2021 System Security Reports

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

December 2021

System strength, inertia and NSCAS reports for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to provide the annual system security reports for the National Electricity Market.

AEMO publishes this System Strength, Inertia, and Network Support and Control Ancillary Services Report in accordance with clauses 5.20.7, 5.20.5 and 5.20.3 of the National Electricity Rules. This publication is generally based on information available to AEMO as at November 2021 unless otherwise indicated.

Disclaimer

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Version control

Version	Release date	Changes
1.0	17 December 2021	Nil.

Executive summary

AEMO has identified system security needs across the National Electricity Market (NEM) for the coming five-year period as the energy transformation continues at pace. Declining minimum operational demand, changing synchronous generator behaviour and rapid uptake of variable renewable energy resources combine to present opportunities in each region for delivery of innovative, essential power system services.

This transformation aligns with State and Commonwealth energy, economic and emissions policies, but must also negotiate great complexity and uncertainty.

These 2021 System Security Reports are part of the National Electricity Rules (NER) framework intended to plan for the security of the power system under these changing operating conditions. The unprecedented nature and pace of change in the NEM means more shortfalls and gaps in requirements for system strength, inertia and Network Support and Control Ancillary Services (NSCAS) are inevitable during this transformational period. The identification of actual or emerging shortfalls and gaps is a natural step to facilitate the necessary services and investment to address these essential system security needs.

Declining minimum demand and changing generator dispatch are projected to push our power system to its limits over the coming five years

Since the 2020 annual assessments of system strength, inertia and NSCAS, the power system transformation has accelerated, with:

- Variable renewable energy resources (VRE) reaching committed or anticipated status well in excess of the forecasts in 2020 and projected to accelerate further.
- An accelerating increase in installation of distributed photovoltaic (PV) by consumers leading to more rapid declines in minimum operational demands.
- Operation of existing synchronous generation changing in response, and expected to change further over the next five years.

Declining minimum operational demand and changing synchronous generator behaviour drive a need for new sources of essential power system services.

Minimum operational demand in Queensland is forecast to nearly halve by 2026-27, and in New South Wales to reduce by approximately 2 gigawatts (GW) over the same period. In Victoria, minimum operational demand is projected to become negative by 2026-27, meaning that there will be times where distributed PV will exceed operational demand in the region. In South Australia, this can be expected in 2022-23[1].

Although the assessments in this report were prepared while the *Progressive Change* scenario was considered most likely, the energy transformation is moving quickly and the Draft 2022 Integrated System Plan (ISP)[2] now reports that a strong consensus of stakeholder representatives see the accelerated *Step Change* scenario as being the most likely. This will likely mean an increasing and accelerating need for new sources of system security services.

[1] These minimum operational demand figures are taken from the 2021 *Electricity Statement of Opportunities* Central scenario, 90POE and were used in the development of the *Progressive Change* scenario.

[2] AEMO. Draft 2022 ISP. December 2021. Available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

Under the *Progressive Change* scenario, by 2026-27, the withdrawal of 3.4 GW of coal-fired power plants is forecast across the NEM. The Draft ISP projects this to increase to 5.6 GW under the *Step Change* scenario. Under the *Progressive Change* scenario, a number of coal units in New South Wales and Queensland are projected to need to operate below existing minimum requirements for more than 1% of time, and in some cases up to 10%, over the coming five years.

System strength, inertia and Network Support and Control Ancillary Services (NSCAS) shortfalls and gaps have been identified across the NEM

AEMO has completed the 2021 system security assessments for each region of the NEM. These studies have been prepared using AEMO's minimum demand projections as at August 2021. In the case of the system strength and inertia results the *Progressive Change* scenario has been applied. AEMO has engaged with transmission network service providers (TNSPs) and jurisdictional planning bodies during these assessments.

Table 1 summarises the assessment outcomes, including declaration of shortfalls and gaps to be addressed by TNSPs and jurisdictional planning bodies. System strength shortfalls are declared in New South Wales and Queensland. Inertia shortfalls are declared in Queensland and South Australia. Voltage control gaps are declared in Queensland and South Australia, as well as a marginal gap in New South Wales. A gap may be declared in Victoria if the delivery of new reactors is delayed. In Tasmania, previous system strength and inertia shortfalls have now been resolved but this report notes their re-emergence when the existing services agreement ends.

AEMO expects further system security needs to be identified as the NEM transitions to 100% instantaneous renewable energy penetration and as the regulatory frameworks change

The shortfalls and gaps identified in this report have been made under the relevant regulatory frameworks. AEMO will work closely with TNSPs and jurisdictional planning bodies on addressing these shortfalls and gaps and considering options for alleviating near-term operational risks.

AEMO expects that additional system security needs will continue to be identified as the Australian energy transformation picks up speed. In 2022 AEMO will:

- Assess the system security requirements for meeting 100% instantaneous renewables penetration by 2025 and will explore avenues for addressing those requirements.
- Prepare for the December 2022 implementation of the new system strength regulatory framework. TNSPs and jurisdictional planning bodies will be required to use reasonable endeavours to meet the full fault level requirements, rather than services for shortfalls alone.
- Study the system security impact of the *Step Change* scenario and identify any further shortfalls or gaps accordingly.

The essential power system needs identified in these 2021 System Security Reports must be considered as early as possible to allow for solution identification, following by procurement, service delivery, and testing timelines. The changes to the NEM, already commenced, are transformational, and the need for additional system security services will only increase over the coming years as power stations that previously supplied these services withdraw from the system. The main question is what technologies will be incentivised to provide these services in future, and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

Table 1 System strength, inertia and NSCAS outcomes, 2022 to 2026 under *Progressive Change* scenario

	System Strength	Inertia	NSCAS
	The ability of the power system to maintain voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.	A fundamental property of power systems such that the power system can resist large changes in frequency arising from an imbalance in power supply and demand caused by a contingency event.	Non-market ancillary services that may be delivered to maintain power system security and reliability, or to maintain or increase the power transfer capability of the transmission network.
New South Wales	Shortfall of 1,448 mega volt amps (MVA) at Newcastle in mid-2026, and shortfall of 865 MVA at Sydney West in mid-2026. AEMO will request services be available from 1 July 2026.	No shortfall declared with New South Wales unlikely to island, but strong decline in projected inertia observed.	Immediate gap of 2 mega vars (MVAr) reactive power absorption in Coleambally.
Queensland	Shortfall at Gin Gin for the full period, ranging from 44 to 65 MVA. AEMO will request services be available from 31 January 2023.	Shortfall in Queensland ranging from 186 megawatt seconds (MWs) to 5,831 MWs for the full period, likely to be substitutable with inertia support services such as fast frequency response. AEMO will request services be available from 31 January 2023.	Immediate gap of 120 MVAr reactive power absorption in southern Queensland, rising to 250 MVAR by 2026.
South Australia	No shortfall, with four new synchronous condensers now delivered by ElectraNet.	Existing shortfall, equivalent to 200 MW of fast frequency response/ inertia support activities, until 30 June 2023. New shortfall, equivalent to 360 MW fast frequency response/ inertia support activities, from 1 July 2023 until expected completion of inter-network testing of Project EnergyConnect in July 2025 [A]. AEMO will request services be available from 1 July 2023.	A 40 MVAr reactive power absorption gap is declared when the requirement for minimum number of synchronous generating units reduces from two to zero.
Tasmania	Previous shortfalls are now addressed by TasNetworks until April 2024. Shortfall declared from April 2024 onwards, for all fault level nodes. AEMO will request services be available from 15 April 2024.	Previous shortfalls are now addressed by TasNetworks until April 2024. Shortfall declared from April 2024 onwards. AEMO will request services be available from 15 April 2024.	No gap.
Victoria	No shortfall declared, but strong decline in projected fault level observed.	No shortfall declared with Victoria unlikely to island, but strong decline in projected inertia observed.	No gap identified, but possible future gap if any delay to delivery of new reactors in mid-2022.

Legend:	No shortfall or gap	Possible future shortfall or gap	Shortfall or gap declared

A. This shortfall could be extinguished as a result of events such as the commencement of the FFR market (October 2023) or the completion of commissioning of a special protection scheme (scheduled for July 2024). ElectraNet and AEMO will continue to monitor these and other events with respect to the inertia shortfall and re-assess as required.

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1 Introduction

Essential power system security services such as system strength, inertia and voltage control need to be carefully planned as the Australian energy transformation continues.

This section outlines the context for the 2021 System Security Reports, including:

- Trends impacting system security assessments (Section 1.1).
- Relationship to other AEMO planning documents (Section 1.2).
- Relationship to ongoing regulatory reforms (Section 1.3).

1.1 Trends impacting system security assessments

Australia's National Electricity Market (NEM) is in the midst of replacing its traditional energy resources with variable renewable generation (VRE) resources largely based on inverters[3]. This section describes how a number of these trends are relevant to AEMO's annual system security assessments.

Identified shortfalls in system strength and inertia are set to be larger and occur sooner under a *Step Change* scenario

The system strength and inertia assessments in this report are based on available modelling results for AEMO's *Progressive Change* scenario[4]. However, recent consultation undertaken by AEMO has now resolved that the accelerated *Step Change* scenario is considered to be most likely for the purposes of the Draft 2022 Integrated System Plan (ISP)[5].

The *Step Change* scenario has five additional coal units retiring and over 4.5 GW of additional VRE capacity by 2026-27 compared to the *Progressive Change* scenario which projects 3.4 GW coal units retire and the development of 5.8 GW additional VRE capacity. Figure 1 shows the difference in retirements between the scenarios over the ISP modelling horizon. These differences are expected to have material implications for system strength and inertia assessments, as VRE resources are not typically direct substitutes for the system strength and inertia services provided by synchronous generating machines.

As the projections for VRE increase, and synchronous machine retirements and withdrawals occur earlier than previously anticipated, shortfalls and gaps identified through the system strength and inertia frameworks will become more commonplace, and the size of the shortfalls will be larger.

AEMO intends to conduct additional studies to those carried out in this report, to assess the impact of the *Step Change* on system security shortfalls and gaps. AEMO also encourages transmission network service providers

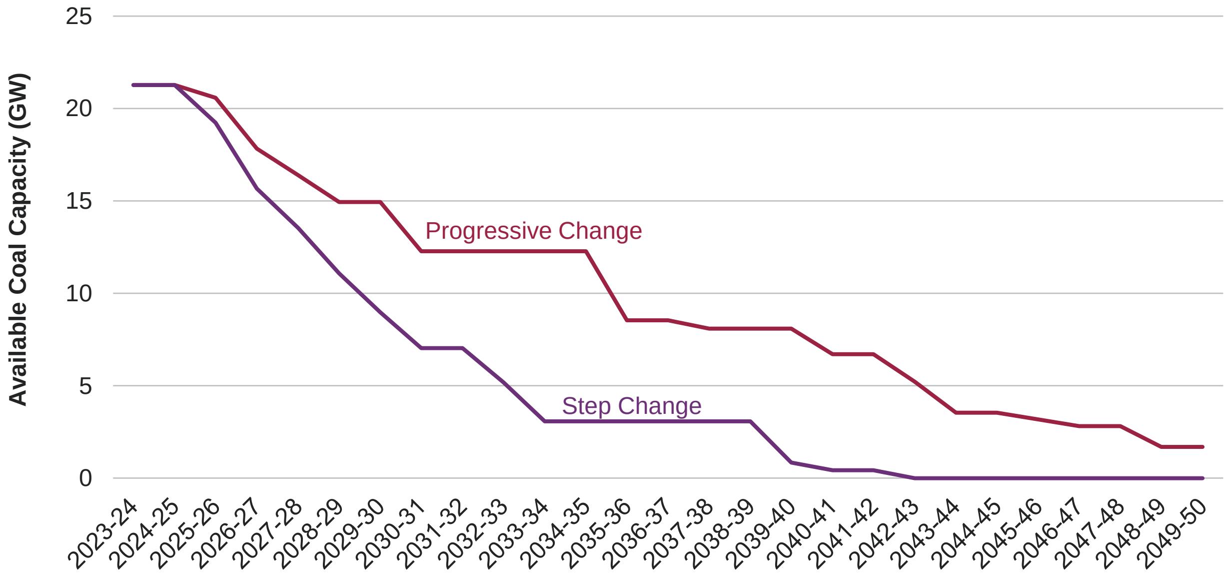
[3] AEMO. Draft 2022 Integrated System Plan (ISP). Available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[4] See Appendix A1 for further details.

[5] AEMO. Draft 2022 Integrated System Plan (ISP). Available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

(TNSPs) to consider the impact of the *Step Change* scenario in their own planning processes, particularly as the likelihood of a *Step Change* makes investments on system security critical to identify as soon as possible.

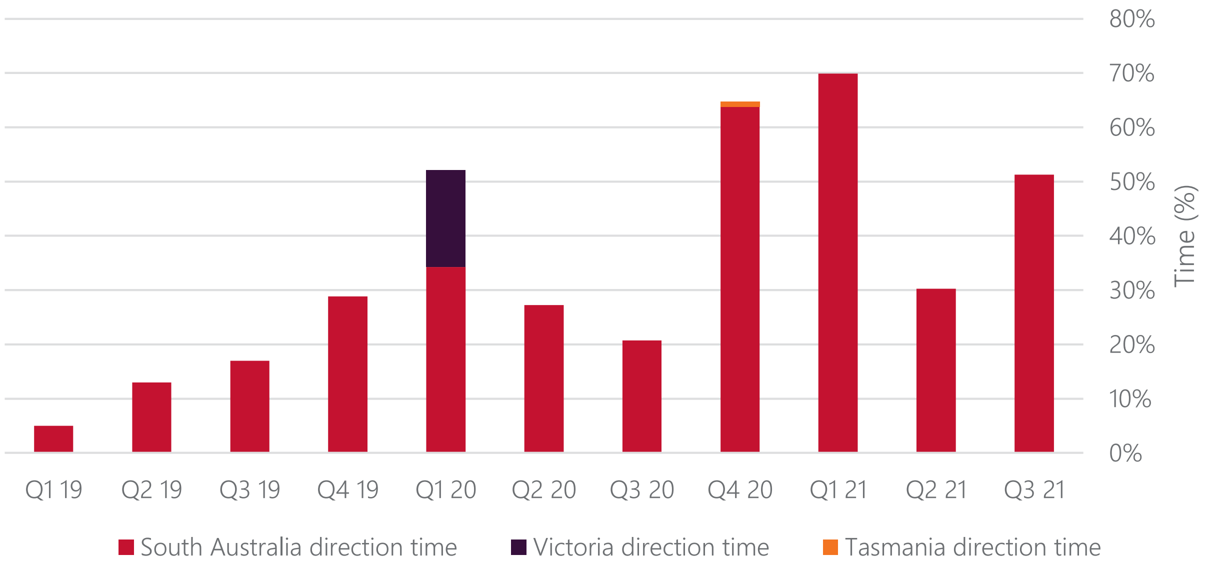
Figure 1 Retirement of coal units in *Progressive Change* and *Step Change* scenarios in the Draft 2022 ISP



Directions are becoming more frequent

As the power system changes, market interventions are being relied on more frequently to keep the system secure. Directions for system security are a last-resort intervention mechanism, when neither the market nor network service provider service contracts have delivered the necessary requirements. As Figure 2 shows, directions to registered market participants to take action to maintain or restore power system security in South Australia have been in place for a substantial amount of time in the past two years, in system normal as well as outage or abnormal conditions.

Figure 2 Recent instances of system security directions in the NEM



AEMO is continuing its work, with ElectraNet, to define the system security needs for South Australia with four synchronous condensers in operation. This is expected to assess the extent to which the NSCAS framework could deliver the outcomes needed to meet or reduce the need for these directions in system normal conditions.

Some operational challenges are not addressed under existing frameworks

Under the existing framework, AEMO declares system strength and inertia gaps when these services are forecast to fall below the minimum requirements for more than 1% of time under typical dispatch patterns[6]. It has been assumed that operational mechanisms such as additional constraints or, in the extreme, directions, can be used to ensure system security for the rest of the time. However, this assumption is no longer a given, and there are times where these mechanisms may not be sufficient. Appendix A5 provides preliminary information on when these times arise, and the types of issues which may arise, including the potential inability for these measures to ensure system security into the future.

AEMO is continuing to explore these issues through work such as the Engineering Framework[7], the upcoming system strength requirements methodology consultation, and consideration of near-term preparatory actions.

The energy transformation will enable innovative new system security solutions

As the power system transforms, new solutions will emerge to address system strength, inertia and NSCAS issues. Emerging and present solutions include:

- Revisions to the system strength requirements and unit combinations following improved modelling capability and understanding of network capabilities.
- Grid-forming inverter technology to operate down to very low levels of system strength, and ultimately to operate as virtual synchronous machines with provision of system stabilising services.
- Inverter control system tuning to reduce the system strength requirement in weak areas of the grid.
- Suitable control and inverter system design to provide reactive support in areas as needed.
- Fast Frequency Response from inverter-based devices can reduce the need for traditional frequency control ancillary services and synchronous inertia.
- Demand response from large electrical loads.

AEMO is constantly seeking to improve its understanding of what solutions are available and intends continually review and reassess power system issues including those identified in this report. In addition, in 2022 AEMO will progress the system security studies required to understand operation of the power system with 100% instantaneous penetration of renewable energy by 2025[8]. However, it is important to note that this should not prevent solutions being implemented to address gaps which are clear and present.

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[6] See National Electricity Rules (NER) 5.20.B, Section 2.1 of this report, and the systems strength and inertia requirements methodologies accessible via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

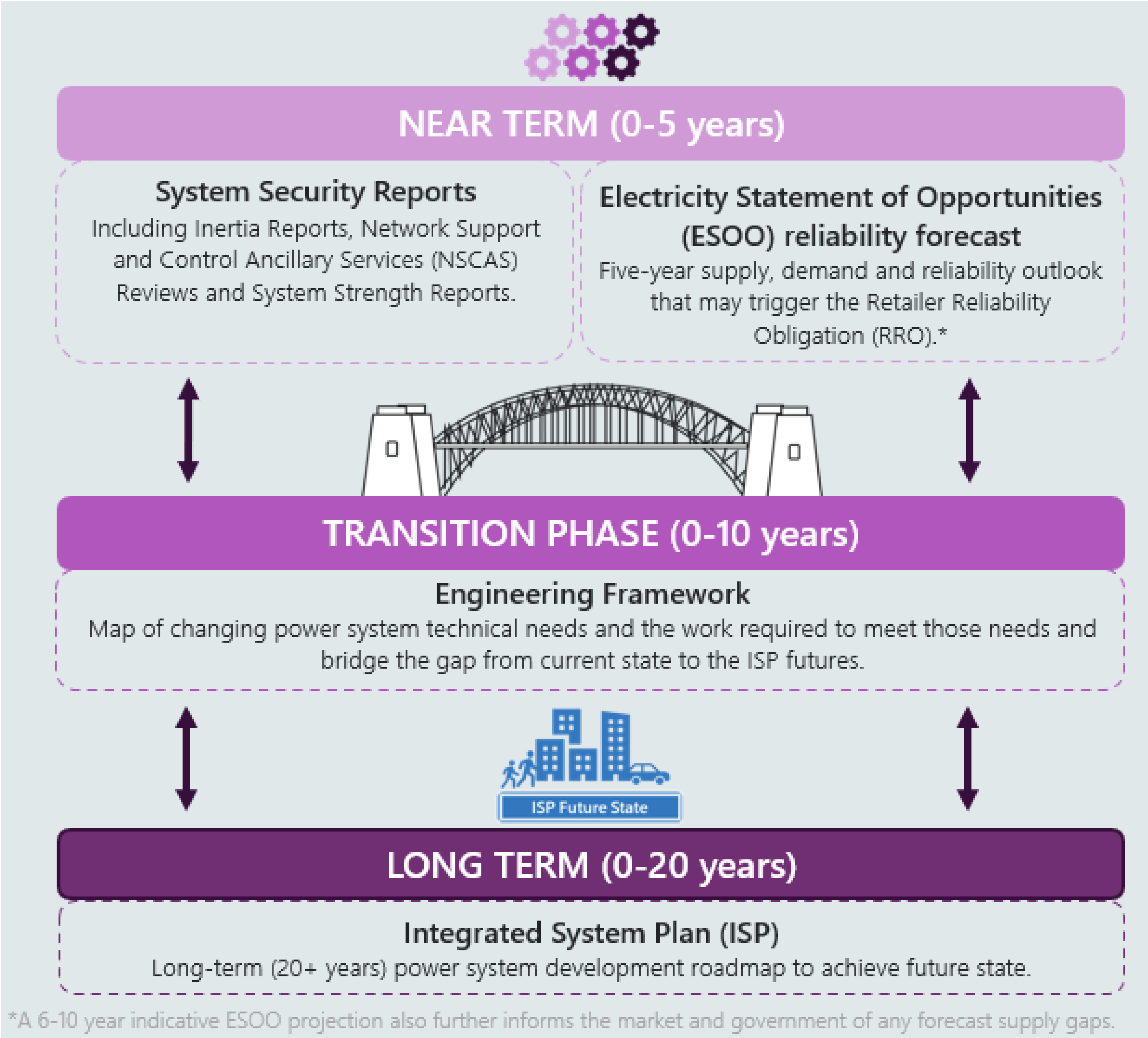
[7] AEMO, Engineering Framework, accessed 2021-12-10 via https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

[8] For more information, see the NEM Engineering Framework materials, available via https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

1.2 Relationship to other AEMO planning documents

The annual system strength, inertia and NSCAS reviews draw inputs from a number of related AEMO reports and processes, and in turn inform and underpin a range of reports and processes owned by AEMO and TNSPs. Figure 3 shows the system security assessments in this report in relation to other key AEMO forecasting and planning documents and processes.

Figure 3 Relationship between AEMO planning documents



1.3 Relationship to regulatory reforms

AEMO has prepared this report consistent with the existing National Electricity Rules (NER). However, three key regulatory changes are expected to affect future system security assessments.

A new system strength framework will apply from December 2022

In October 2021, the Australian Energy Market Commission (AEMC) made its final determination on the 'Efficient management of system strength on the power system' rule change[9]. As a result, from December 2022 onwards:

- AEMO will set a system strength standard for each system strength node, including a three-phase fault level required for a secure system and a forecast of future inverter-based connections at the node, and
- Responsible transmission network service providers will use reasonable endeavours to plan system strength services to meet the standard at each node.

Responsible transmission network service providers will need to meet the new system strength standard from December 2025 onwards, per the December 2022 declarations, and in the interim the shortfall framework will continue to apply. In this 2021 system security report, the existing framework is applied, meaning that some shortfalls are declared for periods which will ultimately be covered by the system standard under the new framework. AEMO expects that networks will seek to address the declared shortfalls in such a manner that the services engaged will ultimately be part of a holistic approach under the new regulatory framework.

AEMO is convening a working group with TNSPs to implement this significant reform. AEMO will consult on amendments to the existing System Strength Requirements Methodology in 2022 to incorporate the outcomes of the final rule determination and to reflect AEMO and industry's evolving understanding of system strength issues.

AEMO will implement a very fast ancillary service market in 2023

In July 2021 the AEMC published a rule requiring that AEMO introduce two new market ancillary services to help control system frequency and keep the future electricity system secure – namely, very fast raise and very fast lower markets which will facilitate the delivery of fast frequency response services.

AEMO is working to implement these markets in 2023. For the purposes of this 2021 system security report, AEMO has assumed that these new ancillary service markets will not necessarily have services available in the near term to allow the reduction of the minimum threshold and secure operating levels of inertia. It will take time for these new market services to be established and understood. Rather, AEMO is declaring inertia shortfalls where they are identified while also noting that there may be earlier opportunities to extinguish the shortfalls depending on the services offered by the very fast raise and lower markets over time.

Significant market reforms are underway

AEMO and its industry partners have recently implemented three major reforms for the NEM: Five Minute Settlements, Wholesale Demand Response, and two-day retail switching. These reforms provide better price signals for fast response and flexible technologies, and support participation of large commercial and industrial businesses through the provision of peak shaving services in the spot energy market.

[9] AEMC, 'Efficient management of system strength on the power system', accessed in November 2021 via https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

Following approval of the Energy Security Board (ESB) post 2025 reform recommendations by Ministers[10], AEMO is working with the AEMC through the rule change process to progress implementation of essential system services for the physical power system, and better integration of DER. The ESB has been tasked by Ministers to undertake further policy work on a capacity mechanism and network congestion mechanism for consideration in late 2022.

