AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

2024 Network Support and Control Ancillary Services (NSCAS) Report

December 2024

A report for the National Electricity Market

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

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

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

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

Important notice

Purpose

The purpose of this publication is to summarise the Network Support and Control Ancillary Service gaps identified by AEMO over a five-year outlook period.

AEMO publishes this report in accordance with clause 5.20.3 of the National Electricity Rules. This publication is based on information available to AEMO as at October 2024 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	2/12/2024	Initial release.

Executive summary

AEMO has identified new system security needs across the National Electricity Market (NEM) over the coming five years. Declining minimum operational demand, reduced operation of synchronous generators, and rapid uptake of variable renewable energy resources (VRE) have combined to create an increased need for essential power system services.

This report is part of a broader planning framework under the National Electricity Rules (NER) that works to ensure the power system can continue to operate securely and reliably as the energy transition continues at pace. The scope of change means there will be an inevitable need for network investment, and while network businesses can already act through their normal planning processes, AEMO's work to declare network support and control ancillary service (NSCAS) gaps remains an important safety net for power system security.

AEMO has explored a broad range of power system needs in the 2024 NSCAS Report

To capture these emerging needs, the 2024 NSCAS Report explores a range of potential power system requirements over the next five years. It includes a regional assessment of the system's ability to stay within thermal and voltage control limits, maintain adequate reactive margins, limit rapid voltage changes, and to provide sufficient options to return to a secure operating state following a credible contingency event. The 2024 report also contains an assessment of system strength and inertia shortfalls in the near term, as these two core system security requirements continue to grow in importance and significance for the power system.

Previous NSCAS analysis has confirmed that system strength is likely to be the most onerous requirement, and notes that inertia needs could be met in tandem by solutions that deliver both services. The work also identifies that leveraging the reactive capabilities of new inverter-based resources (IBR) will be critical in meeting future voltage control needs.

The 2024 assessment considered sensitivity studies against a 'system typical' operating state

This report implements the latest NSCAS Description and Quantity Procedure[1], which includes the introduction of studies against 'system typical' conditions. These aim to allow NSCAS studies to consider common or expected network configurations, and any known long-term planned outage conditions, as a network starting point for security screening studies. While AEMO cannot formally exercise last resort planning powers for these types of non-intact system conditions, they present an opportunity to raise awareness of emerging risks and potentially flag them for action via other mechanisms such as Transitional Non-Market Ancillary Services, or through AEMO's General Power System Risk Review (GPSRR). AEMO also recognises that the challenges facing each region are unique, so has included several region-specific studies that were scoped collaboratively with operators and network businesses.

[1] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

AEMO has identified risks, shortfalls and NSCAS gaps across all regions

Based on the 2024 NSCAS studies, AEMO has confirmed the status of previously declared shortfalls and identified a range of new system strength, inertia, and voltage control shortfalls or emerging risks across several regions. Several marginal or emerging risks have also been highlighted and provided to relevant transmission network businesses for further investigation.

A summary of regional findings is presented in Table 1, and AEMO will continue to work closely with the relevant network businesses to track the magnitude, timing, and remediation associated with each.

Table 1 Summary of new and existing NSCAS gaps

Region	NSCAS outcomes (system strength, inertia, and other)
New South Wales 	**Existing system strength shortfalls at Newcastle and Sydney West have been deferred until 2027-28**, linked with delayed retirement of Eraring Power Station. Transgrid is progressing remediation against a full set of New South Wales requirements as part of its broader System Strength Regulatory Investment Test for Transmission (RIT-T) process, and AEMO will continue to work with Transgrid to track the progress of its remediation activities. **No inertia shortfalls have been identified,** and Transgrid must ensure sufficient inertia is available to meet their full inertia sub-network allocation from 1 December 2027. **No thermal loading or voltage control gaps have been identified**, although several emerging network risks have been identified for supply around Sydney under maximum demand conditions if anticipated generation and network projects do not proceed as planned.
Queensland 	**AEMO has identified new system strength shortfalls of between 153 MVA and 178 MVA across three nodes in Queensland in 2026-27 and Lilyvale in 2027-28.** These shortfalls are primarily linked with decreased energy exports to New South Wales, with more energy available in that region following the delayed retirement of Eraring Power Station. That change has resulted in fewer thermal units expected to be online economically in Queensland, and lower fault levels than previously projected. **The previously declared inertia shortfall in Queensland for islanded conditions has decreased in magnitude to 256 MWs in 2027-28.** Remediation may be possible in parallel with the existing Powerlink System Strength RIT-T. **No thermal loading or voltage control gaps have been identified**.
South Australia 	**No system strength shortfalls have been identified.** **No inertia shortfalls have been identified,** and the existing inertia shortfall has been addressed, primarily through additional registrations in the 1-second Frequency Control Ancillary Services (FCAS) market. **The magnitude and timing of the previously declared voltage control gap remains unchanged.** AEMO is progressing a commercial tender process to seek potential service providers for an interim period until new reactors can be installed by ElectraNet in 2025-26.
Tasmania 	**AEMO has confirmed ongoing shortfalls at all four nodes in Tasmania**, noting sufficient network support agreements in place until 2 December 2025. TasNetworks is progressing a Regulatory Investment Test for Transmission (RIT-T) to ensure sufficient ongoing support arrangements. **Existing inertia shortfalls have been confirmed for the region.** Sufficient network support agreements are in place until 2 December 2025, and longer-term remediation may be possible alongside system strength remediation. **No thermal loading or voltage control gaps have been identified.**
Victoria 	**AEMO has identified a need for system strength services of 368 MVA at Red Cliffs from 2025-26,** primarily linked with the expected end of existing system strength remediation contracts. AEMO Victorian Planning (AVP) is exploring options to extend this agreement**. Shortfalls are also forecast to emerge against requirements at Moorabool, Hazelwood, and Thomastown from 2027-28.** AVP is progressing a regional system strength RIT-T. **The projected level of inertia is expected to fall below the inertia sub-network allocation for Victoria, however sufficient inertia is available to be shared from neighbouring regions**. AVP must ensure sufficient inertia is available to meet their full inertia sub-network allocation from 1 December 2027.

Region	NSCAS outcomes (system strength, inertia, and other)
	AEMO has not identified any new thermal loading or voltage control gaps in Victoria. Risks have been observed for voltage control at Eildon during low demand conditions and these are being managed with an existing operational solution. AEMO has also confirmed the timing and magnitude of the previously declared thermal overloading and voltage control gaps at Deer Park, but notes that these are already being managed by AVP through a local control scheme and longer-term RIT-T. Overloading risks were also identified for transformation into Metropolitan Melbourne following Yallourn Retirement, and AVP has published the Project Specification Consultation Report (PSCR) for the eastern metropolitan grid reinforcement and is planning for western metropolitan grid reinforcement PSCR to be published in Q1 of 2025.

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1 Introduction

Network support and control ancillary services (NSCAS) are defined in the National Electricity Rules (NER) as services with the capability to control the active or reactive power flow into or out of a transmission network. They may be procured to address the following needs under NER 3.11.6(a):

- **Reliability and security ancillary services (RSAS)** – maintain security and supply reliability of the transmission network in accordance with the power system security standards and the reliability standard.
- **Market benefits ancillary services (MBAS)** – maintain or increase capability of the transmission network to maximise net economic benefits to all those who produce, consume or transport electricity in the market.

AEMO assesses the need for these services annually and declares NSCAS gaps where it identifies an unmet need. Gaps generally relate to voltage control, system stability, inertia, system strength, and thermal limits, but can include other aspects that are required for operating a secure power system.

The NER give transmission network service providers (TNSPs) primary responsibility for acquiring NSCAS (with or without a declared gap). AEMO may be required to procure NSCAS under its last resort planning functions but can only do so to meet the RSAS category of NSCAS needs.

Reliability and security ancillary services (RSAS)

To identify RSAS gaps, AEMO considers the ability of the power system to maintain a secure operating state during system normal conditions; that is, the ability of the system to land in a satisfactory operating state following a credible contingency or protected event. RSAS can include any:

- **Non-Market Ancillary Service (NMAS)** required to maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard.
- **Inertia network service** necessary to meet an inertia requirement, where the requirement has been revised to a level that exceeds the currently applicable binding inertia requirements.
- **System strength service** necessary to meet a minimum three phase fault level, where that minimum has been revised to a level that exceeds the currently applicable system strength requirement.

AEMO's NSCAS studies consider actions that can be taken by AEMO in real time to manage power system security, but also factor in future system changes such as committed or anticipated generation and transmission projects, announced generator retirements, and forecast changes in demand.

Market benefits ancillary services (MBAS)

To identify MBAS gaps, AEMO considers whether positive net market benefits could be delivered by relieving high-impact network constraints. AEMO reviews existing constraint statistics, to identify any constraints that bound for at least one hour in the previous calendar year and had a total marginal cost of at least $50,000. AEMO may also consider specific constraints nominated by participants or those forecast to be significant through other power system planning and operational activities.

1.1 Regulatory changes impacting the 2024 NSCAS report

Inertia and system strength services can now be considered under the NSCAS framework

The Australian Energy Market Commission (AEMC) published the National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 in March 2024[2] (ISF Rule). The ISF Rule expands the system security frameworks and provides AEMO with new tools to manage power system security in the National Electricity Market (NEM) through the current energy transition.

With effect from 1 December 2024, the ISF Rule permits inertia network services and system strength services to be considered under the NSCAS framework (removing the previous exclusion of those services). This provides a regulated procurement mechanism for these security needs in specified circumstances.

Under the inertia and system strength frameworks in the NER, transmission network service providers (TNSPs)[3] have three years to deliver any forecast requirements for inertia or system strength from the time AEMO publishes them in the annual *System Strength Report* and *Inertia Report*. Where these requirements change within the three-year period, AEMO can now declare and procure shortfall services via its NSCAS last resort functions.

AEMO consulted on the inclusion of these services in the NSCAS Description and Quantity Procedure[4], and their addition has been reflected in the 2024 *NSCAS Report*.

A new system-wide inertia floor has been introduced with additional obligations on TNSPs

As part of the ISF Rule, the AEMC also introduced new inertia planning requirements, removed restrictions on the procurement of synthetic inertia, and increased the alignment between the inertia and system strength procurement frameworks.

With respect to the inertia shortfall calculations considered in this *NSCAS Report*, the ISF Rule requires that AEMO develop and calculate a new *system-wide inertia level* for the mainland NEM regions which should apply under fully interconnected system operation. Previously *inertia requirements* were only specified to apply during islanded operation of one or more regions.

The ISF Rule also requires that AEMO allocate portions of this *system-wide inertia level* amongst the mainland regions in a way that promotes balanced and representative procurement. The relevant regional TNSP is then required to procure sufficient services or assets to ensure that its full regional allocation is continuously available. TNSPs must deliver these services within three years of the requirements being published or updated by AEMO through the annual *Inertia Report*. This is in addition to the existing islanded regional requirements, which AEMO will continue to update and publish annually.

AEMO consulted on the underlying calculation approach and assumptions in the Inertia Requirements Methodology[5], and has applied this approach to the 2024 *NSCAS Report*.

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[2] At https://www.aemc.gov.au/sites/default/files/2024-03/ERC0290%20-%20ISF%20final%20determination.pdf.

[3] In their capacity as inertia network service providers or system strength service providers respectively.

[4] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

[5] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.

1.2 Scope of analysis

This report presents AEMO's 2024 assessment of *NSCAS gaps* under NER 5.20.3 and covers the five-year period from December 2024 to December 2029 inclusive. The underlying analysis considered a range of power system requirements, as summarised below. All assessments have been conducted in accordance with the latest NSCAS procedures[6], and are based on the latest available data for: committed, anticipated, and actionable ISP projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand.

Contingency analysis

Contingency analysis simulates the state of a power system following a credible contingency event. This type of study is typically used to identify network elements where thermal ratings or voltage limits are exceeded. In the NSCAS context, credible contingency events are applied independently to confirm no limits are violated, and that the system can be operated securely.

Reactive margin

Reactive margins indicate the additional reactive loading that could be applied at a network location before it would result in voltage collapse. Low levels of reactive margin indicate that the system is at greater risk of such collapse, and low reactive margins could exist even when absolute voltages appear normal. In the NEM, reactive margins are required to remain above 1% of the maximum fault level at each connection point, and AEMO has applied this standard when assessing *NSCAS needs* in each region[7].

Rapid voltage change

When reactive power devices are switched in or out of service on the network, nearby voltage levels are impacted. The size of these impacts can vary over time as generation and network loading patterns change. Acceptable levels of voltage change depend on the number of switching events that occur in each period. AEMO has assumed the most onerous system standard of 2.5% when screening these outcomes, however a higher standard of 5% can be applied as per the IEC standard[8].

Resecure risk

While contingency analysis confirms whether the power system lands in a satisfactory state for a single contingency, it does not consider what subsequent options are available to prepare the system for a further credible contingency or protected event. AEMO takes reasonable actions to achieve this, which might require redispatch, network reconfiguration, load shedding, or directions. The 2024 NSCAS assessment has considered these risks for several critical events, as identified with the system operators and the network businesses.

[6] AEMO. NSCAS Description and Quantity Procedure version 3.0, December 2024. At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

[7] Required reactive margin is defined by NER S5.1.8 as "not less than 1% of the maximum fault level (in MVA) at the connection point". For the purposes of this assessment, the required reactive margin was calculated based on the 2024-25 maximum fault level.

[8] AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period.

System typical and region-specific studies

This report also implements the latest NSCAS Description and Quantity Procedure, which includes the introduction of studies against 'system typical' conditions. These are intended to allow the NSCAS studies to consider common or expected network configurations, and any known long-term planned outage conditions as a network starting point for security screening studies. While AEMO cannot formally exercise last resort planning powers for these types of non-intact system conditions, they present an opportunity to raise awareness of these emerging risks, and potentially flag them for action via other mechanisms such as Transitional Non-Market Ancillary Services, or through AEMO's General Power System Risk Review (GPSRR).

AEMO also recognises that the challenges facing each region are unique, so has included several region-specific studies that were scoped collaboratively with operators and network businesses.

Inertia analysis

Following regulatory changes in the AEMC's Improving security frameworks for the energy transition rule in March 2024[9], projections of available inertia and any resulting shortfalls against the inertia requirements are now assessed as part of the annual *NSCAS Report*. AEMO used half-hourly market modelling results to project the typical levels of inertia expected to be available over a three-year horizon.

To identify shortfalls, AEMO compared the minimum inertia requirements in each region against the level of inertia expected to be available 99.87% of the time in a typical year. Each region has a separate inertia requirement specified when planning for times of interconnected and islanded, or credible risk of islanding operation. The latest inertia requirements are calculated and published as part of the 2024 *Inertia Report*[10].

The calculation of shortfalls against these requirements considered any inertia relief likely to be provided by participants in the 1-second frequency control ancillary service (FCAS) market.

System strength analysis

Following regulatory changes in the AEMC's Improving security frameworks for the energy transition rule in March 2024, projections of available fault current and any resulting shortfalls against the minimum fault current requirements are now assessed as part of the annual *NSCAS Report*. AEMO used half-hourly market modelling results coupled with half-hourly power system analysis results to project the typical levels of fault current expected to be available over a three-year horizon.

To identify shortfalls, AEMO compared the minimum fault current requirements at each system strength node against the level of fault current expected to be available 99.87% of the time in a typical year. The latest system strength requirements are calculated and published as part of the 2024 *System Strength Report*[11].

The assessment of system strength shortfalls considered only shortfalls against the minimum fault level requirements and did not consider shortfalls against the efficient level of system strength.

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[9] At https://www.aemc.gov.au/sites/default/files/2024-03/ERC0290%20-%20ISF%20final%20determination.pdf.

[10] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

[11] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

1.3 Structure of this report

The 2024 NSCAS report contains the following information:

- For each region, AEMO's assessment of NSCAS needs and gaps:
  - New South Wales (Section 2.1).
  - Queensland (Section 2.2).
  - South Australia (Section 2.3).
  - Tasmania (Section 2.4).
  - Victoria (Section 2.5).
- An overview of next steps related to 2024 NSCAS findings (Section 3).
- An overview of the methodology and inputs used to prepare this report (Appendix A1).

Each regional section has been prepared to allow it to be easily extracted or read in isolation.

