temperature. This has potential to result in significant operational issues if it coincides with high demand or other network outages.

5.11 Frequency risks

Current and emerging risks related to frequency control and regulation continue to be monitored in the NEM, particularly as synchronous units retire and the quantity of IBR in the network increases.

5.11.1 Frequency regulation risks due to non-credible regional islanding

Frequency regulation risks require greater consideration during islanded conditions. NEM regions may experience poorer frequency regulation during islanding or highly constrained interconnector conditions, particularly where local frequency control resources are limited. This risk is most relevant for South Australia and Queensland, where islanding events can result in rapid changes to frequency control requirements. Operational mitigations are in place for credible scenarios, with constraints to ensure sufficient FCAS is precured in at risk regions. For non-credible islanding scenarios, reliance on effective EFCS is required. This residual risk is being reduced in Queensland, with recent growth in battery capacity improving local frequency response, and South Australia, with PEC Stage 2 reducing the likelihood of islanding as it introduces a second connection from South Australia to the rest of the NEM. AEMO continues to review and track this risk as part of ongoing operational assessments.

5.11.2 Semi-scheduled inverter-based resources dispatch error

Under-delivery by semi-scheduled wind and solar units can contribute to frequency drift even in the absence of a contingency event. Aggregate forecasting error across increasing volumes of IBR has resulted in frequency often moving very close to or sometimes outside the normal operating frequency band (NOFB). This situation is often attributed to forecasting inaccuracies involving several semi-scheduled units, coupled with ramping limitations and control challenges at certain plant. The increasing penetration of BESS in NEM has led to a more aggressive PFR, which can help stabilise frequency; however, it is unable to recover the frequency to the 50 Hz level. During such instances there is a risk that contingency FCAS from BESS are consumed leading to sub-optimal frequency performance if a contingency were to occur simultaneously. AEMO is monitoring this performance and engaging with proponent on rectifying the issues and is also assessing the regulation FCAS volumes, particularly concentrating on cases where regulation FCAS reserves have been exhausted during extended frequency deviations from 50 Hz. AEMO is evaluating options for modifying procurement of regulation amounts to sustain frequency performance in the NEM.

5.11.3 Semi-scheduled primary frequency response implementation

Several semi-scheduled units face technical limitations that prevent them from following dispatch targets and providing PFR at the same time. For certain OEM implementations, these control modes are mutually exclusive, which can lead to reduced PFR during disturbances and prolonged under-delivery following low dispatch targets. AEMO is currently investigating improved compliance monitoring of under-delivery, along with working with participants to improve performance.

5.12 Cyber security

As the power system increasingly incorporates internet-connected devices into business and operational processes, this delivers a range of benefits for NSPs and system operators. However, it also introduces new opportunities for interference.

Increased internet connectivity applies to both large-scale generators, CER and DER. As the capability of NSPs and AEMO to interface with generation assets expands, so does the risk that cyber-attacks could exploit these same interfaces.

5.12.1 Phishing, ransomware and other opportunistic cyber attacks

The energy sector is commonly targeted for ransomware or phishing attacks. The energy industry has many critical entities that may be targets of ransomware or phishing attacks. Any attack on critical energy infrastructure operators will reduce their ability to provide essential service to the power system. Human involvement in business operations can expose organisations to external inputs, creating a risk that social engineering or phishing attacks may be used to gain access to sensitive data and critical systems. In addition, ransomware – a class of attack which encrypts data to render systems inaccessible – remains a present concern. While these attacks historically focused on data encryption to extract payment, they now also involve the theft of sensitive information, which may be released if financial demands are not met.

Beyond these attack classes, a range of threat actors may opportunistically exploit vulnerable IT systems. Although such attacks are typically opportunistic rather than targeted at specific energy system functions, their impact can still be significant, particularly when they coincide with periods of operational or market stress.

5.12.2 Cyber security attacks by sophisticated actors

Sophisticated threat actors may also target the energy sector. Globally, sophisticated threat actors have been observed accessing critical energy systems, seemingly prepositioning for disruptive or destructive activity in which infrastructure could go down. In particular, threat actors have been observed establishing persistent access to systems with potential to disrupt the operation of power distribution and DER generation.

5.12.3 Ongoing importance of consumer/distributed energy resources and increased network density

The growing influence of CER and DER corresponds with a greater potential impact if targeted via a cyber attack. The continued expansion of internet-connected devices in generation units broadens the potential cyber attack surface alongside the complexity of managing energy networks' IT environments. CER/DER in particular represent a step change, with large numbers of internet-native generation devices and internet-enabled control aggregation. The aggregation of device control leads to increased concentration of potential impacts from an individual cyber incident.

CER are becoming increasingly integral to power systems, and their reliance on internet-based communications for control and monitoring make them susceptible to cyber attacks. Interference with these controls can result in changes to CER output and impact power system security. Similar risks are present for the following technologies:

- smart loads such as air-conditioners with internet connections,
- electric vehicles and charging stations,
- smart meters, and
- home battery storage.

It is important that, as these devices are becoming increasingly connected to the internet and communications systems, cyber security is considered from the outset. Secure installations with appropriate standards, encryption and authentication are the best form of protection, rather than relying on secondary approaches such as monitoring, detecting, defending and recovering from cyber attacks.

5.12.4 Supply chain and vendor risk

Supply chain risks must also be considered. As detailed above, systems across the energy sector are increasingly dependent on complex technology supply chains involving device manufacturers, software vendors and cloud-based service providers. Under standard IT practices, it can be difficult to fully exclude the supply chain risks such as unmaintained dependencies, compromised systems with exposed back doors, or information architecture which processes data outside an operator's control. Measures such as vendor mapping, strengthened contract measures, system auditing and assessing remaining dependency exposure may help mitigate these risks.

The supply chain of devices used in the NEM will become increasingly important as the complexity and number of devices connected to the internet increases. It will become difficult to ensure that there are no supply chain issues such as cyber compromised systems that can be activated via back door mechanisms. Even if such systems are identified and replaced, the same risk may still be present for any replacement products. To mitigate this risk, a focus on engineering out vulnerabilities, enhancing resilience and mitigating risks without wholesale replacement, is recommended under the consequence-driven cyber informed engineering methodology[89].

5.12.5 Actions to address cyber risks in the NEM

Cyber risks are actively considered in the NEM, with a number of initiatives underway to identify and address these risks. Work currently being progressed includes:

- AEMO delivers the Australian Energy Sector Cyber Security Framework (AESCSF) maturity program to lift maturity across the energy industry.
- Under the Australian Energy Sector Cyber Security Response Plan (AESCIRP), AEMO coordinates major NEM-wide cyber responses.
- Industry uses the AESCSF and other frameworks to improve cyber maturity, identifying gaps and aligning uplift with security of critical infrastructure (SOCI) requirements and sector expectations.
- The updated AS 4755.2 standard has introduced a section on cyber security of demand response systems.
- Adoption of IEC 62443 and 62351 improves the security and reliability of operational systems.
- Implementation of CSIP-AUS supports secure CER and DER integration by providing a common protocol for visibility and dynamic control.
- The Department of Home Affairs is executing the Cyber Security Strategy 2023-2030 and maintaining the SOCI program, which includes critical energy system assets.
- Under SOCI, enhancements to Critical Infrastructure Risk Management Program (CIRMP) obligations have been proposed which include requiring greater cyber security maturity as well as mandating supply chain mapping and monitoring of vendors of concern to mitigate supply chain risks.

[89] See https://inl.gov/national-security/cce/.

- CER governance reforms including the CER Roadmap and CER Cybersecurity Roadmap address cybersecurity risks of emerging technologies.

5.13 Cyber threat from frontier AI models

Recent advice from the Five Eyes[90] cyber security agencies highlights that frontier AI models[91] are rapidly changing the cyber threat environment, with material changes expected over months rather than years. These models are anticipated to significantly increase the speed, scale and sophistication of cyber attacks while lowering the technical barriers for malicious actors. For the energy sector, this has implications for both IT and operational technology environments, including systems relied on for power system operation, generation and network control.

5.13.1 Paradigm shift in the technical capability of cyber threats

Frontier AI is expected to substantially increase the capability and scale of cyber threats. Frontier AI models have demonstrated advanced capabilities in reading, reasoning and manipulating code, enabling greater automation across the cyber attack chain. Assessments indicate that these systems can assist malicious actors in conducting multi-step cyber attack scenarios and can reduce the need for specialised knowledge when targeting industrial systems. This increases the likelihood that a broader range of threat actors could attempt attacks against critical energy sector assets. While these models are not yet creating fundamentally new vulnerabilities, they are amplifying cyber threats and accelerating the exploitation of existing weaknesses.