AEMO is working with industry to develop a NEM Regulatory and IT implementation Roadmap that appropriately sequences and seeks to reduce overall reform implementation costs and risks. Any market changes resulting from these reforms can be expected to affect the five-year outlook for the system strength, inertia, and NSCAS assessments, given the potential impact on market and system development, and AEMO will take these into consideration as these are designed and implemented.

Market reforms for valuing, procuring, and scheduling essential system security services are under consultation

Consistent with the broader ESB post-2025 reform program, the AEMC is consulting on rule change requests concerning valuing, procuring and scheduling essential system services to ensure the power system remains secure[11].

Any market changes resulting from these rule changes can be expected to affect the five-year outlook for the system strength, inertia and NSCAS assessments. AEMO is working closely with the AEMC on the delivery of these rule change requests and will incorporate their final outcomes in future system security assessments. AEMO considers this an important reform to introduce an additional mechanism to address changes in the way in which these essential system security services are being delivered by the system, in a manner which can adapt flexibly as the power system transition continues[12].

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[10] Energy Security Board, Post-2025 market design, accessed 2December 2021 via Post-2025 market design | energy.gov.au.

[11] AEMC, Capacity commitment mechanism for system security and reliability services, accessed 2 December 2021 via https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services.

[12] AEMO. Submission responding to the AEMC directions paper on Capacity Commitment Mechanism and Synchronous Services Markets. October. Accessible via https:// www.aemc.gov.au/sites/default/files/2021-10/AEMO%5B1%5D.pdf/.

2 Method

AEMO is required to assess system security for each region of the NEM annually and declare any identified shortfalls or gaps[13]. This section notes the methods for each of the system security assessments:

- System strength (Section 2.1).
- Inertia (Section 2.2).
- Network Support and Control Ancillary Services (NSCAS) (Section 2.3).

2.1 System strength

A minimum level of system strength is needed for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance[14]. System strength can broadly be described as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.

Division of system strength responsibilities

In the NEM, the present division of responsibilities for the provision of system strength is as follows:

- AEMO, in consultation with the TNSP or jurisdictional planning body[15], is required to determine the location of fault level nodes.
- AEMO is required to determine the minimum three phase fault level at each node and identify whether a shortfall is likely to exist at any node over the five-year horizon.
- The regional TNSP or jurisdictional planning body is required to ensure that system strength services are available to address any fault level shortfall declared by AEMO at a fault level node.
- Connection applicants and generators subject to the system strength remediation requirements must implement or fund system strength remediation to ensure their new connection or alteration does not have an adverse system strength impact.

This report considers the regional system strength requirements and shortfalls in accordance with the version of the NER in effect as at 1 December 2021. The Australian Energy Market Commission's final determination on the 'Efficient management of system strength on the power system' will change these responsibilities for the 2022 assessment[16]. AEMO will consult on amendments to the existing System Strength Requirements Methodology in 2022 to incorporate the outcomes of the final rule determination and to reflect AEMO and industry's evolving understanding of system strength issues.

[13] NER Version 174, Clauses 5.20.3, 5.20.5 and 5.20.7

[14] For more information on system strength, see AEMO, Power System Requirements, July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf and AEMO, System strength explained, March 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[15] The jurisdictional planning body is the entity having responsibility of planning the transmission system in a region.

[16] AEMC, Efficient management of system strength on the power system, at https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

Assessing system strength requirements

AEMO applies the System Strength Requirements Methodology[17] to determine the system strength requirements for each region of the NEM. Figure 4 lists the fault level node categories and Figure 5 notes the high-level process for calculating the fault levels, with full details available in the methodology.

The requirements apply for normal operating conditions allowing for a credible contingency, and are not designed to address the impact of planned outages for network infrastructure. These levels have been set to ensure generators remain stable and connected, system protection schemes are able to operate as designed, and power quality and voltage stability is maintained. New and modified generator connections are currently required to mitigate their own impact on system strength.

Application of the minimum three phase fault levels in AEMO's transmission network service providers' real time operations is subject to operating conditions and the levels are converted to appropriate operating instructions before they are used.

Figure 4 Categories of fault level nodes

Figure 5 Steps for calculating minimum three phase fault levels

Declaration of a system strength shortfall

To declare a system strength shortfall (a fault level shortfall), AEMO must assess whether, in AEMO's reasonable opinion, there is or is likely to be a fault level shortfall in the region, and assess AEMO's forecast of the period over which the fault level shortfall will exist[18].

For the 2021 System Security Reports, AEMO has performed this assessment by:

- Selecting market modelling results (see Section A2.5) and applying them in a power system model to project the fault level at each of the fault level nodes over the five-year outlook period (see Section A2.3).

[17] AEMO, System Strength Requirements Methodology, July 2018, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

[18] NER 5.20C.2

- Comparing the fault level projection results against the requirements for each node and identifying potential system strength shortfalls where the synchronous three phase fault level at a node falls below the minimum fault level requirements for more than 1% of the year over the coming five-year period.
- Where a potential system strength shortfall is identified, considering the potential drivers of the shortfall and forming a reasonable opinion of the likelihood of the shortfall existing. AEMO considers many factors in forming this opinion, including but not limited to market modelling results, market trends and insights, and relevant government policy announcements.

The requirements for TNSPs or jurisdictional planning bodies to make services available to address a declared system strength shortfall are covered in NER clauses 5.20C.3 and 5.20C.4.

System strength information provided in this report, and key assumptions

This report sets out, for each region of the NEM: AEMO's assessment of fault level nodes and minimum fault level requirements; fault level projections at each fault level node; and declaration of any fault level shortfalls for the period from December 2021 to December 2026. Further details are provided in Appendix A1 and Appendix A3.

The fault level projections are prepared using the 2021 ESOO 50POE[19] minimum demand projection and the *Progressive Change* scenario[20]. Further details are provided in Appendix A1.

Although the declaration period is from December 2021 to December 2026, modelling has been undertaken based on financial years, so data for 2021-22 to 2026-27 is presented.

[19] 90% probability of exceedance (90POE) means demand is expected to be lower than forecast one year in 10; 50% probability of exceedance (50POE) means demand is expected to be lower one year in two.

[20] AEMO. Draft 2022 ISP. December 2021. Available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

2.2 Inertia

A minimum level of inertia is required in the power system to suppress and slow frequency deviations so that automatic controls can respond to sudden changes in the supply-demand balance. Inertia is a rapid and automatic injection of energy to suppress rapid frequency deviations and slow the rate of change of frequency.

Division of inertia responsibilities

In the NEM, the present division of responsibilities for the provision of inertia is as follows:

- AEMO is required to determine the boundaries of inertia sub-networks (either a region or a sub-region of the NEM), and inertia requirements for each inertia sub-network.
- AEMO must identify whether a shortfall is likely to exist for each inertia sub-network over the five-year horizon.
- The regional TNSP or jurisdictional planning body is required to ensure that inertia network services are available to address any declared inertia shortfall for an inertia sub-network, and may make inertia support services available to reduce the inertia requirements.

This report considers the inertia requirements in accordance with NER 5.20.5.

Assessing inertia requirements

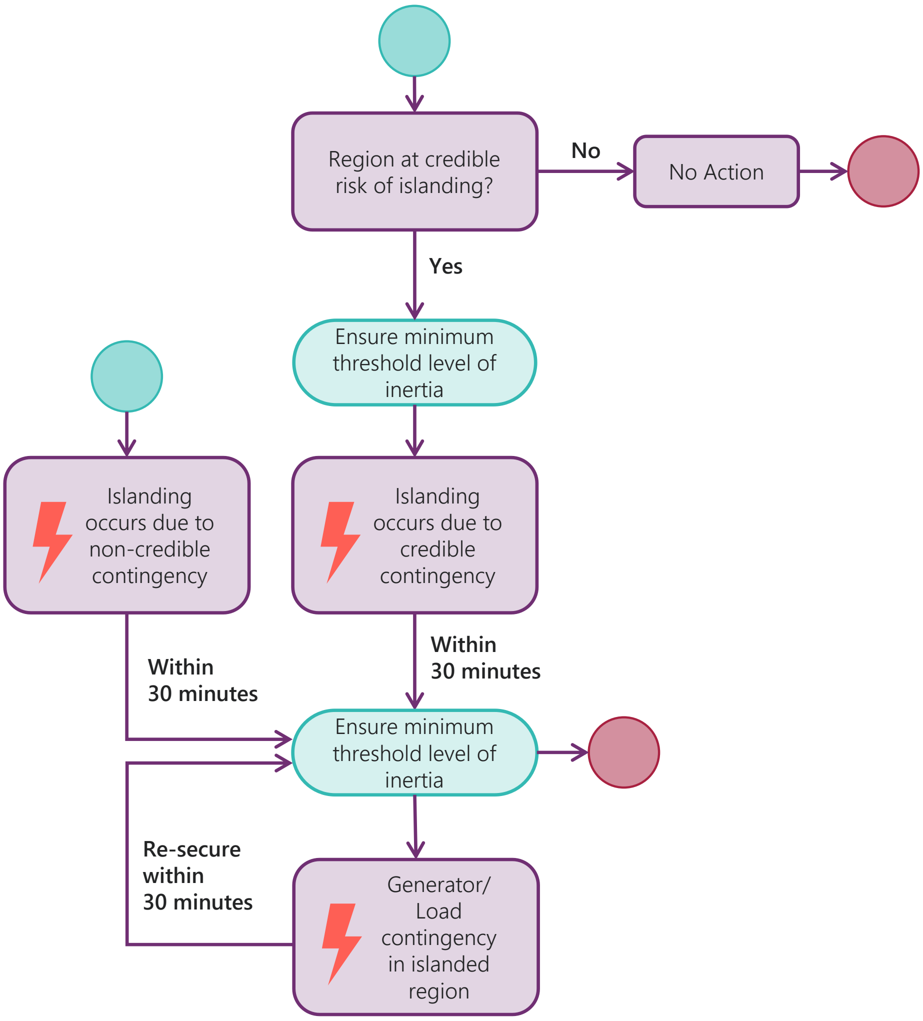
AEMO applies the Inertia Requirements Methodology[21] to determine the inertia sub-networks of the NEM and then calculate the minimum threshold level of inertia and secure operating level of inertia for each inertia sub-network. The minimum threshold level represents the minimum amount of inertia needed to operate in a satisfactory operating state when islanded, and applies when the sub-network is at credible risk of islanding. The secure operating level represents the inertia required to operate in a secure operating state when the sub-network is islanded. Figure 6 shows the relationship between the two requirements, with full details available in the methodology.

The requirements are designed to ensure that the system will be maintained within an acceptable frequency range[22] on and after separation of the inertia-sub-network.

[21] AEMO, Inertia Requirements Methodology, July 2018, via https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[22] Frequency operating standard - effective 1 January 2020, available through the AEMC website via https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

Figure 6 Relationship between minimum threshold level of inertia and secure operating level of inertia



Declaration of an inertia shortfall

To declare an inertia shortfall, AEMO must assess:

1. the level of inertia typically provided in the inertia sub-network having regard to typical patterns of dispatched generation in central dispatch as per the market modelling results in (Section A2.5)
2. whether in AEMO's reasonable opinion, there is or is likely to be an inertia shortfall in the inertia sub-network and AEMO's forecast of the period over which the inertia shortfall will exist; and
3. where AEMO has previously assessed that there was or was likely to be an inertia shortfall, whether in AEMO's reasonable opinion that inertia shortfall has been or will be remedied.

In making this assessment, AEMO must take into account the following factors:

- over what time period and to what extent the inertia that is typically provided in the inertia sub-network is or is likely to be below the secure operating level of inertia;
- the levels of inertia that are typically provided in adjacent connected inertia sub-networks and the likelihood of the inertia sub-network becoming islanded; and
- any other matters that AEMO reasonably considers to be relevant in making its assessment.

For the purposes of this report AEMO has assessed inertia shortfalls based on 99th percentile results of the selected market modelling projection, rather than considering results for one standard deviation from the mean. The standard deviation method identified in the Inertia Requirements Methodology is no longer considered to be an appropriate threshold to meet the NER requirements for declaring a shortfall against typical patterns of dispatched generation, given the spread of market dispatch and results.

Arrangements for how AEMO requires that TNSPs or jurisdictional planning bodies make services available to address the shortfall (or reduce the requirement) are covered in NER clauses 5.20B.3, 5.20B.4 and 5.20B.5.

Inertia information provided in this report

This report sets out for each region of the NEM, AEMO's assessment of inertia sub-networks and the minimum threshold level and secure operating level of inertia, and declaration of any fault level shortfalls for the period from December 2021 to December 2026. Further details are provided in Appendix A1 and Appendix A4.

The fault level projections are prepared using the 2021 ESOO 50POE minimum demand projection for the central scenario and the *Progressive Change* scenario[23]. Further details are provided in Appendix A1.

Although the declaration period is from December 2021 to December 2026, modelling has been undertaken based on financial years and so data for 2021-22 to 2026-27 is presented.

[23] AEMO. Draft 2022 ISP. December 2021. Accessible via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

2.3 NSCAS

Network support and control ancillary services (NSCAS)[24] are non-market ancillary services that may be procured to address the following NSCAS needs:

- Maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard[25].
- Maintain or increase power transfer capability of the transmission network to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market[26].

Division of NSCAS responsibilities

AEMO must, at least annually, identify any NSCAS need forecast to arise in the next five years. AEMO's assessment includes identification of any NSCAS gap for a NEM region, as well as the relevant trigger date for any power system security and reliability gap, a report on any NSCAS acquired by AEMO (in its last resort procurement capacity) in the previous calendar year, and any other information AEMO considers relevant.

The NER give TNSPs the primary responsibility for acquiring NSCAS. If AEMO is required to procure NSCAS under its last resort responsibility, it can only do so to meet the first of the NSCAS needs – for power system security and reliability.

Assessing NSCAS needs

AEMO conducts the NSCAS review in accordance with the NSCAS description and quantity procedure[27], which defines two types of NSCAS – system reliability and security ancillary services (RSAS) and market benefits ancillary services (MBAS).

System reliability and security ancillary services (RSAS)

To identify RSAS needs, AEMO considers the ability 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. On a case-by-case basis AEMO may also assess if the system can be returned to a secure operating state within 30 minutes of a credible contingency or protected event.

AEMO NSCAS studies emulate actions taken by the control room to manage system security issues but also factor in future network changes such as committed generation and transmission projects, generator retirements and forecast change in demand. Use of emergency last-resort responses such as load-shedding are not assumed for planning studies. The operational actions AEMO can take in the control room are outlined in the Power System Security Guidelines[28].

During the 2021 NSCAS assessment, AEMO applied updated voltage management planning assumptions (recorded in Appendix A2) which were an outcome of a planning assumptions review conducted with input from AEMO control room and TNSP planning and operations experts.

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[24] The NSCAS definition is in the Chapter 10 Glossary of NER Version 174.

[25] NER Version 174, Clause 3.11.6 (a)(1).

[26] NER Version 174, Clause 3.11.6 (a)(2).

[27] AEMO, NSCAS

[28] Power System Security Guidelines, 24 Oct 2021 at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en.

Market benefits ancillary service (MBAS)

AEMO's NSCAS assessment considers whether network constraints can be relieved using market benefits ancillary services (MBAS) to maximise net market benefits. AEMO reviews existing constraints for an intact transmission system (no outages) under classical system normal conditions, where those constraints had a binding impact of at least $50,000 and bound for at least one hour, as identified in AEMO's 2020 NEM constraint report summary[29].

AEMO may also consider, where appropriate, any constraints nominated by participants as inputs into the market benefits assessment process as well as the consideration of possible future binding constraints in alignment with the NSCAS description and quantity procedure[30]. AEMO, in the 2020 NSCAS report[31] encouraged stakeholders to provide any input on potential market benefits assessments to planning@aemo.com.au by 26 February 2021. AEMO did not received any input from stakeholders.

2021 review investigation of planning assumptions for times of low demand

The 2020 NSCAS review[32] revealed that the impact of changing generation, network and demand dynamics on operational risk may not be sufficiently accounted for under traditional network planning assumptions. This raised questions as to whether planning assumptions applied in the past remain suitable for future planning, to design the power system appropriately for real-time operation.

AEMO investigated its voltage management planning assumptions to ensure the power system is designed appropriately for real-time operation as the power system transitions. Through consultation with TNSPs' planning and operational specialists, updated voltage management planning assumptions are provided in Appendix A2 and applied in this 2021 NSCAS assessment. This includes no longer assuming pre-contingent line-switching for system normal planning studies for the management of high voltages, following consultation on an amendment to the NSCAS description and quantity procedure[33].

[29] AEMO. NEM Constraint Report 2020 summary data. 24 March 2021, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2020/nem-constraint-report-2020-summary-data.xlsx

[30] AEMO, Network Support and Control Ancillary Services Description and Quantity Procedure, September 2020, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/ncas/2020-nscas-description-and-quantity-procedure.pdf?la=en.

[31] AEMO, 2020 Network Support and Control Ancillary Service Review, December 2020, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-nscas-report.pdf?la=en

[32] AEMO. 2020 NSCAS Review. December 2020. Accessible via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[33] AEMO, NSCAS description and quantity procedure consultation, via https://aemo.com.au/consultations/current-and-closed-consultations/network-support-and-control-ancillary-services-description-and-quantity-procedure-consultation.

Summary of NSCAS contracts

AEMO, as National Transmission Planner, had no active NSCAS contracts during 2021. Table 2 notes the NSCAS service costs accrued over the past five years by AEMO as part of its NSCAS function.

Table 2 NSCAS services costs from 2017 to 2021

Facility	NSCAS Service	Size (megavolt-amperes reactive [MVAr])	NSCAS Contract End Date	Annual Cost				
				2016-17	2017-18	2018-19	2019-20	2020-21
Combined Murray and Yass substations	Voltage Control Ancillary Service[A] (VCAS)	800[B]	30 June 2019	$10,159,498	$10,375,519	$10,572,619	$0	$0
Murray and Tumut power stations	VCAS	1,650[C]	30 June 2018	$147,088	$3,842,236	$0	$0	$0

A. NSCAS procured under the previous NSCAS types developed in 2011.
B. The maximum capacity available from this service.
C. The maximum capacity used at any one time over the years shown.

NSCAS information provided in this report, and key assumptions

In this document, AEMO provides the NSCAS assessment for each region of the NEM, including declaration of any identified gaps[34], for the period from 2021-22 to 2025-26.

The 2021 ESOO projects lowered minimum demand values for many regions of the NEM. As such, this 2021 NSCAS report focuses on the impacts of high system voltages which are particularly exacerbated during periods of low or minimum demand. High voltages can lead to equipment damage and cascading failures if no measures are taken to keep within acceptable ranges.

The NSCAS assessments are prepared using the 2021 ESOO Central scenario 90POE minimum demand projection[35]. Further details are provided in Appendix A1. The NSCAS assessment includes committed generation projects but does not incorporate the *Progressive Change* scenario (or any other Draft 2022 ISP modelling results) because those results were not available when the voltage control studies needed to begin in order to meet the annual NSCAS reporting requirement. AEMO will consider how best to address discrepancies between these studies in 2022.

The NSCAS assessment assumes all committed and anticipated transmission augmentations are delivered by dates advised by TNSPs. If any augmentations are delayed, this could lead to new or larger NSCAS gaps arising as demand continues to decline before projects that mitigate the resulting high voltages are in place. If TNSPs believe any relevant projects may be delayed, the TNSP should inform AEMO at the earliest opportunity.

[34] NER Version 174, Clause 5.20.3.

[35] AEMO National Electricity and Gas Forecasting portal at http://forecasting.aemo.com.au/Electricity/MinimumDemand/Operational.

3 New South Wales

The *Progressive Change* scenario is forecasting declining synchronous generation online in New South Wales and reducing minimum operational demand. System strength shortfalls are declared at Sydney West and Newcastle as a result.

Opportunities to manage an immediate marginal NSCAS absorbing reactive power gap in the NSW Coleambally region will be explored with Transgrid.

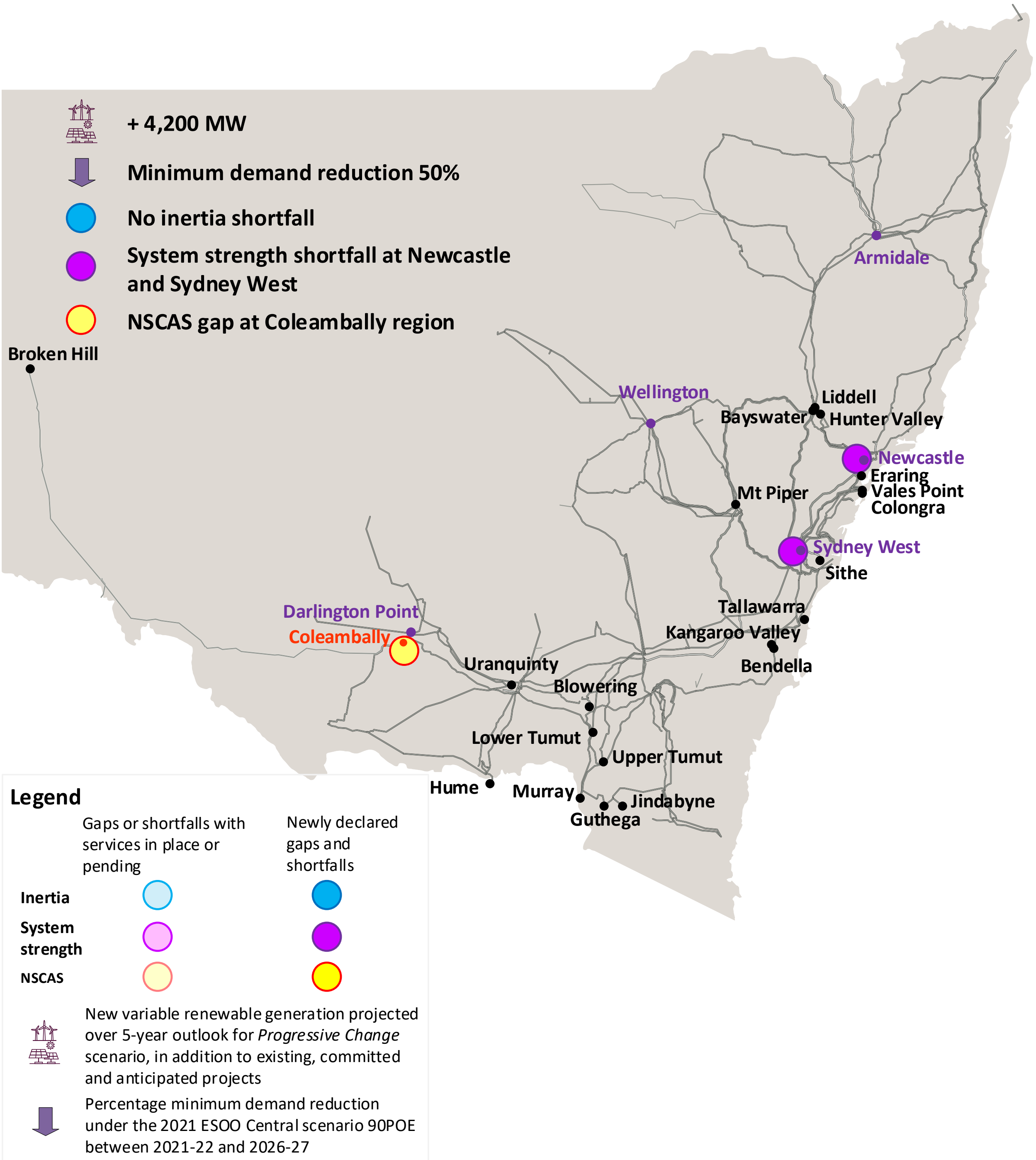
Holistic and innovative power system design and operation will be needed to navigate this energy transition as traditional synchronous generation behaviour changes and renewable energy zones are urgently prioritised and delivered.

Under the *Step Change* scenario, one large coal unit is projected to retire one year earlier in New South Wales over the five-year outlook period compared to the *Progressive Change* scenario. This would likely bring forward the system strength shortfalls identified in this assessment. AEMO will consider the *Step Change* scenario in 2022.

In this section:

- A map of the system security five-year outlook (Figure 7).
- Supply and demand outlook (Section 3.1).
- Assessment of system strength requirements and shortfalls (Section 3.2).
- Assessment of inertia requirements and shortfalls (Section 3.3).
- Assessment of NSCAS needs (Section 3.4).