1.4 Relationship with other AEMO documents

Effective system security management requires a range of tools and frameworks working in tandem, across multiple timescales, participant types, and geographic areas. Figure 1 summarises AEMO's multilayered approach with respect to this report; and its relationship to other AEMO documents.

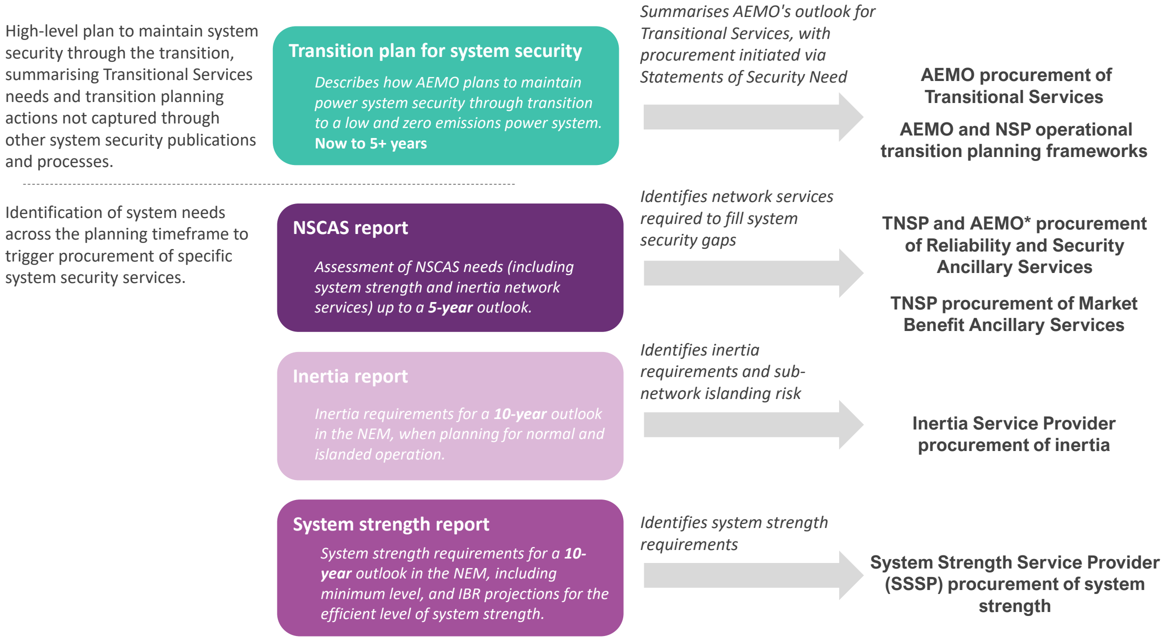
While procurement of security services is typically the role of the TNSP, AEMO has specific roles to:

- **Set minimum security requirements** for inertia and system strength over a 10-year horizon, which must then be planned for and delivered by the relevant network business in each region. This is done through the respective annual *Inertia Report* and *System Strength Report*.
- **Act as a last resort planner** where security needs emerge faster than normal TNSP planning processes can accommodate. This is done annually with a three- to five-year outlook horizon through the NSCAS report, and AEMO is able to procure last-resort services through this framework.
- **Map and respond to future engineering challenges and transition points** associated with operating a 100% renewable power system. This is done through AEMO's Engineering Roadmap, which prioritises the critical engineering actions required; and through AEMO's new *Transition Plan for System Security* which provides a holistic outlook of transition planning activities and transitional services required to support a low- or zero-emissions power system.
- Coupling with these security focused functions, AEMO also publishes the *Integrated System Plan* (ISP)[12] and the *Electricity Statement of Opportunities* (ESOO)[13] which present a long-term view of the power system under a range of possible future scenarios.

[12] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[13] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Figure 1 Relationship between AEMO system security reports and *Transition Plan for System Security*



*Note: Under the NSCAS framework, AEMO can only procure Reliability and Security Ancillary Services under last resort planning powers.

1.5 Summary of NSCAS contracts

AEMO has had no active NSCAS contracts during the past five years under its last resort planning obligations. All identified NSCAS gaps during this period have been (or are being) managed by regional TNSPs.

AEMO is currently exploring potential interim options to procure NSCAS services in South Australia in response to the voltage control gap identified in the 2023 *NSCAS Report*, however no contracts have yet been entered.

2 NSCAS assessment

2.1 New South Wales

- **Existing system strength shortfalls at Newcastle and Sydney West have been deferred until 2027-28.** Newcastle and Sydney West shortfalls are primarily linked with a delay to retirement of Eraring Power Station. Transgrid is progressing remediation against a full set of New South Wales requirements as part of its broader System Strength Regulatory Investment Test for Transmission (RIT-T) process, and AEMO will continue to work with Transgrid to track the progress of its remediation activities.
- **No inertia shortfalls have been identified,** and Transgrid must ensure sufficient inertia is available to meet their full inertia sub-network allocation of 9,600 MWs from 1 December 2027.
- **AEMO has not identified any other thermal, voltage, or inertia gaps** in New South Wales over the five-year period. However, several emerging thermal loading and voltage control challenges have been identified under maximum demand conditions if anticipated generation and network projects do not proceed as planned.

Scope of assessment

AEMO assessed NSCAS needs in New South Wales over a five-year outlook period, under a range of demand, generation, and network project assumptions. This section summarises the results of these assessments relating to:

- Voltage control and thermal loading (Section 2.1.1).
- Rapid voltage change (Section 2.1.2).
- Reactive margin (Section 2.1.3).
- System strength, over a three-year period (Section 2.1.4).
- Inertia, over a three-year period (Section 2.1.5).
- Market benefit ancillary services (MBAS, Section 2.1.6).

Table 20 provides an overview of the core scenarios studied for New South Wales. Appendix A1 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2024 NSCAS assessment.

Table 2 New South Wales NSCAS scenarios and outcomes

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand (day)	Committed projects only	2024-25	No gaps identified
	Committed projects only	2029-30	No gaps identified
	System typical	2024-25	No gaps
	System typical	2029-30	Emerging risk
High demand	Committed projects only	2024-25	Emerging risk- managed operationally
	Committed projects only	2029-30	Emerging risk
	Committed and anticipated projects	2029-30	Emerging risk
	Committed, anticipated and ISP actionable projects	2029-30	No gaps identified
System strength	Market modelling with 50 generator outage patterns, ISP optimal development pathway (ODP) transmission[A] and generation projections, 50% probability of exceedance (POE) demand, and system normal network configuration.	2027-28	Existing gaps deferred at Sydney West and Newcastle nodes.
Inertia	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand. Interconnected system.	2024-25 to 2027-28	No gaps identified

A. Adjustments have been made to the ISP ODP for transmission to account for recent announcements in Eraring's extension and recent changes in generation and transmission timings and commitments.

2.1.1 Voltage control and thermal loading

AEMO has assessed expected voltage control and thermal loading issues in New South Wales over a five-year outlook period, under both low and high demand scenarios. This included testing several different assumptions relating to committed, anticipated, and announced changes to both generation[14] and transmission projects[15].

No gaps were identified under system normal operating conditions or following single credible contingency events. However, several emerging thermal loading and voltage control challenges have been identified under maximum demand conditions if anticipated generation and network projects do not proceed as planned.

System typical

The 2024 NSCAS assessment for New South Wales considered a system typical sensitivity. This sensitivity acknowledges that not all network elements are in service under typical operating conditions.

For New South Wales, AEMO assessed several prior outage conditions based on the frequency and duration of line outages patterns over the past three years. The top ranked outage elements were considered both

[14] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/nem-generation-information-july-2024.xlsx?la=en.

[15] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transmission-augmentation-information/nem-transmission-augmentation-information-august-2024.xlsx?la=en.

individually and under coincident combinations[16] during off peak demand conditions for both 2024-25 and 2029-30.

The studies indicated no specific thermal loading or voltage control issues in most cases. However, some overloading was observed on the 132 kilovolts (kV) network in 2029-30 for coincident outages of the following 330 kV lines:

- Armidale – Tamworth (line 86) & Liddell – Muswell Brook (line 83) , and
- Tamworth – Uralla (Line 85) & Wellington – Wollar West (Line 79) & Yass – Marulan (Line 5).
- Automated control schemes and operational switching are available to relieve these issues, however this flags the need for close operational coordination between AEMO and Transgrid during such planned outages.

Emerging risk for thermal loading and voltage control around Sydney

The 2024 ISP projected that as much as 90% of coal capacity in the National Electricity Market would retire by 2034-35 under *Step Change* (the most likely scenario)[17]. Around a third of this retiring capacity would be in New South Wales, and the ISP forecasts that more than 5 gigawatts (GW) of this generation may retire in New South Wales within the next five years[18].

As coal generators retire, managing maximum demand periods in 2029-30 may require significantly different patterns of power flow on the network within and between regions. This presents new risks for thermal loading and voltage control challenges to emerge but may also alleviate existing pockets of heightened loading – both of which are highly sensitive to the distribution and timing of new generation and network projects within the region.

The 2024 NSCAS report has considered a sensitivity which includes anticipated generation and transmission augmentation projects. Results indicate that these projects, if they proceed as planned, will alleviate several thermal overloads and voltage control challenges in delivering power to Sydney. Planned REZ capacity, in combination with actionable transmission projects identified in the 2024 ISP, will also offer relief in several parts of the 330 kV network.

Without such projects, operational control schemes and the use of 5-minute ratings remain possible options to address some of these risks – however these also increase the complexity of power system operations and reduce its resilience as a result. Potential network options are also noted in Transgrid's 2024 Transmission Annual Planning Report (TAPR) relating to similar constraints in Sydney East.

Given that a range of options are available, but that some of these may rely on the timing or commitment of anticipated and actionable projects, AEMO considers that this is an emerging risk, and will continue to work with Transgrid to monitor the need for TNSP response.

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[16] Individually: Line 83, Line 86, Line 2, Line 6X, Line 11; Coincident: Line 6X & Line 2, Line 86 & Line 83, Line 85 & Line 79 & Line 5.

[17] See page 10 https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

[18] See figure 1 https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

Resecure Risks

AEMO has considered potential resecure risks in New South Wales for contingency events on existing and anticipated network projects. This identified potential resecure challenges associated with contingency events on the anticipated HumeLink network project under some operating conditions.

HumeLink is a proposed 365 km 500 kV transmission loop between Maragle, Bannaby, and Gugaa substations[19]. This project is currently considered an anticipated network project.

The 2024 NSCAS studies considered the loss of any one of these 500 kV circuits, and whether the system could be resecured within 30 minutes under a range of operating conditions. Several thermal overloads and voltage control challenges were seen for the loss of a HumeLink circuit, requiring the use of 5-minute ratings, redispatch of generation, or reconfiguration in the 330 kV network.

While it was generally feasible to resecure the system within 30 minutes for these events, under some conditions pre-contingent constraints to manage Snowy generation and flows from Queensland and New England may be required to mitigate risks and ensure the system can be resecured within 30 minutes following an initial loss of Bannaby – Maragle or Bannaby – Gugaa 500 kV.

As HumeLink remains an anticipated project, AEMO is noting this as an emerging risk that will need to be managed or mitigated as part of operationalising the project. AEMO will continue to work with Transgrid on appropriate management of these risks as the project progresses towards committed status.

2.1.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in New South Wales. Table 3 summarises the results of this analysis which are greater than 2.5%, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the IEC Standard[20].

Table 3 Rapid voltage change results for reactive plant switching in New South Wales

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum demand	Committed projects only	2024-25	3.39%	Chullora 132 kV	120 megavolt amperes reactive (MVAr) reactor at Mason Park 132 kV	3%-5%	Yes
	Committed projects only	2029-30	3.00%	Chullora 132 kV	120 MVAr reactor at Mason Park 132 kV		Yes

[19] See https://www.transgrid.com.au/media/tzclb1hb/tapr-2024.pdf.

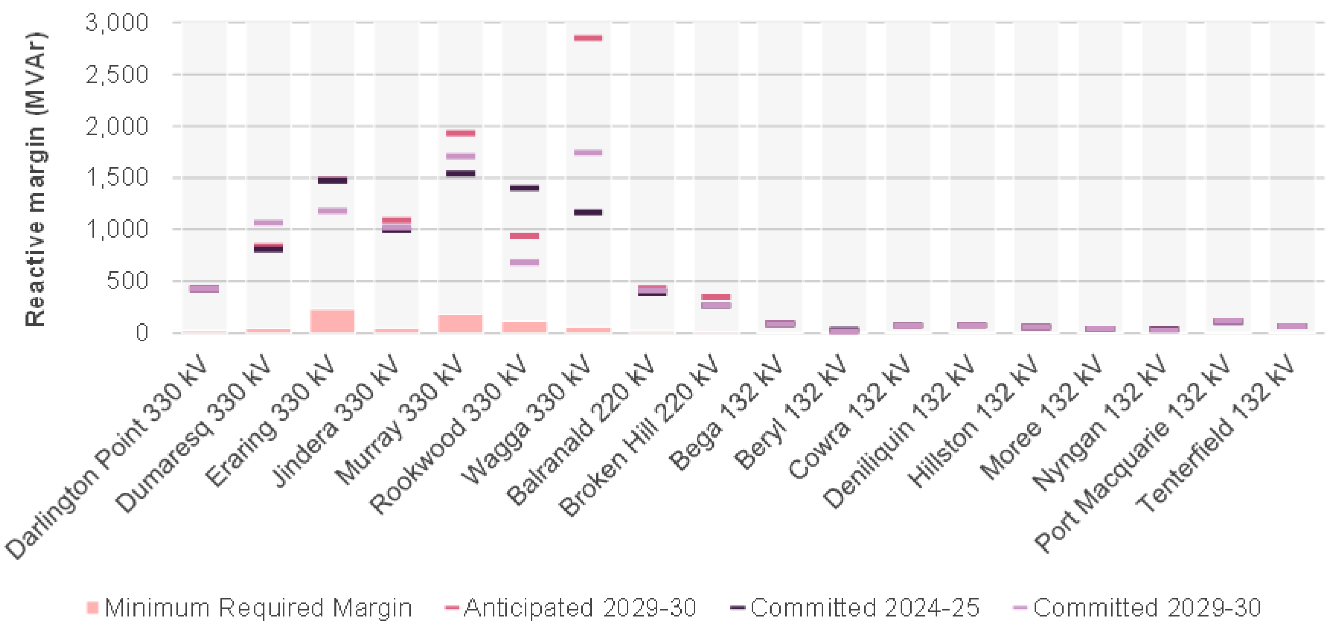
[20] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed 4 within a 24-hour period, with each change allowing a permissible variation of 3-5%.

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Maximum demand	Committed projects only	2029-30	2.64%	Bankstown 132 kV	100 MVAr switched shunt at Rookwood 132 kV		Yes
	Committed and anticipated	2029-30	2.86%	Sydney North 132 kV	110 MVAr capacitor at Sydney East 132 kV		Yes
	Committed and anticipated	2029-30	2.60%	Wagga 132 kV	160 MVAr switched shunt at Wagga 132 kV		Yes
	Committed and anticipated	2029-30	2.80%	Murrumburrah 132 kV	80 MVAr switched shunt at Yass 132 kV		Yes
	Committed and anticipated	2029-30	2.60%	Sydney south 330 kV	150 MVAr reactor at Sydney south 330 kV		Yes
	Committed and anticipated	2029-30	2.63%	Canberra 132 kV	80 MVAr switched shunt at Canberra 132 kV		Yes
	Committed and anticipated	2029-30	2.63%	Quakers hill 132 kV	160 MVAr switched shunt at Sydney West 132 kV		Yes

2.1.3 Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in New South Wales are expected to remain above the system standard[21] of 1% of the local maximum fault level over the five-year outlook period. Figure 2 summarises the results and indicates that all reactive margins remain above the standard.

Figure 2 Minimum reactive margin (MVAr) observed for critical buses in New South Wales



21 Required reactive margin is defined by NER S5.1.8 as "not less than 1% of the maximum fault level (in MVA) at the connection point". For the purposes of this assessment, the required reactive margin was calculated based on the 2024-25 maximum fault level.

2.1.4 System strength

AEMO assessed expected levels of three phase fault current at each system strength node in New South Wales against the latest minimum fault current requirements published in the 2024 *System Strength Report*[22]. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year.