AI-enabled cyber threats may increasingly extend to operational technology environments. Assessments of recently developed AI systems have demonstrated the potential to support multi-step cyber attacks involving industrial and operational technology environments. While these systems currently appear less capable in operational technology environments than conventional IT systems, they have demonstrated domain-specific knowledge of cyber attacks against industrial control systems and infrastructure. This may reduce the specialised expertise previously required to target critical infrastructure, increasing potential exposure across power system assets, network infrastructure and generating plant.

5.13.2 Energy sector considerations

The energy sector may face heightened exposure due to operational complexity, legacy assets and supply chain dependencies. Critical infrastructure sectors, including energy, are particularly exposed to AI-enabled cyber threats because of complex operating environments, legacy systems and interconnected supply chains. Lower barriers to entry mean that poorly secured or legacy systems may become more attractive targets for increasingly capable threat actors. For the NEM, the implications extend beyond individual organisations, as cyber vulnerabilities affecting key market participants, suppliers or operational service providers could impact operational continuity and market confidence.

Cyber resilience must be treated as a core business and operational risk rather than solely an IT issue. The Five Eyes agencies emphasise that cyber resilience is central to operational continuity and market trust, and should be managed as a leadership and governance responsibility. Businesses must ensure that foundational controls are in place, tested, and capable of

---

[90] The Heads of cyber intelligence across Australia, Canada, New Zealand, the United Kingdom and the United States.

[91] See https://www.cyber.gov.au/about-us/view-all-content/news/frontier-models-and-their-impact-on-cyber-security-update.

performing under real incident conditions. Priority actions include reducing exposed attack surfaces, accelerating patching, addressing legacy systems, strengthening identity and access controls, and preparing for incidents before they occur.

5.13.3 Cyber maturity uplift

Ongoing cyber maturity uplift will be required as frontier AI accelerates changes in the threat environment. Security agencies have advised that traditional cyber security controls such as patching, network monitoring and access control remain fundamental mitigations that will become increasingly important as cyber threats grow in sophistication. Agencies also recommend awareness of the exposed attack surface, including adopting security by design and a focus on supply chain monitoring to identify open source or unmaintained software which may be vulnerable to automated vulnerability discovery[92].

AI may provide opportunities to improve cyber defence, but adoption requires strong governance and oversight. While there are risks associated with the emergence of AI, there are also opportunities to utilise it to improve cyber defence[93,94]. Businesses that can successfully integrate AI tools into security operations will be able to detect vulnerabilities earlier and respond faster to incidents. Other potential defensive applications of AI may assist organisations in managing a greater volume of cyber threats such as alert monitoring, network remediation and threat analysis. However, AI-enabled defensive tools will require strong governance frameworks and human oversight due to their evolving and potentially unpredictable behaviour. Realising the benefits of AI for cyber defence will depend on implementing appropriate controls, assurance processes and operational governance arrangements.

5.14 International system operator risk considerations

The International System Operator Network (ISON) brings together six system operators to share insights and align on shared priorities associated with operating power systems through the energy transition. Through ISON, system operators have noted common challenges relating to integrating and operating with very high levels of decentralised, inverter-based and variable generation, as well as broader changes to power system operation, technology, tools and governance.

5.14.1 Current and future risks relevant to the International System Operator Network and the NEM

Large power-electronic loads such as data centres introduce emerging operational and modelling challenges. Discussions held by ISON indicated that these loads may exhibit behaviour that is sensitive to voltage and frequency disturbances and may contribute to large, rapid changes in demand. Hence, inadequate performance standards or modelling approaches for such loads could increase the risk of system instability.

Oscillation detection and tracing remain an active focus for system operators. ISON has identified the need for methods and tools for off-line and on-line analysis and detection of instabilities including oscillations. International incident reviews have highlighted forced oscillations as an initiating driver in major events, reinforcing the importance of wide-area monitoring and improved detection approaches.

92 See https://www.protectivesecurity.gov.au/system/files/2026-05/pspf-policy-advisory-001-2026.pdf.

93 See https://www.ncsc.gov.uk/blogs/why-cyber-defenders-need-to-be-ready-for-frontier-ai.

94 See https://www.cyber.gov.au/business-government/secure-design/artificial-intelligence/opportunities-for-ai-in-cyber-defence.

Voltage control is a material contributor to major outages. Recent event analysis describes instances where oscillation management actions and reactive power conditions contributed to upward voltage trends. These types of interactions illustrate the importance of robust voltage control arrangements across both transmission and distribution interfaces.

Model accuracy and fit-for-purpose analysis capability remain key enablers for managing emerging phenomena. International reviews note cases where observed system behaviour (including voltage collapse following a contingency) was not predicted by simulation models. These discrepancies were linked to inverter-based plant response and controller behaviour.

5.14.2 Actions taken to manage risks considered through the International System Operator Network

There are several actions underway through ISON and related AEMO activities to improve understanding of the abovementioned risks and apply relevant learnings to the NEM. These include:

- **AEMO maintains ongoing structural engagement through ISON.** System operators are actively sharing technical expertise on large power-electronic loads such as data centres, oscillation detection and voltage control. This supports AEMO in the early identification of risks and potential mitigations applicable to local systems.
- **AEMO is collaborating with ISON members on evaluating tools for oscillation detection.** This includes evaluation of oscillation detection algorithms, including regular discussions and consideration of in-person engagement to support deeper technical exchange.
- **ISON is uplifting modelling capability.** ISON is progressing work on a shared modelling roadmap, supported by system operators and vendors, to address gaps in plant modelling, validation, and analysis workflows that have contributed to poor prediction of system behaviour in major events.

5.15 Power system model adequacy and accuracy

AEMO uses modelling data and simulation models to assess technical performance standards and determine power system operational limits. Power system models are used for purposes ranging from assessing the security of the system in real-time operations to developing constraints, limits and designing power system requirements in planning and connection studies. AEMO relies on adequate and accurate power system models to fulfil its security and reliability functions.

Key NER obligations that support the effective management of power system models include:

- S5.5.7(a)(3) – AEMO defines power system model requirements through the Power System Model Guidelines. AEMO collaborates with NSPs through the Power System Model Reference Group (PSMRG) under the NEM Operational Committee (NEMOC) and consults with industry under S5.5.7(f).
- 5.2.3(d)(8) – NSPs are required to maintain power system models for planning and operational purposes.
- S5.2.4(d) – participants are required to provide model information including updates.

There are a number of challenges related to power system modelling that must be addressed to support AEMO in meeting its obligations above.

AEMO is currently considering a number of key power system modelling risks. Maintaining adequate and accurate power system models requires continual maintenance of existing models, addition of new models or network augmentations, implementation of upgrades to improve efficiency, and the incorporation of new features. These are risks that AEMO is currently considering related to power system modelling:

- **Reliance on third party software packages, models and servers** – there are risks associated with dependence on third parties relating to simulation software, associated tools including compilers, models and computational hardware.
- **Challenges in managing model quality and access to a centralised model data base** – it takes significant business effort to maintain a centralised model data base with high quality models. The increasing number and complexity of models further increases the effort required, with potential to reduce business efficiency, and lead to sub-optimal study outcomes if model data quality is affected.
- **Increasing complexity of models resulting in significant run time increases or potential for modelling errors** – the increasing complexity of the power system is leading to increased modelling complexity such as the introduction of models for new generators, BESS, IBLs and DPV. As these models are integrated into the wide-area model, increases in complexity may lead to increased simulation run times. Increased run times degrade the efficiency of using the model and reduce the productivity of users. Increased complexity also introduces potential sources for error.

Actions are currently underway to address power system modelling challenges. Maintaining accurate power system models is critical to assessment of power system performance and risks in the NEM. AEMO and industry rely extensively on power system models to support decision-making across the NEM, including for network planning, assessment of connections, defining power system operating limits and assessment of risks and mitigations. As such, maintaining accurate and fit-for-purpose models is essential to sound decision-making and the secure operation of the power system. AEMO is currently progressing a range of actions to identify and resolve power system model issues, including:

- centralising models used for specialist studies to improve usability for a range of studies,
- improving integration of market modelling and engineering analysis tools to support planning for operability,
- evaluating modelling tools, analysis approaches and hardware capabilities to ensure that simulation times remain tenable,
- assessing ability to apply tools used in the offline environment in the real time environment,
- continuously reviewing model accuracy and tracking, logging and resolving model data issues in collaboration with network businesses, participants and OEMs,
- routine assessment of model performance against system disturbance events,
- migration to latest software versions to leverage capabilities, and
- provision of modelling information to participants through the data request process, as well as NSPs directly through the AEMO Modelling Platform and provision of Power System Computer Aided Design (PSCAD)™ models under 4.6.6.