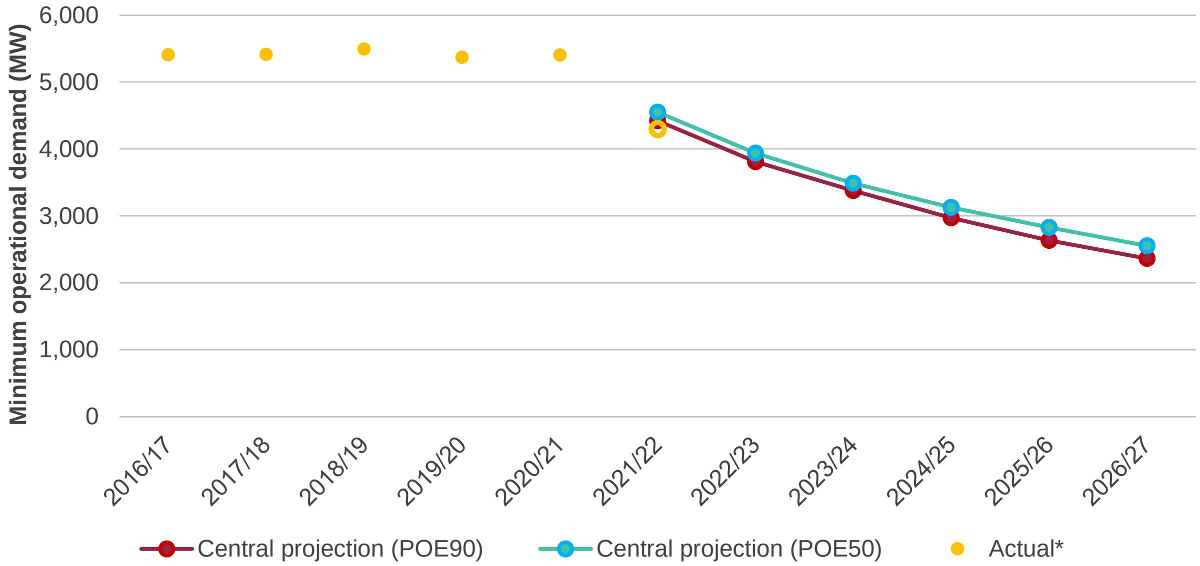
Figure 7 System security five-year outlook for New South Wales



3.1 Supply and demand outlook

Minimum operational demand (sent-out[36]) for New South Wales is forecast to decrease by approximately 2,050 MW between 2021-22 and 2026-27 in the 2021 ESOO Central scenario, as seen in Figure 8.

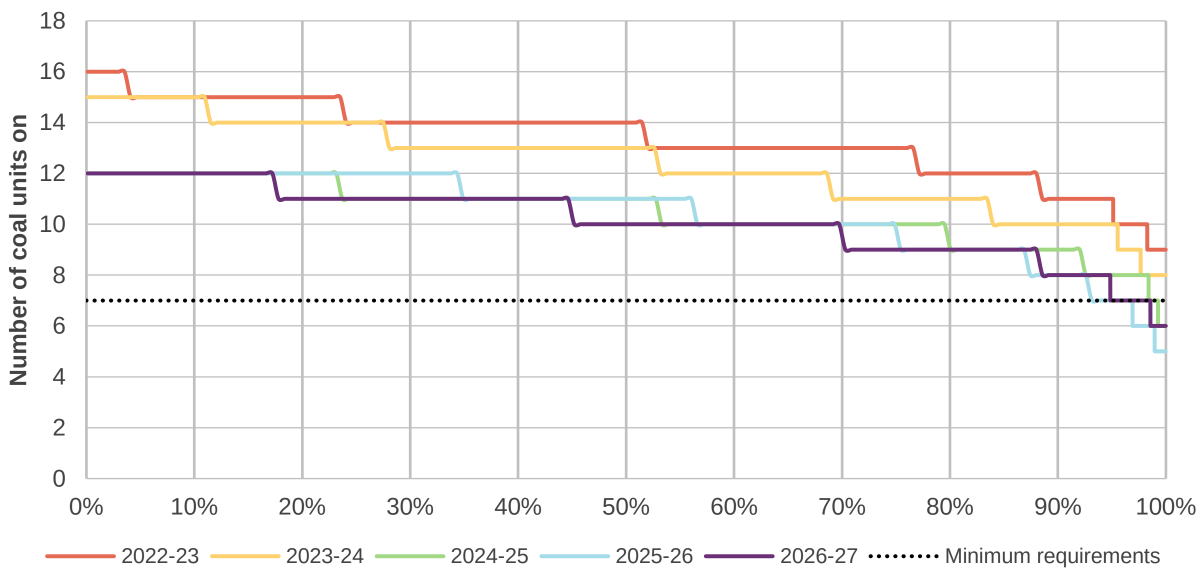
Figure 8 Actual minimum demand and 2021 ESOO forecast 90POE and 50POE shoulder minimum operational demand (sent-out) for New South Wales (Central scenario)



* Record minimum demand occurred 17 October 2021 (4,296 MW sent-out), included as an outlined circle in this figure for illustrative purposes only as the year is still incomplete.

The number of coal generators projected to be online in New South Wales across the year is forecast to fall below current minimum combinations for more than 1% of the time from 2023-24 onwards, as shown in Figure 9.

Figure 9 Number of coal units projected online under *Progressive Change* scenario, New South Wales [A]

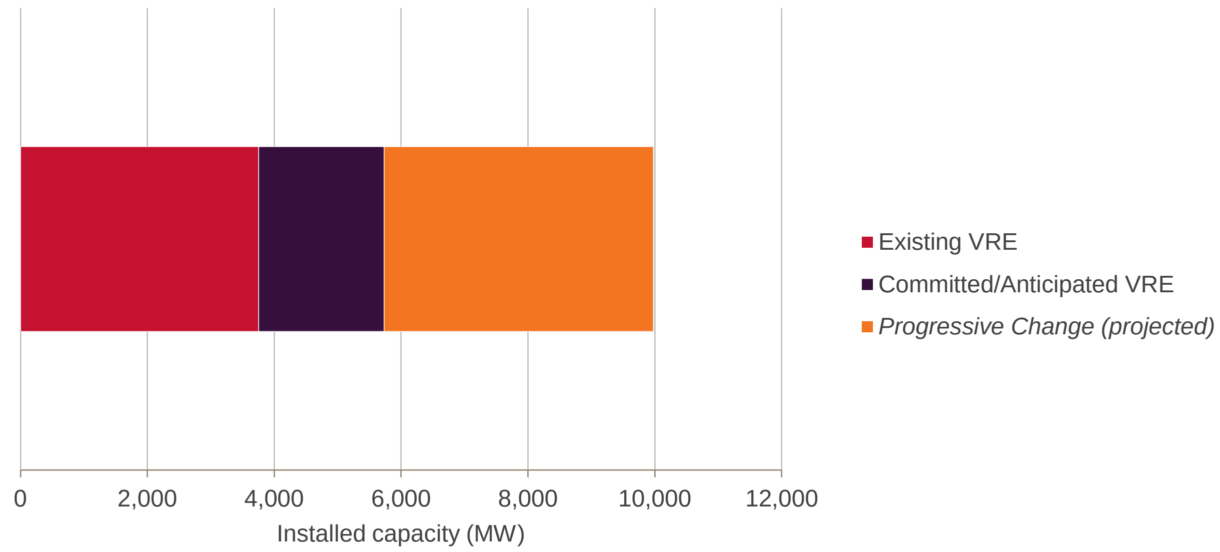


A. See Appendix A3 for further details about the minimum requirements.

[36] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

VRE generation modelled in New South Wales for the system strength and inertia projections is shown in Figure 10. New South Wales has approximately 5,800 MW of existing, committed and anticipated VRE generation projects, as well as just over 4,200 MW of new VRE generation projected over the five-year outlook period for the *Progressive Change* scenario.

Figure 10 New South Wales existing, committed and anticipated VRE generation projects and the *Progressive Change* projected VRE projects out to 2026-27



3.2 2021 System strength assessment

3.2.1 Requirements

AEMO is not changing the system strength requirements in New South Wales for now, but will reassess in 2022. Table 3 provides the requirements.

AEMO and Transgrid have agreed that a new node should be declared at Buronga substation given concerns about system strength management in that area. Joint planning assessments are underway, and AEMO will declare the node and its minimum fault levels requirements in 2022.

Table 3 New South Wales system strength requirements

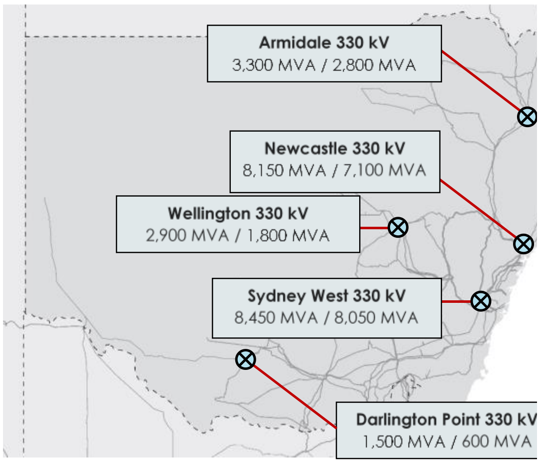
Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Armidale 330 kV	High IBR[37]	3,300	2,800	Per December 2020 declaration.
Newcastle 330 kV	Synchronous generation centre	8,150	7,100	Per December 2020 declaration.
Wellington 330 kV	High IBR	2,900	1,800	Per December 2020 declaration.
Sydney West 330 kV	Metropolitan load centre	8,450	8,050	Per December 2020 declaration.
Darlington Point 330 kV	High IBR; Remote from synchronous generation	1,500	600	Per December 2020 declaration.

A. 2020 System Strength and Inertia Report, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[37] The term inverter-based resources (IBR) is used in the System Strength Requirements Methodology to refer to variable renewable energy generation resources.

3.2.2 Outcomes

New South Wales



AEMO is declaring system strength shortfalls at both Newcastle and Sydney West with the *Progressive Change* scenario now projecting major changes in synchronous generation behaviour, and declining minimum demand.

Other fault level nodes also see projected reductions in fault level under the *Progressive Change* scenario, although none below the minimum requirements.

AEMO considers that there will be a range of novel options to address system strength issues, including inverter-tuning, synchronous condensers, network augmentations, potentially batteries with advanced inverters, and contributions from existing market participants.

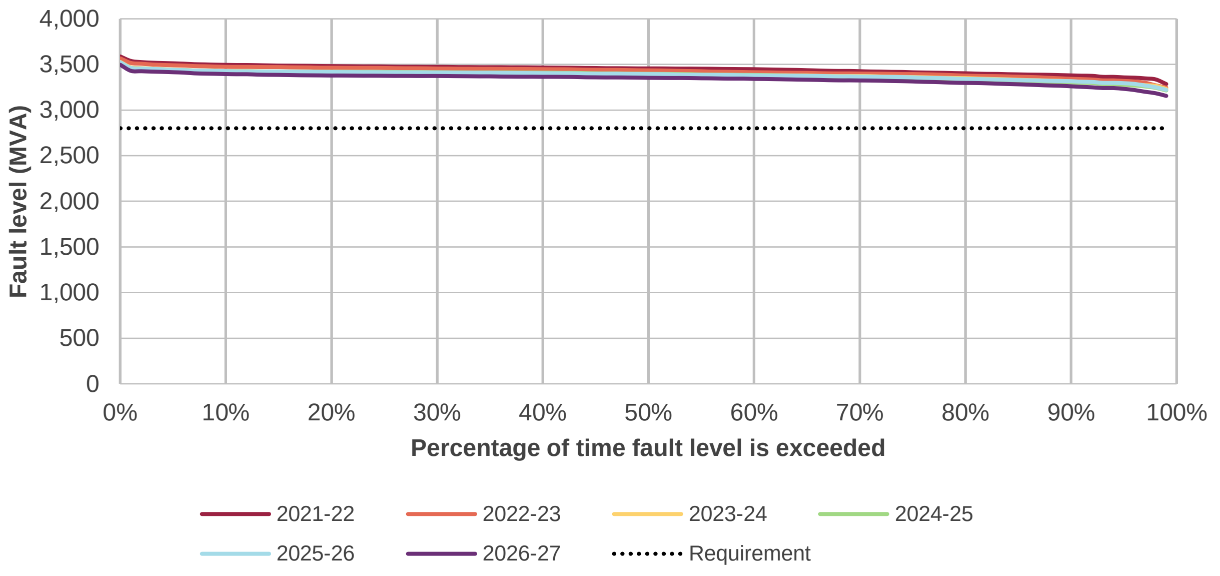
There may also be opportunity for innovative reductions in minimum requirements in New South Wales as part of system strength management.

Projections (*Progressive Change*) and shortfalls

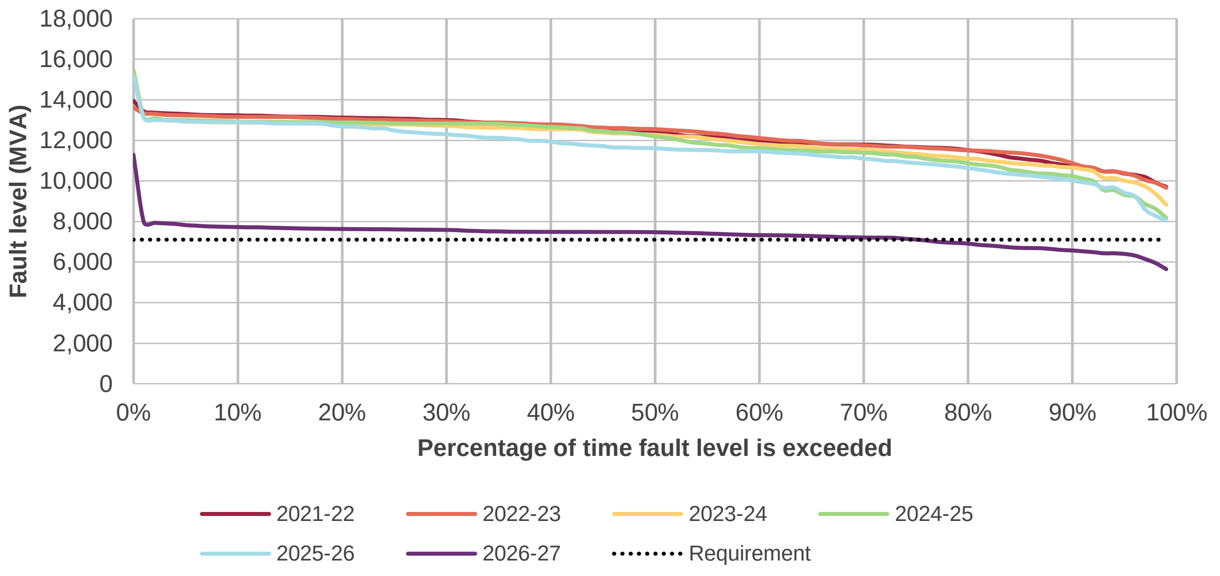
Node	Projected minimum three phase fault level for 99% of the time						Shortfalls and comments [A]
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	
Armidale 330 kV	3,284	3,245	3,233	3,213	3,221	3,156	No shortfall
Newcastle 330 kV	9,707	9,670	8,830	8,186	8,031	5,652 (1,448 MVA shortfall)	A shortfall of 1,448 MVA is declared for 1 July 2026. AEMO will request that Transgrid provide system strength services to address the shortfall by 1 July 2026. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Wellington 330 kV	1,990	2,001	1,979	2,003	3,302	3,220	No shortfall.
Sydney West 330 kV	9,785	9,442	8,904	8,205	8,357	7,185 (865 MVA shortfall)	A shortfall of 865 MVA is declared for 1 July 2026. AEMO will request that Transgrid provide system strength services to address the shortfall by 1 July 2026. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Darlington Point 330 kV	695	696	709	723	723	741	No shortfall

A. The system strength outcomes for New South Wales are assessed on a post-contingent basis.

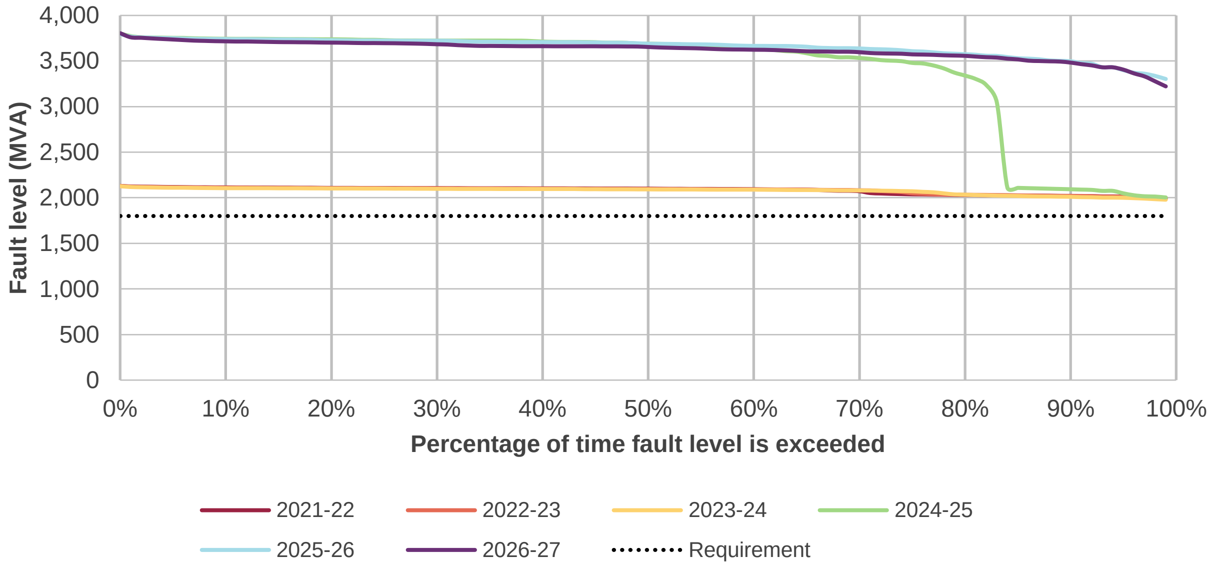
Armidale 330 kV



Newcastle 330 kV

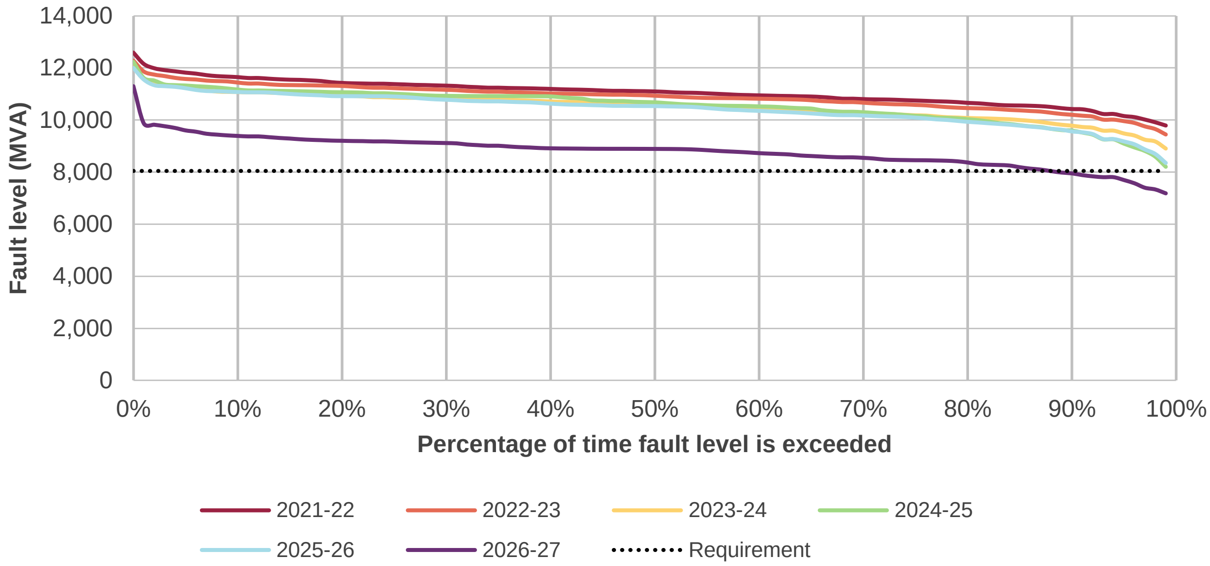


Wellington 330 kV

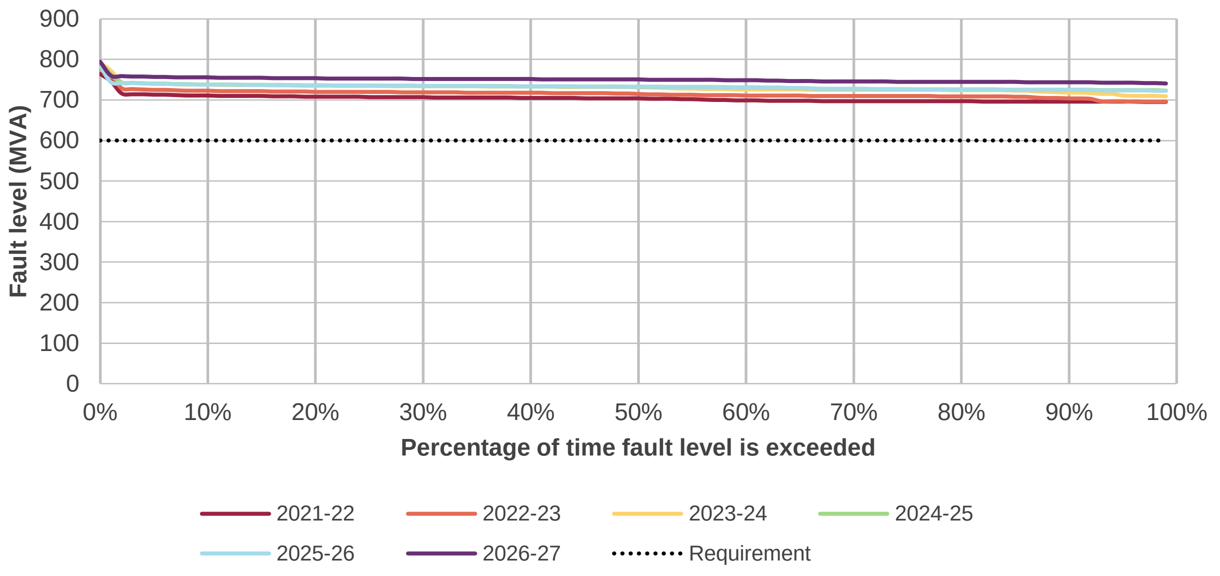


*Increases in fault level projections in the latter years are due to expected network augmentations associated with the nearby Central West Orana REZ. Over time the projections and requirements at Wellington will need to be re-assessed to consider the changing network and market conditions in this area.

Sydney West 330 kV



Darlington Point 330 kV



3.3 2021 Inertia assessment

New South Wales

Under the *Progressive Change* scenario, AEMO projects that inertia in New South Wales will decline over the coming five-year outlook period, including declining below the secure operating level in the final year of the period. However, as New South Wales islanding from the remainder of the NEM is not considered likely, no shortfall is able to be declared under the current framework

While the retirement of Liddell Power Station in 2023 is not expected to lead to inertia shortfalls because the region is not considered sufficiently likely to island, future decommitment of large synchronous generators in response to low demand periods may cause a reduction in online inertia in the New South Wales region.

Inertia requirements

	2020	2021
Secure operating level of inertia (MWs)	12,500	12,500
Minimum operating level of inertia (MWs)	10,000	10,000
Net distributed PV trip (MW)	-	-
Risk of Islanding	Not likely	Not likely

The secure operating level and minimum operating level of inertia for New South Wales are held steady at the values determined in July 2018.