The results of this assessment are summarised in 0, and confirm expected shortfalls of 1,854 megavolt amperes (MVA) and 1,401 MVA at Newcastle and Sydney West 330 kV nodes from 2027-28. Studies also indicate a 305 MVA shortfall at Buronga node in 2025-26, AEMO Victorian Planning is progressing options for a closely matched shortfall at Red cliffs node in Victoria (including extending existing contract arrangements). On this basis, AEMO has not declared a gap at Buronga node . Transgrid is currently progressing a regional RIT-T to deliver sufficient assets or service contracts to meet the full suite of system strength requirements in New South Wales. Given this progress and no change to the existing minimum requirements, AEMO has not identified a need to intervene by declaring an NSCAS gap or exercising its last resort planning functions. AEMO will continue to work with Transgrid to track the progress of its remediation activities.

Table 4 New South Wales fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (MVA)	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Armidale 330 kV	3,300	3,599	3,593	3,571	3,540	0	0	0	0
Darlington Point 330 kV	1,500	1,654	1,632	1,862	2,043	0	0	0	0
Newcastle 330 kV	8,150	9,230	8,618	9,005	6,296	0	0	0	1,854
Sydney West 330 kV	8,450	9,198	9,193	9,212	7,049	0	0	0	1,401
Wellington 330 kV	2,900	2,998	2,984	3,021	2,920	0	0	0	0
Buronga 330 kV	1,755	2,074	1,450	2,653	2,774	0	305[A]	0	0

A. Shortfall not declared on the basis AEMO Victorian Planning is exploring remediation options for a closely matched shortfall at Red Cliffs

The 2024 *System Strength Report* provides additional detail on the calculation of fault level requirements, and the modelling analysis used to assess the typical levels of availability. That report also provides individual fault level duration curves for each node, and specifies additional, efficient level requirements for system strength, which are outside the scope of the NSCAS assessment.

2.1.5 Inertia

AEMO assessed the expected levels of available inertia in New South Wales against the latest inertia requirements published in the 2024 *Inertia Report*[23]. The assessment considered the New South Wales portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded. The 2024 *Inertia Report* provides further detail on the calculation and application of these inertia requirements.

[22] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

[23] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

As part of that assessment, AEMO has deemed New South Wales to be unlikely to island on its own[24] given its strong interconnection with neighbouring regions, and so has only considered inertia shortfalls against New South Wales' allocation of the *system-wide inertia level* (the *inertia sub-network allocation*).

System-wide inertia level assessment for New South Wales

Figure 3 and Table 5 present the projected levels of inertia expected to be available under typical operation of the New South Wales region over the next three years. This indicates that projected levels of inertia are expected to remain above the New South Wales proportion of the *system-wide inertia level* (the *inertia sub-network allocation*).

Transgrid has a binding inertia obligation to meet its *inertia sub-network allocation* from 1 December 2027.

Figure 3 Projected inertia for the three-year outlook, *Step Change* scenario, New South Wales

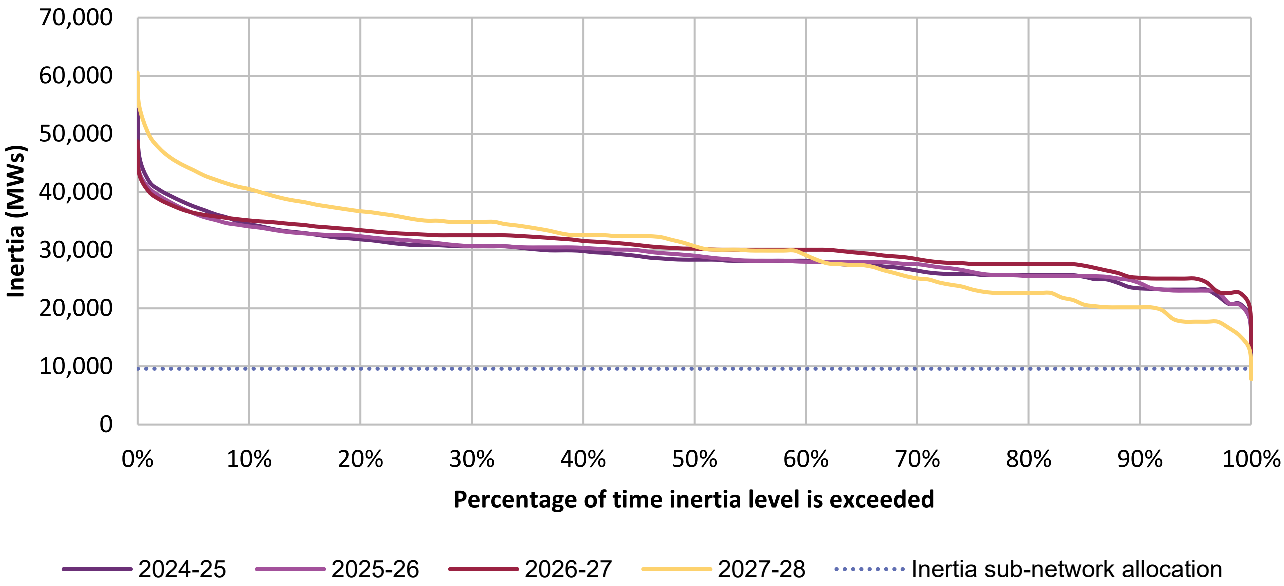


Table 5 Inertia sub-network allocation and projections for New South Wales

	2024-25	2025-26	2026-27	2027-28
***Inertia sub-network allocation* (MWs)**	9,600	9,600	9,600	9,600
Available inertia 99.87% of the time (MWs)	18,254	18,060	20,157	12,720
***NSCAS gap* (MWs)**	-	-	-	-

Note: Modelling is conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.

[24] Historically AEMO has assessed a scenario where the NEM has separated with Queensland and New South Wales forming an island. For completeness, AEMO has confirmed that no inertia shortfall exists for this scenario with updated inputs in 2024, however AEMO considers that the system-wide inertia level requirement assessment should supersede the need for this scenario in future.

2.1.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in New South Wales. 0 provides a comparison of binding hours and marginal values for the highest impact constraints observed[25]. All constraints with a marginal value exceeding $50,000 per year have been discussed with Transgrid, and Transgrid has confirmed the status, project, control scheme, or other mitigation strategy applicable or underway for each. These constraints are being monitored through Transgrid's annual TAPR process.

[25] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

Table 6 New South Wales high-impact constraint summary for 2023-24

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
N>NIL_94T	Avoid thermal overload on Molong to Orange North line	$24M ((↓$4.4M)	1,703	Committed project to address N>NIL_94T. The latest Transgrid 2024 TAPR (page 52) provides the advice on a project to alleviate this constraint. The project to improve thermal capacity is "Increasing capacity for generation in the Molong and Parkes area". Transgrid have completed RIT-T for this project. It is in project delivery stage now.
N>NIL_969	Avoid thermal overload on Gunnedah to Tamworth line	$19M (↑$3M)	1,644	Transgrid don't have committed project in this revenue period to address the constraint. Transgrid have proposed project in next revenue period (2028-2033) to address this need. It requires further load growth in Narrabri and Gunnedah. The scope will include duplicate line Tamworth to Gunnedah 132kV circuit that will assist in alleviating this constraint
N>>NIL_9XX_051	Avoid thermal overload Burrinjuck to Yass on trip of Wagga to Lower Tumut (line	$12.6M (↑$12.6M)	914	The current binding constraint will be improved following the commissioning of the anticipated transmission project HumeLink, which is planned for late 2026. This project should assist in elevating the current binding constraint. Other projects that can be considered that are likely to assist in removing this constraint are a Wagga – Yass line split scheme which may assist in the interim
N>NIL_94K_1	Avoid O/L Suntop Tee to Wellington on trip of Nil.	$12.4M (↑$3M)	1253	Project proposed (not committed) in 2024 TAPR (page 52). is the project that will help improve this constraint is "*Maintaining reliable supply to Bathurst, Orange and Parkes areas Stage 2". The scope of this project is to rebuild Wellington to Parkes 132 kV to double circuit. This is driven by future load growth in Parkes."*
N^^N_NIL_X5_xxx	Limit power flow from Balranald to Darlington Point to avoid voltage collapse at Balranald for contingency trip of Bendigo to Shepparton 220 kV line in NW Victoria	$7.5M (↓$8M)	1041	To address the very high power flows in the 220 kV network, which are leading to severe under voltages at Balranald and issues with voltage stability limit on Darlington Point on a contingent trip of a transmission line in North West Victoria. This project proposes to install a 220 kV 20 MVAr capacitor bank to provide additional reactive support which improves the Darlington Point stability limit.
N>NIL_9R6_9R5	Avoid overloading Wagga North to Wagga 132 kV on trip of Wagga North to Wagga 330 kV line	$5.3M (↑$2.3M)	605	Increasing capacity for generation in the Wagga North area (Page 52). Proposed date is 2027 for this project. "*To increase transfer capacity for renewable generation in the Wagga North areas. Options considered include upgrading the 132 kV line between Wagga and Wagga North*".
N>NIL_9R6_991	Avoid overload of Wagga North to Wagga (9R6) 132 kV line on trip of Wagga North to Murrumburrah (991) 132 kV line	$4.3M (↑$4.3M)	438	Increasing capacity for generation in the Wagga North area (Page 52). Proposed date is 2027 for this project. "*To increase transfer capacity for renewable generation in the Wagga North areas. Options considered include upgrading the 132 kV line Wagga and Wagga North".*

Note: From annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been prioritised as per financial year 2023-24 data. Information sourced from Transgrid Annual Planning Report 2024, at https://www.transgrid.com.au/media/tzclb1hb/tapr-2024.pdf.

2.2 Queensland

- **AEMO has identified new system strength shortfalls of between 153 MVA and 178 MVA across three nodes in Queensland in 2026-27 and Lilyvale alone in 2027-28.** These shortfalls are primarily linked with decreased energy exports to New South Wales, with more energy available in that region following the delayed retirement of Eraring Power Station. That change has results in fewer thermal units expected to be online economically in Queensland, and lower fault levels than previously projected. Powerlink has arrangements in place to address the previous shortfall at Gin Gin node and is progressing a RIT-T to meet system strength requirements across Queensland nodes.
- **The previously declared inertia shortfall in Queensland for islanded conditions has decreased in magnitude to 256 MWs in 2027-28.** There may be options to explore remediation for this gap through the existing Powerlink System Strength RIT-T, and Powerlink must ensure sufficient inertia services are available to meet their full inertia sub-network allocation of 10,500 MWs from 1 December 2027.
- **AEMO has not identified any other NSCAS gaps in Queensland over the five-year period**.

Scope of assessment

AEMO has assessed *NSCAS needs* in Queensland over a five-year outlook period, under a range of demand, generation, and network assumptions. This section summarises the results of these assessments relating to:

- Voltage control and thermal loading (Section 2.2.1).
- Rapid voltage change (Section 2.2.2).
- System strength, over a three-year period (Section 2.2.3).
- Inertia, over a three-year period (Section 2.2.4).
- Market benefit ancillary services (Section 2.2.5).

Table 7 provides an overview of the core scenarios studied for Queensland. Appendix A1 provides further detail on the specific input sources, modelling assumptions, and methodology used for the 2024 NSCAS assessment.

Table 7 Queensland NSCAS scenarios and outcomes

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand (day)	Committed projects only	2024-25	No new gaps identified
	Committed projects only	2029-30	No new gaps identified
Low demand (night)	Committed projects only	2024-25	No new gaps identified
	Committed projects only	2029-30	No new gaps identified
System strength	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand, and system normal network configuration.	2024-25 to 2027-28	Shortfalls identified against requirements at Lilyvale, Greenbank, and Western Downs
Inertia	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand.	2024-25 to 2027-28	Updated gap against the *secure level of inertia*, to be managed by Powerlink through its System Strength RIT-T.

A. Adjustments have been made to the ISP ODP for transmission to account for recent announcements in Eraring's extension and recent changes in generation and transmission timings and commitments.

2.2.1 Voltage control and thermal loading

AEMO assessed expected voltage control and thermal loading issues in Queensland over a five-year outlook period, under both minimum daytime demand and minimum nighttime demand scenarios. These included testing several different assumptions relating to committed and announced changes in both generation and transmission projects.

No new issues have been identified. Due to long radial topology of the Queensland network in North and Far North Queensland, post-contingent voltages can result in larger voltage changes, and pre-contingent voltages may need to be kept low under some conditions (though still within limits) to ensure that post-contingent voltages are secure. AEMO will continue to monitor closely as minimum daytime demand continues to decline.

2.2.2 Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in Queensland. Table 8 summarises the results of this analysis which are greater than 2.5%, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the IEC Standard[26, 27].

[26] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed 4 within a 24-hour period, with each change allowing a permissible variation of 3-5%.

[27] Queensland previous derogation 9.37.12 to use AS2279 to plan for voltage step changes has been superseded by TR IEC 61000.3.7.

Table 8 Rapid voltage change results for reactive plant switching in Queensland

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum demand (day)	Committed projects only	2024-25	3.90%	Aurumfield 275 kV	37 MVAr reactor at Aurumfield 275 kV	3%-5%	Yes
	Committed projects only	2029-30	3.90%	Aurumfield 275 kV	37 MVAr reactor at Aurumfield 275 kV		Yes
Minimum demand (night)	Committed projects only	2024-25	4.00%	Aurumfield 275 kV	37 MVAr reactor at Aurumfield 275 kV		Yes
	Committed projects only	2029-30	4.00%	Aurumfield 275 kV	37 MVAr reactor at Aurumfield 275 kV		Yes

2.2.3 System strength

AEMO assessed the expected levels of three phase fault current at each system strength node in Queensland against the latest minimum fault current requirements published in the 2024 *System Strength Report*. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year.

The results of this assessment are summarised in Table 9, and identify shortfalls of 153 MVA to 178 MVA across three nodes in Queensland in 2026-27, and Lilyvale alone in 2027-28. These shortfalls are primarily linked with decreased energy exports to New South Wales in the near-term, with more energy available following the delayed retirement of Eraring Power Station. That change has resulted in fewer thermal units expected to be online in Queensland, and lower fault levels than previously projected. Modelling results have been adjusted to reflect the impact of Powerlink commercial arrangements to address a previously declared system strength shortfall at Gin Gin. This arrangement adds a clutch to a gas generator at Townsville, allowing it to be operated as a synchronous condenser when necessary for security.

Powerlink is currently progressing a regional RIT-T to deliver sufficient assets or service contracts to meet all system strength requirements in Queensland from 1 December 2025. Given this process is underway, and AEMO has made no changes to the existing minimum requirements that impact the first three years, AEMO has not identified a need to intervene by declaring an NSCAS gap. AEMO will continue to work with Powerlink to track the progress of its remediation activities.

Table 9 Queensland fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (MVA)	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Gin Gin 275 kV	2,800	3,150	3,155	3,088	2,877	0	0	0	0
Greenbank 275 kV	4,350	4,513	4,534	4,199	4,473	0	0	151	0
Lilyvale 132 kV	1,400	1,400	1,400	1,295	1,247	0	0	105	153
Ross 275 kV	1,350	1,350	1,350	1,350	1,350	0	0	0	0
Western Downs 275 kV	4,000	4,121	4,150	3,827	4,078	0	0	173	0

The 2024 *System Strength Report*[28] provides additional detail on the calculation of fault level requirements, and the modelling analysis used to assess the typical levels of availability. That report also provides individual fault level duration curves for each node, and specifies additional, efficient level requirements for system strength, which are outside the scope of the NSCAS assessment.

2.2.4 Inertia

AEMO assessed the expected levels of available inertia in Queensland against the latest *inertia requirements* published in the 2024 *Inertia Report*[29]. The assessment considered the Queensland portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded. The 2024 *Inertia Report* provides further detail on the calculation and application of these *inertia requirements*.

AEMO's assessment of the resulting inertia needs, summarised in Table 10 and Table 11, indicates an inertia shortfall in Queensland of 256 MWs in 2027-28 against the *secure level of inertia* for Queensland. Consistent with the system strength findings, Powerlink is progressing inertia remediation measures in parallel with its System Strength RIT-T, and AEMO has not identified a need to intervene by declaring an *NSCAS gap* or exercising its last resort planning functions. AEMO will continue to work with Powerlink to track the progress of its remediation activities. Powerlink is required to ensure sufficient supplies are available to meet Queensland's *inertia sub-network allocation* from 1 December 2027.