AEMO continues to uplift its modelling capabilities where possible to best support system security in the NEM.

6 Performance of existing emergency frequency control schemes

In addition to the evaluation of the selected priority risks, the GPSRR also provides an overview of risk mitigation measures encompassing existing EFCSs, operational capabilities and other emerging risks in the context of an evolving power system. EFCSs are emergency control schemes that are relied on to maintain power system frequency within the operating limits specified in the Frequency Operating Standard (FOS)[95] following the occurrence of a non-credible contingency event.

6.1 Over frequency generation shedding review

OFGS schemes operate to trip generators for extreme or high consequence over-frequency events. At present, OFGS schemes are in operation in Tasmania, South Australia and Western Victoria. An OFGS is also in the implementation phase in Queensland. The following updates relate to improvements that are being pursued or planned to improve OFGS operation in different regions:

- **South Australian OFGS:**
  - The implementation of OFGS updates in South Australia is still underway with some delays to the delivery schedule. ElectraNet has approved change management documentation for upcoming plants which will be ready to begin implementation once previous updates have been completed.
  - A South Australian OFGS constraint was implemented early this year to account for the increased South Australian export capacity with PEC Stage 1 and the increased Heywood limit. This includes the South Australian OFGS wind capacity available and the BESS footroom.
- **Queensland OFGS:**
  - The Queensland OFGS implementation includes:
    - Energy Queensland is progressing implementation for seven solar farms, with two expected to be completed by Q3 2026.
    - Powerlink is coordinating implementation across 18 facilities including a mix of wind, solar and synchronous generation. Six of these have been fully implemented and several others have settings in place with documentation to be completed.

6.2 Emergency under frequency management

UFLS is a last resort "safety net", designed to prevent black system events when severe non-credible generation contingencies occur and the resultant drop in frequency has not been arrested by PFR and FCAS. It involves the automatic disconnection of load circuits to rebalance supply and demand. Increasing levels of generation from DPV are reducing the

[95] Effective 9 October 2023, at https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20Operating%20Standard.pdf.

load on UFLS circuits and reducing the effectiveness of UFLS. With very high levels of DPV generation, UFLS circuits can operate in reverse flows, which means that in the absence of intervention, UFLS relays will act to disconnect circuits that are net generators, exacerbating the supply demand imbalance when they activate following an under frequency event.

Table 8 summarises key emergency under frequency management initiatives underway to mitigate risks associated with increasing DPV and its impact on UFLS.

Table 8 Summary of mainland NEM regions under frequency load shedding remediation projects

Region	Project	Lead	Status
NEM	2026 NEM UFLS adequacy review	AEMO	• AEMO plans to carry out NEM UFLS adequacy review in the second part of 2026.
	NSPs UFLS Workshop	AEMO	• In August 2025 AEMO held two UFLS workshops for all NEM and Western Australian Wholesale Electricity Market (WEM) NSPs. The purpose was to familiarise NSPs with the NER UFLS requirements and associate processes.
	Power System Simulator for Engineering (PSS®E) model uplift for non-credible events	AEMO	• AEMO is working on relevant protection models inclusion into PSS®E to enable more realistic non-credible events analysis. Protection models include UFLS relays, V/Hz, under-excitation, under/over voltage and overspeed protection.
South Australia	Dynamic arming[A] of UFLS relays (blocks UFLS activation if circuit is in reverse flow)	South Australian NSPs	• The Australian Energy Regulator (AER) approved SAPN cost pass-through application for the costs of dynamic arming equipment[B]. • SAPN will continue to monitor feeder flows, and maintain suitable coverage of dynamic arming over time, as more feeders pass reverse flow thresholds.
	Real time SCADA feed of UFLS load in each band	South Australian NSPs	• Real-time SCADA feed established for total South Australian UFLS load. • SAPN is now providing visibility of load in individual UFLS bands.
Victoria	Real time SCADA feed of UFLS load in each band	Victorian NSPs	• Real time SCADA feed established for the total Victorian UFLS load. • Ausnet is now providing visibility of load in individual UFLS bands.
	Addressing large wind/solar farms behind UFLS relays	Victorian NSPs	• AEMO report identified several UFLS circuits in significant reverse flows due to large wind and solar farms connected behind UFLS relays[F]. Recommended that NSPs seek rectification. • AusNet Transmission developed a rectification proposal and received approval from AEMO, but the AER determined that the proposal was not compliant with the Service Target Performance Incentive Scheme and could not be accepted, so AusNet Transmission proposed to remove reverse flowing feeders from UFLS system. A Jurisdictional System Security Coordinator (JSSC)-led review of respective load shedding procedures is in progress.
	Connections process updates to account for UFLS	Victorian NSPs	• AEMO report recommended that NSPs update their connections processes to minimise detrimental UFLS impacts for new generator connections[F]. • Under consideration via the Victorian Electricity Emergency Committee (VEEC).
	Adding new loads to UFLS	Victorian NSPs	• AusNet Transmission has conducted an audit of Victorian UFLS and identified “Stage 1” rectification actions, including circuits to be removed from the UFLS (in frequent reverse flows), and circuits to be added to UFLS.

Region	Project	Lead	Status
			• Proposed Stage 1 actions have been reviewed and endorsed by VEEC and Victorian DNSPs. AusNet Transmission is working with Powercor with the endorsement. • AusNet Transmission has received approval from AEMO, but the AER determined that the proposal was not compliant with the Service Target Performance Incentive Scheme and could not be accepted, so AusNet Transmission proposed removing reverse flowing feeders. A JSSC-led review of respective load shedding procedures is in progress.
	Explore options to address the impacts of distributed PV on the UFLS scheme.	Victorian NSPs	• AusNet Transmission is now looking to address the impacts of DPV on the UFLS scheme. Expected to be carried out in the 2026-31 period, the preliminary design works to start in 2026, subject to AER funding.
New South Wales	UFLS Adequacy Review	AEMO	• NSPs are working with AEMO on the latest UFLS and non-UFLS datasets in preparation for 2026-27 UFLS Adequacy Review.
	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to DPV[H]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	New South Wales NSPs	• NSPs to identify metering uplifts required, especially to identify UFLS circuits in reverse power flow.
Queensland	UFLS Adequacy Review	AEMO	• NSPs are working with AEMO on the latest UFLS and non-UFLS datasets in preparation for 2026-27 UFLS Adequacy Review.
	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to DPV[I]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	Queensland NSPs	• NSPs to identify metering uplifts required, especially to identify UFLS circuits in reverse power flow. Energy Queensland has completed excluding certain reverse flowing feeders.

A. AEMO (May 2021) *South Australian Under Frequency Load Shedding – Dynamic Arming*, https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.
B. AER (2022) *SA Power Networks – Cost pass through – Emergency standards 2021-22*, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322.
C. Further information on AEMO advice on delayed UFLS is provided in 2022 Power System Frequency Risk Review (PSFRR), Section 3.3.3 (July 2022), https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.
D. AEMO (August 2021) *Phase 1 UFLS Review: Victoria*, https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.
E. AEMO (May 2023) *Victoria: UFLS load assessment update*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2023-05-25-vic-ufls-2022-review.pdf?la=en&hash=CFDBA2D60117E8E7FE452B2C2F468B3B.
F. AEMO (August 2021) *Phase 1 UFLS Review: Victoria*, (Section 3.5, Section 4.1), https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.
G. AEMO (October 2023) *Under frequency load shedding: Exploring dynamic arming options for adapting to distributed PV*, https://aemo.com.au/-/media/files/initiatives/der/2023/dynamic-arming-options-for-ufls.pdf?la=en&hash=F6B7A015C8EB872C83513BA9C95EFE5B.
H. AEMO (December 2021) *Phase 1 UFLS Review: New South Wales*, https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.
I. AEMO (December 2021) *Phase 1 UFLS Review: Queensland*, https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

6.3 Future UFLS projects

AEMO's review of UFLS to date has identified a number of areas where further UFLS review or rectification should be explored. These are summarised in **Table 9.**.

AEMO is also currently working on the 2026-27 NEM UFLS adequacy review with support from NSPs. This review will involve a detailed evaluation of the regional UFLS bands and assess the performance and adequacy of the current UFLS schemes.