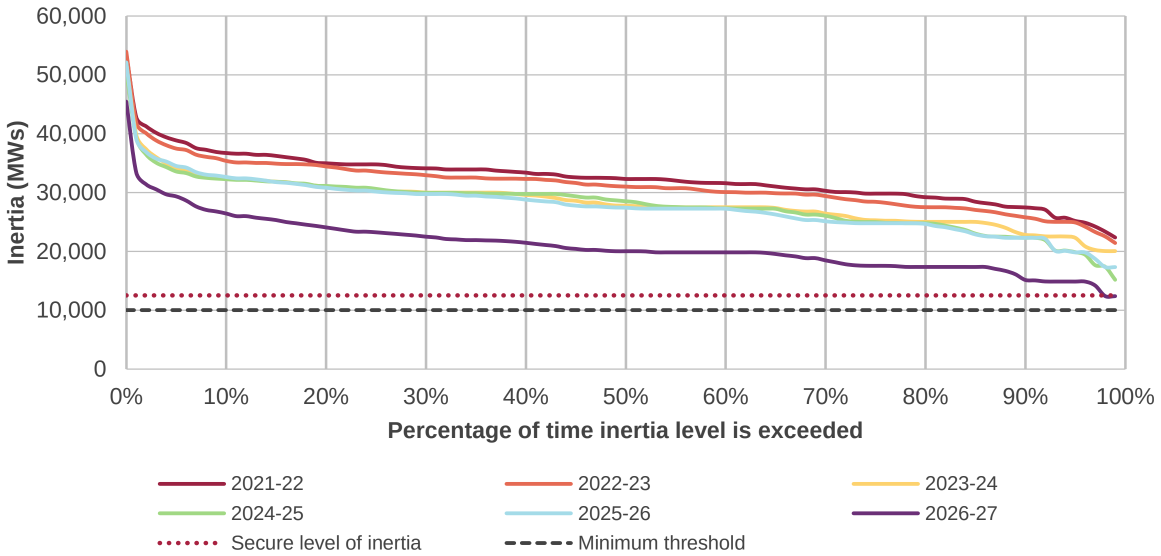
Declaration of any inertia shortfall for a region must also consider the likelihood of islanding. Islanding of New South Wales alone remains unlikely, consistent with AEMO's 2020 and 2018 assessments. This finding is largely driven by the diversity and number of AC interconnectors that exist between New South Wales and the adjacent regions.

Net distributed PV trip has not been incorporated in this assessment, and the secure operating level is not provided as a ratio of synchronous inertia and fast frequency response or Fast FCAS, because islanding is not considered likely and so a shortfall will not be declared.

Inertia projections (*Progressive Change*)

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Available inertia for 99% of the time (MWs)	22,366	21,410	20,034	15,202	17,354	12,391

Figure 11 Projected inertia for the five-year outlook, *Progressive Change* scenario, New South Wales



3.4 2021 NSCAS assessment

AEMO declares an immediate RSAS gap of 2 MVAr reactive power absorption in the Coleambally region, but notes that Transgrid have operational measures in place to manage the post-contingent voltages and will begin the Regulatory Investment Test – Transmission (RIT-T) process in early 2022 to identify a longer-term solution.

Context

AEMO assessed voltage control in New South Wales for the five-year outlook period, including future committed transmission projects, committed generators, announced generator retirements, and forecast change in demand. This 2021 NSCAS review incorporated changes identified through AEMO's review of planning assumptions for voltage control (more information is provided in Appendix A2). In addition, the minimum synchronous machine requirement associated with the system strength requirements is adhered to for these studies[38].

Results

AEMO has identified an immediate marginal RSAS gap of approximately 2 MVAr absorbing reactive power at Coleambally to manage post contingent high voltages at Coleambally during overnight low demand when nearby solar generation is out of service. The size of the NSCAS gap is not expected to change over the five-year period. The optimal location and solution for addressing this identified gap is to be determined by the TNSP.

Table 4 notes the scenarios assessed and the results of the assessment.

Table 4 New South Wales NSCAS outcomes for scenarios assessed

Time of day	Financial year ending	Demand (MW)	Inter-connector flows	Pre-contingent line switching assumption	NSCAS gap
Daytime	2026	2,606	• Low transfer from New South Wales to Queensland • Low transfer from New South Wales to South Australia • High transfers from New South Wales to Victoria	No line switching	No NSCAS gap identified.
	2026	2,606	• High transfer from New South Wales to Queensland • Low transfer from New South Wales to South Australia • Low transfers from New South Wales to Victoria	No line switching	No NSCAS gap identified.
Overnight	2022	5,193	• Medium transfer from Queensland to New South Wales • Low transfer from New South Wales to South Australia	No line switching	An NSCAS RSAS gap identified of approximately 2 MVAR reactive power absorption identified at Coleambally 132 kV busbar.

[38] Seven synchronous units online.

Time of day	Financial year ending	Demand (MW)	Inter-connector flows	Pre-contingent line switching assumption	NSCAS gap
			• Low transfers from New South Wales to Victoria		
	2022	5,193	• Medium transfer from Queensland to New South Wales • Low transfer from New South Wales to South Australia • Low transfers from New South Wales to Victoria	Deniliquin – Finley 132 kV line	No NSCAS gap identified
	2026	5,193	• Medium transfer from Queensland to New South Wales • Low transfer from New South Wales to South Australia • Low transfers from New South Wales to Victoria	No line switching	An NSCAS RSAS gap identified of approximately 2 MVAR reactive power absorption identified at Coleambally 132 kV busbar.
	2026	5,193	• Low transfer from Queensland to New South Wales • Low transfer from New South Wales to South Australia • Low transfers from New South Wales to Victoria	No line switching	An NSCAS RSAS gap identified of approximately 2 MVAR reactive power absorption identified at Coleambally 132 kV busbar.
	2026	5,193	• Low transfer from Queensland to New South Wales • Low transfer from New South Wales to South Australia • Low transfers from New South Wales to Victoria	Deniliquin – Finley 132 kV line	No NSCAS gap identified

AEMO did not identify any NSCAS gaps for maximising market benefits in New South Wales.

Next steps

AEMO declares an immediate RSAS gap of 2 MVAR absorbing reactive power in the Coleambally region.

AEMO notes that Transgrid has operational measures in place to manage the post contingent voltages at Coleambally. This includes the switching of the 132 kV line between Deniliquin and Finley. This operational measure does place load at risk for the loss of a further contingency.

AEMO notes that Transgrid have proposed a project to manage post contingent high voltages in the Darlington Point, Coleambally, Deniliquin and Finley area. The solution will be determined through a RIT-T process, which AEMO understands will begin in early 2022. AEMO considers that this project would, once implemented, address the identified NSCAS gap.

AEMO declares an NSCAS trigger date[39] of 17 December 2021 and an NSCAS tender date that has already passed[40]. AEMO will continue to receive updates from Transgrid on the resolution of this matter.

[39] "NSCAS trigger date" is defined in clause 5.20.1 of the NER as the date the NSCAS gap first arises.

[40] "NSCAS tender date" is defined in clause 5.20.1 of the NER as the date (or indicative date) on which AEMO would need to act to meet the NSCAS gap by the NSCAS trigger date if it is required to do so under clause 3.11.3(c). In this case, AEMO's modelling has identified that the gap already exists as of the publication date of the report.

4 Queensland

Under the *Progressive Change* scenario, AEMO projects declining synchronous generation online in Queensland and reducing minimum operational demand. A system strength shortfall has emerged at Gin Gin, as well as a region-wide inertia shortfall and a need for more voltage management services in southern Queensland.

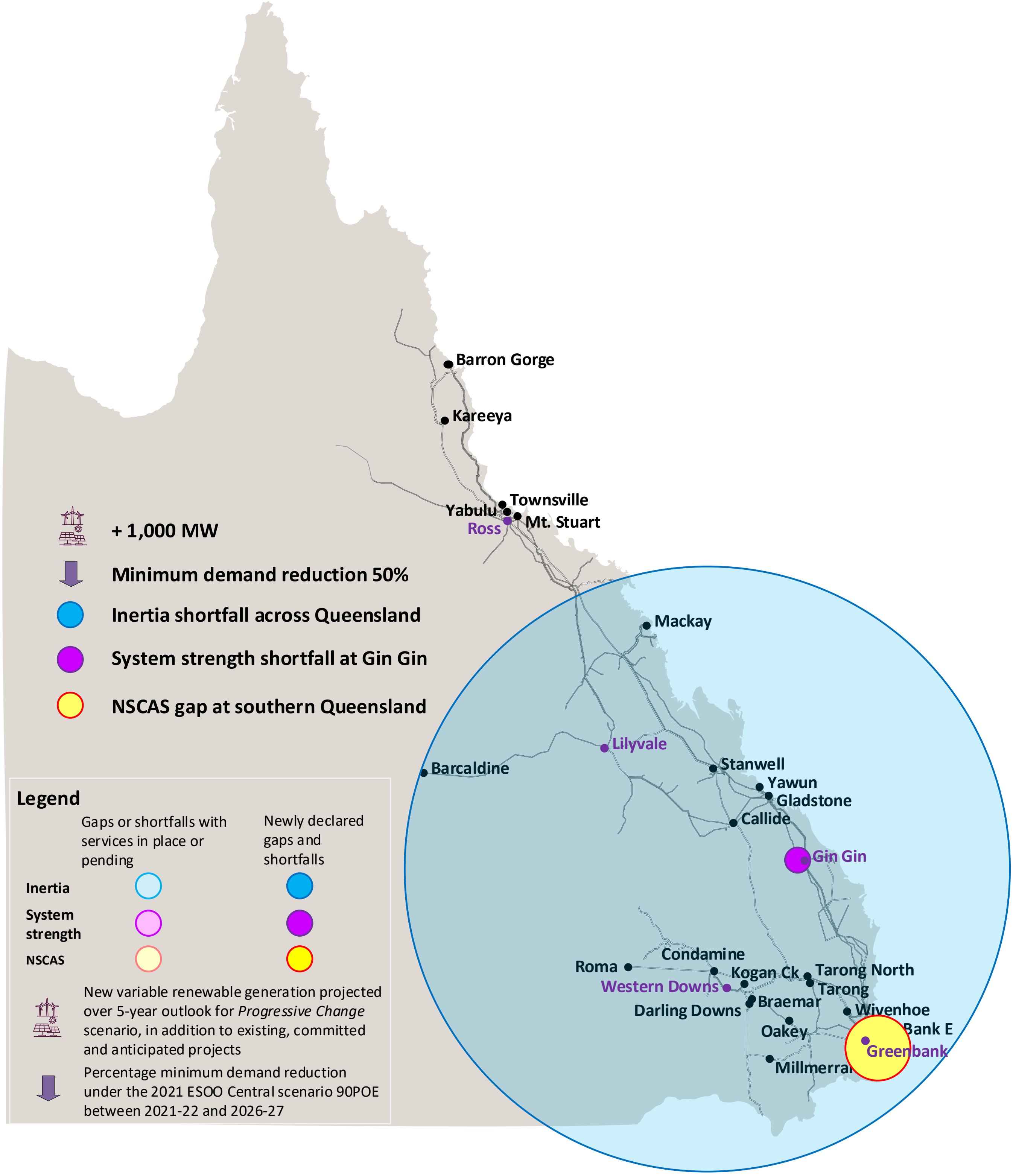
Under the *Step Change* scenario, two additional coal units are projected to withdraw in Queensland over the five-year outlook compared to *Progressive Change*. This may increase the size of the system strength and inertia shortfalls. AEMO will reassess the shortfalls under the *Step Change* scenario early in 2022.

Innovative power system design techniques, deployment of new technologies, and flexible operational practices could be applied to address these urgent system security needs, as longer-term solutions are deployed aligned with the ongoing, broader transition of the system.

In this section:

- A map of the system security five-year outlook (Figure 12).
- Supply and demand outlook (Section 4.1).
- Assessment of system strength requirements and shortfalls (Section 4.2).
- Assessment of inertia requirements and shortfalls (Section 4.3).
- Assessment of NSCAS needs (Section 4.4).

Figure 12 System security five-year outlook for Queensland



4.1 Supply and demand outlook

Minimum operational demand (sent-out[41]) for Queensland is forecast to nearly halve between 2021-22 and 2026-27 in the 2021 ESOO Central scenario, as seen in Figure 13. Figure 14 shows the projection for rapidly declining demand in the middle of the day.

Figure 13 Actual minimum demand and 2021 ESOO 90POE and 50POE forecast winter minimum operational demand (sent-out) for Queensland (Central scenario)

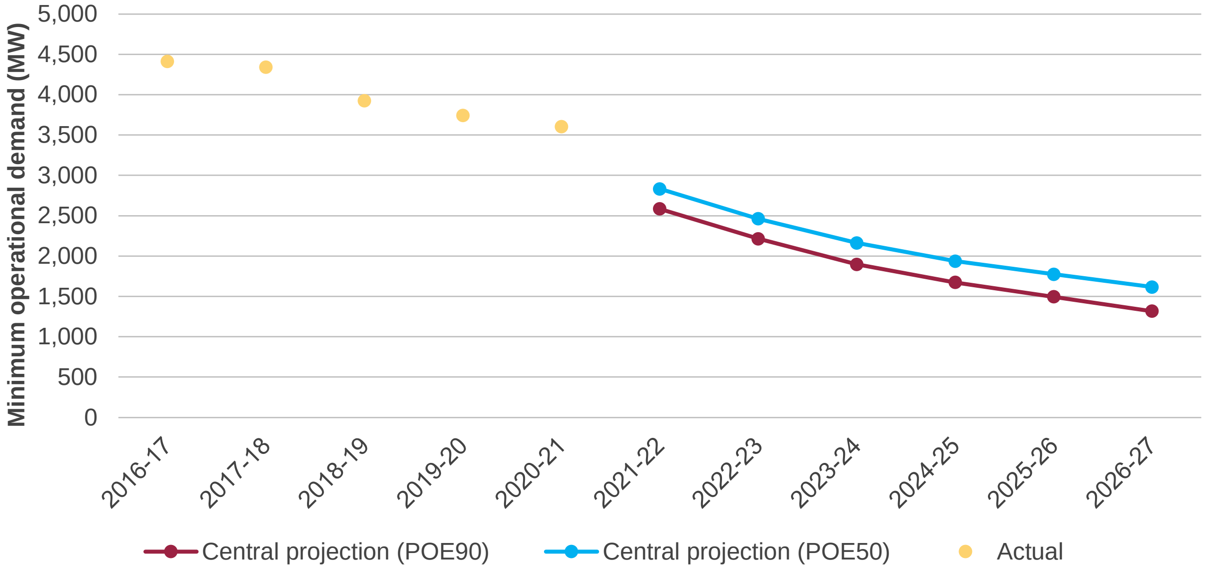
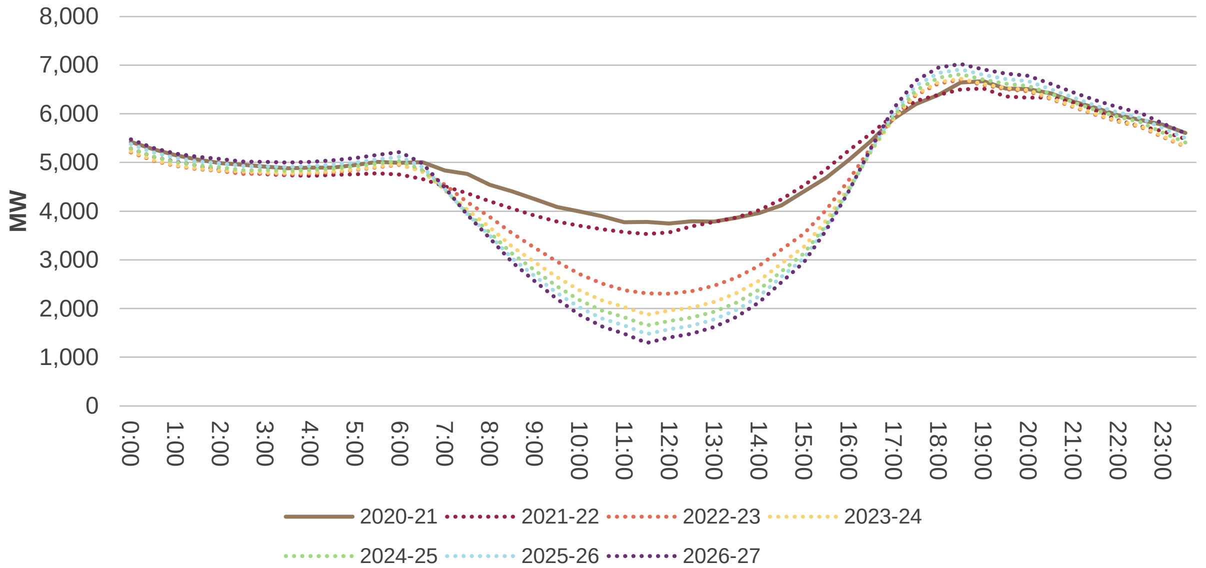


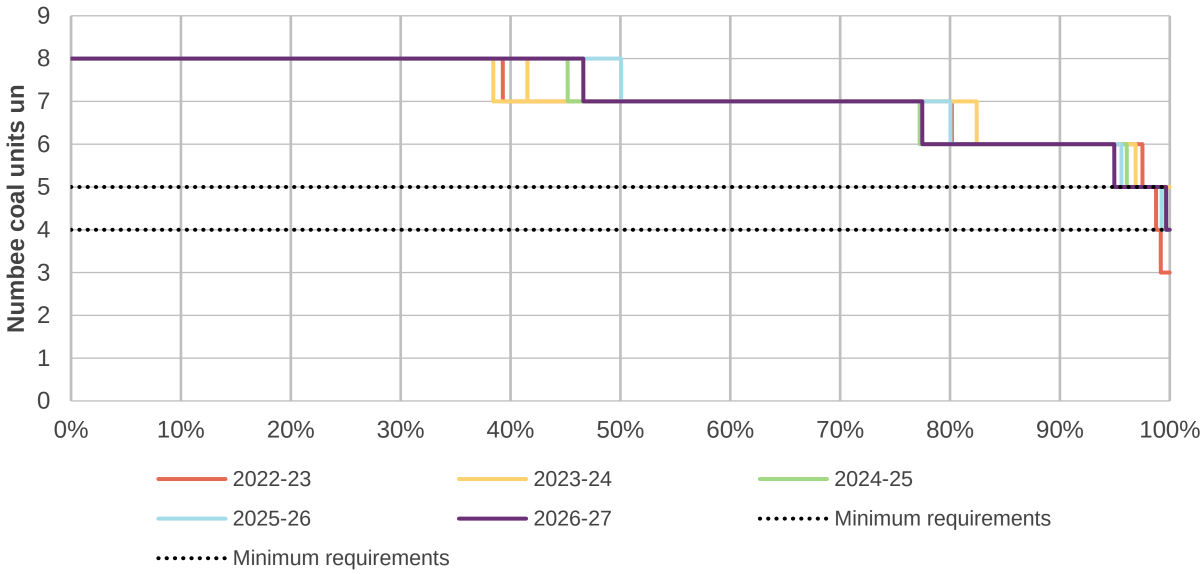
Figure 14 Example of minimum demand day for Queensland, 2021 ESOO Central projection 90POE



[41] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

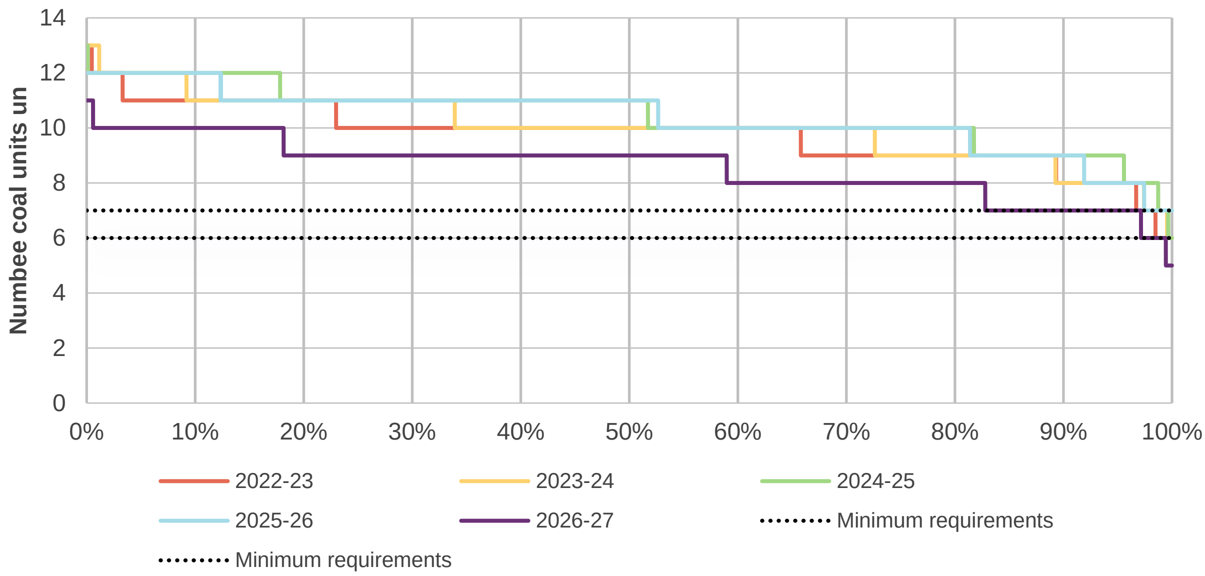
The number of coal generators projected to be online in southern Queensland and central Queensland across the year is forecast to fall below current minimum combinations for 1.5% to 10.7%% of the time for the five-year outlook period, as shown in Figure 15 and Figure 16.

Figure 15 Number of coal units projected online under *Progressive Change* scenario, southern Queensland [A]



A. Two minimum requirements are presented to reflect different unit combinations. See Appendix A3 for further details.

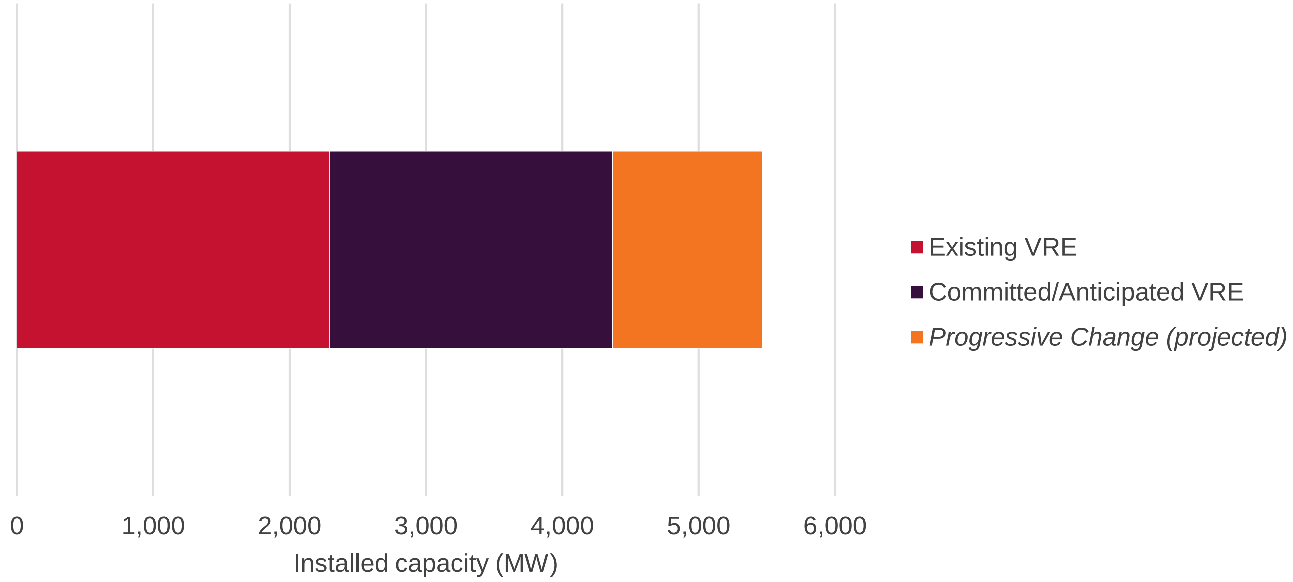
Figure 16 Number of coal units projected online under *Progressive Change* scenario, central Queensland



A. Two minimum requirements are presented to reflect different unit combinations. See Appendix A3 for further details.

VRE generation modelled in Queensland for the system strength and inertia projections is shown in Figure 17. Queensland has approximately 4,600 MW of existing, committed and anticipated VRE generation projects, as well as just over 1,000 MW of new VRE generation projected over the five-year outlook period in the *Progressive Change* scenario.

Figure 17 Queensland existing, committed and anticipated VRE generation projects and the *Progressive Change* projected VRE projects out to 2026-27



4.2 2021 System strength assessment

4.2.1 Requirements

AEMO is not changing the system strength requirements in Queensland for now, but will reassess in 2022. Table 5 provides the requirements, including the impact of novel inverter-tuning measures delivered by Powerlink and local generators at Ross.