AEMO has deemed Queensland as sufficiently likely to island on its own[30], and so has assessed the region against both its portion of the *system-wide inertia level* (the *inertia sub-network allocation*), and its individual (islanded) *secure level of inertia*.

System-wide inertia level assessment for Queensland

Figure 4 and Table 10 present the projected levels of inertia expected to be available under typical operation of the Queensland region over each of the next three years. This indicates that projected levels of inertia are expected to remain above the Queensland *inertia sub-network allocation* across this period.

[28] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

[29] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

[30] Until QNI Connect is commissioned, expected in 2033.

Figure 4 Projected inertia for the three-year outlook, *Step Change* scenario, Queensland

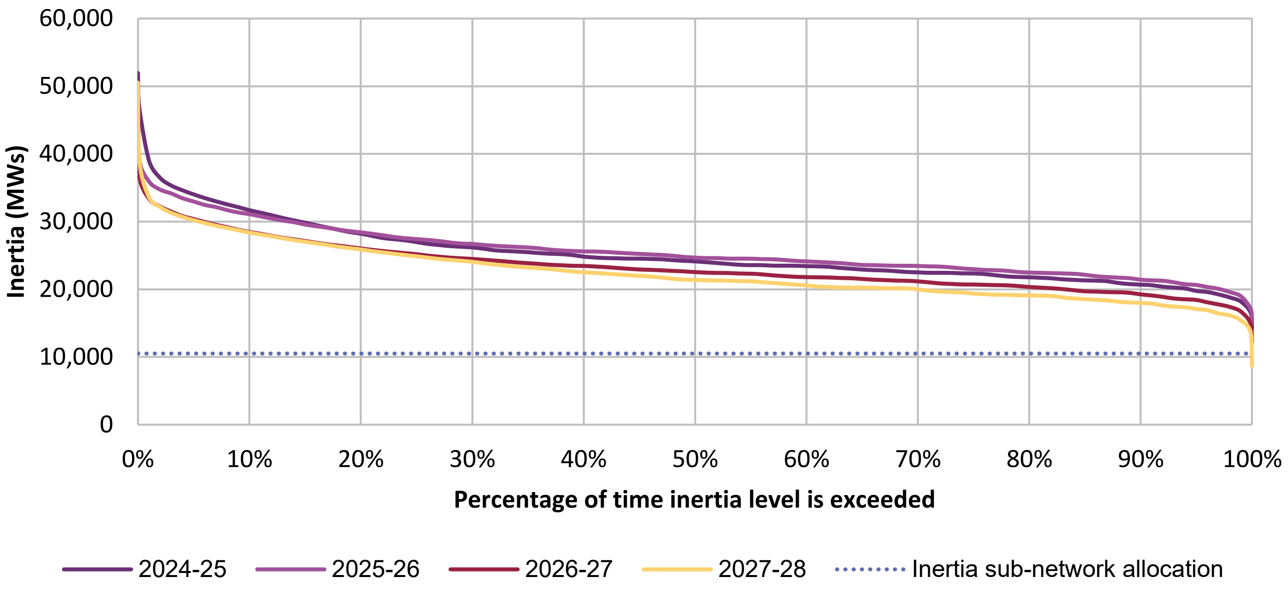


Table 10 Inertia sub-network allocation and projections for Queensland

	2024-25	2025-26	2026-27	2027-28
***Inertia sub-network allocation* (MWs)**	10,500	10,500	10,500	10,500
Available inertia 99.87% of the time (MWs)	16,579	17,125	14,975	13,362
***NSCAS gap* (MWs)**	-	-	-	-

Secure inertia requirements assessment for Queensland

Figure 5 and Table 11 present the projected levels of inertia expected to be available under islanded operation, or credible risk of islanding of the Queensland region over each of the next three years. This indicates an inertia shortfall in Queensland of 256 MWs in 2027-28. Powerlink is progressing inertia remediation measures in parallel with its System Strength RIT-T, and AEMO has not identified a need to intervene by declaring an *NSCAS gap* or exercising its last resort planning functions.

Figure 5 Projected inertia for the three-year outlook, *Step Change* scenario, Queensland islanded case

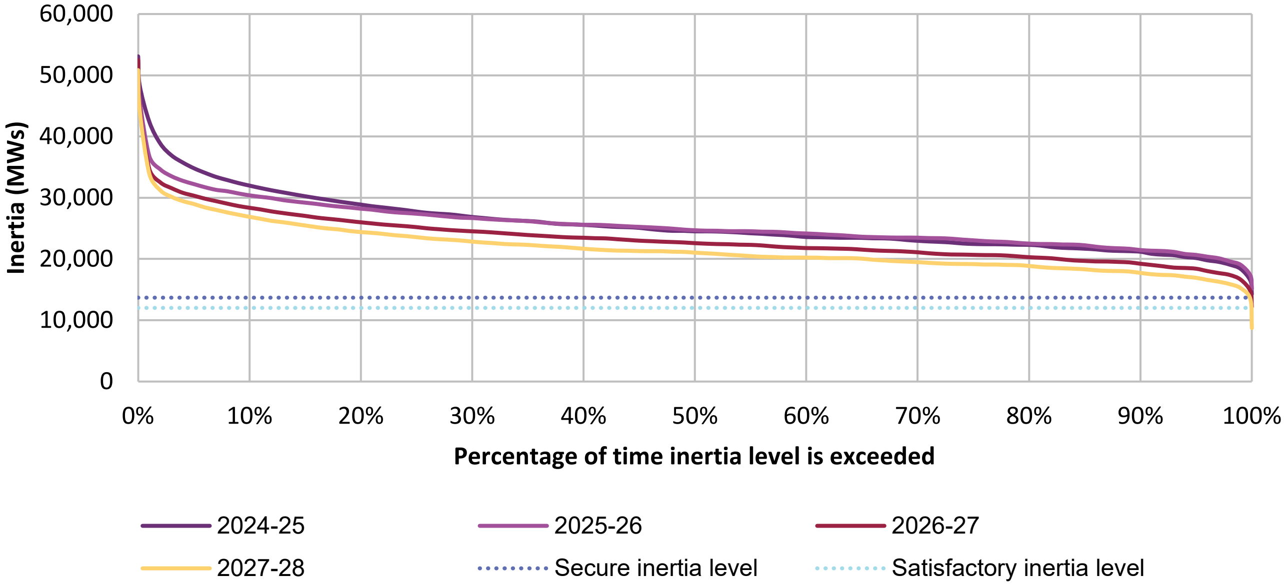


Table 11 Secure Inertia requirements and projections for Queensland

	2024-25	2025-26	2026-27	2027-28
Assumed level of 1-second FCAS (MW)	165	165	165	165
***Secure inertia level* (MWs)**	13,700	13,700	13,700	13,700
Available inertia 99.87% of the time (MWs)	16,487	17,289	14,747	13,444
***NSCAS gap* (MWs)**	-	-	-	256

Note: Modelling is conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.

2.2.5 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Queensland.

Table 12 provides a comparison of binding hours and marginal values for the highest impact constraints observed[31]. All constraints with a marginal value exceeding $50,000 per year have previously been discussed with Powerlink, and it has confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through Powerlink's annual TAPR process and may trigger action if market benefits exceed remediation costs.

[31] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

Table 12 Queensland high-impact constraint summary for 2023-24

Constraint ID	Description	Marginal Value (↓↑ change)	Binding Hours	TNSP Comments
Q>NIL_YLMR	Avoid thermal overload on 110 kV feeders between Yarranlea and Middle Ridge	$ 7M (↑ $ 2.6M)	676	Energy Queensland has existing runback schemes on the nearby solar farms to manage loading on these lines.
Q>NIL_EMCM_6056	Avoid thermal overload on Emerald to Comet 66 kV Feeder	$ 1M (↓ $ 6.5M)	628	Energy Queensland is progressing projects to assist with this constraint.
Q>NIL_DRLCLB_NIL	Out= Nil, avoid OL on 7490 or 7491 (T280 Drillham to T194 Columboola) 132 kV feeder	$ 0.14M (↑ $ 0.43)	10.4	Energy Queensland has existing runback schemes on the nearby solar farms to manage loading on these lines.
Q>NIL_EMBW_EMLV_DS	Limit Emerald SF to 40 MW to avoid overload on Emerald – Lilyvale 66 kV line for trip of Emerald–Comet– Blackwater 66 kV line	$ 0.094M (↓ $ 0.5M)	110	Energy Queensland is progressing projects to assist with this constraint.

Note: Note: From annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been prioritized as per financial year 2023-24 data.

2.3 South Australia

- **AEMO has confirmed that the magnitude and timing of the previously declared gap for voltage control in South Australia under low demand conditions remains urgent and unchanged.** ElectraNet is remediating this issue through new switchable reactors in the Adelaide and South East regions, expected to be in service from June 2026. In the interim, AEMO is progressing tender activities to identify if any near-term service providers are available to meet this declared gap.
- **AEMO has not identified any system strength or inertia shortfalls in South Australia**, and the previously declared inertia shortfall has been resolved, primarily through additional registrations in the 1-second FCAS market. ElectraNet must ensure sufficient inertia services are available to meet their full inertia sub-network allocation of 4,300 MWs from 1 December 2027.

Scope of assessment

AEMO has assessed *NSCAS needs* in South Australia over a five-year outlook period, under a range of demand, generation, and network assumptions. This section summarises the results of these assessments relating to:

- Voltage control and thermal loading (Section 2.3.1).
- Rapid voltage change (Section 2.3.2).
- Ramping risk (Section 2.3.3).
- System strength, over a three-year period (Section 2.3.4).
- Inertia, over a three-year period (Section 2.4.4).
- Market benefit ancillary services (Section 2.3.6).

Table 13 provides an overview of the core scenarios studied for South Australia. Appendix A1 provides further detail on the specific input sources and modelling assumptions used for the 2024 NSCAS assessment.

Table 13 South Australian NSCAS scenarios and outcomes

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand day	Committed projects only, PEC stage 1 in service, demand less than 10 MW.	2024-25	Existing voltage RSAS gap for low demand
	Sensitivity: Committed projects only, PEC stage 1 in service, demand less than 10 MW. Negative reactive power for demand. 0 unit in service.	2024-25	Existing voltage RSAS gap for low demand
	System typical	2024-25	Emerging risk
	Committed projects only, demand less than 10 MW, PEC Stage 2.	2029-30	Emerging risk
	Sensitivity: Committed projects only, demand less than 10 MW, Negative	2029-30	Emerging risk identified

Case	Scenario assumptions	Year of assessment	NSCAS gap
	reactive power for demand, PEC Stage 2.		
	System typical	2029-30	Emerging risks
Low demand night	Committed projects only, Demand greater than 500 MW. Capacitive reactive power for demand. PEC stage 1 in service.	2024-25	Existing voltage RSAS gap for low demand
	System typical	2024-25	Emerging risk
	Committed projects only, Demand greater than 500 MW. Negative reactive power for demand. PEC stage 2 in service.	2029-30	No new gaps identified
	System typical	2029-30	Emerging risk
System Strength	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand, and system normal network configuration.	2024-25 to 2027-28	No new gaps identified
Inertia	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand. Interconnected system, islanded system with South Australia operating as an island.	2024-25 to 2027-28	No new gaps identified

Note: While core studies low demand day and low demand night studies were based on 2024 ESOO demand projections, additional sensitivities were conducted to confirm the existing gap and emerging risks.
A. Adjustments have been made to the ISP ODP for transmission to account for recent announcements in Eraring's extension and recent changes in generation and transmission timings and commitments.

2.3.1 Voltage control and thermal loading

AEMO assessed expected voltage control and thermal loading issues in South Australia over a five-year outlook period. Studies focused on low demand conditions, as there have not been any material changes expected to have worsened power system security outcomes since the maximum demand studies were conducted in December 2023. The analysis considered a range of region-specific network sensitivities and operating conditions to provide full coverage of heightened risk periods in South Australia under both minimum daytime and minimum nighttime demand.

Voltage control challenges in South Australia – previously declared NSCAS gap

In December 2023, AEMO declared an NSCAS gap for voltage control in South Australia, representing an immediate need for up to 200 MVAr in the Adelaide metropolitan area. Following this declaration, ElectraNet provided advice on its planned remediation through a RIT-T process, with additional shunt reactors located at Adelaide Metropolitan region (4 x 60 MVAr) and South East (1 x 50 MVAr) expected to be in service from June 2026.

AEMO deemed that the gap would remain in the interim period until that longer-term solution could be delivered, and has subsequently commenced expression of interest, and tendering activities[32] to seek service providers capable of meeting the gap during the intervening period.

As part of the 2024 NSCAS Report, AEMO reassessed the voltage control needs that underpinned this original declaration and found that both the magnitude and timing of the gap remain unchanged. AEMO will continue to progress its commercial tender processes in response.

Voltage control challenges in South Australia with leading power factor

As part of the 2024 NSCAS studies, AEMO undertook an additional sensitivity to assess the impact of changes in the power factor of demand (making it more capacitive) under minimum demand conditions. This follows discussion with ElectraNet and SA Power Networks indicating a longer-term trend in this direction for overnight demands. The results of this assessment indicate that this trend is likely to further exacerbate voltage control challenges over time. While the ElectraNet voltage control RIT-T will provide some relief for this issue, AEMO notes this as an emerging risk and will continue to work with ElectraNet and SA Power Networks to track trends in the nature of reactive demand over time.

System typical

The 2024 NSCAS assessment for South Australia has considered a system typical sensitivity, developed with input from AEMO Operations and ElectraNet. This sensitivity acknowledges that not all network elements are in service under typical operating conditions.

For South Australia, AEMO has assessed four potential prior network outage conditions independently:

- One Para static VAR compensators (SVC) out of service.
- One South East SVC out of service.
- One Robertstown synchronous condenser out of service.
- One Davenport synchronous condenser out of service.

The results of these studies indicate that these SVCs and synchronous condensers are critical for meeting South Australia's voltage control needs, particularly under low demand conditions. In the each of the scenarios for minimum day demand and minimum night demand, the reactive power limits were exceeded under either pre-contingent or post-contingent conditions. There were certain contingencies across the regions that had impact for South Australia for example, a loss of Alcoa Portland (APD) or loss of 500 kV Tarrone – Heywood line caused South East SVC to be very close to its rated reactive power limits.

The installation of shunt reactors as part of the ElectraNet Transmission Voltage Control RIT-T does provide some relief for these prior outage conditions, however outage of South East SVC and trip of the APD load or a single 500 kV Heywood – Tarrone line can still result in limit excursions at the remaining South East SVC.

[32] See https://aemo.com.au/consultations/tenders/nscas-procurement.

- While studies under prior outage conditions cannot be used to declare NSCAS gaps, AEMO does consider that the impact (and potentially long mean-time-to-repair for such assets) does make them an emerging risk that must be considered in operational and maintenance planning discussions between AEMO and ElectraNet.
- AEMO will continue to monitor the status of these assets and their impact to the power system.

2.3.2 Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in South Australia.

0 summarises the results of this analysis which indicted all the scenarios being below 2.5%, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the IEC Standard[33].

Table 14 Rapid voltage change results for reactive plant switching in South Australia

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum Demand Day	Committed projects only	2024 -25	1.13%	Bundey 330 kV	60 MVAr reactor at Bundey 330 kV Bus	3%-5%	Yes
	Committed projects only	2029 -30	1.17%	Para 275 kV	40 MVAr reactor at City West 275 kV Bus		Yes
Minimum Demand Night	Committed projects only	2024 -25	1.10%	Para 275 kV	40 MVAr reactor at City West 275 kV Bus		Yes
	Committed projects only	2029 -30	1.16%	Para 275 kV	40 MVAr reactor at City West 275 kV Bus		Yes

AEMO also conducted this analysis for each of the system typical scenarios defined in the previous section, however all outcomes remained within the system standard for these studies. The worst result observed was under conditions with one Para SVC out of service, following a reactor switching event at City West which resulted in a 2.48% voltage step at Para 275 kV.

2.3.3 Ramping risk for South Australia

In 2020, AEMO's *Renewable Integration Study* report[34] highlighted that the magnitude and frequency of large ramps in variable renewable energy (VRE) was increasing across the NEM. This will result in larger and more frequent fluctuations in generation that will need to be managed to maintain the supply-demand balance.

[33] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed 4 within a 24-hour period, with each change allowing a permissible variation of 3-5%.