Table 9 Summary of future UFLS rectification areas

Area	Region	Notes
Review of UFLS settings	South Australia	• Review and possible optimisation of UFLS and OFGS settings following dynamic arming upgrades and 2026-27 UFLS Adequacy Review.
	Victoria	• Review and possible optimisation of UFLS and OFGS settings following dynamic arming upgrades and 2026-27 UFLS Adequacy Review.
	New South Wales	• Review and possible optimisation of UFLS settings following dynamic arming upgrades and 2026-27 UFLS Adequacy Review.
	Queensland	• Review and possible optimisation of UFLS settings following dynamic arming upgrades and 2026-27 UFLS Adequacy Review. • Review of the Queensland UFLS QNI inhibit scheme (inhibits operation of some UFLS bands under certain power system conditions). Review of ongoing scheme appropriateness and optimal settings is required.
	Tasmania	• The Tasmanian scheme must be reviewed, and possibly retuned, before Marinus Link is commissioned.
Real time SCADA feed of UFLS load in each band	New South Wales	• Capability to measure reverse power flow on circuits required. Likely requires significant uplift of infrastructure (for example, metering improvements to identify reverse flows accurately). • Real-time visibility should be explored to support improved real-time decision-making in low demand periods.
	Queensland	• Capability to measure reverse power flow on circuits required. Likely requires significant uplift of infrastructure (for example, metering improvements to identify reverse flows accurately). • Real-time visibility should be explored to support improved real-time decision-making in low demand periods.
PSS®E modelling uplift	NEM	• AEMO is working on the model uplift to improve the accuracy of simulations of non-credible events.

7 Review of incidents

AEMO reviews power system incidents of significance in accordance with NER 4.8.15, referred to as 'reviewable operating incidents'. AEMO identifies incidents as reviewable based on the criteria set out in NER 4.8.15 and the Reliability Panel's 'Guidelines for identifying reviewable operating incidents'[96].

For an incident to be reviewable, it must be a noteworthy or significant event on the power system and typically includes an impact to power system security, frequency, voltage or results in load disconnection or loss. Based on its experience reviewing power system incidents, AEMO has observed that unexpected power system responses often occur during such incidents. These can increase an event's severity through impacts such as:

- protection maloperation,
- unexpected load disconnection,
- issues with DPV FRT performance, and
- issues with generator FRT performance.

7.1 Summary of reviewable operating incidents in 2025-26

In financial year 2025-26 there were 21 reviewable operating incidents, including one major incident. Details of these reviewable operating incidents are in published incident reports, available on AEMO's website[97].

Figure 21 shows the root causes of incidents in 2025-26 compared to those in 2024-25. There has been an increase in reviewable operating incidents with protection/control system root causes. However, no trend or increased risk to the power system has been identified, as the failure mechanisms were not related.

Figure 22 shows the number of incidents AEMO has reviewed over the past six financial years, to demonstrate trends over a longer time period. These have also been separated into categories based on the criteria that classifies them as reviewable. The most common criteria of reviewable incident are those that involve non-credible contingency events impacting critical transmission elements. However, some incidents met multiple criteria, meaning they qualified under more than one condition for being classified as reviewable. These are typically more significant incidents. AEMO has also undertaken reviews of other incidents considered to be of significance at its discretion, consistent with the Reliability Panel's Guidelines.

[96] At https://www.aemc.gov.au/sites/default/files/2022-09/Final%20guidelines.pdf.

[97] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

Figure 21 Root cause of reviewable operating incidents, 2024-25 and 2025-26

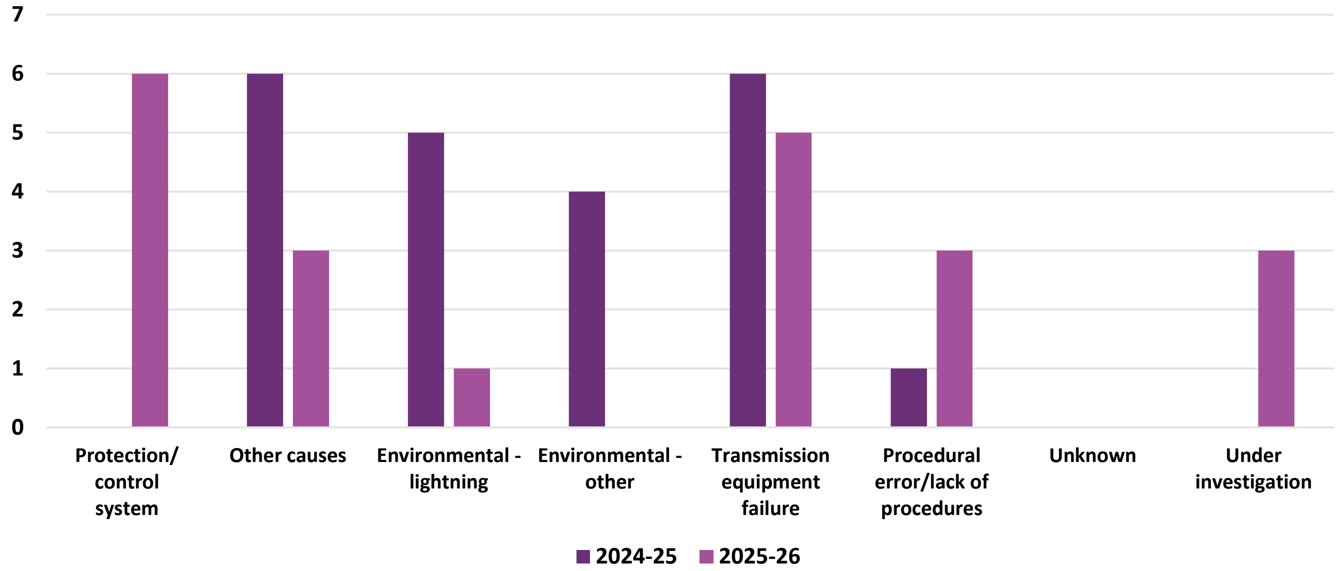
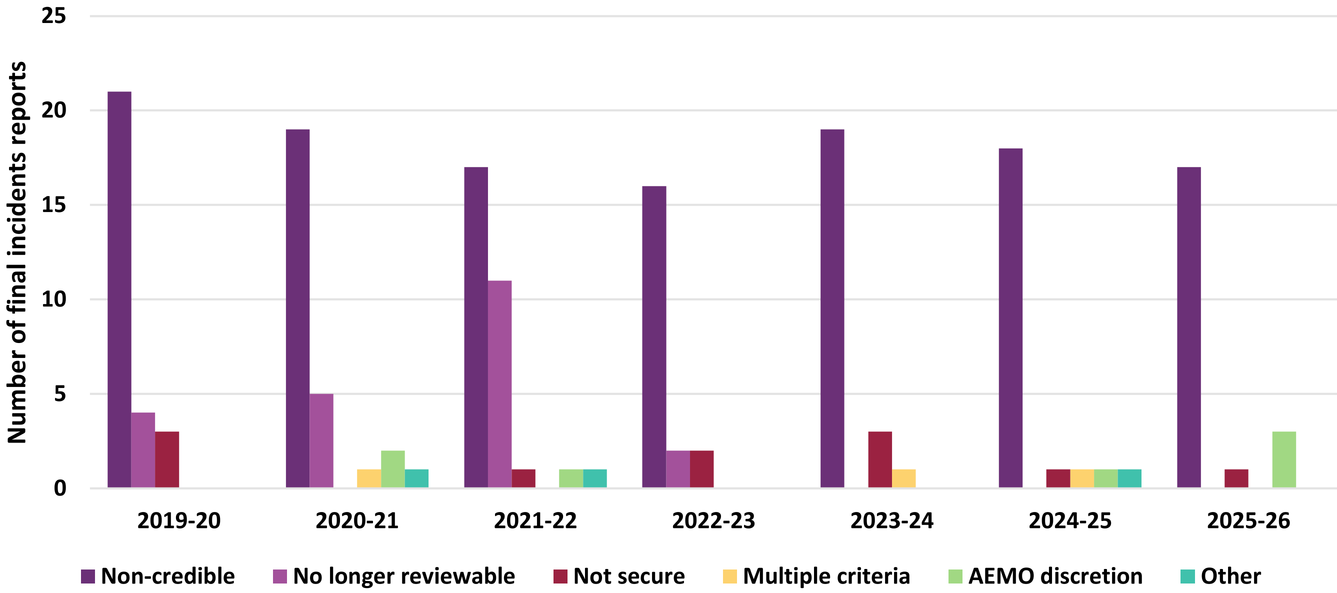


Figure 22 Reviewable incidents by criteria, 2019-20 to 2025-26



Note: The "No longer reviewable" category reflects incidents that were previously classified as reviewable based on criteria that have now been excluded in the latest Reliability Panel's guidelines.

7.2 Relevant recent incidents

Some reviewable operating incidents have highlighted potential risks to the power system that could lead to cascading failures or major supply disruptions. **Table 10** details recent incidents that are relevant to the GPSRR.