Table 5 Queensland system strength requirements

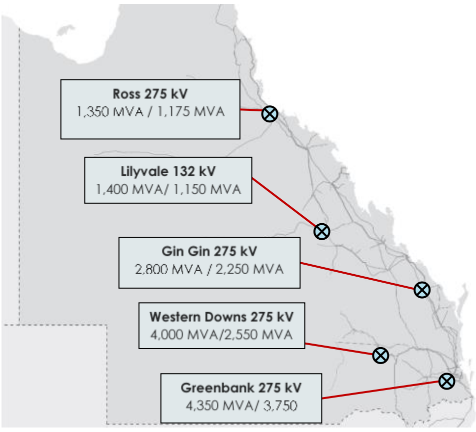
Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments
		Pre-contingency	Post-contingency	
Ross 275 kV	High IBR; Remote from synchronous generation	1,350	1,175	Per June 2021 declaration [A].
Lilyvale 132 kV	High IBR; Remote from synchronous generation	1,400	1,150	Per December 2020 declaration [B].
Gin Gin 275 kV	Synchronous generation centre	2,800	2,250	Per December 2020 declaration [B].
Greenbank 275 kV	Metropolitan load centre	4,350	3,750	Per December 2020 declaration [B].
Western Downs 275 kV	Synchronous generation centre	4,000	2,550	Per December 2020 declaration [B].

A. 2021 Notice of change to system strength requirement and shortfall at Ross, available via aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

B. 2020 System Strength and Inertia Report and 2021, available via aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

4.2.2 Outcomes

Queensland



AEMO is declaring an immediate system strength shortfall at Gin Gin due to the projected decline in the number of synchronous machines online in central Queensland in response to declining minimum demand and increasing VRE and distributed PV.

Other fault level nodes also see projected reductions in fault level under the *Progressive Change* scenario, although none below the minimum requirements.

AEMO considers that there will be a range of options to address system strength issues, including inverter-tuning, synchronous condensers, network augmentations, potentially batteries with advanced inverters, and contributions from existing market participants.

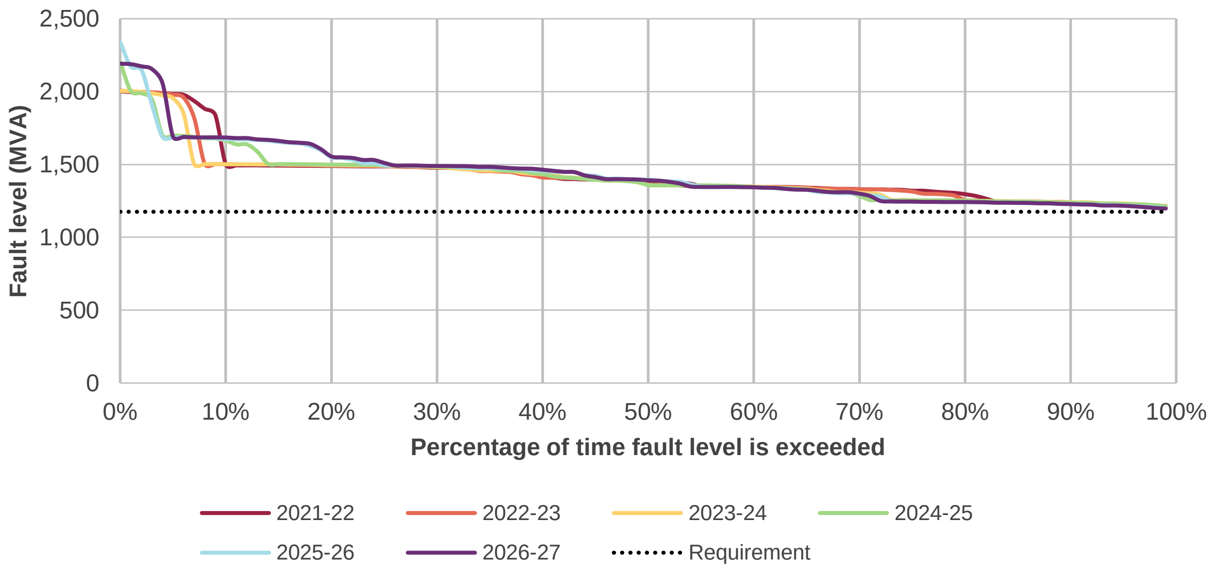
There may also be opportunity for innovative reductions in minimum requirements in Queensland as part of system strength management.

Projections (*Progressive Change*) and shortfalls

Node	Projected minimum three phase fault level for 99% of the time						Shortfalls and comments [A]
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	
Ross 275 kV	1,215	1,201	1,214	1,210	1,199	1,197	No shortfall. In June 2021, the requirement was changed and the previous shortfall closed, following inverter-tuning of local generators.
Lilyvale 132 kV	1,193	1,196	1,215	1,214	1,192	1,186	No shortfall.
Gin Gin 275 kV	2,190 (60 MVA shortfall)	2,198 (52 MVA shortfall)	2,206 (44 MVA shortfall)	2,191 (59 MVA shortfall)	2,190 (60 MVA shortfall)	2,185 (65 MVA shortfall)	A shortfall range of 44 to 65 MVA is declared for the period. AEMO will request that Powerlink provide system strength services to address the shortfall by 31 January 2023. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Greenbank 275 kV	4,737	4,797	4,539	4,553	4,566	4,811	No shortfall.
Western Downs 275 kV	2,922	2,872	2,920	2,870	2,911	2,952	No shortfall.

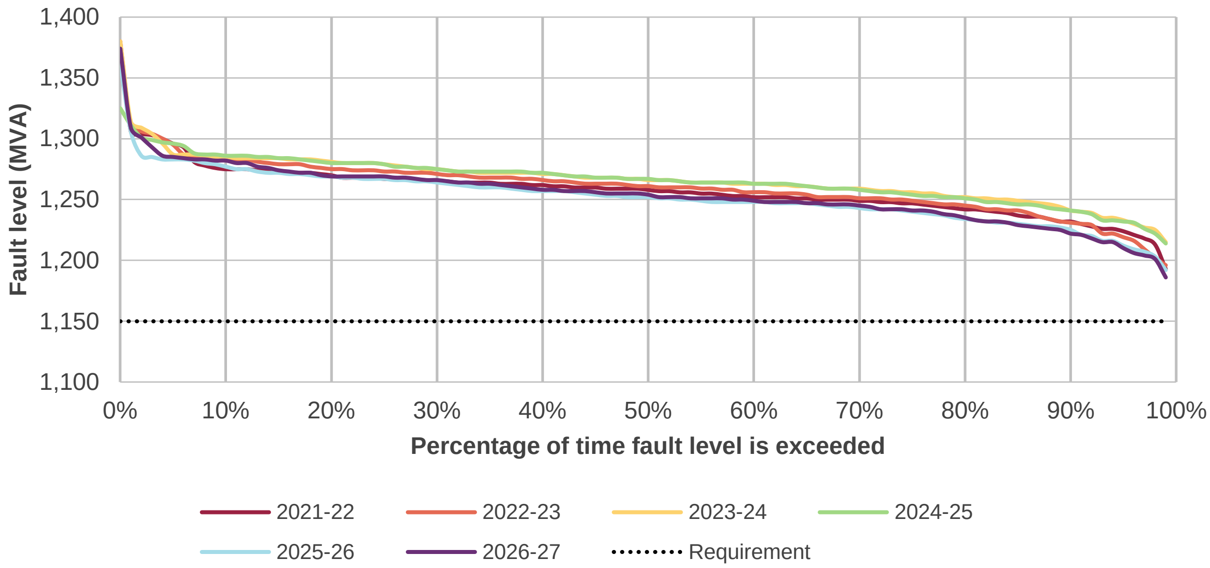
A. The system strength outcomes for Queensland are assessed on a post-contingent basis.

Ross 275 kV

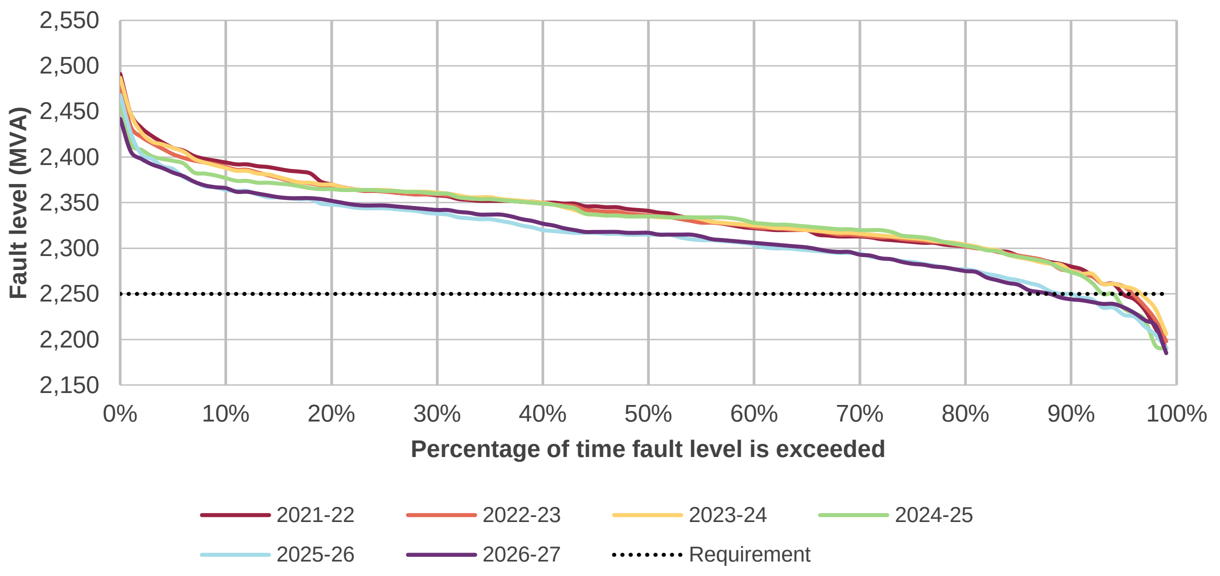


*In 2021, Powerlink and local generators delivered inverter-tuning solutions resulting in a changed minimum requirement and closed system strength shortfall.

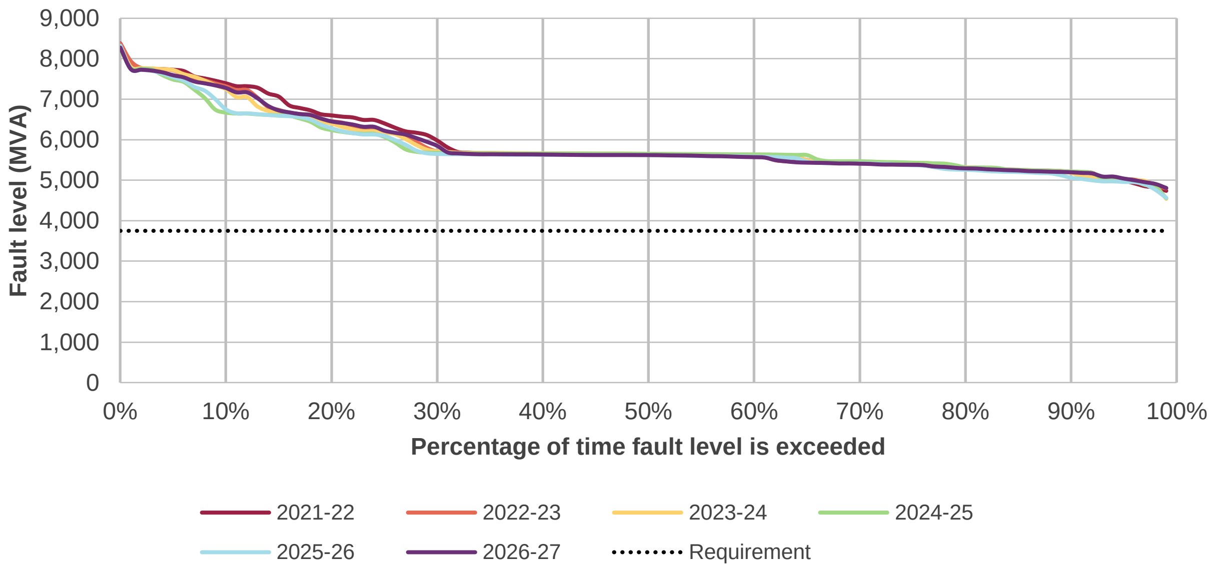
Lilyvale 132 kV



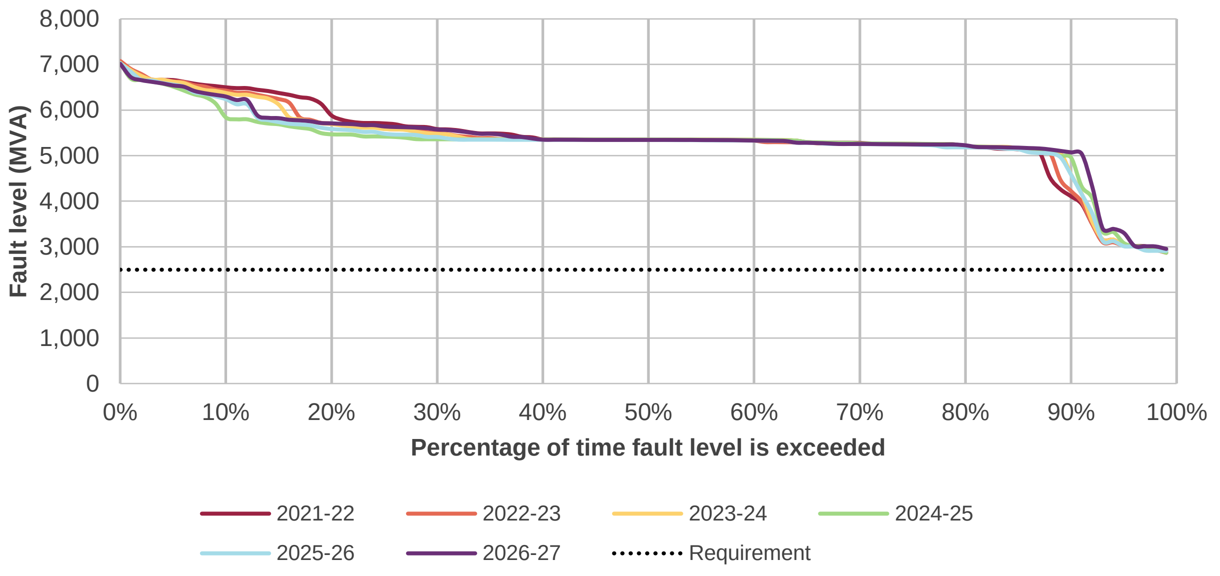
Gin Gin 275 kV



Greenbank 275 kV



Western Downs 275 kV



4.3 2021 Inertia assessment

Queensland

AEMO declares a shortfall against the secure operating level of inertia in the Queensland region. The shortfall ranges from 186 megawatt seconds (MWs) to 5,831 MWs, and it is likely that a variety of services will be able to meet this shortfall efficiently including inertia support activities such as fast frequency response.

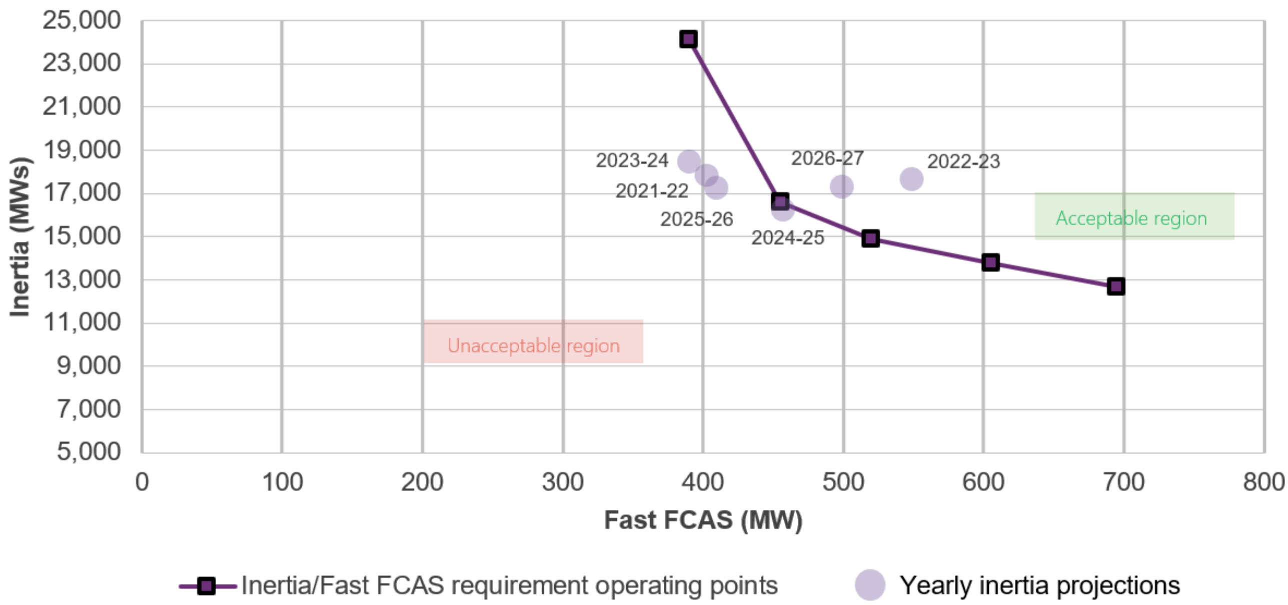
For the period to 2026-27, AEMO has assessed that the minimum threshold level of inertia will be met. However, a shortfall is projected against an updated secure operating level of inertia. Based on inertia projections for the *Progressive Change* scenario, a shortfall range is declared until 31 December 2026. AEMO will request that the services be made available from 31 January 2023. The shortfall values vary greatly from year to year because the inertia requirement in Queensland is highly inter-related with the amount of Fast FCAS[42] available. Solutions to address the shortfall will need to be prepared with consideration given to the interplay between available inertia (MWs), Fast FCAS through market services, and any inertia support services such as fast frequency response.

The December 2026 end date for the shortfall could be affected by the provision of sufficient services through the establishment of very fast raise and lower ancillary services markets (market start due October 2023). AEMO and Powerlink will monitor these and other events and will re-assess the shortfall if required.

[42] 'Fast FCAS' refers to the fast raise and lower frequency control ancillary services markets. More information is available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services.

Inertia requirements			
	2020	**2021**	The secure operating level in Queensland is dependent on the Fast FCAS available and is also likely to be able to be reduced by any fast frequency response that may be made available through inertia support services. The 2021 requirements do not assume fast frequency response from utility-scale batteries as part of the typical dispatch used to set the requirements. Figure 18 shows the relationship between inertia required and available Fast FCAS. With the latest forecasts for *Progressive Change*, the net distributed PV disconnection size in Queensland has increased from last year's calculated 130 MW, to 270 MW this year. This is a driver for the declaration of a new secure operating level of inertia for Queensland in this report. Appendix A4 details the calculation method for determining net distributed PV disconnection size. Appendix A4 provides further information.
Secure operating level of inertia (MWs) (and related MW Fast FCAS)	14,800 MWs	24,100 MWs at 390 MW Fast FCAS 16,600 MWs at 455 MW Fast FCAS	
Minimum operating level of inertia (MWs)	11,900	11,900	
Net distributed PV trip (MW)	130	270	
Risk of islanding	Likely	Likely	

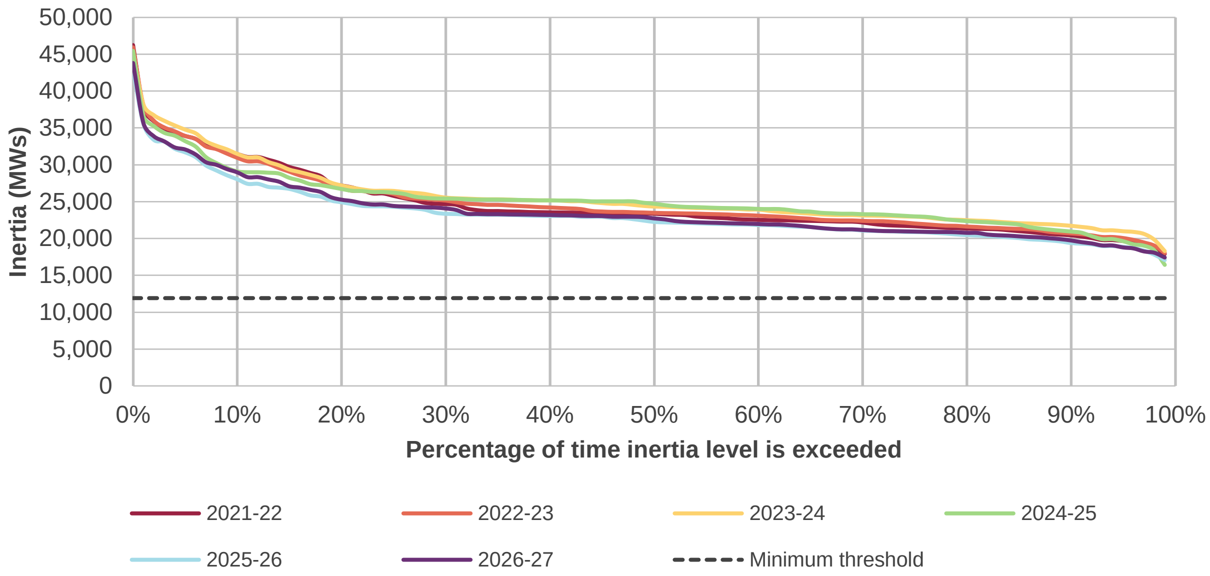
Figure 18 2021 secure operating level of inertia requirement and five-year projections for 99th percentile, Queensland [A, B, C, D]



A. The figure represents the relationship between the level of inertia required against the amount of Fast FCAS required for each level of inertia. The Fast FCAS does not include any fast frequency response from utility-scale batteries or other inverter-based resources.
B. Square data points show the operating points which have been modelled and provide a secure system. A line is drawn between the operating points to broadly indicate where the system may be considered to be secure.
C. The area above and to the right of the purple line is acceptable from a system security perspective, and the area below and to the left is unacceptable.
D. The projection for inertia and Fast FCAS for each year in the five-year outlook period is shown with a purple circle (99th percentile of time, *Progressive Change* scenario). The projections can include both synchronous generating units and committed utility-scale batteries, noting that the impact of any fast frequency response (as opposed to Fast FCAS) in the projections is not displayed on this inertia-Fast FCAS figure.

Inertia projections (*Progressive Change*)						
	2021-22	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Available inertia for 99% of the time (MWs)	17,913	18,018	18,269	16,414	17,076	17,420
Fast FCAS projected available at 99th percentile (MW)	406	546	390	453	410	500
Inertia shortfall against secure operating level (MWs)	4,341	None	5,831	186	4,716	None

Figure 19 Projected inertia for the five-year outlook, *Progressive Change* scenario, Queensland [A]



A. Inertia projections are shown against the minimum threshold level of inertia. The secure operating level is not shown as a single value because it is a function of available inertia and Fast FCAS.

4.4 2021 NSCAS assessment

AEMO declares an immediate RSAS gap of 120 MVAr reactive power absorption in southern Queensland, increasing in size to 250 MVAr by 2026.

Context

AEMO assessed voltage control in Queensland for the five-year outlook period, including future committed transmission projects, committed generators, announced generator retirements, and forecast change in demand. This 2021 NSCAS review incorporated changes identified through AEMO's review of planning assumptions for voltage control (more information is provided in Appendix A2). In addition, the minimum synchronous machine dispatch requirement associated with the system strength requirements is adhered to for these studies[43].

Results

AEMO has identified an immediate RSAS gap of approximately 120 MVAr absorbing reactive power in South East Queensland. The gap increases to 250 MVAr absorbing reactive power by 2026. Approximately 140 MVAr is required near Mudgeeraba and approximately 110 MVAr near Goodna, to manage the identified post contingent high voltages in South East Queensland most notably at Greenbank, Mudgeeraba and Goodna. The optimal location and solution for addressing this identified gap is to be determined by the TNSP.

Table 6 notes the scenarios assessed and the results of the assessment. This assessment considers maintaining the system in a secure state during system normal conditions and subject to a credible contingency. Restoring the network to a secure operating state within 30 minutes has not been considered in this assessment.

Table 6 Queensland NSCAS outcomes for scenarios assessed

Time of day	Financial year ending	Demand (MW)	Queensland to New South Wales transfer	Pre-contingent line switching assumption	NSCAS gap
Daytime	2026	1,650	High [A]	No line switching	No gap
Overnight	2022	4,455	Low	No line switching	NSCAS gap identified of approximately 120 MVAR reactive power absorption identified at Greenbank 275 kV busbar.
	2026	4,504	Low	No line switching	NSCAS gap identified of 140 MVAR reactive power absorption at Mudgeeraba 275 kV busbar and 110 MVAr reactive power absorption at Goodna 275 kV busbar.
	2022	4,455	Low	275 kV Greenbank – Middle Ridge line	NSCAS gap identified of approximately 90 MVAR reactive power absorption at Greenbank 275 kV busbar.
	2026	4,504	Low	275 kV Greenbank – Middle Ridge line	NSCAS gap identified of 140 MVAR reactive power absorption at Mudgeeraba 275 kV busbar and 50 MVAr reactive power absorption at Goodna 275 kV busbar.