[34] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

Distributed photovoltaic (DPV, rooftop PV) output continues to hit record highs in South Australia[35]. To understand the impact of increasing wind and solar penetrations on the system's ability to meet future ramping requirements, this year's NSCAS assessment undertook several exploratory studies to characterise projected levels of variability in South Australia.

Voltage control and thermal loading

In this exploratory assessment, to investigate the impact of voltage control risks, power system analysis studies assessed following large power changes (ramping) of variable generation in South Australia (both VRE and DER). This was performed under forecast system conditions for both 2024-25 and 2029-30, and included a five-minute un-forecast ramping event under a range of critical demand scenarios.

Table 15 provides an overview of the core scenarios studied.

[35] See https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q1-2024.pdf?la=en.

Table 15 Summary of ramping scenarios

Case no.	Ramping scenarios	Year of assessment	Ramping size	Ramping on network
1A	Reduction of wind generation under a low demand situation	2024-25	-564 MW	Interconnectors are at high export levels pre-ramp event.
				Wind farms in mid-north region were ramped down to zero.
				The ramp MW deficit is supplied through interconnectors.
				Interconnectors are close to zero flows post-ramp event.
1B	Simultaneous variation of wind and DPV generation under a low demand situation		Net -564 MW	Interconnectors are at high export levels pre-ramp event.
			-975 MW of wind	Wind Farms in mid-north region were ramped down to zero. Simultaneously, DPV generation around Adelaide Metro area was increased.
			+410 MW of DPV	The ramp MW deficit is supplied through Interconnectors.
				Interconnectors are close to zero flows post-ramp event.
1C	Reduction of DPV for the NSCAS Mid-day scenario base case		-564 MW	Interconnectors are lightly loaded pre-ramp event.
				DPV generation around Adelaide Metro area was decreased.
				The ramp MW deficit is supplied through Interconnectors.
1D	DPV ramp up under a low demand situation		+386 MW	Interconnectors are at high export levels pre-ramp event.
				DPV generation around Adelaide Metro area was increased.
				The additional MW is exported through interconnectors.
				Interconnectors are pushed beyond their limit post-ramp event.
2A	Reduction of wind generation under a low demand situation	2029-30	-677 MW	Interconnectors are at high export levels pre-ramp event.
				Wind Farms in mid-north region were ramped down to zero.
				The ramp MW deficit is supplied through Interconnectors.
				Interconnectors are close to zero flows post-ramp event.
2B	Simultaneous variation of wind and DPV generation under a low demand situation		Net -677 MW	Interconnectors are at high export levels pre-ramp event.
			-975 MW of wind	Wind Farms in mid-north region were ramped down to zero. Simultaneously, DPV generation around Adelaide Metro area was increased.
			+300 MW of DPV	The ramp MW deficit is supplied through Interconnectors.
				Interconnectors are close to zero flows event.
2C	Reduction of DPV for the NSCAS Mid-day scenario base case		-677 MW	Interconnectors are lightly loaded pre-ramp event.
				DPV generation around Adelaide Metro area was decreased.
				The ramp MW deficit is supplied through Interconnectors.
2D	DPV ramp up post cloud coverage under a low demand situation		+470 MW	Interconnectors are at high export levels pre-ramp event.
				DPV generation around Adelaide Metro area was increased.
				The additional MW is exported through interconnectors.
				Interconnectors are pushed beyond their limit post-ramp event.

Ramping risk results

In both the 2024-25 and 2029-30 cases, thermal overload are observed in the scenario where DPV is ramping up under very low demand conditions (Cases 1D and 2D). The additional power generated by DPV in the Adelaide

Metro Area flows through the 275 kV transmission corridors and interconnectors to adjacent regions. The observed overloading is mainly for parallel lines in the corridor between Adelaide Metro area and Heywood Interconnectors[36] where the contingency of one line will cause the remaining line to be above its post contingency thermal rating.

When the ramping is at maximum in the 2024-25 case, under voltage issues are identified at South-East and Black Range 275 kV buses following a credible contingency of Project Energy Connect (PEC) Stage 1.

This would be considerably exacerbated under prior outage conditions of one of the South-East SVCs, causing the SVC at Para and the remaining SVC at South East to exceed their rated reactive power limits. Under the system typical scenario in 2024-25 and 2029-30, where there are outages on the synchronous condenser or SVC, an under voltage occurs and the remaining synchronous condensers or SVC exceed their reactive power limits when there is a credible contingency of PEC Stage 2.

AEMO considers this as an emerging risk, and although there is voltage control logic and a remediation scheme in place around South East region and Para substation, further analysis is warranted to assess if these are sufficient to manage all observed issues. AEMO will continue to engage with ElectraNet and SA Power Networks on the risks presented by unexpected ramping events or drift at the interconnectors.

2.3.4 System strength

AEMO assessed expected levels of three phase fault current at each system strength node in South Australia against the latest minimum fault current requirements published in the 2024 *System Strength Report*. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year.

The results of this assessment are summarised in Table 16, and indicate no expected shortfalls in South Australia across the three-year study horizon.

Table 16 South Australia fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (MVA)	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Davenport 275 kV	2,400	2,555	2,567	2,629	2,624	0	0	0	0
Para 275 kV	2,250	2,745	2,574	2,511	2,485	0	0	0	0
Robertstown 275 kV	2,550	2,897	3,084	3,451	3,449	0	0	0	0

The 2024 *System Strength Report*[37] provides additional detail on the calculation of fault level requirements, and the modelling analysis used to assess the typical levels of availability. That report also provides individual fault level duration curves for each node, and specifies additional, efficient level requirements for system strength, which are outside the scope of the NSCAS assessment.

[36] The 275 kV transmission corridor consisting of Tungkillo – Tailem Bend – South East to Heywood.

[37] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

2.3.5 Inertia

AEMO assessed expected levels of available inertia in South Australia against the latest *inertia requirements* published in the 2024 *Inertia Report*[38]. The assessment considered the South Australia portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded.

AEMO's assessment of the resulting inertia needs, summarised in Table 17Table 17 and Table 18Table 18, indicates sufficient inertia is available to meet the *inertia requirements* in South Australia. ElectraNet is also required to ensure sufficient supplies are available to meet its *inertia sub-network allocation* from 1 December 2027.

AEMO has deemed South Australia as sufficiently likely to island on its own until the commissioning of PEC Stage 2 and associated control schemes are in place. On this basis, AEMO has assessed the region against both its *inertia sub-network allocation* and its individual (islanded) *secure level of inertia*.

System-wide inertia level assessment for South Australia

Figure 6 and Table 17 present the projected levels of inertia expected to be available in South Australia over the next three years. This indicates that levels are expected to remain above the *inertia sub-network allocation*.

Figure 6 Projected inertia for the three-year outlook, *Step Change* scenario, South Australia, NEM intact case

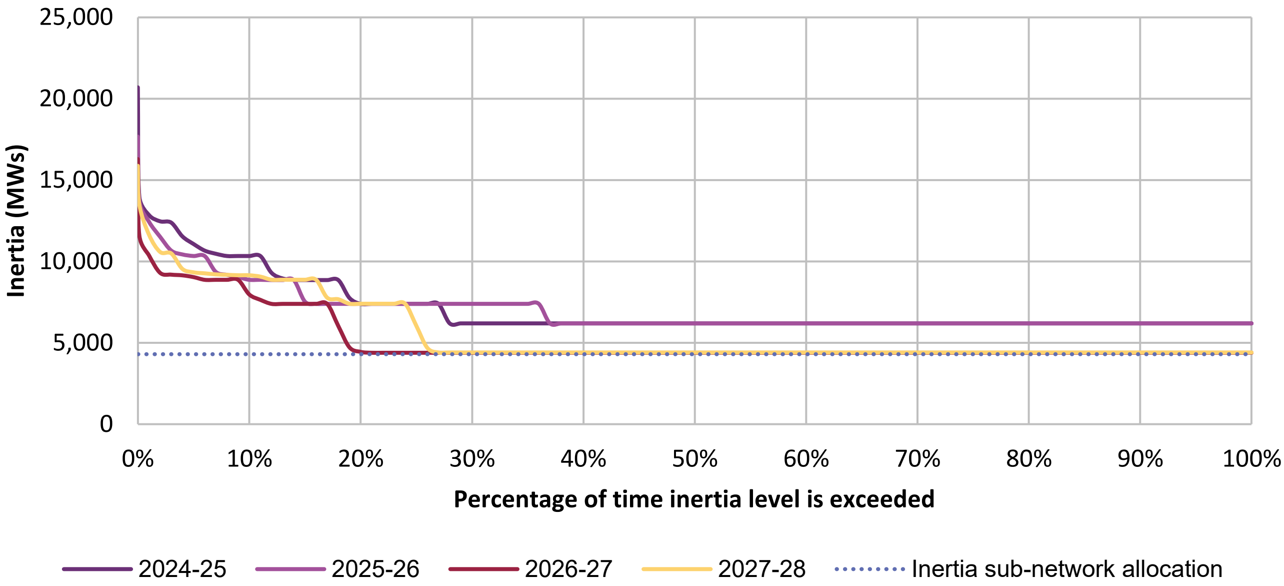


Table 17 Inertia sub-network allocation and projections for South Australia

	2024-25	2025-26	2026-27	2027-28
***Inertia sub-network allocation* (MWs)**	4,300	4,300	4,300	4,300
Available inertia 99.87% of the time (MWs)	6,200	4,400[A]	4,400	4,400
***NSCAS gap* (MWs)**	-	-	-	-

[38] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

A. The projected level of inertia noted here is the expected availability after the commissioning of PEC Stage 2, and associated control schemes.

Secure inertia requirements assessment for South Australia

Figure 7 and Table 18 present the projected levels of inertia expected to be available under islanded operation of the South Australia region over each of the next three years. This indicates that projected levels of inertia are expected to remain above the South Australia *secure level of inertia* while the region is sufficiently likely to island.

Figure 7 Projected inertia for the three-year outlook, *Step Change* scenario, South Australia islanded case

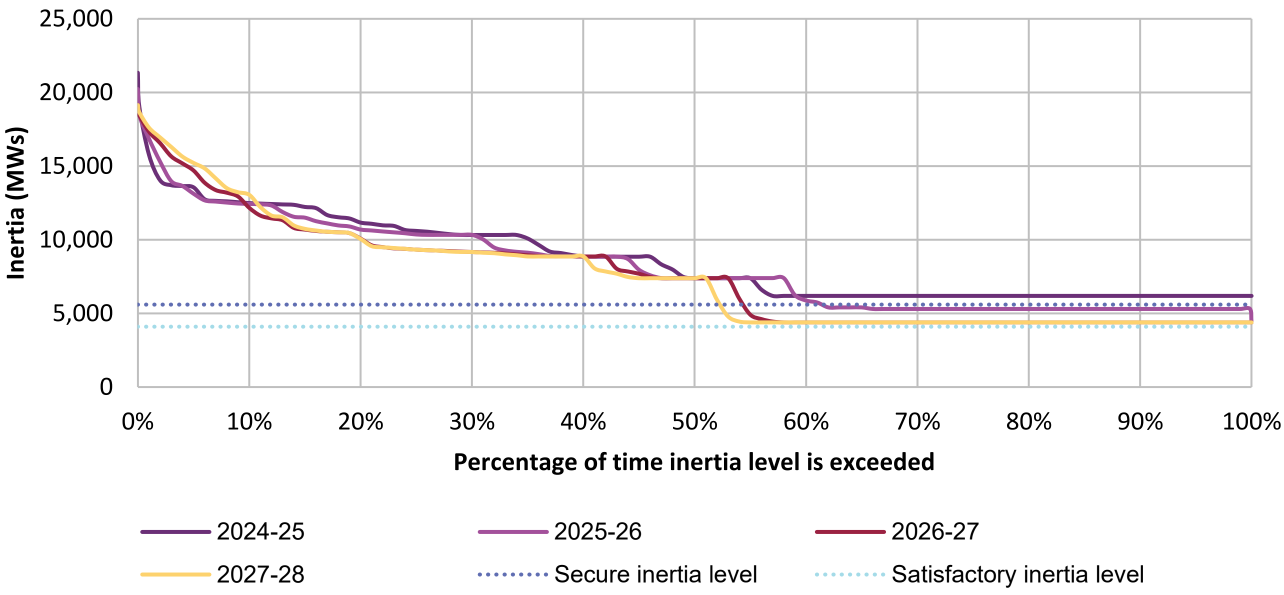


Table 18 Secure Inertia requirements and projections for South Australia

	2024-25	2025-26[A] (Early)	2025-26[A] (Late)	2026-27	2027-28
Assumed level of 1-second FCAS (MW)	315	315	315	315	315
***Secure level of inertia* (MWs)**	5,600	5,600	5,600	5,600	5,600
Available inertia 99.87% of the time (MWs)	6,200	6,200	5,300	4,400	4,400
Inertia sub-network likely to island	Likely	Likely	Unlikely[B]	Unlikely	Unlikely
***NSCAS gap* (MWs)**	-	-	-	-	-

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.
A. A significant transition happens within this year, following the expected commissioning of PEC Stage 2, and associated control schemes. As such, results for 2025-26 have been split into values that apply before and after PEC commissioning.
B. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of PEC Stage 2 and necessary protection schemes are in place to manage the non-credible loss of PEC and the Heywood interconnector.

2.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in South Australia. Table 19 provides a comparison of binding hours and marginal values for the highest impact constraints observed[39]. All constraints with a marginal value exceeding

[39] Marginal values were used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

$50,000 per year have previously been discussed with ElectraNet, which has confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through ElectraNet's annual TAPR process and may trigger action if market benefits exceed remediation costs.

Table 19 South Australian high-impact constraint summary for 2023-24

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP Comments
S>NIL_MHNW1_MHNW2	Avoid thermal overloads on Monash –North West Bend #2 132 kV line for trip of Monash – North West Bend #1 132 kV line.	$8M (↓$4M)	1,336	ElectraNet has projects in its 2024 TAPR that refers to a Network Capability Incentive Parameter Action Plan (NCIPAP) project to install capacitor bank at Monash. If this project proceeds, then the increase of Murraylink can occur. The project scope to increase of Murraylink transfer capacity entailed the following- upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required [A] will also assist to alleviate this constraint.
S>NIL_HUWT_STBG3	Avoid thermal overload on Snowtown–Bungama line for loss of Hummocks–Waterloo line.	$3M (↓ $2M)	368	ElectraNet is monitoring to determine if proposed project noted in its 2024 TAPR to increase transmission uprating- which falls under the NCIPAP project is likely to alleviate this constraint [A].
S>NIL_NWRB2_NWRB1	Avoid thermal overload on North West Bend – Robertstown #1 132 kV line on trip of North West Bend – Robertstown #2 132 kV line.	$2.7M (↑ $1M)	376	This constraint will be alleviated when project noted in the 2024 TAPR to install capacitor bank at Monash (NCIPAP) occurs. Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required[A] will also assist to alleviate this constraint.
SVML^NIL_MH-CAP_ON	Voltage stability upper transfer limit on Murraylink from South Australia to Victoria to manage voltage collapse at Monash (note: applies when capacitor banks at Monash are available and I/S for switching).	$0.6M ((↓ $1M)	520	ElectraNet is monitoring to determine if proposed project noted in its 2024 TAPR to increase transmission uprating- which falls under the NCIPAP project is likely to alleviate this constraint [A].
S>>NIL_TWPA_TPRS	Avoid thermal overload on Templers–Roseworthy 132 kV line on trip of Templers West – Para 275 kV line.	$0.3M (↓ $0.4M)	64	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the project noted in 2024 TAPR Mid North REZ Expansion project[A].

Note: from annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been prioritized as per financial year 2023-24 data.
A. See Table 4 page 49 of ElectraNet's TAPR, October 2024, at https://electranet.com.au/wp-content/uploads/2024/11/ElectraNet-2024-TAPR-2.pdf
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2.4 Tasmania

- **AEMO has confirmed ongoing system strength and inertia shortfalls across the Tasmanian region.** TasNetworks has sufficient network support agreements in place to provide these necessary services until 2 December 2025, and is progressing further arrangements as part of its broader regional System Strength RIT-T.
- **AEMO has not identified any other thermal or voltage gaps** in Tasmania over the five-year period. Future power system changes, including connection of new large loads, could impact voltage control and reactive margins in some locations, and AEMO will continue to monitor these risks.