Table 10 Power system risks from recent reviewable operating incidents and market suspension events

Incident	Incident summary	Relevance to the GPSRR
Self-forecasting errors and frequency excursion on 19 August 2025[A]	An error originating from a single self-forecast provider altered the dispatch self-forecasts for 34 semi-scheduled generators and resulted in over-generation with a maximum dispatch error of approximately 1,700 MW. Mainland frequency exceeded the NOFB for approximately 15 minutes and peaked at 50.21 Hz.	Significant dispatch errors have the potential to cause frequency excursions which utilise the available FCAS and PFR. This makes the power system more vulnerable to frequency events while these events are ongoing. Should a contingency occur while the dispatch error is present it has the potential to cascade into a severe power system incident. Likewise, a prolonged and unmitigated large dispatch error has the potential to continuously increase or decrease frequency and thereby causing a cascading failure of the power system. AEMO plans to consider this risk in the 2027 GPSRR.
Trip of Yallourn 'W' Power Station unit 3 and unit 4 on 16 October 2025[B]	Yallourn 'W' PS unit 3 and unit 4 tripped due to the loss of cooling system water flow to both units. Following the non-credible contingency, AEMO issued directions to Jeeralang A2, A3 and B3 the meet the Victorian system strength requirements provided in limits advice. The solutions available to AEMO operators on the day were limited due to fast-start requirements and unit availability.	As discussed in Section 2 of this GPSRR, this incident highlights how AEMO may be required to issue multiple directions in response to non-credible events impacting system strength.
Trip of Callide C Power Station unit 3 and unit 4 on 15 January 2026[C]	This incident involved the non-credible trip of Callide C Power Station unit 3 and unit 4, resulting in sudden unavailability of two large synchronous units. The minimum system combinations continued to be met in this incident.	This incident is an illustrative example of the loss of two coal units at a substation, which is used as a basis for the studies in Section 2 of this GPSRR.
Trip of Vales Point unit 5 and unit 6 on 2 February 2026[D]	This incident involved the non-credible trip of Vales Point unit 5 and unit 6, resulting in sudden unavailability of two large synchronous units. The minimum system combinations continued to be met in this incident.	This incident is an illustrative example of the loss of two coal units at a substation, which is used as a basis for the studies in Section 2 of this GPSRR.
New South Wales Market Suspension on 23 March 2026[E]	AEMO began to experience a loss of New South Wales SCADA service due to an issue originating within Transgrid's SCADA network. This initially resulted in a partial loss of SCADA service and escalated to a complete loss of New South Wales SCADA service at AEMO.	The loss of SCADA materially impacts AEMO's ability to operate the power system in a secure operating state as it impedes situational awareness and thereby its ability to respond to contingency events. As part of the final report, AEMO plans to review the actions identified in its previously published review of multiple SCADA incidents across the NEM[F] and identify any further required actions.

A. AEMO is in the process of reviewing this incident and is expecting to publish a report in Q2 2026.
B. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2025/trip-of-yallourn-w-power-station-unit-3-and-unit-4.pdf.
C. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2026/trip-of-callide-c-power-station-unit-3-and-4.pdf.
D. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2026/trip-of-vales-point-unit-5-and-unit-6.pdf.
E. Given the significance of this event, AEMO has prepared and published a preliminary report covering this event. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2026/preliminary-report-nsw-market-suspension-on-23-march-2026.pdf. The final report on this incident is expected to be published in Q4 2026.
F. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/multiple-incidentsimpacting-nem-scada-between-2021-and-2023.pdf.

Part C: Stakeholder engagement and recommendation tracking

8 Stakeholder engagement

8.1 Feedback on the draft 2026 GPSRR report

AEMO values input from a wide variety of stakeholders to inform its thinking as part of an ongoing commitment to engage, listen and understand stakeholder perspectives.

The 2026 GPSRR report has been developed through stakeholder engagement and planning undertaken since April 2025. It follows a two-stage consultation process, including consultation on the 2026 GPSRR approach paper, released in December 2025[98], and consultation on the draft report, released in May 2026.

The draft 2026 GPSRR report was open for submissions between May and June 2026. AEMO received six formal submissions from ACEREZ, Justice and Equity Centre (JEC), Save Our Surroundings Riverina, SMA Australia, Transgrid and Tesla, which were published on AEMO's website[99].

The formal consultation process was supplemented by ongoing engagement with stakeholders throughout the development of the report, including regular meetings with TNSPs and DNSPs, targeted briefings with industry groups, forums, industry presentations and open discussions. These engagements informed consideration of emerging risks associated with data centre growth, draft findings on large non-credible generation and network contingencies, the potential scale and practical challenges of mitigation measures, and the role of future technologies such as BESS.

In addition, AEMO hosted an industry briefing on 12 June 2026 to provide an overview of the draft report and an opportunity to ask questions. The briefing was attended by 44 stakeholders representing a broad cross-section of industry, including network operators, generators, developers, government agencies and market bodies. Discussion during the Q&A focused on data centre risks, system stability and modelling, and network investment and voltage control. **Table 11** summarises engagement milestones to support the development, consultation and publication of the final 2026 GPSRR report.

Table 11 GPSRR report consultation process and timeline

Consultation steps	Dates
Monthly meetings with TNSPs on GPSRR progress, studies and risk inputs	December 2025 – March 2026
Engagement with NSPs on draft findings following completion of studies	March – April 2026
DNSP briefing on draft 2026 GPSRR analysis	April 2026
Data Centres Australia briefing on draft 2026 GPSRR analysis (Priority Risk 1)	April 2026
NSP consultation on the draft 2026 GPSRR report	April 2026
GPSRR update during AEMO's DNSP Executive Forum	May 2026
Formal consultation on the draft 2026 GPSRR report	29 May – 26 June 2026
Draft 2026 GPSRR report industry briefing	12 June 2026
Publication of the final 2026 GPSRR report	31 July 2026

[98] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-general-power-system-risk-review-approach-consultation.

[99] See https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-general-power-system-risk-review-report-consultation.

AEMO identified more than 30 individual points of feedback across six submissions to the draft 2026 GPSRR report. **Table 12** summarises the material feedback raised by stakeholders and AEMO's responses, sorted by the four priority risks and other common feedback themes. Feedback received through earlier stages of engagement and consultation, including development of the 2026 GPSRR approach paper and draft report, is documented in the relevant consultation papers and supporting materials published throughout the GPSRR process. More detail is provided in the *Consultation Summary Report* published alongside this final report[100]. AEMO thanks all stakeholders who contributed feedback during consultation on the draft 2026 GPSRR report.

Table 12 Summary of stakeholder feedback and AEMO response

Stakeholder feedback	AEMO response
Priority Risk 1: Increasing large load connections	
Save Our Surroundings Riverina highlighted the role of synchronous generation in supporting increasing demand from large loads.	AEMO notes this feedback but considers that expanding dispatchable synchronous generation is not relevant to the specific risks highlighted in the 2026 GPSRR related to large loads.
Tesla recommended distinguishing between different sources of oscillatory behaviour at large load connection points. It also encouraged consideration of alternatives to disconnection for AI training loads and highlighted practical challenges associated with assessing oscillation risks from large data centre connections.	AEMO acknowledges the differences between oscillations arising from control interactions and those caused by load profile variability. The 2026 GPSRR highlights that there are power system risks associated with forced oscillations and there is a need to limit them. The method used to achieve this could include co-located BESS or other solutions. Where oscillations are identified, actions would be taken through an agreed hierarchy, with disconnection only considered where necessary to maintain system security and not as the first response.
Priority Risk 2: Non-credible system strength risks associated with unavailability of synchronous machines	
ACEREZ recommended greater coordination of commissioning activities between AEMO and TNSPs, and improvements to the assessment of cumulative risk associated with outages.	AEMO notes that risks associated with future commissioning activities can be progressed through appropriate workstreams supporting delivery of major generation and network augmentation projects across the NEM. AEMO also notes ACEREZ's suggestion to consider enhancements to existing frameworks. Where suitable, enhancements to existing frameworks will be prioritised over the introduction of new regulatory obligations.
JEC recommended greater consideration of least-cost system strength solutions and alternatives to synchronous condensers, including reassessment of their role and independent analysis of costs, capabilities and risks.	AEMO acknowledges this feedback but notes that re-evaluation of the existing pipeline of synchronous condensers, and the broader framework for determining the appropriateness of synchronous condensers as responses to system strength issues, does not constitute a power system risk. Investment decisions in synchronous condensers or other technologies are managed through the RIT-T.
Save Our Surroundings Riverina highlighted system strength risks associated with the retirement of synchronous generation.	AEMO notes this feedback but considers that discussion of the adequacy of energy policy settings is outside the scope of the GPSRR.
SMA Australia recommended greater clarity on the definition and demonstration of 'protection quality' fault current capability and development of a cost benefit framework to compare system strength solutions, including synchronous condensers, GFM BESS and protection equipment.	AEMO acknowledges the feedback on fault current capability of GFM inverters and the definition of protection-quality fault current and the suggestion to establish new frameworks for cost-benefit analysis of system strength solutions. These matters are being considered through other workstreams relating to system security frameworks and emerging technologies.
Tesla encouraged further investigation of the relationship between IBR reactive power absorption and post-contingency voltage oscillations.	AEMO advises that further investigation of the relationship between IBR reactive power absorption and post-contingent voltage oscillations is already underway. Post-contingent voltage oscillations have been observed in simulation results in other scenarios, indicating this is not a localised issue.
Transgrid recommended further analysis of coincident coal unit outages, and gas supply and pipeline limitations when assessing system strength risks and potential mitigation options.	AEMO acknowledges Transgrid's support for the assessment of coincident coal unit outages highlighted in the 2026 GPSRR and will continue to monitor these risks through assessments of power system adequacy, identifying necessary actions where risks are identified. AEMO will also continue to monitor gas supply and pipeline limitations and their impacts on system strength. Where material risks are identified, appropriate actions will be considered.