A. With the forecast low demand in Queensland, high solar generation and the minimum number of synchronous units in service to maintain system strength, to manage flows across the Queensland to New South Wales interconnector generation needed to be curtailed. Should generation, such as solar generation, constrain further in response to negative prices during daytime low demand periods or an inability to export to NSW due to surplus generation in NSW and/or coincident low demand periods, it may lead to lower QNI flows and higher voltages in south east Queensland. If daytime gaps resulted from such conditions arising on the network, the reactive support associated with the overnight gap may be sufficient to secure the network from high voltages during daytime low demand periods with low Queensland to New South Wales transfers.

AEMO did not identify any NSCAS gaps for maximising market benefits in Queensland.

[43] Seven synchronous units in central Queensland, four in southern Queensland, and two in northern Queensland.

Next steps

AEMO declares an immediate RSAS gap of approximately 120 MVAr reactive power absorption in Southern Queensland increasing in size to 250 MVAr by 2026.

AEMO notes that Powerlink have commenced a regulatory investment test for transmission (RIT-T) by publishing the project specification report[44] for managing high voltages in South East Queensland. The proposed solution includes the installation of three 120 MVAr reactors to be installed at Woolooga, Blackstone and Belmont substations. The first reactor is expected in service in 2023 with the remaining two in 2025.

AEMO also notes that the RSAS gap assessment was based on the 2021 ESOO, which while it used the 2021 forecasts of minimum operational demand, also assumed less distributed PV and VRE than is projected in the *Step Change* scenario in the ISP. Voltage challenges can be very location specific, and accelerated retirement of generation may bring about voltage challenges in certain parts of the network. It is also recognised that there have also been prominent examples of installed VRE in the NEM providing substantive additional reactive support and addressing what would have otherwise been a reactive need. This will depend on the type of VRE (for example, if predominantly solar then overnight may be more of concern) and where it is located relative to emerging reactive needs. For these reasons, AEMO will reassess this early in 2022 using the outcomes of the *Step Change* scenario.

AEMO notes that Powerlink have put a range of operational measures[45] in place with the AEMO control room to manage voltages in South East Queensland until any options are implemented.

AEMO declares an NSCAS trigger date[46] of 17 December 2021 and an NSCAS tender date that has already passed[47]. Consistent with NER 3.11.3, AEMO will request that Powerlink advise when it will have arrangements in place to meet this NSCAS gap or provide reasons why this gap will not be met.

[44] Powerlink Queensland Project Specification Consultation Report: Managing high voltages in South East Queensland, available at https://www.powerlink.com.au/sites/default/files/2021-07/Powerlink%20Queensland%20-%20Project%20Specification%20Consultation%20Report%20-%20Managing%20voltages%20in%20South%20East%20Queensland.pdf.

[45] Powerlink Queensland 2021 Transmission Annual Planning Report available at https://www.powerlink.com.au/sites/default/files/2021-11/Transmission%20Annual%20Planning%20Report%202021%20-%20Full%20report.pdf.

[46] “NSCAS trigger date” is defined in clause 5.20.1 of the NER as the date the NSCAS gap first arises.

[47] “NSCAS tender date” is defined in clause 5.20.1 of the NER as the date (or indicative date) on which AEMO would need to act to meet the NSCAS gap by the NSCAS trigger date if it is required to do so under clause 3.11.3(c). In this case, AEMO’s modelling has identified that the gap already exists as of the publication date of the report.

5 South Australia

Under the *Progressive Change* scenario, projections for declining minimum demand lead to an inertia shortfall and a voltage control gap in South Australia. The voltage control gap is also related to future reductions in numbers of synchronous generating units online.

No system strength shortfalls were identified, with ElectraNet's four new synchronous condensers now delivering both system strength and inertia for the region.

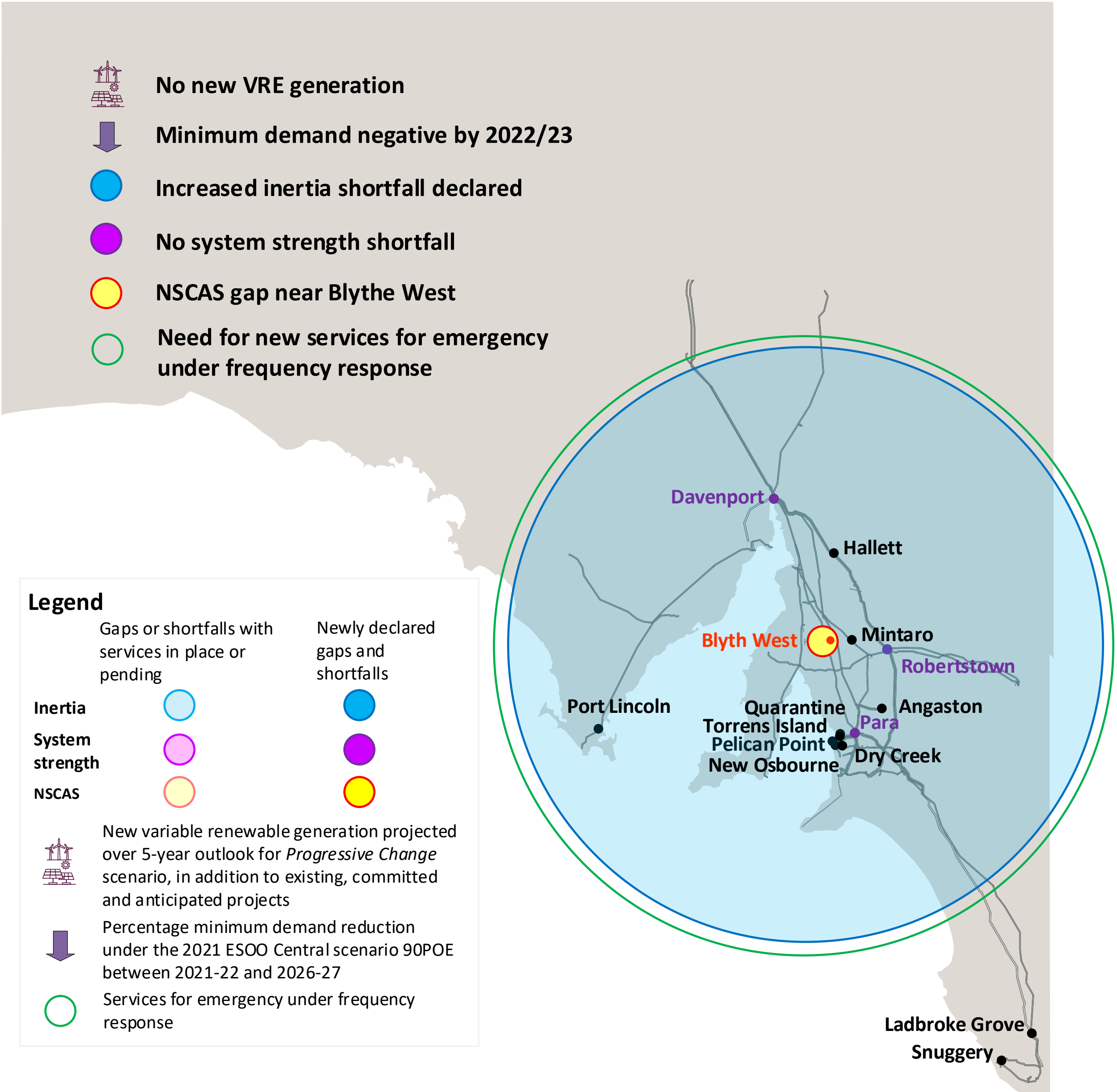
A range of innovative solutions will be needed to address the inertia and voltage needs identified in this report, as well as to meet new emergency response requirements and to support the energy transformation in South Australia as the number of synchronous generating units online decreases.

The *Step Change* scenario does not see any additional synchronous units retire in South Australia over the five-year outlook compared to *Progressive Change*. AEMO will consider the impact of the greater VRE generation seen in the *Step Change* scenario in 2022.

In this section:

- A map of the system security five-year outlook (Figure 20).
- Supply and demand outlook (Section 5.1).
- Assessment of system strength requirements and shortfalls (Section 5.2).
- Assessment of inertia requirements and shortfalls (Section 5.3).
- Assessment of NSCAS needs (Section 5.4).

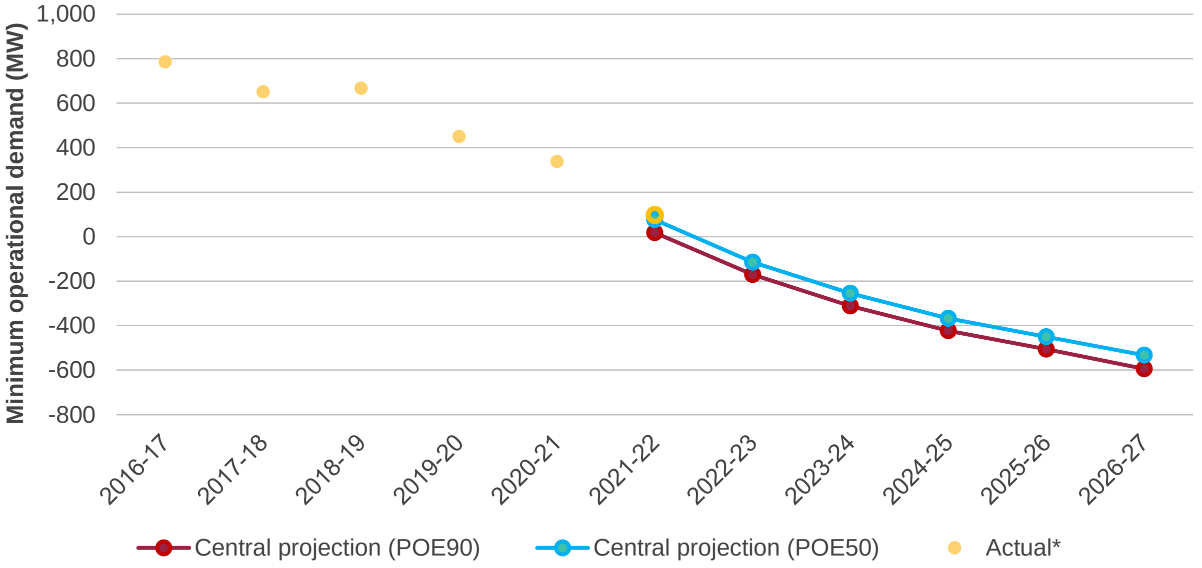
Figure 20 System security five-year outlook for South Australia



5.1 Supply and demand outlook

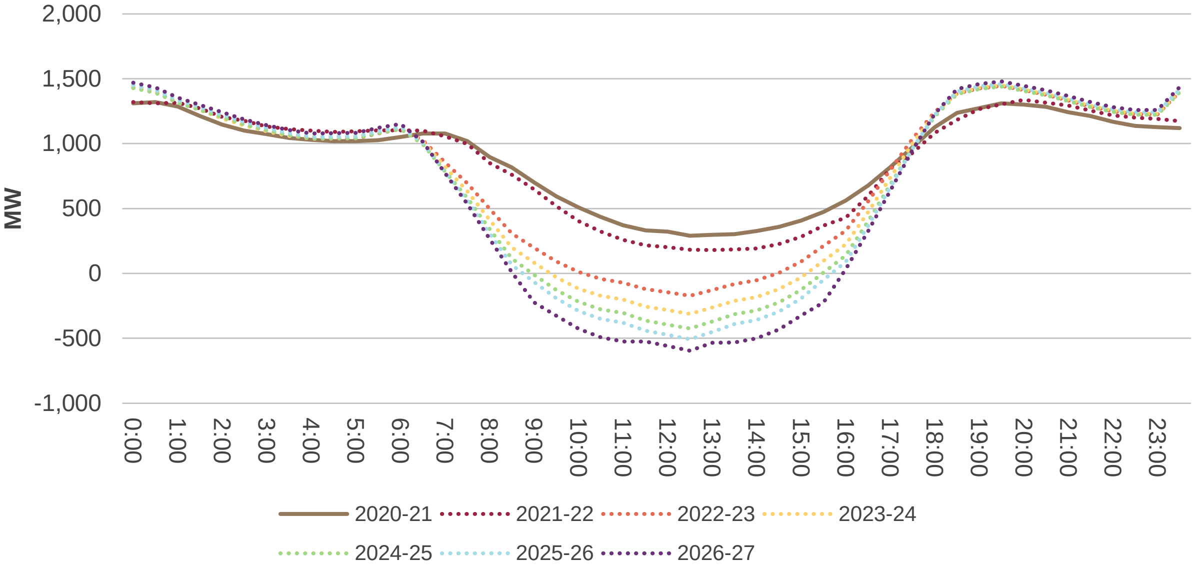
A 600 MW decrease in minimum operational demand (sent-out[48]) for South Australia is projected between 2021-22 and 2026-27 in the 2021 ESOO Central scenario, as seen in Figure 21. Figure 22 shows the projection for rapidly declining demand in the middle of the day.

Figure 21 Actual minimum demand and 2021 ESOO forecast 90POE and 50POE summer minimum operational demand (sent-out) for South Australia (Central scenario)



A. Record minimum demand occurred 21 November 2021 (97 MW sent-out), included as an outlined circle in this figure for illustrative purposes only as the year is still incomplete.

Figure 22 Example of minimum demand day for South Australia, 2021 ESOO Central projection 90POE

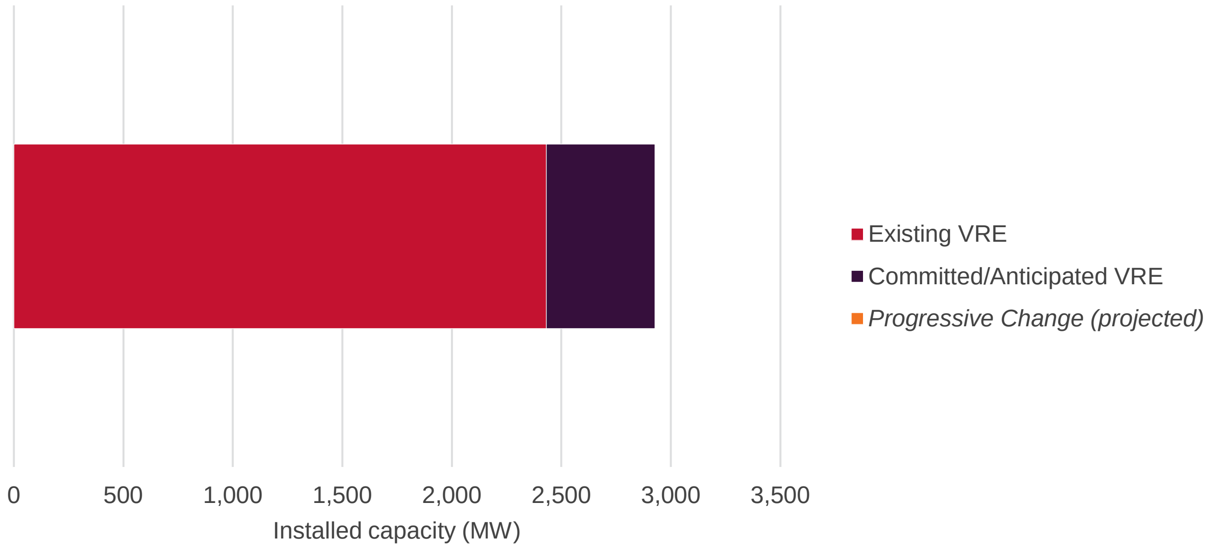


[48] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

VRE generation modelled in South Australia for the system strength and inertia projections is shown in Figure 23. South Australia has almost 3,000 MW of existing, committed and anticipated VRE generation projects, with no additional new VRE generation projected over the five-year outlook period for the *Progressive Change* scenario.

AEMO understands that a range of potential new VRE projects are under development in South Australia. In addition, a number of utility-scale battery system projects are also being progressed[49].

Figure 23 South Australia existing, committed and anticipated VRE generation projects and the *Progressive Change* projected VRE projects out to 2026-27



AEMO is working with ElectraNet and SA Power Networks to ensure sufficient emergency response measures are available in South Australia given ongoing decline in minimum demand[50]. SA Power Networks is currently investigating options to ensure sufficient emergency under-frequency response, by restoring and supplementing the existing under-frequency load shedding (UFLS) scheme. This scheme is designed as the last line of defence to manage severe frequency disturbances through controlled disconnection of load to correct a large supply-demand imbalance.

Given declining minimum demand in the state, the capability of the South Australia UFLS scheme is now significantly reduced and in the next few years without intervention it could act to exacerbate an under-frequency disturbance[51]. Remediation measures may include adding more load to the scheme, implementing dynamic arming of UFLS relays[52], and seeking supplementary services such as fast frequency response.

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[49] For example, AGL is proposing to construct a 250MW / 250MWh battery on Torrens Island. AGL, 'AGL invests $180 million in Torrens Island grid-scale battery', 9 August 20201, via https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/august/agl-invests-180-million-in-torrens-island-grid-scale-battery.

[50] Consistent with NER clauses S5.1.10.1(a), 4.3.1(pa) and 4.3.1(k).

[51] AEMO. Appendix A1, *2020 Power System Frequency Risk Review – Stage 1*. July 2020. Available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

[52] AEMO. *South Australian Under Frequency Load Shedding – Dynamic Arming*. May 2021. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

5.2 2021 System strength assessment

5.2.1 Requirements

AEMO is not changing the system strength requirements in South Australia for now, but will reassess in 2022. Table 7 provides the requirements.

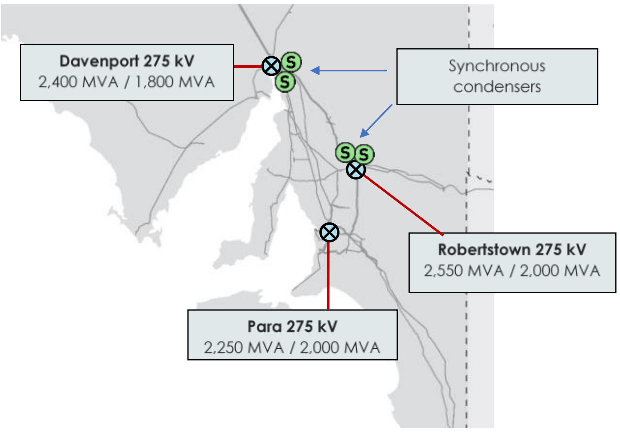
Table 7 South Australia system strength requirements

Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Davenport 275 kV	High IBR; Remote from synchronous generation	2,400	1,800	Per December 2020 declaration.
Para 275 kV	Metropolitan load centre; Remote from synchronous generation	2,250	2,000	Per December 2020 declaration.
Robertstown 275 kV	High IBR; Remote from synchronous generation	2,550	2,000	Per December 2020 declaration.

A. 2020 System Strength and Inertia Report, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

5.2.2 Outcomes

South Australia



Although the South Australia fault level nodes see projected reductions in fault level under the *Progressive Change* scenario, none are below the minimum requirements.

The four new synchronous condensers installed in South Australia will meet the system strength requirements for the outlook period. In addition, Project EnergyConnect will help improve system strength in the longer term.

The analysis incorporates the AEMO planning assumption that at least two synchronous generating units remain online for system security purposes until the commissioning and testing of Project EnergyConnect is complete[53].

Construction and energisation of Project EnergyConnect is modelled for completion by 2024 (Stage 2) with full capacity expected to be available after inter-network testing in July 2025.

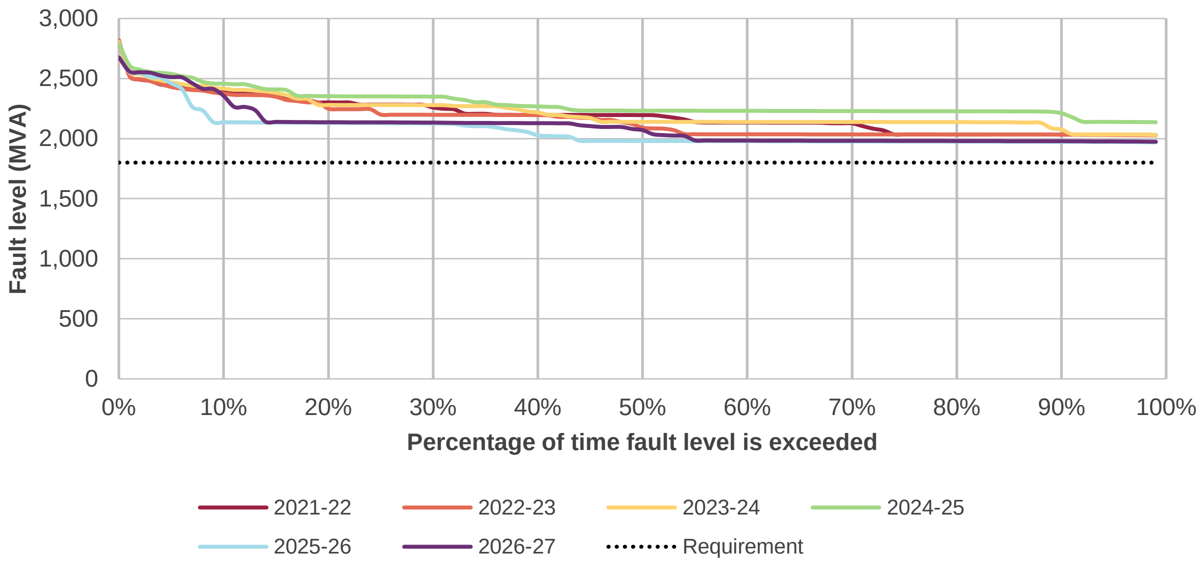
Projections (*Progressive Change*) and shortfalls

Node	Available minimum three phase fault level for 99% of the time						Shortfalls and comments [A]
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	
Davenport 275 kV	2,030	2,026	2,029	2,136	1,968	1,975	No shortfall
Para 275 kV	2,955	2,938	2,894	3,086	2,287	2,299	No shortfall
Robertstown 275 kV	2,442	2,435	2,442	2,876	2,791	2,817	No shortfall

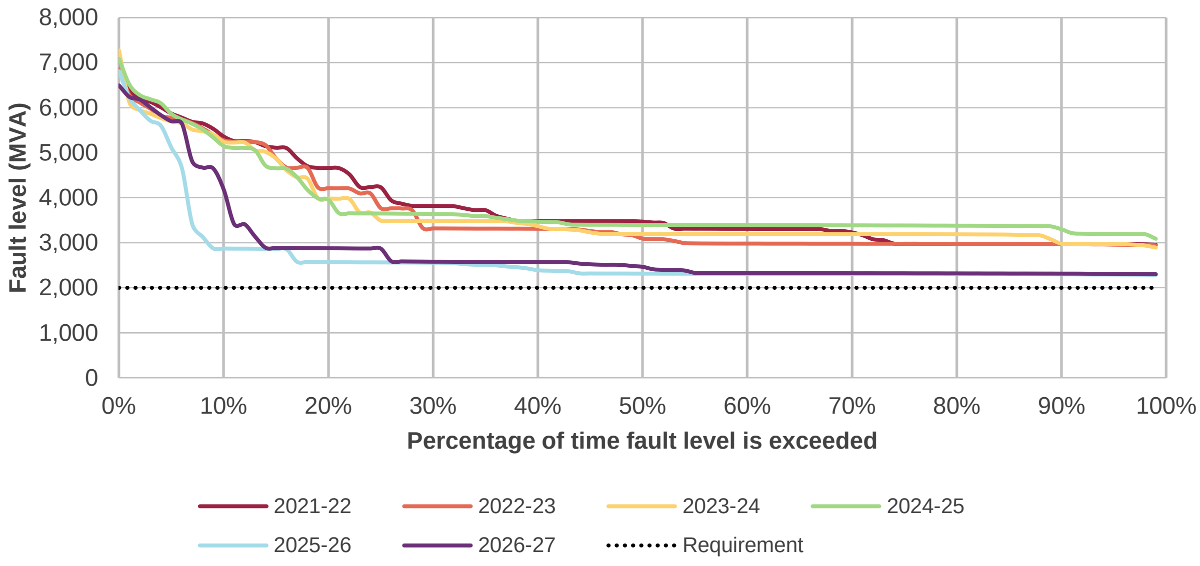
A. The system strength requirements for South Australia are assessed on a post-contingent basis.