Scope of assessment

AEMO has assessed NSCAS needs in Tasmania over a five-year outlook period, under minimum day demand scenario and network project assumptions. This section summarises the results of these assessments relating to:

- Voltage control and thermal loading (Section 2.4.1).
- Rapid voltage change (Section 2.4.2).
- System strength, over a three-year period (Section 2.4.3).
- Inertia, over a three-year period (Section 2.4.4).
- Market benefit ancillary services (Section 2.4.5).

Table 20 provides an overview of the core scenarios studied for Tasmania. Appendix A1 provides further detail on the specific input sources and modelling assumptions used for the 2024 NSCAS assessment.

Table 20 Tasmanian NSCAS scenarios and outcomes

Case	Project scenarios	Year of assessment	NSCAS gap
Low demand (day)	Committed projects only	2024-25	No new gaps identified
	Committed projects only	2029-30	No new gaps identified
System strength	Market modelling with 50 generator outage patterns, ISP ODP transmission[A] and generation projections, 50% POE demand, and system normal network configuration.	2024-25 to 2027-28	Gaps confirmed at all Tasmania nodes upon end of the existing contract with Hydro Tasmania.
Inertia	Market modelling with 50 iterations, ISP ODP transmission[A] and generation projections, 50% POE demand – system with Tasmania operating as an island	2024-25 to 2027-28	Gaps confirmed upon end of existing contract with Hydro Tasmania.

A. Adjustments have been made to the ISP ODP for transmission to account for recent announcements in Eraring's extension and recent changes in generation and transmission timings and commitments.

2.4.1 Voltage control and thermal loading

AEMO assessed expected voltage control and thermal loading issues in Tasmania over a five-year outlook period. To study the most onerous voltage control scenarios, Basslink was modelled as importing to Tasmania during low demand conditions. These studies did not identify any thermal overloading or voltage control problems in Tasmania across the study horizon.

2.4.2 Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in Tasmania. Table 21 summarises the results of this analysis which are greater than 2.5%, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the IEC Standard[40].

Table 21 Rapid voltage change results for reactive plant switching in Tasmania

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Low demand	Committed projects only	2024-25	3%	Basslink 220 kV	43 MVAr capacitor bank at Basslink	3%-5%	Yes
	Committed project only	2029-30	3%	Basslink 220 kV	43 MVAr capacitor bank at Basslink		Yes

2.4.3 System strength

AEMO assessed the expected levels of three phase fault current at each system strength node in Tasmania against the latest minimum fault current requirements published in the 2024 *System Strength Report*. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of three phase fault current expected to be available for 99.87% of a typical year.

The results of this assessment are summarised in Table 22, and confirm expected shortfalls at all nodes from 2025-26. TasNetworks has sufficient network support agreements in place with Hydro Tasmania to cover these shortfalls until 2 December 2025.

Beyond that time, TasNetworks is progressing additional measures through a System Strength RIT-T process, and AEMO has not identified a need to intervene by declaring an NSCAS gap or exercising its last resort planning functions. AEMO will continue to work with TasNetworks to track the progress of its remediation activities.

[40] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed 4 within a 24-hour period, with each change allowing a permissible variation of 3-5%.

Table 22 Tasmania fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (MVA)	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Burnie 110 kV	750	750	488	396	409	0	262	354	341
George Town 220 KV	1,450	1,450	763	558	584	0	687	892	866
Risdon 110 KV	1,330	1,330	964	700	741	0	366	630	589
Waddamana 220 KV	1,400	1,400	1,018	705	743	0	382	695	657

The 2024 *System Strength Report*[41] provides additional detail on the calculation of fault level requirements, and the modelling analysis used to assess the typical levels of availability. That report also provides individual fault level duration curves for each node, and specifies additional, efficient level requirements for system strength, which are outside the scope of the NSCAS assessment.

2.4.4 Inertia

AEMO assessed the expected levels of available inertia in Tasmania against the latest *inertia requirements* published in the 2024 *Inertia Report*[42]. Tasmania is not subject to the *system-wide inertia level*, so this assessment considers only the islanded regional requirement, and the likelihood of islanding events. The 2024 *Inertia Report* provides further detail on the calculation and application of these *inertia requirements*.

Secure inertia requirements assessment for Tasmania

AEMO's assessment of the resulting inertia needs, summarised in Table 23, indicates an inertia shortfall in Tasmania of between 2,184 MWs and 2,710 MWs from 2025-26 until the end of the horizon against the *secure inertia level*.

Consistent with the system strength findings, TasNetworks has sufficient network support agreements in place with Hydro Tasmania to cover these shortfalls until 1 December 2025. Beyond that time, TasNetworks is progressing inertia remediation measures in parallel with its System Strength RIT-T, and AEMO has not identified a need to intervene by declaring an *NSCAS gap* or exercising its last resort planning functions. AEMO will continue to work with TasNetworks to track the progress of its remediation activities.

[41] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

[42] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

Figure 8 Projected inertia for the three-year outlook, *Step Change* scenario, Tasmania

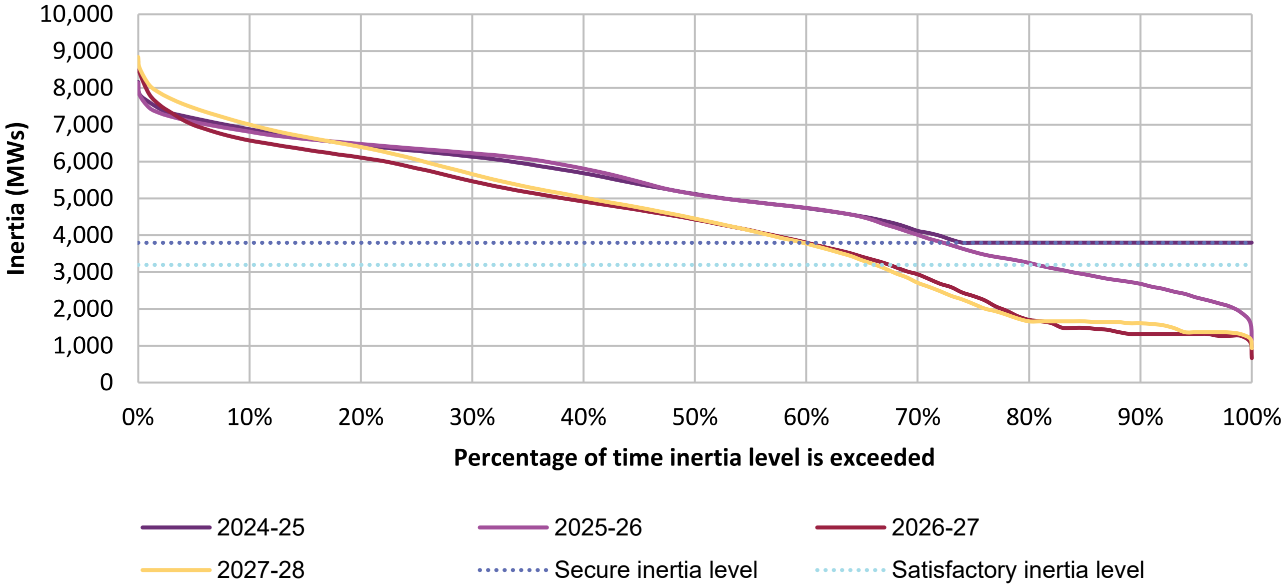


Table 23 Secure level of inertia requirements and projections for Tasmania

	2024-25	2025-26	2026-27	2027-28
***Secure level of inertia* (MWs)**	3,800	3,800	3,800	3,800
Available inertia 99.87% of the time (MWs)	3,800	1,616	1,090	1,193
***NSCAS gap* (MWs)**	-	2,184	2,710	2,607

Note: Modelling is conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.

2.4.5 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Tasmania. Table 24 provides a comparison of binding hours and marginal values for the highest impact constraints observed[43]. All constraints with a marginal value exceeding $50,000 per year have previously been discussed with TasNetworks, and TasNetworks has confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through the TasNetworks annual TAPR process.

Table 24 Tasmanian high-impact constraint summary for 2023-24

Constraint ID	Description	Marginal Value (↓↑ change)	Binding Hours	TNSP Comments
T::T_NIL_1	Prevent transient instability for fault and trip of a Farrell to Sheffield line.	$0.6M (↑ $0.2M)	1,650	Planned future augmentation of Sheffield–Palmerston 220 kV.
T_MRWF_GCS	Musselroe wind farm Generator Control Scheme (GCS).	$0.5M (↑ $0.3M)	237	This constraint binds only when GCS was not arming enough load.

Note: Note: From annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been prioritised as per financial year 2023-24 data.

[43] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en.

2.5 Victoria

- **AEMO has identified a need for system strength services of 368 MVA at Red Cliffs from 2025 26,** primarily linked with the expected end of existing system strength remediation contracts. AEMO Victorian Planning (AVP) is exploring options to extend this arrangement. **Shortfalls are also forecast to emerge against requirements at Moorabool, Hazelwood, and Thomastown from 2027-28,** and AVP is progressing a regional system strength RIT-T**.**
- **The projected level of inertia is expected to fall below the inertia sub-network allocation for Victoria, however sufficient inertia is available to be shared from neighbouring regions**. AVP must ensure sufficient inertia services are available to meet their full inertia sub-network allocation of 11,800 MWs from 1 December 2027.
- **AEMO has not identified any new thermal loading or voltage control gaps in Victoria.** Risks have been observed for voltage control at Eildon during low demand conditions from 2024-25, however these are being managed with an existing operational solution. Low demand conditions like this are expected to grow over time, and may already present challenges during outage conditions.
- **AEMO has confirmed the existing thermal overloading and voltage control gap on the 220 kV network near Deer Park.** AVP has commissioned a control scheme to enable higher pre-contingent loading in this area to address the thermal overloading gap and is expected to commence the Western Metropolitan Reinforcement RIT-T in Q1 2025 to identify a longer-term solution to the thermal overload limitations. AVP is separately progressing a Metropolitan Melbourne Voltage Management RIT-T, which will conclude soon with publication of the PACR planned for mid-December 2024, that will confirm the preferred option that addresses voltage control needs Deer Park. AEMO will continue to monitor the status of remediation activities.
- **Overloading risks remain for transformers between the 500 kV and 220 kV network supplying Metropolitan Melbourne following Yallourn Retirement in 2028-29.** AVP has developed an operational solution, and is considering longer-term remediation options. The Eastern Metropolitan Grid Reinforcement Project Specification Consultation Report (PSCR) was published in November 2024. The Western Metropolitan Grid Reinforcement PSCR is planned to be published in Q1 2025. AEMO considers that this NSCAS need is being managed, and will continue to monitor the status of associated remediation.

Scope of assessment

AEMO assessed NSCAS needs in Victoria over a five-year outlook period, under a range of demand, generation, and network assumptions. This section summarises the results of these assessments relating to:

- Voltage control and thermal loading (Section 2.5.1).
- Rapid voltage change (Section 2.5.2).
- Reactive margin (Section 2.5.3).
- System strength, over a three-year period (Section 2.5.4).
- Inertia, over a three-year period (Section 2.5.5).

- Market benefit ancillary services (Section 2.5.6).

Table 25 provides an overview of the core scenarios studied for Victoria. Appendix A1 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2024 NSCAS assessment.

Table 25 Victorian NSCAS scenarios and outcomes

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand day	Committed projects only	2024-25	Voltage control need at Eildon 220 kV but can be managed operationally
	Committed projects only	2029-30	Voltage control need at Eildon 220 kV but can be managed operationally
	System typical	2024-25	Emerging risk
	System typical	2029-30	Emerging risk
Low demand night	Committed projects only	2024-25	Risk of over voltage but managed by existing operational agreement Surrounding Glenrowan 220 kV network has voltage control risk but no identified need[A].
	Committed projects only	2029-30	Risk of over voltage but managed existing by operational agreement. Surrounding Glenrowan 220 kV network has voltage control risk but no identified need[A]
	System typical	2024-25	Emerging risk
	System typical	2029-30	Emerging risk
High demand	Committed projects only	2024-25	NSCAS need managed operationally
	Committed projects only	2029-30	NSCAS need- RIT-T
System strength	Market modelling with 50 generator outage patterns, ISP ODP transmission[B] and generation projections, 50% probability of exceedance (POE) demand, and system normal network configuration.	2024-25 to 2027-28	Shortfalls against requirements have been identified at Hazelwood, Moorabool, Red Cliffs and Thomastown
Inertia	Market modelling with 50 generator outage patterns, ISP ODP transmission[B] and generation projections, 50% POE demand. Interconnected system.	2024-25 to 2027-28	No gaps identified

A. The absence of a gap is dependent on committed projects providing reactive support.
B. Adjustments have been made to the ISP ODP for transmission to account for recent announcements in Eraring's extension and recent changes in generation and transmission timings and commitments.

2.5.1 Voltage control and thermal loading

AEMO assessed expected voltage control and thermal loading issues in Victoria over a five-year outlook period, under minimum daytime demand, minimum night-time demand and a maximum demand scenario. This included testing several different assumptions relating to committed and announced changes to both generation and transmission projects.

Thermal overloads and voltage control gaps at Deer Park Terminal Station

The 2024 NSCAS studies confirmed the previously declared gap at Deer Park for thermal overloads, however following declaration of this gap last year, a system overload control scheme was commissioned which closes this gap. The control scheme enables higher pre-contingent loading on the Geelong – Deer Park 220 kV and Geelong – Keilor 220 kV lines. The control scheme also responds to remove any overload following a contingent outage of a 220 kV circuit between Geelong and Keilor corridor.

The 2023 NSCAS report also identified an RSAS gap for voltage control following credible contingencies on the 220 kV network near Deer Park, and a need for additional reactive support near Deer Park towards the end of the NSCAS horizon. Since that time, AVP has commenced a RIT-T which is expected to address voltage control at Deer Park[44].

Low demand conditions

Over voltages were observed during periods of projected low demand (both day and night) at Eildon 220 kV, when no hydro generating units are online.

Pre-contingent line switching can be used operationally during low demand conditions when Eildon Power station is not already online to provide reactive power support. During daytime minimum demand conditions, switching a single 220 kV line is currently sufficient to resolve the need. Furthermore, during minimum demand night-time conditions, switching both 220 kV lines resolves the over voltage in the event there is a contingency. In this operating condition the station maybe switched off. Existing operational arrangements are in place to support this operational event if it becomes necessary.

The commissioning of additional VRE and BESS committed and anticipated projects over the study horizon is expected to provide additional sources of reactive power capability within the region.

AEMO is not declaring this an immediate NSCAS gap, but will continue to monitor the nature of this need, the appropriateness of operational solutions and agreements, and the status of proposed VRE, BESS and transmission augmentations projects that may provide further relief.

Yallourn retirement and transformation into the Melbourne metropolitan area

The 2023 NSCAS Report highlighted an emerging risk for reliability of supply during high demand caused by transformer loading limits at key points between the 500 kV and 220 kV networks supplying Metropolitan

[44] See https://www.aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/melbourne-metropolitan-voltage-management-project-assessment-draft-report.pdf?la=en.

Melbourne. These limits tightened following the announced retirement of Yallourn Power Station. The potential risks existed even for scenarios that include both committed and anticipated projects.

This was identified as a priority limitation in AVP's 2023 *Victorian Annual Planning Report* (VAPR)[45], and AVP developed a network switching arrangement that would reconfigure the Latrobe Valley network into parallel mode and attempt to reduce loading on the 500 kV network by redirecting flows onto the 220 kV corridor. The 2024 VAPR[46] notes that implementation of this reconfiguration has progressed with the relevant asset owners, and has been expanded to also include inter-trip protection to prevent line overloads on the Hazelwood – Yallourn 220 kV lines if a Hazelwood 500/220 kV transformer is lost.

The NSCAS studies found that:

- While the reconfiguration is effective in the short-term following Yallourn retirement, the gap is expected to re-emerge as maximum demand continues to grow and new loads are added in other parts of the region.
- By 2029-30, following a credible contingency, thermal overloads are still present on the Moorabool – Geelong 220 kV line, Geelong – Deer Park – Keilor, and the Mount Beauty – Eildon 220 kV lines.

AVP has published the Eastern Victoria Grid Reinforcement RIT-T[47], and expects to commence a Western Victoria equivalent in the new year. These will consider grid reinforcement needs, including this transformation concern. AEMO will continue to monitor remediation of this need and may declare a gap based on assessment of progress in a future NSCAS Report.