[100] At https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-general-power-system-risk-review-report-consultation.

Stakeholder feedback	AEMO response
Priority Risk 3: Large non-credible generation and network contingency events	
Transgrid supported the use of market actions under the protected event framework to manage the large non-credible generation and network contingency event risks in conjunction with the use of targeted remedial action schemes. Transgrid also committed to ongoing collaboration with AEMO, including sharing information and models to support risk assessments and the development of practical long-term solutions.	AEMO acknowledges Transgrid's support for the use of the protected event framework to manage non-credible contingency risks, particularly where emergency control schemes cannot fully mitigate the risk. AEMO appreciates Transgrid's commitment to ongoing collaboration, including the sharing of information and models, to support comprehensive risk assessments and the development of practical long-term solutions to address emerging risks across the NEM.
Priority Risk 4: Voltage control risks	
ACEREZ supported expanded assessment of voltage control risks to include non-credible contingency events, and consideration of small signal stability analysis. **Transgrid** recommended further evaluation of voltage control risks, including voltage oscillations and the effectiveness of existing approaches to managing oscillatory behaviour.	AEMO acknowledges ACEREZ's support for expanded voltage control risk assessments and consideration of small signal stability analysis. AEMO also acknowledges ACEREZ's insights regarding IBR interactions, control system coordination, and voltage control performance, and notes the information provided from its work in the CWO REZ. AEMO acknowledges Transgrid's support for a more rigorous evaluation of voltage control risks. This aligns with Recommendation 5 of the 2026 GPSRR to extend voltage control studies in a future GPSRR.
Other feedback themes	
GPSRR methodology and implementation **Save Our Surroundings Riverina** suggested the GPSRR consider whether current energy policy and increasing operational complexity are contributing to power system risks. **Transgrid** sought greater transparency regarding GPSRR methodologies, implementation costs, timelines and decision making processes, and greater clarity on how options, protected events and RASs are assessed and selected. It also sought greater clarity on funding, approval and cost recovery pathways for options identified through the GPSRR.	AEMO notes this feedback. Increasing operational actions such as the implementation of protected events or RASs supports secure operation of the power system while reducing the need for investment in transmission infrastructure. An appropriate balance between operational complexity and investment must be considered to support an economical and sustainable power system design. AEMO acknowledges Transgrid's request for greater transparency regarding GPSRR assessment and implementation processes. AEMO will continue to assess implementation costs and timelines when developing recommendations and, where appropriate, undertake assessments over multiple GPSRR cycles if required to support additional consultation. NSPs are engaged regularly throughout the GPSRR process and are provided opportunities to contribute to the assessment of priority risks and mitigation options, including the feasibility of declaring protected events to manage non-credible contingency events where necessary. Work to define RAS parameters is already underway through Recommendation 3 of the 2025 GPSRR. AEMO acknowledges that while clear funding, approval and cost recovery pathways to support implementation of risk mitigation measures are important, this is not an accountability of AEMO.
System strength considerations and future development **JEC** recommended greater consideration of system strength services as separate components and accelerated analysis of alternative technologies, including batteries, pumped hydro and clutches. It also recommended consideration of alternatives to transmission business responsibility for inertia as part of improving the efficiency of system strength responses. **SMA Australia** recommended further research and evidence gathering on 'protection quality' fault current capability, together with review of legacy and modern protection equipment requirements relevant to assessing GFM BESS system strength capabilities.	AEMO notes this feedback and is continuing to progress analysis of alternative technologies as outlined in the 2025 TPSS. AEMO notes this feedback and is currently progressing market engagement to procure Type 2 transitional services for trials to demonstrate protection-quality fault current, as outlined in the 2025 TPSS. AEMO also acknowledges that review of protection settings and equipment across the NEM could identify potential power system risks relevant to future GPSRR assessments and, if undertaken, may provide useful information to support understanding of protection-quality fault current requirements. Consideration of these issues in future GPSRRs will depend on the assessed relative likelihood and consequence of any identified risks leading to cascading failures or major supply disruptions.
Stakeholder engagement and communication **SMA Australia** recommended clearer communication of power system security services and system strength concepts, greater precision in how system strength components are described, and support for consumer participation in discussions on system strength and protection quality fault current. **Tesla** welcomed ongoing industry discussion on large load integration and power system security, including further discussion on IBR behaviour under stressed system conditions.	AEMO notes SMA Australia's feedback regarding system strength terminology, power system security services and protection-quality fault current. While the GPSRR primarily focuses on power system risks, AEMO will continue to progress discussion of power system security services and GFM capabilities through the TPSS and related workstreams. AEMO also recognises the importance of clear and accessible communication and will continue to support stakeholder participation through existing consultation processes and engagement forums where appropriate. AEMO welcomes the opportunity for ongoing discussion with industry on power system security and the integration of large loads.

8.2 Forward consultation and next steps

AEMO thanks NSPs, industry and other stakeholders for their advice and input over the past 15 months as part of the 2026 GPSRR engagement process. This engagement has informed development of the approach paper and the final report.

AEMO will continue to engage with stakeholders on emerging power system risks and potential areas of focus for future GPSRRs. Early feedback received through the 2026 GPSRR consultation process will be considered as part of development of the 2027 GPSRR approach paper in late 2026.

9 Update on previous General Power System Risk Review and Power System Frequency Risk Review recommendations

Table 13 summarises the status of open or recently closed GPSRR and Power System Frequency Risk Review (PSFRR) recommendations and a brief update on actions taken to progress each recommendation. Closed items are coloured grey.

Table 13 Summary of previous GPSRR and PSFRR recommendation status

Report	Recommendation	Status	Update
2020 PSFRR **(Section 6.2.1, Table 37, page 73)**	Various recommendations to address the identified South Australian UFLS issues	Closed	SAPN and ElectraNet have both updated their capabilities to provide visibility of load in individual UFLS bands. All other actions have been completed. This recommendation is now marked as closed.
2020 PSFRR **(Executive summary, Page 6 and page 70)**	AEMO, in consultation with ElectraNet, will review the effectiveness of the OFGS and modify it if required, to include additional generation in the scheme.	Ongoing	ElectraNet and AEMO Victorian Planning (AVP) have updated all required settings in South Australia and Western Victoria. ElectraNet is working with commercial aspects of OFGS implementation with participants.
2022 PSFRR **Recommendation 1**	New OFGS scheme to manage Queensland over-frequency during Queensland separation: AEMO and Powerlink to implement OFGS in Queensland.	Ongoing	10 of 19 generators have applied the OFGS settings. Most of the remaining generators have committed to have the settings applied in either Q1 or Q2 of 2026.
2022 PSFRR **Recommendation 3**	To manage loss of both Columboola – Western Downs 275 kV lines: Powerlink to implement a new SPS under NER S5.1.8.	Ongoing	Scheme settings have been finalised and detailed design is complete. Site work and commissioning is ongoing. Scheme logic and settings are with AEMO for due diligence. Commissioning date has changed from February 2026 to May 2026.
2022 PSFRR **Recommendation 4a**	Management of Queensland UFLS: Powerlink and Energy Queensland to identify and implement measures to restore UFLS load, and to collaborate with AEMO on the design and implementation of remediation measures.	Ongoing	Powerlink has provided AEMO data relating to UFLS participants so that AEMO can undertake modelling.
2022 PSFRR **Recommendation 5**	Review of wide area monitoring protection and control (WAMPAC) scheme to mitigate risks associated with non-credible loss of Calvale – Halys 275 kV lines: Powerlink to review the adequacy of WAMPAC to manage increased risks due to QNI transfers increases following QNI upgrade (tranche 2).	Closed	Studies to confirm the requirement of tripping large load blocks has been completed. This confirmed the existing project scope, allowing design and scheme settings work to commence. Estimated commissioning is early 2027. The recommended review of the WAMPAC scheme can be now marked as closed.
2022 PSFRR **Recommendation 6**	Further work is required to mitigate risks associated with reduced effectiveness of UFLS schemes as reported in the 2020 PSFRR: To address the impact of DPV growth on UFLS. To restore emergency under frequency response to as close as possible to the level of 60% of underlying load at all times. NSPs to investigate measures to remediate the impacts of 'reverse' UFLS operation.	Closed	NSPs will continue to progress these initiatives and any relevant updates will be provided in the "Performance of existing emergency frequency control schemes" section in each GPSRR. The UFLS adequacy review is also underway to mitigate risks related to UFLS. This recommendation is marked as closed.