[53] AEMO is continuing to assess ongoing power system requirements for South Australia, including the requirement to keep two synchronous generating units online, and will provide quarterly updates on this work plan in 2022.

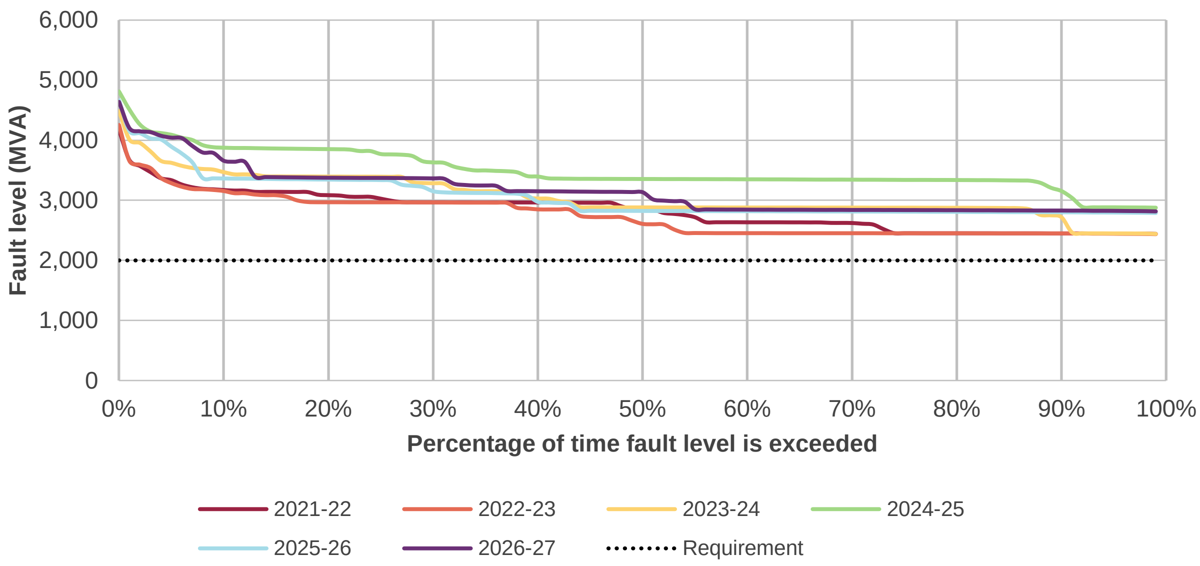
Davenport 275 kV



Para 275 kV



Robertstown 275 kV



5.3 2021 Inertia assessment

South Australia

AEMO is declaring an inertia shortfall from 1 July 2023 until the completion of inter-network testing of Project EnergyConnect, against the secure operating level of inertia in the South Australia region. This shortfall is for approximately 28,800 MWs, although it is likely to be more practicable to fill this shortfall with inertia support activities such as fast frequency response (FFR) equivalent to 360 MW. The existing inertia shortfall also persists until 30 June 2022.

For the period to 2026-27, AEMO has assessed that the minimum threshold level of inertia will be met. However, a shortfall is projected against an updated secure operating level of inertia. Based on inertia projections for the *Progressive Change* scenario, 360 MW of inertia support activities such as FFR will be needed in South Australia (or equivalent amounts of synchronous inertia, approximately 28,800 MWs, or a combination of both). This shortfall is declared for the period from 1 July 2023 until the completion of inter-network testing of Project EnergyConnect, by end of July 2025[54]. In addition, the existing inertia shortfall declared in August 2020 persists until 30 June 2022, with ElectraNet continuing to pursue options to address this shortfall.

The July 2025 end date for the shortfall could be affected by the provision of sufficient services through the establishment of very fast raise and lower ancillary services markets (market start due October 2023), or the completion of updates to a special protection scheme for South Australia (scheduled for July 2024). AEMO and ElectraNet will monitor these and other events and will re-assess the shortfall if required.

[54] With the competition in the inter-network testing of Project EnergyConnect, AEMO expects that South Australia will no longer be considered likely to island and therefore a shortfall will not be expected after that date.

Inertia requirements

	2020	2021
Secure operating level (MWs) (and related MW FFR)	14,390 MWs with 70 MW FFR	6,200 MWs with 360 MW FFR 4,400 MWs with 367 MW FFR
Minimum threshold level of inertia (MWs)	4,400	4,400
Net distributed PV trip (MW)	230	300
Risk of islanding	Likely	Likely

AEMO originally declared an inertia shortfall as part of the 2018 National Transmission Network Development Plan and updated the secure operating level of inertia for South Australia in August 2020 and December 2020. These changes resulted from findings from the South Australia islanding events in early 2020, and due to increased distributed PV contingency size and implications of declining minimum demand in the region[55].

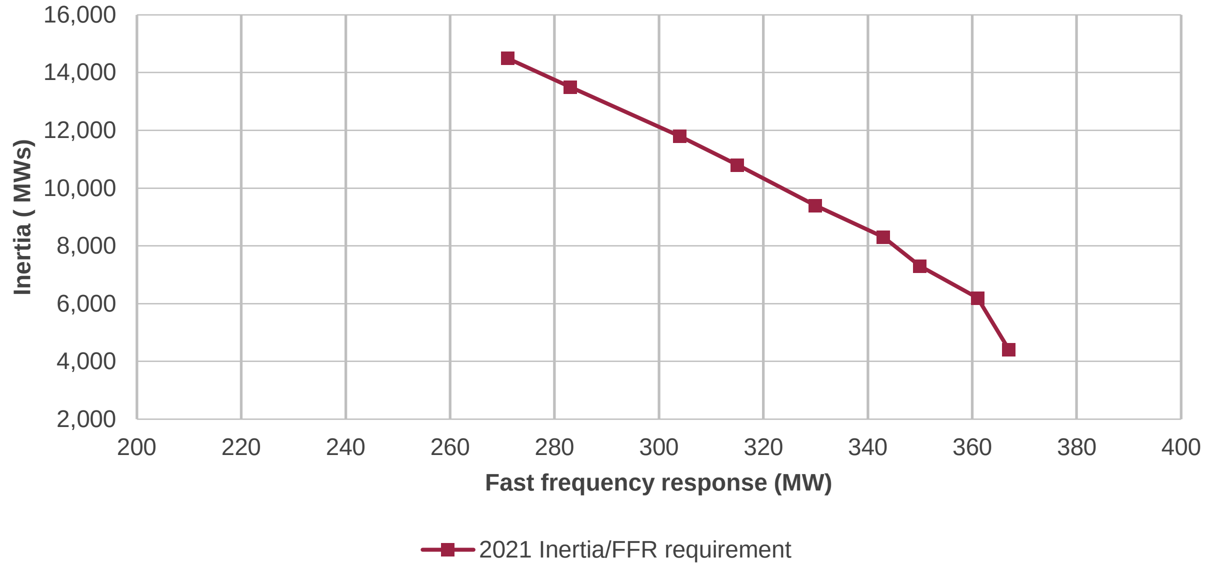
The secure operating level in South Australia is dependent on the amount of inertia support activities available, such as FFR. If more FFR (MW) is available then less synchronous inertia (MWs) is required. Figure 24 shows the relationship between inertia required and FFR provided.

With the latest forecasts for *Progressive Change*, the net distributed PV disconnection size in South Australia has increased from last year's calculated 230 MW, to 300 MW this year. This is a driver for the declaration of a new secure operating level of inertia in this report. Appendix A4 details the calculation method for determining net distributed PV disconnection size.

This analysis incorporates an assumption that at least two synchronous generating units will remain online if South Australia is islanded, until completion of commissioning and inter-network testing of Project EnergyConnect[56]. This analysis also incorporates 70 MW (and 10 MWh) of capacity reservation provided to the South Australia Government by Hornsdale Power Reserve.

Appendix A4 provides further information.

Figure 24 2021 secure operating level of inertia requirement, South Australia [A, B]



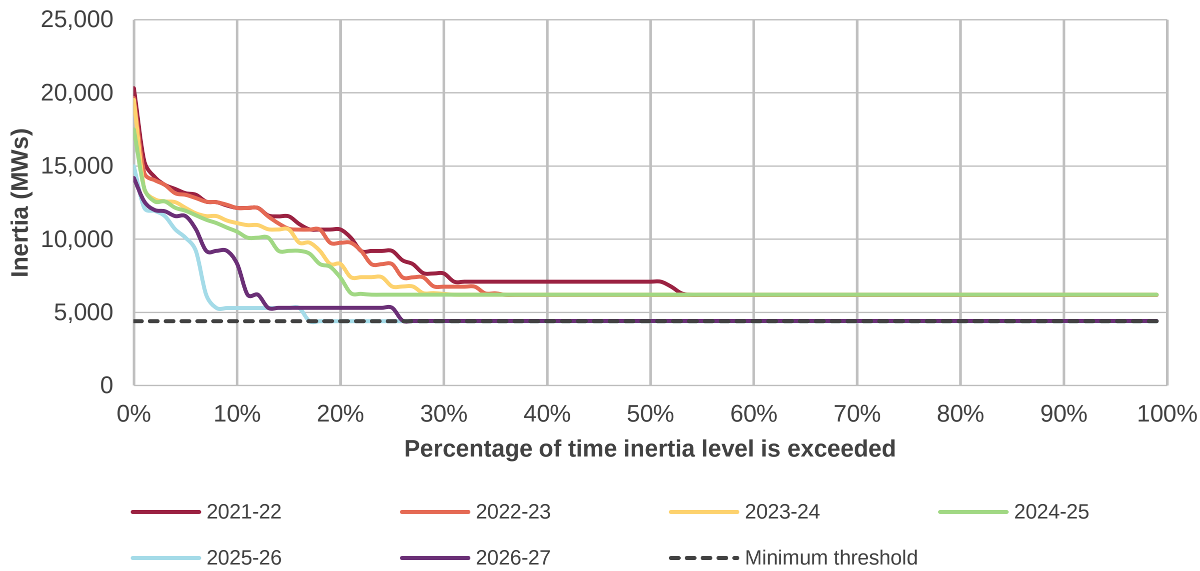
A. The figure represents the relationship between the level of inertia required against the amount of FFR required for each level of inertia.
B. Square data points show actual operating points which have been modelled and provide a secure system. A line is drawn between the operating points to broadly indicate where the system may be considered to be secure.

[55] August 2020 notice of change to South Australia inertia requirements and shortfall, and December 2020 System Strength and Inertia Report, both accessible via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[56] AEMO is continuing to assess ongoing power system requirements for South Australia, including the requirement to keep two synchronous generating units online. AEMO will be providing quarterly updates on this work plan in 2022.

Inertia projections (*Progressive Change*)						
	2021-22	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Available inertia for 99% of the time (MWs)	6,200	6,200	6,200	6,200	4,400	4,400

Figure 25 Projected inertia for the five-year outlook, *Progressive Change* scenario, South Australia [A]



A. Inertia projections are shown against the minimum threshold of inertia. The secure operating level of inertia is not shown as a single value because it is a function of available inertia and fast frequency response/inertia support activities.

5.4 2021 NSCAS assessment

AEMO declares an RSAS gap of 40 MVAr reactive power absorption in South Australia, applicable from when the requirements for a minimum combination of synchronous generating units to remain online in normal conditions is relaxed.

AEMO notes that ElectraNet has identified, in its 2021 TAPR, an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage steady-state voltage levels at times of low system demand.

AEMO also notes that ElectraNet and SA Power Networks (SAPN) have identified a need for larger reactive absorption than is identified in these NSCAS studies, as a result of investigating the interrelated challenges of controlling voltages across the distribution and transmission systems during low demand periods.

This RSAS gap of 40 MVAr reactive power absorption is made within the specific confines of the NSCAS assessment and does not negate or undercut the need for even greater reactive power absorption in South Australia in order to support voltage control across the transmission and distribution systems.

Context

AEMO assessed voltage control in South Australia over the five-year outlook period, including future committed transmission projects, committed generators, announced generator retirements and forecast change in demand. This 2021 NSCAS review incorporated changes identified through AEMO's review of planning assumptions for voltage control (more information is provided in Appendix A2).

Results

AEMO has identified an RSAS gap of 40 MVAr reactive power absorption near Blyth West that will apply when the current requirement for two synchronous generators to be online in South Australia) during normal operating conditions) is relaxed. This is because these two generating units provide the necessary reactive support to control voltages.

With no synchronous generation units in service in South Australia, during periods of low demand or low transfers between South Australia and Victoria, post-contingency high voltages are observed near Blyth West. 40 MVAr of reactive absorption is required to resolve these post-contingent high voltages. The optimal location and solution for addressing this identified gap is to be determined by the TNSP.

AEMO did not identify any NSCAS gaps for maximising market benefits in South Australia.

Table 8 notes the scenarios assessed and the results of the assessment.

Table 8 South Australia NSCAS outcomes for scenarios assessed

Time of day	Financial year ending	Demand (MW)	Project EnergyConnect status	Dispatch of synchronous units	Pre-contingent line switching assumption	NSCAS gap
Daytime	2022	Near Zero	-	2 Torrens Island B[A]	No line switching	No NSCAS gap identified
	2023	Near Zero	-	2 Torrens Island B	No line switching	No NSCAS gap identified
	2024	Near Zero	Project EnergyConnect stage 1 in service	2 Torrens Island B	No line switching	No NSCAS gap identified
	2025	Near Zero	Project EnergyConnect stage 1 and 2 in service	None	No line switching	NSCAS gap identified of approximately 40 MVAR reactive power absorption near Blyth West.
		Near Zero[B]	Project EnergyConnect stage 1 and 2 in service	None	Magill – East Terrace 275 kV cable	No NSCAS gap identified
	2026	Near Zero[B]	Project EnergyConnect stage 1 and 2 in service	None	No line switching	NSCAS gap identified of approximately 40 MVAR reactive power absorption near Blyth West.
		Near Zero[B]	Project EnergyConnect stage 1 and 2 in service	None	Magill – East Terrace 275 kV cable	No NSCAS gap identified
		-490 MW		None	No line switching	No NSCAS gap identified

A. Aligned with current operating advice[57], two synchronous units are assumed in service. These assumptions will be re-assessed as new information comes to light, and further studies undertaken. AEMO will release quarterly updates on this work plan in 2022.

B. Although demand in South Australia is projected to become negative, AEMO considers that high voltages will be more prevalent when the demand is closer to 0 MW. High voltage will also be challenging for demands up to approximately 300 MW if interconnector transmission lines are simultaneously lightly loaded, this will depend on in service generation at the time. 0 MW demand is expected to occur in South Australia twice a day during low demand periods, as the solar drives the demand downwards after sunrise and then again as demand picks up with evening peak and sunset which means the most challenging periods for managing voltages will occur more frequently.

Context for timing of NSCAS needs in South Australia

The 40 MVAr reactive power absorption RSAS gap declared in this report is contingent on the relaxation of the existing requirement for a minimum combination of synchronous generating units to remain online in normal conditions. The initial trigger date for this need has been set by applying the assumption that the need for two synchronous generators online in South Australia will remain until the commissioning of Project EnergyConnect. Should this requirement be removed earlier, the trigger date will be brought forward.

AEMO will investigate further and confirm the ongoing needs for secure operation of the South Australian power system with four operational synchronous condensers and provide quarterly updates during 2022. This will include consideration of the existing minimum synchronous generator unit assumptions. Depending on the outcomes of this work plan, AEMO may need to bring forward the NSCAS gap declared in this report, or may declare additional NSCAS gaps.

Next steps

AEMO declares an RSAS gap of 40 MVAr reactive power absorption in South Australia following the relaxation of requirements for a minimum combination of synchronous generating units to remain online in normal conditions.

[57] AEMO. *Transfer Limit Advice – System Strength in South Australia and Victoria*. October 2021. Available via https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

These NSCAS studies investigated voltage exceedances in the transmission network under contingency conditions. AEMO acknowledges that under low demand conditions voltage challenges may also exist in the distribution network which have a flow-on impact on the ability to adjust voltage control set points in the transmission network – these conditions are beyond the extent of what AEMO modelled in this NSCAS assessment. ElectraNet and SA Power Networks (SAPN) have identified a need for larger reactive absorption than identified in these NSCAS studies.

AEMO notes that ElectraNet has identified, in the 2021 TAPR[58], an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage steady-state voltage levels at times of low system demand. ElectraNet's proposed solution is to install a suite of 50-60 MVAr shunt reactors at various locations, expected to be in service in 2024.

AEMO declares an NSCAS trigger date[59] of 1 August 2024 with an indicative NSCAS tender date[60] of 1 February 2023. This trigger date has been set on the assumption that the need for two synchronous generators online in South Australia will remain until the commissioning of Project EnergyConnect. Should this requirement be removed earlier, or should there be changes to Project EnergyConnect delivery dates, the trigger date may need to be brought forward.

Consistent with NER 3.11.3, AEMO will request that ElectraNet advise when it will have arrangements in place to meet this NSCAS gap or provide reasons why this gap will not be met.

[58] ElectraNet Transmission Annual Planning Report 2021, available at https://www.electranet.com.au/wp-content/uploads/2021-ElectraNet-Transmission-Annual-Planning-Report.pdf.

[59] "NSCAS trigger date" is defined in clause 5.20.1 of the NER (version 173), to mean the date that the NSCAS gap first arises.

[60] "NSCAS tender date" is defined in clause 5.20.1 of the NER (version 173), to mean the indicative date that AEMO would need to act so as to call for offers to acquire NSCAS to meet that NSCAS gap by the relevant NSCAS trigger date in accordance with clause 3.11.3(c)(4) of the NER.

6 Tasmania

Previously declared shortfalls in system strength and inertia are being addressed through a services agreement between TasNetworks and Hydro Tasmania.

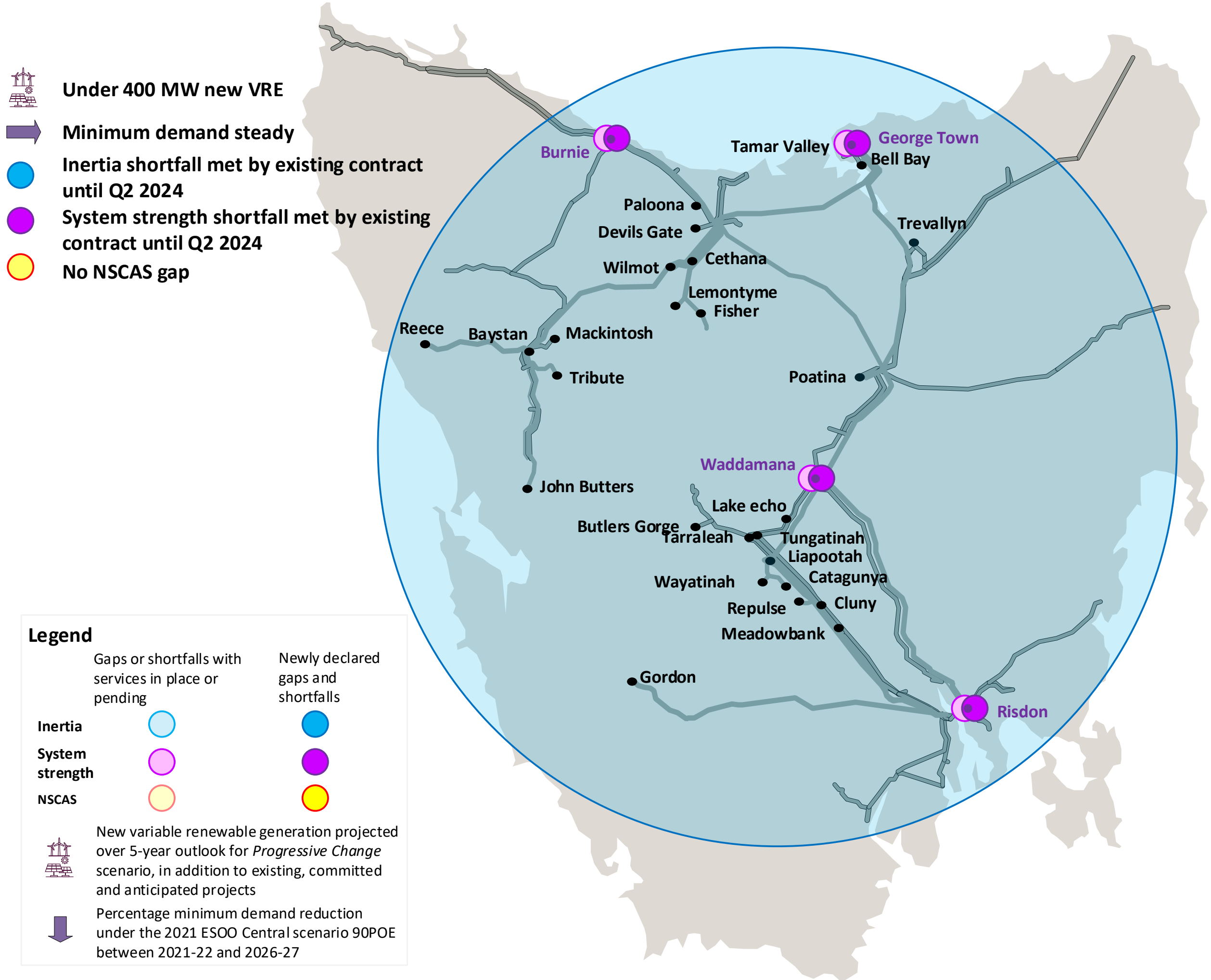
AEMO declares shortfalls for the period after this agreement ends in mid-April 2024, including increases to the shortfalls due to projections for generator dispatch under the *Progressive Change* scenario. TasNetworks will seek expressions of interest from the market in the first half of 2022 to identify new or intending system security service providers in Tasmania.

Under the *Step Change* scenario, AEMO does not project the withdrawal of any additional synchronous units in Tasmania over the five-year outlook period. However, under the *Step Change* scenario, AEMO projects increased VRE in Tasmania. AEMO will investigate the outcomes of this further early in 2022.

In this section:

- A map of the system security five-year outlook (Figure 26).
- Supply and demand outlook (Section 6.1).
- Assessment of system strength requirements and shortfalls (Section 6.2).
- Assessment of inertia requirements and shortfalls (Section 6.3).
- Assessment of NSCAS needs (Section 6.4).

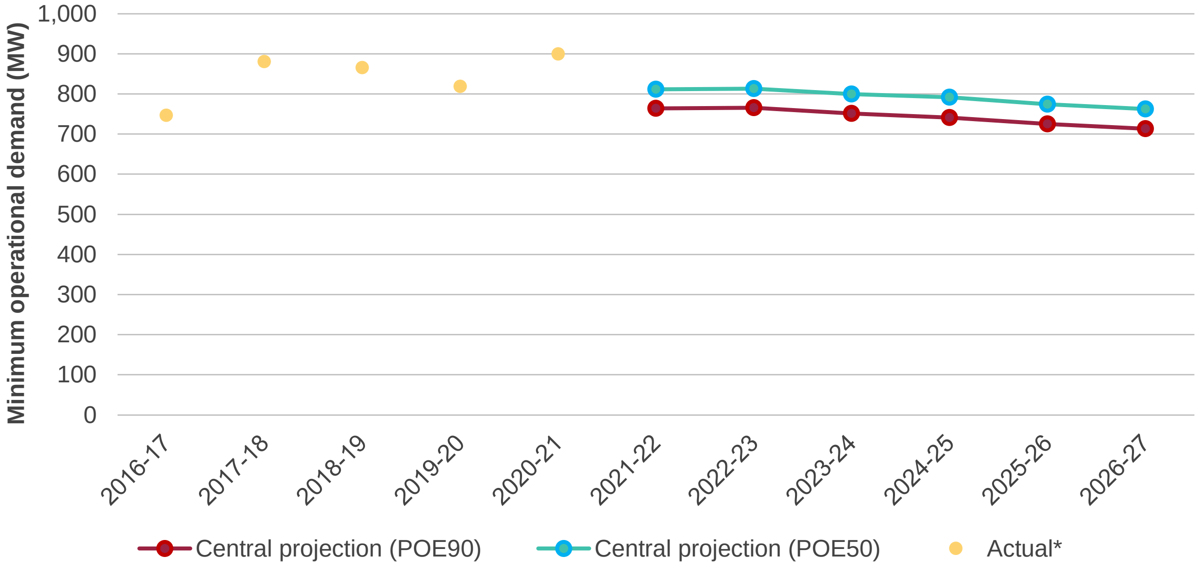
Figure 26 System security five-year outlook for Tasmania



6.1 Supply and demand outlook

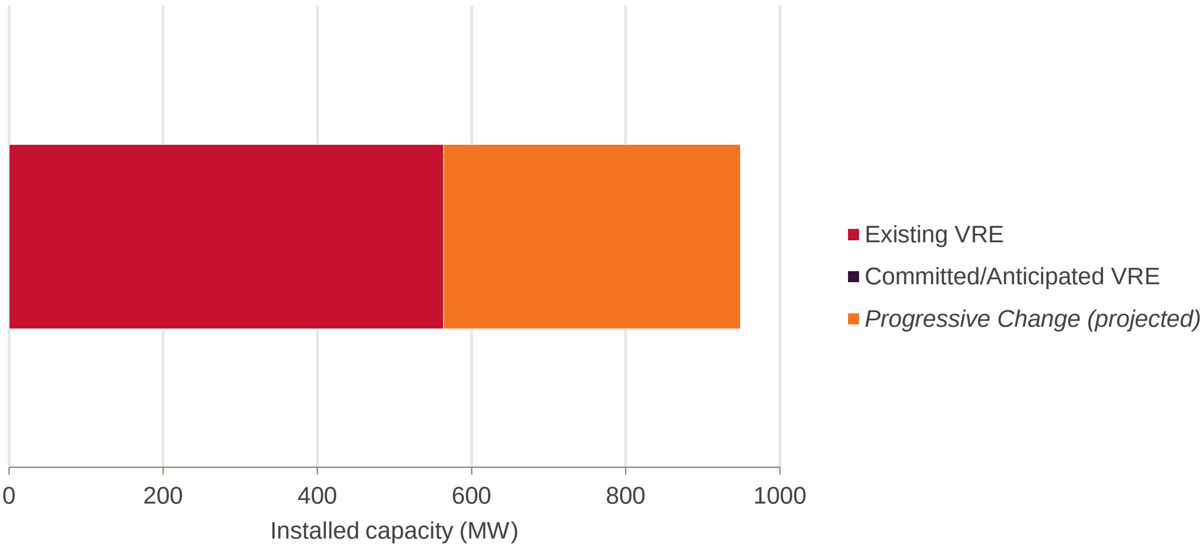
Minimum operational demand (sent-out[61]) in Tasmania is forecast to decrease by approximately 50 MW between 2021-22 and 2026-27 in the 2021 ESOO Central scenario, as seen in Figure 27.