System typical

The 2024 NSCAS assessment for Victoria considered a system typical sensitivity. This sensitivity acknowledges that not all network elements are in service under typical operating conditions.

For Victoria, AEMO assessed two potential prior network outage conditions independently during a system minimum demand scenario:

- Outage on Alcoa Portland (APD) (loss of load).
- Outage on Basslink high voltage direct current (HVDC).

These studies indicated that operating the Victorian system under minimum demand conditions will be particularly difficult, particularly following a prior outage of APD or Basslink. Under these conditions, it is possible for Victoria to experience negative local demand by 2029-30, requiring excess power to be exported to ensure a minimum level of synchronous generation can remain online in Victoria for system security.

Regions can often have strongly correlated timing of their minimum demand periods, and coincident minimum demands may require AEMO to intervene by increasing the level of BESS charging or instructing local distribution network service providers (DNSPs) to reduce contributions from CER.

While these outcomes were seen under prior outage conditions, they highlight the growing complexity of operating a secure power system at times of low or negative regional demand. This flags both a growing need for

[45] https://wa.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf?la=en
[46] https://wa.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2024/2024-victorian-annual-planning-report.pdf?la=en
[47] At https://aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf?la=en

operational coordination around major outages, but also the importance of AEMO's ongoing work to quantify the power system risks and develop appropriate control mechanisms to cater for minimum system load conditions.

Minimum system load (MSL)

In the 2024 ESOO[48], AEMO estimated that a minimum of approximately 4.3 GW of operational demand was required in the NEM to support the minimum generation levels of units providing essential system security services and using the current operational toolkit. This need could be as high as 7 GW under conditions with unplanned network or unit outages.

That report forecast that operational demand could fall below 7 GW by as early as 2025-26, under exceptionally low (90% probability of exceedance (POE)) demand conditions. If unplanned outages occur at these times, AEMO may need to take emergency action to increase operational demand by potentially curtailing distributed PV. Such mechanisms are already in place or are being progressed across all regions of the NEM. In addition, measures are being progressed to reduce the minimum stable level of essential generating units and promote investment in additional assets capable of providing system security services without associated energy production (such as synchronous condensers, batteries, and/or reactors).

For Victoria, the 2024 ESOO forecasts a minimum day demand as low as 982 MW for 2024-25, and AEMO has already needed to issue three operational warnings about forecast MSL conditions in September and October 2024[49].

MSL issues are expected to first emerge under unplanned outage conditions, and the 2024 NSCAS studies have confirmed such voltage control issues exist through its system typical studies (see previous section). In addition, the 2024 NSCAS assessment has identified an immediate voltage control gap under credible contingency events (see low demand conditions section above).

These risks and gaps were not identified in previous NSCAS studies, primarily because:

- System typical (significant prior outage) conditions were not previously permitted under the NSCAS methodology. These have now been included to provide better forewarning of these types of risks, but remain outside the formal NSCAS provisions and procurement framework in the NER. AEMO may use system typical studies in the NSCAS report to trigger response via Transitional NMAS or other operational risk mitigation mechanisms.
- Projected levels of minimum demand have fallen much faster than previously forecast, particularly under 90% POE conditions, with DPV uptake a significant driver of this uncertainty. AEMO continues to refine and update its demand forecasts annually through the ESOO, and periodically between these publications through the ESOO Update process.
- Planning advice from AVP[50] indicates that switching of a single 500 kV line between Hazelwood and South Morang can be an acceptable measure to manage over voltages in Victoria. Assessment on the continued

[48] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf?la=en&hash=2B6B6AB803D0C5F626A90CF0D60F6374.

[49] Market Notices MN 118475, MN 118836, MN 119760, at https://aemo.com.au/market-notices.

[50] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/notice-of-nscas-planning-assumption-line-switching-victoria.pdf?la=en.

appropriateness of this assumption is occurring and may have a material impact on the MSL thresholds in the region.

The magnitude and timing of MSL-related risks are strongly influenced by the assumed levels of reactive power support provided by future IBR projects. The NSCAS assessment considered all committed projects, and included cases both with and without anticipated projects – compared to levels of IBR in service in 2023-24, the impact of newly commissioning IBR in 2024-25 is as much as 300 MVAr.

The NSCAS assessment also identified that the magnitude of forecast MSL issues is sensitive to the assumed power factor of demand during low demand conditions, with more capacitive demands resulting in worse voltage outcomes for the region. There is a trend towards more capacitive minimum demands over time, however this varies considerably depending on time-of-day and the nature of the underlying demand at those times. AEMO will continue to monitor and quantify these trends for use in future NSCAS reports.

AEMO is progressing MSL investigations and necessary remediation mechanisms holistically for the NEM as part of the *Transitional Plan for System Security*[51]. AEMO will consider the need for additional MSL sensitivities as part of scoping for the 2025 NSCAS. AEMO will continue to report and declare gaps for these issues where they overlap with the defined NSCAS framework.

2.5.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in Victoria[52]. Table 26 summarises the results of this analysis which are greater than 2.5%, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the IEC Standard[53].

Table 26 Rapid voltage change results for reactive plant switching in Victoria

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Maximum demand day	Committed projects only	2024 -25	2.67%	Altona 220 kV bus	200 MVAr capacitor at Altona 220 kV bus	3%-5%	Yes
	Committed projects only	2029 -30	3.85%	Dederang 330 kV bus	225 MVAr capacitor at Dederang 330 kV bus		Yes

[51] At: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

[52] Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level provided by AVP.

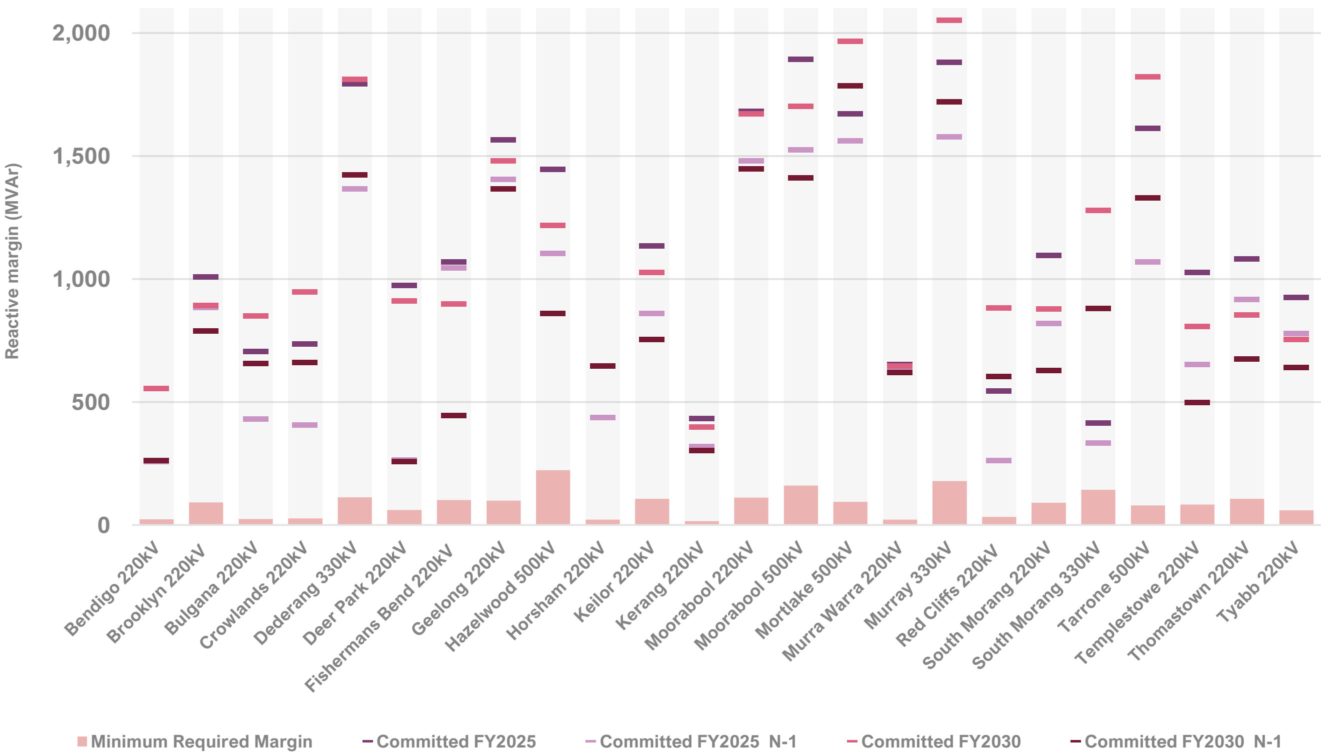
[53] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6- Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed 4 within a 24-hour period, with each change allowing a permissible variation of 3-5%.

2.5.3 Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in Victoria are expected to remain above the system standard[54] of 1% of the local maximum fault level over the five-year outlook period. Figure 9 summarises the results, which indicate that all reactive margins remain above the standard.

The results for 2029-30 were based on operating the Latrobe Valley in radial mode[55], and reactive margins typically improved when assessed under parallel network configurations.

Figure 9 Minimum reactive margin (MVAr) observed for critical buses in Victoria



2.5.4 System strength

AEMO assessed the expected levels of three phase fault current at each system strength node in Victoria against the latest minimum fault current requirements published in the 2024 *System Strength Report*. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year.

The results of this assessment, summarised in Table 27, identify expected shortfalls against requirements of 517 MVA at Moorabool, 1,963 MVA at Hazelwood, and 561 MVA at Thomastown, all commencing from 2027-28. AEMO has additionally identified a need for system strength services of 368 MVA at Red Cliffs from 2025-26 when existing contracts expire. AEMO is not declaring a gap on the basis AEMO is aware AVP is exploring remediation

[54] Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2024-25 maximum fault level provided by AVP.

[55] See AEMO, 2022 VAPR, Figure 37, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf.

options including 12-month extension of the existing system strength services contract and that PEC stage 2 will be expected to provide additional remediation.

AVP is currently progressing a regional RIT-T to deliver sufficient assets or service contracts to meet the full suite of system strength requirements in Victoria. Given this progress and no changes to the existing minimum requirements, AEMO has not identified a need to intervene by declaring an NSCAS gap or exercising its last resort planning functions in Victoria.

AEMO will continue to work with AVP to track the progress of its remediation activities.

Table 27 Victoria fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (MVA)	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Dederang 220 kV	3,500	3,862	3,833	4,099	3,847	0	0	0	0
Hazelwood 500 kV	7,700	7,805	7,800	7,762	5,737	0	0	0	1,963
Moorabool 220 kV	4,600	4,813	4,844	4,963	4,083	0	0	0	517
Red Cliffs 220 kV	1,786	1,965	1,418	2,398	2,510	0	368	0	0
Thomastown 220 kV	4,700	5,265	5,253	5,381	4,139	0	0	0	561

The 2024 *System Strength Report*[56] provides additional detail on the calculation of fault level requirements, and the modelling analysis used to assess the typical levels of availability. That report also provides individual fault level duration curves for each node, and specifies additional, efficient level requirements for system strength, which are outside the scope of the NSCAS assessment.

2.5.5 Inertia

AEMO assessed the expected levels of available inertia in Victoria against the latest *inertia requirements* published in the 2024 *Inertia Report*[57]. The assessment considered the Victoria portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded. The 2024 *Inertia Report* provides further detail on the calculation and application of these *inertia requirements*.

As part of that assessment, AEMO deemed Victoria unlikely to island on its own[58] given its strong interconnection with neighbouring regions, so has only considered inertia shortfalls against Victoria's *inertia sub-network allocation*.

[56] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

[57] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

[58] Historically AEMO has assessed a scenario where the NEM has separated with Victoria and South Australia forming an island. For completeness, AEMO has confirmed that no inertia shortfall exists for this scenario with updated inputs in 2024, however AEMO considers that the *system-wide inertia level* requirement assessment should supersede the need for this scenario in future.

System-wide inertia level assessment for Victoria

Figure 10 and Table 28 present the projected levels of inertia expected to be available under typical operation of the Victoria region over each of the next three years. This indicates that projected levels of inertia are expected to fall below Victoria's *inertia sub-network allocation* by between 2,606 MWs and 6,532 MWs. AEMO has confirmed the minimum amount of inertia available to be shared from neighbouring regions at times when the inertia in Victoria falls below its *sub-network allocation*, and confirmed that the total inertia available to Victoria remains above the *inertia requirements*. AVP must ensure that their full *inertia sub-network allocation* of 11,800 MWs is met from 1 December 2027.

Figure 10 Projected inertia for the three-year outlook, *Step Change* scenario, Victoria

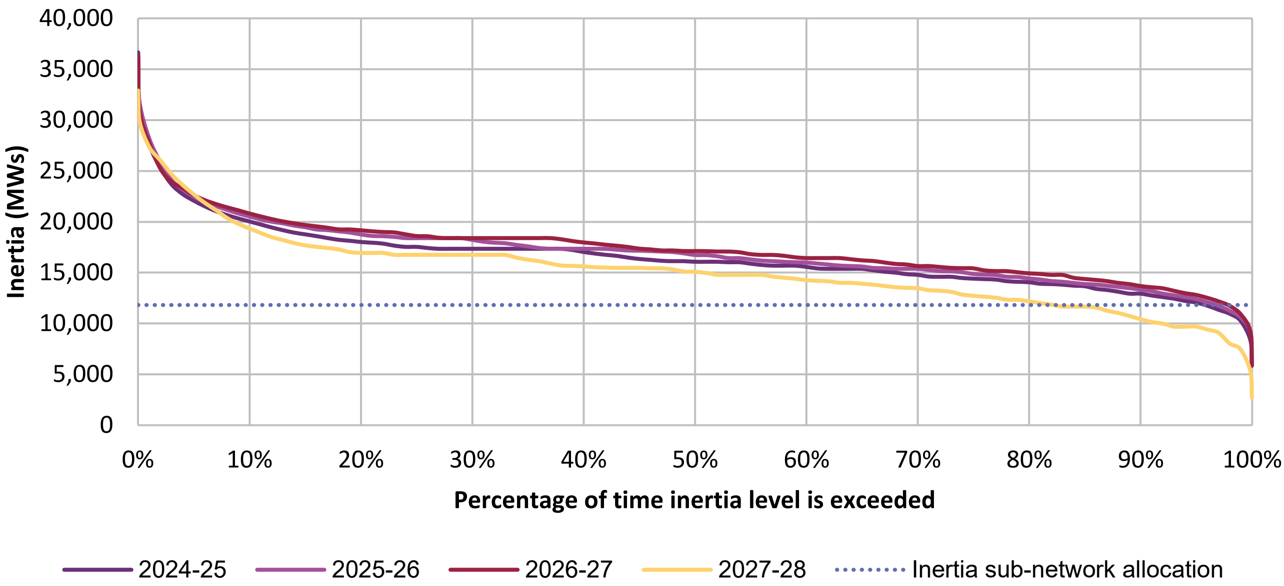


Table 28 Inertia sub-network allocation and projections for Victoria

	2024-25	2025-26	2026-27	2027-28
***Inertia sub-network allocation* (MWs)**	11,800	11,800	11,800	11,800
Available inertia 99.87% of the time (MWs)	8,337	9,158	9,194	5,268
Minimum inertia available to be shared at times of low Victorian inertia (MWs)	19,491	22,991	17,108	14,643
***NSCAS gap* (MWs)**	-	-	-	-

Note: Modelling is conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.

2.5.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Victoria. Table 29 provides a comparison of binding hours and marginal values for the top impact constraints in Victoria[59]. All constraints with a marginal value exceeding $50,000

[59] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

per year have previously been considered by AVP. In each case, a risk status, project, control scheme, or other mitigation strategy has been identified. These options are being monitored through the annual VAPR process and may trigger action if market benefits exceed remediation costs.