Report	Recommendation	Status	Update
2022 PSFRR **Recommendation 9**	Manage risks associated with large generation ramping events in South Australia.	Closed	The ramping event risk due to solar generation is now being managed through the Reclassification Criteria in the Power System Security Group (PSSG). Any further risks and developments to manage these potential abnormal events will be considered for inclusion in the PSSG. This recommendation is now marked as closed.
2023 GPSRR **Recommendation 2**	Given the potentially significant impact QNI instability could have on the NEM, AEMO recommends that Powerlink and Transgrid investigate, design and implement an SPS under NER S5.1.8 to mitigate the risk of QNI instability and synchronous separation of Queensland following a range of non-credible contingencies.	Ongoing	A working group comprising of AEMO, Powerlink, Transgrid, AVP and ElectraNet has been set up to address this issue and are completing analysis on potential mitigation options.
2023 GPSRR **Recommendation 3**	Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas, AEMO recommends that AEMO, AVP, ElectraNet and Transgrid continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection and generation tripping schemes.	Ongoing	AVP has completed studies for potential non-credible events in south-west Victoria and identified the requirement for a new control scheme in Victoria, Heywood Interconnector Remedial Action Scheme (HIC RAS). This scheme will work alongside SAIT RAS and will cover both South Australian net import and export conditions. AEMO has since completed studies as illustrated in Section 3.2.2 and will produce a technical memo in response. AVP is also reviewing the settings of the existing Emergency Alcoa Portland Tripping (EAPT) control scheme and working closely with Alcoa on potential solutions to improve Alcoa Portland (APD) FRT.
2023 GPSRR **Recommendation 4**	AEMO recommends that each participating jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risks.	Ongoing	Refer to Section 2 of the 2026 GPSRR, which discusses the risks related to extended outages of synchronous generation.
2023 GPSRR **Recommendation 5**	In the context of the transforming power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.	Closed	Progress is ongoing with NSPs currently implementing or developing various initiatives, from new tools to improve situational awareness to performing capability uplifts through training. This recommendation is now marked as closed.
2023 GPSRR **Recommendation 6**	AEMO recommends that, in line with the requirements of NER S5.1.8, NSPs continue to consider non-credible contingency events which could adversely impact the stability of the power system.	Closed	In accordance with NER S5.1.8, NSPs are currently assessing various non-credible contingency events associated with the commissioning of future infrastructure, generally associated with interconnectors or REZs, and are determining the need for RASs accordingly. This recommendation is now marked as closed.
2023 GPSRR **Recommendation 7**	Transgrid is investigating the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following potential Eraring Power Station closure. AEMO recommends that Transgrid share its investigation findings with AEMO for consideration in future GPSRRs.	Closed	The WSB SIPS has been implemented. This recommendation is now closed.
2024 GPSRR **Recommendation 1**	Given the criticality of the site for system reliability as well as system strength and security, AEMO recommends that AVP design and implement a suitable solution to improve the overall resilience of the Loy Yang substation	Closed	AVP has conducted a HILP assessment and concluded that any network augmentation to modify the current configuration at Loy Yang 500 kV is unlikely to be economically justified given the assessed likelihood of the risk. As AVP has

Report	Recommendation	Status	Update
	as a priority and share its findings with AEMO for consideration in future GPSRRs.		completed and shared the findings of its review, this recommendation is now closed out.
2024 GPSRR **Recommendation 2**	Given the potentially significant impact of non-credible loss of HumeLink 500 kV circuits during times of high northerly flows, AEMO recommends implementing cost-effective measures to minimise the probability of this risk. If a scheme is found viable, Transgrid to implement an emergency control scheme to mitigate risks associated with voltage collapse in the Bannaby area.	Ongoing	Transgrid is continuing active communication with AEMO to develop a plan to prioritise the development of a viable solution and maintain RIT-T timeframes. Ongoing scheme assessments will be required as additional generators come online in the network.
2024 GPSRR **Recommendation 3**	AEMO recommends that NSPs outside South Australia, in conjunction with AEMO, investigate (and implement wherever possible) low-cost measures, such as dynamic arming, to restore UFLS availability in addition to the existing and planned projects/initiatives.	Ongoing	AEMO is currently following up with NSPs around the dynamic arming project, including costs, approvals, and SCADA points. AEMO is also conducting a NEM UFLS adequacy review. This review will shed more light on the urgency of dynamic arming implementation in regions.
2024 GPSRR **Recommendation 4**	AEMO anticipates significant operational challenges to emerge as thermal generating units retire and will develop operational procedures for scenarios where insufficient synchronous units are available for AEMO to direct to meet the minimum regional system strength requirements.	Closed	This has been investigated in the 2026 GPSRR and will be tracked further through the 2026 recommendation. Refer to Section 2 for more information. The 2025 *Thermal Audit* was also completed to understand the capability of thermal generation in the NEM. The risks related to retirement of thermal generation will continue to be considered in the GPSRR where necessary in the future. This recommendation is marked as closed.
2024 GPSRR **Recommendation 6**	UFLS data quality: AEMO strongly recommends real-time visibility of UFLS availability is established in all mainland NEM regions (similar to that which exists for South Australia). Given escalating operational risks, AEMO recommends this occur without delay.	Ongoing	AEMO is currently following up with NSPs around initiatives taken to establish real-time visibility of UFLS availability in all mainland NEM regions. The NEM UFLS adequacy review will also assess the risk.
2024 GPSRR **Recommendation 7**	Updates to UFLS schedules and procedures: AEMO recommends that NSPs work with AEMO to provide up-to-date and accurate UFLS availability information to support AEMO's review of UFLS adequacy.	Ongoing	NSPs are working with AEMO to provide up to date UFLS data for use in AEMO studies and the AEMO control room.
2024 GPSRR **Recommendation 8**	UFLS scheme review: Consolidate the 121 UFLS bands in New South Wales to reduce (unnecessary) complexity. Review the QNI inhibit scheme to ensure it remains effective at preventing QNI instability for remote frequency disturbances south of Queensland.	Ongoing	Transgrid will consider the consolidation of bands in the near future. Powerlink is working with AEMO to provide information on the QNI Inhibit scheme.
2024 GPSRR **Recommendation 9**	RAS Guidelines review: Given the growing number and complexity of NEM RASs, AEMO recommends that, as part of the existing obligations under NER S5.1.8 and 5.14, NSPs in collaboration with AEMO engage in extensive and detailed joint planning to review the RAS Guidelines.	Closed	As per 2025 GPSRR Recommendation 3, AEMO is leading a project to expand the RAS guidelines into explicit requirements. This recommendation is now marked as closed and all progress will be tracked through 2025 GPSRR Recommendation 3.
2024 GPSRR **Recommendation 10**	To reduce the number of transmission line trips due to lightning in South Australia, AEMO recommends that ElectraNet investigate South Australia transmission tower earthing and lightning protection based on recent contingency events to identify or rule out any existing design weaknesses. Additionally, AEMO	Ongoing	ElectraNet is progressing work on the RIT-T for Mid North REZ, which may address this risk. In parallel, ElectraNet is exploring a new control scheme to prevent South Australia intra-regional separation as part of the 2028-2033 regulatory submission.

Report	Recommendation	Status	Update
	recommends, in accordance with NER S5.1.8, that ElectraNet investigates the suitability of a RAS to prevent South Australia intra-regional separation.		
2025 GPSRR Recommendation 1	The lack of emergency backstop mechanisms is contributing to operational risk during MSL conditions. To address this, the recommendations outlined in the Supporting Secure Operation with High Levels of Distributed Resources section of the 2025 GPSRR should continue to be implemented with high priority.	Closed	AEMO is continuing work on MSL procedures, with a focus on incorporating management of transmission connected BESS into MSL procedures. The risks related to the lack of emergency backstop were highlighted in the 2025 GPSRR and actions will continue in the relevant workstreams. This recommendation is marked as closed.
2025 GPSRR Recommendation 2	The lack of compliance with the latest AS/NZS 4777.2:2020 inverter requirements standard is contributing to operational risks during MSL conditions. To address this, the recommendations outlined in the Compliance of Distributed Energy Resources with Technical Settings: Update section of the 2025 GPSRR should continue to be implemented with high priority.	Closed	The risks related to non-compliance with the latest AS/NZS 4777.2 inverter requirements standard were highlighted in the 2025 GPSRR and actions will continue in the relevant workstreams. This recommendation is marked as closed.
2025 GPSRR Recommendation 3	It is recommended that AEMO leads a project with input from industry to investigate and implement explicit requirements related to RASs in the NEM.	Ongoing	AEMO is currently undertaking scoping activities related to this work.
2025 GPSRR Recommendation 4	It is recommended that AEMO completes detailed studies and analysis on the management of non-credible contingencies into the future.	Closed	This has been completed under the studies in the 2026 GPSRR. Refer to Section 3 for more information. This recommendation is now marked as closed.
2025 GPSRR Recommendation 5	AEMO recommends that all NSPs, as well as AEMO, commit to: • Continue monitoring the location, control settings, and timelines of expected BESS or other fast-acting IBR connections in their respective networks or regions. • Continue sharing any changes in concentration of IBR in regions or sub-regions that could affect power system stability.	Closed	NSPs are continually engaging with AEMO with respect to BESS and other fast-acting IBR connections in their network. In addition, NSPs are undertaking analysis as required to assess the concentration of BESS and other fast-acting IBR on power system security. The potential risks related to concentration of BESS or IBR in regions or sub-regions were highlighted in the 2025 GPSRR. Actions will continue in the relevant workstreams. This recommendation is now marked as closed.

Abbreviations and key terms

Abbreviation	Term	Abbreviation	Term
AAS	automatic access standard	FFR	fast frequency response
AC	alternating current	FOS	frequency operating standard
AEMC	Australian Energy Market Commission	FRT	fault ride-through
AEMO	Australian Energy Market Operator	GFL	grid-following
AER	Australian Energy Regulator	GFM	grid-forming
AESCIRP	Australian Energy Sector Cyber Security Response Plan	GPS	generator performance standard
AESCSF	Australian Energy Sector Cyber Security Framework	GPSRR	General Power System Risk Review
AESO	Alberta Electric System Operator	GPU	graphics processing unit
AI	artificial intelligence	GW	gigawatt/s
APD	Alcoa Portland	HIC	Heywood Interconnector
ATC	American Transmission Company	HIC RAS	Heywood Interconnector Remedial Action Scheme
AVP	AEMO Victorian Planning	HIL	hardware in the loop
BESS	battery energy storage system/s	HILP	high impact low probability
CBD	central business district	HVDC	high voltage direct current
CBF	circuit breaker failure	HYTS	Heywood terminal station
CER	consumer energy resources	Hz	hertz
CIGRE	Conseil International des Grands Réseaux Electriques	IBL	inverter-based load
CIRMP	Critical Infrastructure Risk Management Program	IBR	inverter-based resource/s
CPUE	Citipower, Powercor and United Energy	ICT	information and communications technology
CSIP-AUS	Common Smart Inverter Protocol – Australia	IMS	inverter management system
CWO	Central West Orana	ISF	Improving Security Frameworks
DCCEEW	Department of Climate Change, Energy, the Environment and Water	ISON	International System Operator Network
DER	distributed energy resources	ISP	Integrated System Plan
DNSP	Distribution Network Service Provider	IT	information technology
DPV	distributed photovoltaic	ITIC	Information Technology Industry Council
EAPT	Emergency Alcoa Portland Tripping	JEC	Justice and Equity Centre
ECMC	Energy and Climate Change Ministerial Council	JSSC	Jurisdictional System Security Coordinator
EFCS	emergency frequency control scheme	kV	kilovolt/s
EMS	energy management system	kW	kilowatt/s
EMT	electromagnetic transient	LOR	lack of reserve
ENTSO-E	European Network of Transmission System Operators for Electricity	MAS	minimum access standard
ERCOT	Electric Reliability Council of Texas	MLTS	Moorabool terminal station
ESIG	Energy Systems Integration Group	ms	millisecond/s
ESOO	Electricity Statement of Opportunities	MSL	minimum system load
FCAS	frequency control ancillary services	MT PASA	medium term projected assessment of system adequacy

Abbreviation	Term	Abbreviation	Term
MVA	megavolt ampere/s	s	second/s
MVAr	megavolt ampere/s reactive	SAIT RAS	South Australia Interconnector Trip Remedial Action Scheme
MW	megawatt/s	SAPN	South Australia Power Networks
MVF	Market Visibility Framework	SCADA	supervisory control and data acquisition
NEM	National Electricity Market	SCR	short circuit ratio
NEMDE	National Electricity Market Dispatch Engine	SIPS	system integrity protection scheme
NEMOC	National Electricity Market Operations Committee	SISC	System Integration Steering Committee
NER	National Electricity Rules	SOCI	security of critical infrastructure
NERC	North American Electric Reliability Corporation	SPS	special protection scheme
NOFB	normal operating frequency band	SRAS	system restart ancillary service
NSCAS	network support and control ancillary services	SSAT	Small Signal Analysis Tool
NSP	network service provider	SSCI	sub-synchronous control interactions
OD	operational demand	SSIAG	System Strength Impact Assessment Guidelines
OEM	original equipment manufacturer	SSN	system strength node
OFGS	over frequency generator shedding	SSRS	system strength remediation scheme
OSM	oscillatory stability monitor	SSTI	sub-synchronous torsional interactions
p.u.	per unit	STATCOM	static synchronous compensator
PEC	Project EnergyConnect	SVC	static VAr compensator
PFR	primary frequency response	SYTS	Sydenham terminal station
PLL	phase-locked loop	TNSP	Transmission Network Service Provider
PMU	phasor measurement unit	TPSS	Transition Plan for System Security
PNIP	priority network infrastructure project	TOV	temporary overvoltage
POD	power oscillation damper	TWh	terawatt hour/s
PPC	power plant controller	UFLS	under frequency load shedding
PSCAD™	Power System Computer Aided Design	UPS	uninterruptible power supply
PSFRR	Power System Frequency Risk Review	VAr	volt ampere reactive
PSMRG	Power System Model Reference Group	VBM	Victorian Backstop Mechanism
PSS	power system stabiliser	VDS	VAr dispatch scheduler
PSSG	Power System Security Group	VEEC	Victorian Electricity Emergency Committee
PSS®E	Power System Simulator for Engineering	VNI	Victoria – New South Wales Interconnector
PVNSG	Photovoltaic non-scheduled generation	VNI West	Victoria – New South Wales Interconnector West
QNI	Queensland – New South Wales interconnector	VPP	virtual power plant
RAS	remedial action scheme	VSC	voltage source converter
REZ	renewable energy zone	WAMPAC	wide area monitoring protection and control
RIT-D	regulatory investment test – distribution	WRL	Western Renewables Link
RIT-T	regulatory investment test - transmission	WSB	Waratah Super Battery
RoCoF	rate of change of frequency		

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. The table of simplified meanings below is for ease of reference, and these are not exact transcriptions of the NER definitions.

Term	Definition
Satisfactory operating state	The power system is in a satisfactory operating state when all of the following apply: • Power system frequency is within the normal operating frequency band. • Voltage magnitudes are within relevant limits. • Current flows on all transmission lines are within equipment ratings. • All other plant forming part of the power system is being operated within its ratings. • The power system is being operated such that fault potential is within circuit breaker capabilities. • The power system is considered stable.
Secure operating state	The power system is defined to be in a secure operating state when both: • The power system is in a satisfactory operating state. • The power system will return to a satisfactory operating state following any credible contingency event.
Credible contingency event, or credible contingency	A contingency event is considered credible when AEMO considers its occurrence to be reasonably possible in the surrounding circumstances including the technical envelope. Without limitation, examples of credible contingency events are likely to include: • the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or • the unexpected disconnection of one major item of transmission plant (for example, a transmission line, transformer or reactive plant) other than as a result of a three-phase electrical fault anywhere on the power system.
Non-credible contingency event, or non-credible contingency	A contingency event other than a credible contingency event. Without limitation, examples of non-credible contingency events are likely to include: • three-phase electrical faults on the power system; or • simultaneous disruptive events such as: – multiple generating unit failures; or – double circuit transmission line failure (such as may be caused by tower collapse).
Protected event	A non-credible contingency event that the Reliability Panel has declared to be a protected event under NER 8.8.4 after consultation on a request made by AEMO, where that declaration has not been revoked.