Table 29 Victorian high-impact constraint summary for 2023-24

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
V^^V_NIL_KGTS V^^V_NIL_KGTS_2	Avoid voltage collapse for loss of either Crowlands– Bulgana– Horsham lines or the Horsham – Murra Warra – Kiamal 220 kV lines	$8M (↑ $2.5M)	1140	EnergyConnect and the connection of Koorangie Energy Storage System are expected to reduce impact of these constraints by 2027-28.
V>>NIL_ARWB_KGBE	Avoid overload Ararat to Waubra 220 kV line on trip of Kerang to Bendigo 220 kV line	$2.3M (↓ $3.3M)	255	Following an RDP Stage 1 project milestone, the static ratings at Ararat have already been upgraded in August 2023. As the previous static ratings at Ararat have been the primary driver of this constraint, this constraint has already been improved compared to 2022-23. The impact of this limitation is expected to be further reduced after the completion of the WRL project.
V>>NIL_WBBA_KGBE	Avoid O/L Waubra to Ballarat 220 kV line on trip of Kerang to Bendigo 220 kV line	$1.1M ((↓$0.3M)	120	It is expected that minor augmentations as part of the Victorian Government's RDP Stage 1[A] projects and Western Renewable Link project increase the thermal capability of the Ballarat – Waubra – Ararat – Crowlands – Bulgana –Horsham – Murra Warra – Kiamal 220 kV line, and thereby reduce the impact of this limitation.

Note: From annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been prioritised as per financial year 2023-24 data.
A. See http://www.gazette.vic.gov.au/gazette/Gazettes2022/GG2022S547.pdf.

3 Next steps

Based on the 2024 NSCAS studies, AEMO has confirmed the status of previously declared shortfalls, and has identified a range of new system strength, inertia, and voltage control gaps across several regions. Table 30 summarises these findings, and AEMO will work closely with the TNSPs to develop or monitor remediation plans in each case.

To allow adequate consideration ahead of scoping and development for the 2025 report, AEMO seeks feedback by 28 February 2025 via planning@aemo.com.au.

Table 30 Summary of new and existing NSCAS gaps

Region	NSCAS gap
New South Wales 	**Existing system strength shortfalls at Newcastle and Sydney West have been deferred until 2027-28**, linked with delayed retirement of Eraring Power Station. Transgrid is progressing remediation against a full set of New South Wales requirements as part of its broader System Strength Regulatory Investment Test for Transmission (RIT-T) process, and AEMO will continue to work with Transgrid to track the progress of its remediation activities. **The projected level of inertia is expected to remain above the inertia sub-network allocation for New South Wales from 2027-28,** and Transgrid must ensure sufficient inertia is available to meet their full inertia sub-network allocation from 1 December 2027. **No thermal loading or voltage control gaps have been identified**, although several emerging network risks have been identified for supply around Sydney under maximum demand conditions if anticipated generation and network projects do not proceed as planned.
Queensland 	**AEMO has identified new system strength shortfalls of between 153 MVA and 178 MVA across three nodes in Queensland in 2026-27 and Lilyvale alone in 2027-28.** These shortfalls are primarily linked with decreased energy exports to New South Wales, with more energy available in that region following the delayed retirement of Eraring Power Station. That change has resulted in fewer thermal units expected to be online economically in Queensland, and thus lower fault levels available. Powerlink has remediation arrangements in place to address the previous shortfall at Gin Gin node and is progressing a RIT-T to meet system strength requirements across Queensland. **The previously declared inertia shortfall in Queensland for islanded conditions has increased in magnitude to 1,512 MWs in 2026-27 and to 2,221 MWs in 2027-28.** Remediation may be possible in parallel with the existing Powerlink System Strength RIT-T. **No thermal loading or voltage control gaps have been identified**.
South Australia 	**No system strength shortfalls have been identified.** **No inertia shortfalls have been identified,** and the existing inertia shortfall has been addressed, primarily through additional registrations in the 1-second Frequency Control Ancillary Services (FCAS) market. **The magnitude and timing of the previously declared voltage control gap remains unchanged.** AEMO is progressing a commercial tender process to seek potential service providers for an interim period until new reactors can be installed by ElectraNet in 2025-26.
Tasmania 	**AEMO has confirmed ongoing shortfalls at all four nodes in Tasmania**, noting sufficient network support agreements in place until 2 December 2025. TasNetworks is progressing a Regulatory Investment Test for Transmission (RIT-T) to ensure sufficient ongoing support arrangements. **Existing inertia shortfalls have been confirmed for the region.** Sufficient network support agreements are in place until 1 December 2025, and longer-term remediation may be possible alongside system strength remediation. **No thermal loading or voltage control gaps have been identified.**

Region	NSCAS gap
Victoria 	**AEMO has identified a need for system strength services of 368 MVA at Red Cliffs from 2025-26,** primarily linked with the expected end of existing system strength remediation contracts. AEMO Victorian Planning (AVP) is exploring options to extend this arrangement**. Shortfalls are also forecast to emerge against requirements at Moorabool, Hazelwood, and Thomastown from 2027-28,** and AVP is progressing a regional system strength RIT-T. **The projected level of inertia is expected to fall below the inertia sub-network allocation for Victoria,** and AVP must ensure sufficient inertia is available to meet their full inertia sub-network allocation from 1 December 2027. **AEMO has not identified any new thermal loading or voltage control gaps in Victoria. R**isks have been observed for voltage control at Eildon during low demand conditions and these are being managed with an existing operational solution. AEMO has also confirmed the timing and magnitude of the previously declared thermal overloading and voltage control gaps at Deer Park, but notes that these are already being managed by AVP through a local control scheme and longer-term RIT-T. Overloading risks were also identified for transformation into Metropolitan Melbourne following Yallourn Retirement, and AVP has published the PSCR for the eastern metropolitan grid reinforcement and is planning for western metropolitan grid reinforcement PSCR to be published in Q1 of 2025.

A1. Methodology and inputs

AEMO assessed NSCAS needs in each region over a five-year outlook period under maximum and minimum demand conditions. The underlying analysis considered a range of power system requirements, and this appendix provides an overview of the methodology and input data sources used to conduct these studies.

In some cases, an alternative scenario or bespoke set of study conditions was needed to explore specific regional issues or observed operational challenges. These exceptions are described in more detail as they occur through the regional sections of the main report.

All assessments have been conducted in accordance with the latest NSCAS procedures[60], and are based on the latest available data at the point where studies were initiated. In most cases, this data cut-off was 1 August 2024.

A1.1 Study methods and parameters

Contingency analysis

Contingency analysis simulates the state of the power system following a credible contingency event. This type of study is typically used to identify network elements where thermal ratings or voltage limits are exceeded. In the NSCAS context, credible contingency events are applied independently to confirm no limits are violated, and that the system can be operated securely.

AEMO conducted this analysis using PSS®E load flow studies with the following settings:

- Loads were modelled as constant power.
- Pre-contingency cases were solved using the Newton-Raphson method, with transformer taps allowed to move and shunts allowed to switch.
- Post-contingency transformer taps and shunts were locked.

Reactive margin

Reactive margins indicate the additional reactive loading that could be applied at a network location before it would result in voltage collapse. Low levels of reactive margin indicate that the system is at greater risk of such collapse, and these could exist even when absolute voltages appear normal. NER S5.1.8 requires that reactive margins remain above 1% of the maximum fault level at each connection point, and AEMO has applied this standard when assessing NSCAS needs in each region.

Reactive margins can be derived from a QV curve, which shows the amount of reactive power (Q) required for a specified voltage level (V). These curves exhibit a knee-point, below which the system is deemed to be unstable. The position of this knee-point indicates whether there is excess reactive margin, or a reactive margin shortfall.

[60] AEMO. NSCAS Description and Quantity Procedure version 3, December 2024. At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

AEMO used PSS®E for this assessment, coupled with an in-house python tool that automates the study process. In particular, the tool creates a QV curve for each specified bus, based on a set of given contingencies. It does this by applying a fictitious synchronous condenser and varying its target voltage to observe the required reactive power output and to achieve each voltage setpoint. AEMO only applied the reactive margin assessment for maximum demand studies.

Rapid voltage change

When reactive power devices are switched in or out of service on the network, nearby voltage levels are impacted. The size of these impacts can change over time as network loading, connections, and power flow patterns change. To avoid instability and provide operators with granular control of voltage, it is important that capacitor or reactor bank operation does not result in excessive voltage swings.

NER S5.1a.5 provides acceptable voltage change criteria, linked to the number of switching events that occur in each period. AEMO has assumed the most onerous system standard of 2.5% when screening these outcomes, however a higher standard of 5% can be applied as per the IEC standard[61].

AEMO assessed these values by running PSS®E's AC Contingency Calculation (ACCC) analysis on the relevant case with capacitor and reactor banks set as contingency events. For every reactive element contingency, the corresponding voltage change on all network buses can be observed and compared against the standard.

Resecure risk

While contingency analysis confirms whether the power system is robust to a single contingency, it does not consider what subsequent options are available to prepare the system for a further credible contingency or protected event. AEMO takes all reasonable actions to achieve this outcome during system operations. The 2024 NSCAS assessment considered the risk of not re-establishing a secure operating state within this timeframe for several critical events, as identified collaboratively with the system operators and the network businesses.

These studies are typically quite manual, and tailored to very specific system conditions that maximise stress on the network or limit operational responses. Standard contingency analysis may be used, but more often a specific contingency event is selected, and AEMO then considers how operators would prepare the system to withstand the 'next worst' contingency event.

In cases where either no action, redispatch, or network reconfiguration were available options, the NSCAS studies considered these events to be resecurable. In cases where load shedding would be necessary to resecure the power system, the NSCAS studies flagged these events for further consideration by the relevant TNSP. Only in cases where no operational solutions were available would the NSCAS studies consider this a potential NSCAS gap.

Inertia

When assessing an inertia shortfall, AEMO compares the levels of inertia typically available in each region of the NEM against that region's inertia requirements. In 2024, projected shortfalls of inertia are included as *NSCAS*

[61] AS/NZS 61000.3.7 2001 has been superseded by TR IEC 61000.3.7. Table 6 - Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period.

needs in the NSCAS Report in alignment with the 2024 NSCAS Description and Quantity Procedure[62]. In alignment with this Procedure, inertia shortfalls are assessed against the 99.87th percentile, or three standard deviations from the mean (three-sigma).

Shortfall declarations in this report are made for the three-year period from December 2024 to December 2027. However, the inertia projections presented in this report are based on market modelling using financial years, so inertia projection data is presented for 2024-25 to 2027-28.

When considering the potential for inertia shortfalls in the event of combined islands (New South Wales and Queensland, and Victoria and South Australia), AEMO compared the combined inertia level projection across the two sub-networks against the secure operating level and minimum threshold level of inertia of the sub-network with the largest credible contingency size.

Ramping risk

As part of AEMO's Engineering Roadmap to 100% instantaneous renewables program[63], a quasi-dynamic simulation will be carried out to explore and characterise emerging voltage control risks associated with highly variable generation from VRE and DER in the NEM.

The 2024 NSCAS assumptions for the South Australia region will be considered, with minor modifications as follows:

- A 100% instantaneous renewable penetration scenario will be considered as the base case. This will be derived from a recent high renewable penetration snapshot to reflect a realistic dispatch availability.
- Minimum demand/high export from South Australia would be the focus of studies as a starting point. Sensitivity analysis for capacitive demand will be performed.
- Plausible ramping scenarios (magnitude and duration) will be sourced from previous AEMO studies reflecting weather-driven patterns impacting daily demand and supply as well as intraregional megawatt flow changes.

Then consecutive snapshots will be developed reflecting sequential time intervals for the above-mentioned plausible ramp events, where:

- The number of available taps for main transformers will be limited to 1 tapping each 30 seconds.
- There will be no switching for manual capacitor/reactors where there is no specific control scheme available.

The hypothesis is that increasing variability and uncertainty of generation in the power system will drive up complexity of future voltage control needs.

System strength

When assessing a system strength shortfall, AEMO compares the levels of three phase fault level typically available in each region of the NEM against that region's inertia minimum system strength requirements. In the 2024 NSCAS Report, projected shortfalls of system strength have been included as *NSCAS needs*, in alignment

[62] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

[63] AEMO. *Renewable Integration Study* stage 1 Appendix C: Managing variability and uncertainty, April 2020, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

with the 2024 NSCAS Description and Quantity Procedure[64]. Also, in alignment with this Procedure, system strength shortfalls were assessed against the 99.87th percentile, or three standard deviations from the mean (three-sigma).

Shortfall declarations in this report are made for the three-year period from December 2024 to December 2027. However, the system strength projections presented in this report are based on market modelling using financial years, so system strength projection data is presented for 2024-25 to 2027-28.

A1.2 Key input assumptions and sources

Generator and network project sources

The casefiles developed for the 2024 NSCAS assessments considered:

- All existing, committed, and anticipated scheduled and semi-scheduled generators and energy storage projects from the July 2024 NEM Generation Information page[65].
- All announced generator withdrawals from the July 2024 NEM Generation Information page.
- If appropriate, projected renewable energy zone (REZ) development and generator withdrawals from the 2024 ISP *Step Change* scenario[66].
- Committed, anticipated, and actionable transmission projects from the August 2024 NEM Transmission Augmentation Page[67].
- Voltage planning assumptions consistent with those developed in 2021 and published in Appendix A2 of the 2022 NSCAS Report[68].
- Forecast maximum demand projections for each region from the 10% POE and forecast minimum demand projects from the 90% POE current trajectory in the 2024 ESOO for the NEM[69,].

Case development

Cases were developed by:

- Extracting representative maximum demand and minimum demand casefiles for each region.
- Confirming all existing, committed, and advanced generation and storage projects, SVCs, and synchronous condensers were modelled correctly according to their Generator Performance Standards (GPS), particularly

[64] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.

[65] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/nem-generation-information-july-2024.xlsx?la=en.

[66] At https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en.

[67] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transmission-augmentation-information/nem-transmission-augmentation-information-august-2024.xlsx?la=en.

[68] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2022-nscas-report.pdf?la=en.

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

their reactive capability. For future casefiles, new generating and storage projects were added according to their expected full commercial use date published on the NEM Generation Information page.

- Dispatching renewable generation according to historical data for expected availability during maximum and minimum demand periods.
- Adding future transmission augmentation projects using modelling data received from the relevant TNSP.
- Scaling real power demand based on the 10% POE and 90% POE forecasts from the 2024 ESOO. Demand was scaled using a constant PQ ratio for maximum demand scenarios. Reactive power was not scaled for minimum demand scenarios. Reactive power for minimum night was calculated by taking a linear fit to data from historical snapshots from the same timestamp as the current minimum night demand case.
- Interconnector flow was based on historical data at the time of maximum demand or minimum demand and synchronous generation dispatch was then adjusted to meet demand while keeping the system within network limits.
- This process was repeated as necessary for each region and year studied.

A2. Market modelling assumptions

AEMO undertakes integrated energy market modelling to forecast future investment in and operation of electricity generation, storage and transmission in the NEM[70].

Projected generation and storage investment, and dispatch from the *Step Change* scenario results, are drawn from the results in the 2024 ISP, and have been used for inertia and system strength forecasts in this report, with some updates to reflect the latest information such as the Eraring extension and Humelink project advancement. These market modelling results:

- Cover the financial years from 2024-25 to 2027-28.
- Are based on the *Step Change* scenario generator, storage and transmission build outcomes for the 2024 ISP[71].
- Include generator dispatch projections from a time-sequential model using the 'bidding behaviour model' for realistic generator dispatch results given the generation and build outcomes. The bidding behaviour model uses historical analysis of actual generator bidding data and back-cast approaches for the purposes of calibrating projected dispatch[72].
- Apply the *Step Change* scenario 50% probability of exceedance (POE) demand projection from the 2023 Electricity Statement of Opportunities (ESOO) for the NEM.
- Applied projections of generation outages based on Monte Carlo simulation.
- Applied projections of planned maintenance. Maintenance events are assumed to be distributed throughout the year such that they minimise planned outages at times when it is most required when consumer demand is high, to avoid exacerbating reliability risks.
- Incorporate a range of market modelling iterations for each year of the study period, capturing multiple generator outage patterns. This better captures the variability in generator outage patterns, and hence gives better regard of typical dispatch patterns.

When applying the market modelling results to assess the inertia and system strength projections, some post model adjustments were made where necessary based on industry knowledge and known operational practices.

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[70] Information about AEMO's energy market modelling can be found in the 2024 *ISP Methodology*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology.

[71] At https://aemo.com.au/-/media/files/major-publications/isp/2024/supporting-materials/2024-isp-generation-and-storage-outlook.zip?la=en.

[72] Details for the bidding behaviour model are provided in AEMO's Market Modelling Methodologies report, July 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptionsmethodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.