Figure 27 Actual minimum demand and 2021 ESOO forecast 90POE and 50POE shoulder minimum operational demand (sent-out) for Tasmania (Central scenario)



VRE generation modelled in Tasmania for the system strength and inertia projections is shown in Figure 28. Tasmania has approximately 560 MW of existing VRE generation projects, as well as just under 400 MW of new VRE generation projected over the five-year outlook period for the *Progressive Change* scenario.

Figure 28 Tasmania existing, committed and anticipated VRE generation projects and the *Progressive Change* projected VRE projects out to 2026-27



[61] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

6.2 2021 System strength assessment

6.2.1 Requirements

AEMO is not changing the system strength requirements in Tasmania for now, but will reassess in 2022. Table 9 provides the requirements.

Table 9 Tasmania system strength requirements

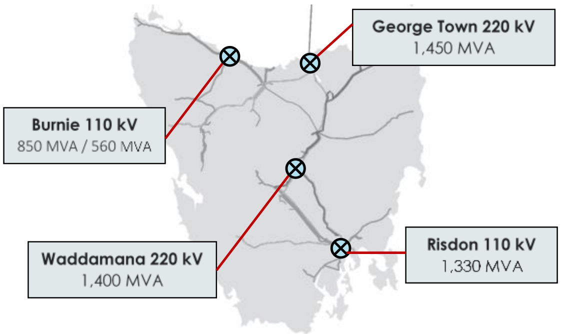
Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A,B]
		Pre-contingency	Post-contingency	
Burnie 110 kV	Remote from synchronous generation	850	560	Per December 2020 declaration.
George Town 110 kV	High IBR	1,450	-	Per December 2020 declaration.
Risdon 110 kV	Metropolitan load centre	1,330	-	Per December 2020 declaration.
Waddamana 220 kV	Synchronous generation centre	1,400	-	Per December 2020 declaration.

A. 2020 System Strength and Inertia Report, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

B. AEMO and TasNetworks use the pre-contingency values to inform the operational arrangements for system strength requirements in Tasmania. System strength outcomes in Tasmania are assessed against their pre-contingent levels due to specific local requirements including maintaining Basslink requirements, switching requirements for local reactive plant, and some power quality requirements for metropolitan load centres.

6.2.2 Outcomes

Tasmania



TasNetworks has addressed the system strength and inertia shortfalls declared in May 2021[62].

AEMO declares shortfalls for the period after this agreement ends in mid-April 2024, including increases to the shortfalls due to projections for generator dispatch under the *Progressive Change* scenario.

TasNetworks is intending to conduct an expressions of interest process in the first half of 2022 to test the market for new or intending providers of system security services in Tasmania.

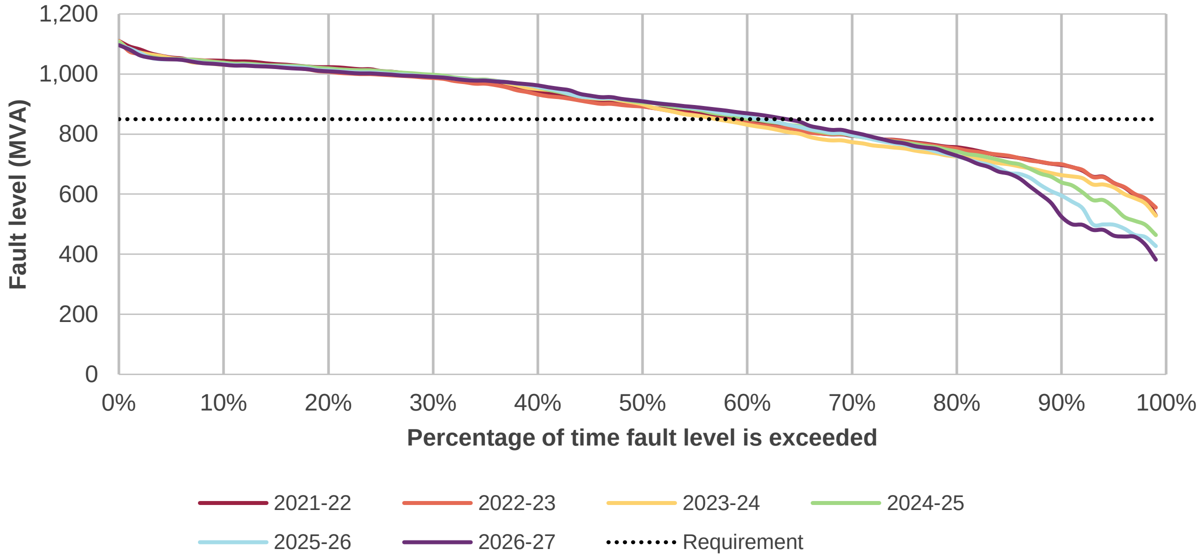
Projections (*Progressive Change*) and shortfalls

Node	Projected minimum three phase fault level for 99% of the time						Shortfalls and comments A, B, C
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	
Burnie 110 kV	529	556	528	464 (386 MVA shortfall)	427 (423 MVA shortfall)	382 (468 MVA shortfall)	A shortfall range of 386 to 468 MVA is declared for 15 April 2024 to 31 December 2026.
George Town 220 kV	828	906	817	700 (750 MVA shortfall)	621 (829 MVA shortfall)	531 (919 MVA shortfall)	A shortfall range of 750 to 919 MVA is declared for 15 April 2024 to 31 December 2026.
Risdon 110 kV	1,020	1,020	988	825 (505 MVA shortfall)	698 (623 MVA shortfall)	674 (656 MVA shortfall)	A shortfall range of 505 to 656 MVA is declared for 15 April 2024 to 31 December 2026.
Waddamana 220 kV	1,081	1,096	1,046	881 (519 MVA shortfall)	767 (633 MVA shortfall)	672 (728 MVA shortfall)	A shortfall range of 519 to 728 MVA is declared for 15 April 2024 to 31 December 2026.

A. The system strength outcomes for Tasmania are assessed on a pre-contingent basis due to specific local requirements including maintaining Basslink requirements, switching requirements for local reactive plant, and some power quality requirements for metropolitan load centres.
B. AEMO has confirmed to TasNetworks that the amendments to its services agreement with Hydro Tasmania address the system strength and inertia shortfalls declared in May 2021.
C. AEMO will request that TasNetworks provide system strength services to address the shortfall by 15 April 2024.

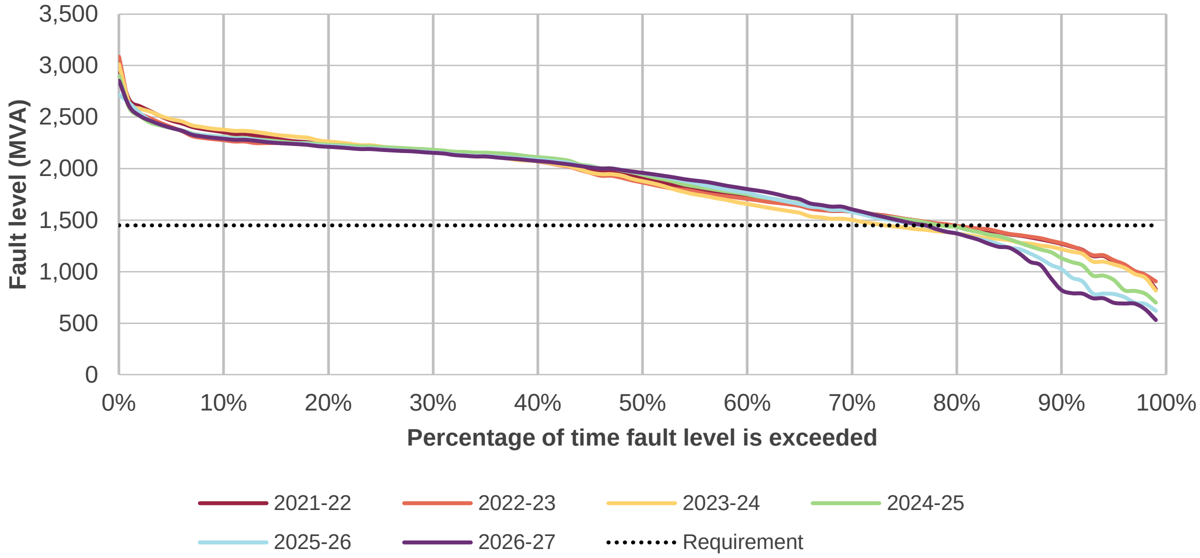
[62] AEMO, 2021 Notice of Tasmania system strength and inertia shortfall, May 2021, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

Burnie 110 kV



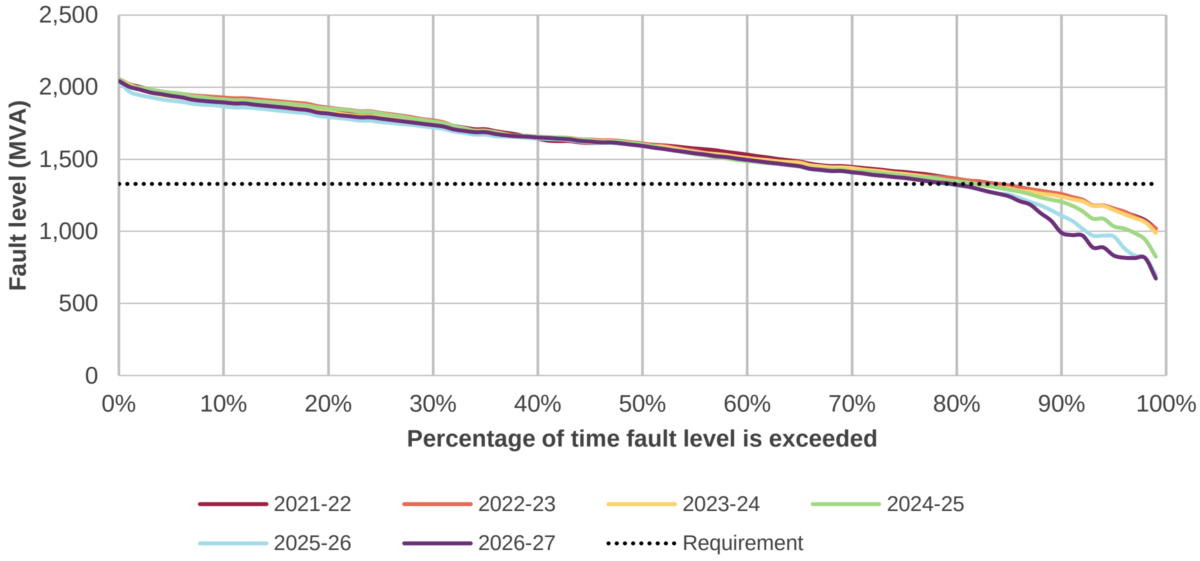
*Does not include the system strength contributions from the existing agreement to address the 2019 and 2021 declared system strength shortfalls.

George Town 220 kV



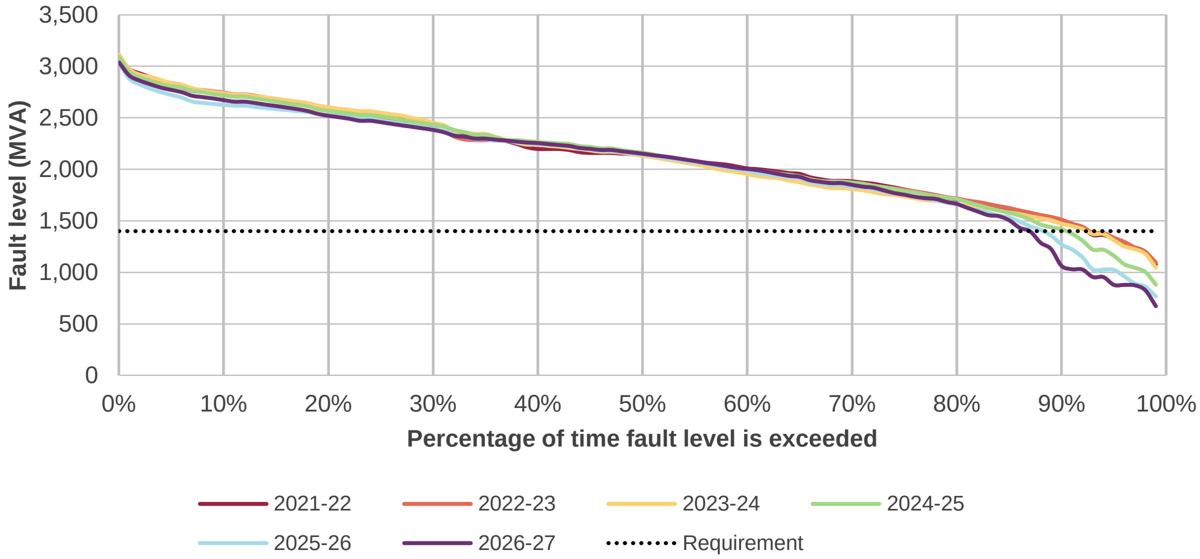
*Does not include the system strength contributions from the existing agreement to address the 2019 and 2021 declared system strength shortfalls.

Risdon 110 kV



*Does not include the system strength contributions from the existing agreement to address the 2019 and 2021 declared system strength shortfalls.

Waddamana 220 kV



*Does not include the system strength contributions from the existing agreement to address the 2019 and 2021 declared system strength shortfalls.

6.3 2021 Inertia assessment

Tasmania

TasNetworks has amended its agreement with Hydro Tasmania to address the system strength and inertia shortfalls declared in May 2021[63]. AEMO declares a shortfall range of 2,163 to 2,714 MWs against the secure operating level of inertia, for the period after this agreement ends in mid-April 2024. This includes increases due to projections for generator dispatch under the *Progressive Change* scenario.

TasNetworks is intending to conduct an expressions of interest process in the first half of 2022 to test the market for new or intending providers of system security services in Tasmania.

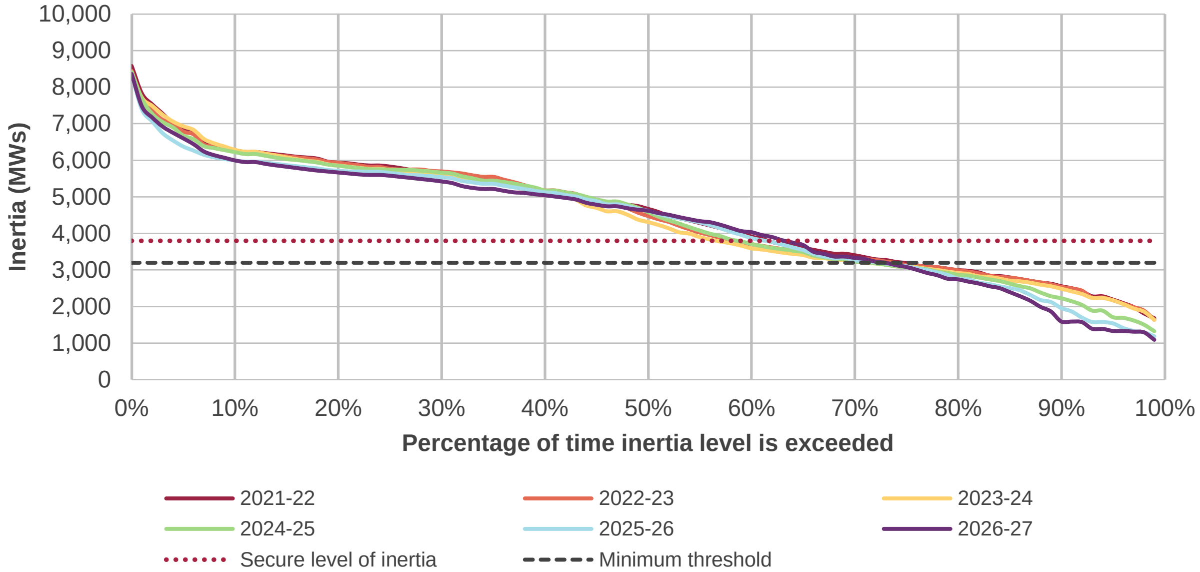
Inertia requirements

	2020	2021	
Secure operating level of inertia (MWs)	3,800	3,800	The secure operating level and minimum operating level of inertia for Tasmania are held steady at the values determined in November 2019. AEMO has confirmed to TasNetworks that its services agreement with HydroTas closes the previous inertia shortfall until the agreement ends in mid-April 2024. In effect, Tasmania is always operated as an island with respect to inertia because its interconnector to the NEM (Basslink) is a DC connection and does not transport synchronous inertia (although it does provide frequency control).
Minimum threshold level of inertia (MWs)	3,200	3,200	
Contracted inertia (MWs)	-	2,620	
Risk of islanding	Likely	Likely	

[63] AEMO. *2021 Notice of Tasmania system strength and inertia shortfall*. May 2021. Available via https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

Inertia projections (*Progressive Change*)						
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Available inertia 99% of the time (MWs)	1,679	1,637	1,637	1,327	1,180	1,086
Inertia shortfall against secure operating level (MWs)	Contracted	Contracted	2,163	2,473	2,620	2,714

Figure 29 Projected inertia for the five-year outlook, *Progressive Change* scenario, Tasmania



*Does not include the inertia contributions from the existing agreement to address the 2019 and 2021 declared system strength shortfalls.

6.4 2021 NSCAS assessment

AEMO has not identified any NSCAS gap in Tasmania over the five-year period, provided requirements for contracting of system strength and inertia services continue.

Tasmania has limited forecast change in minimum demand and few committed power system changes in the five-year outlook period. In addition, TasNetworks have put an agreement in place to meet the system strength and inertia shortfalls declared in May 2021. That agreement will ensure a minimum number of synchronous units in service at times when system strength or inertia issues are expected to arise – that is, for low demand periods – which will also provide voltage support on the network.

AEMO has not identified an RSAS or MBAS NSCAS gap in Tasmania over the five-year outlook period.

AEMO will re-assess Tasmania NSCAS needs once the Tasmania system strength and inertia services are known for the period after the current agreement is due to end in mid-April 2024.

7 Victoria

Under the *Progressive Change* scenario, AEMO projects declining synchronous generation online in Victoria but no system security shortfalls are declared under this assessment. Inertia in Victoria is expected to decline below the minimum threshold level and the secure operating level throughout the coming five-year outlook period. However, as islanding of Victoria from the remainder of the NEM is not considered likely, no shortfall is able to be declared under the current framework. The Red Cliffs system strength shortfall has now been closed.

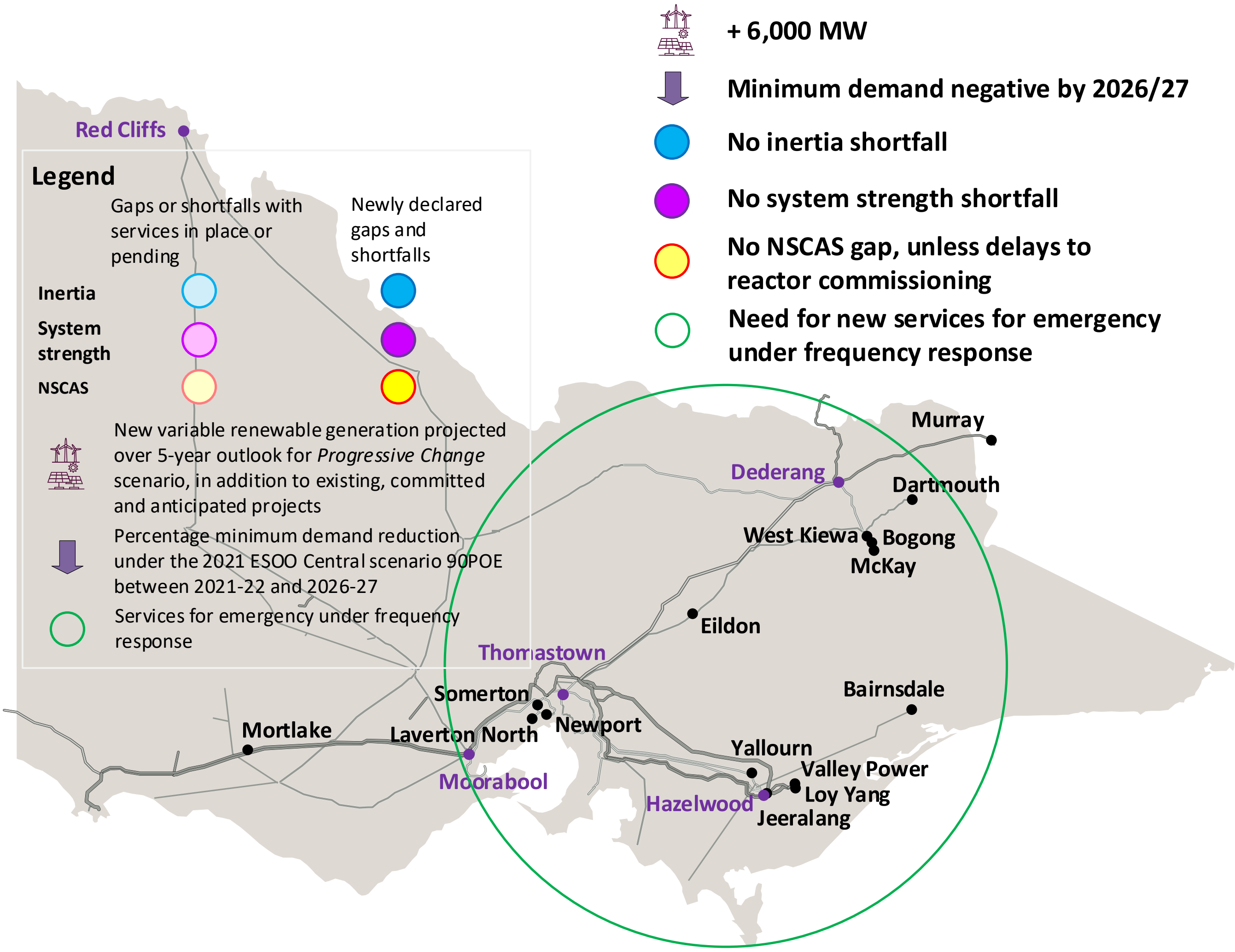
Additional shortfalls may be declared in 2022 if market or network conditions change, and AEMO notes that an NSCAS voltage control gap may emerge if there are delays to commissioning of new reactors currently planned for operation by mid-2022.

Under the *Step Change* scenario, two additional Latrobe valley coal units are projected to retire by 2026-27 compared to the *Progressive Change* scenario. AEMO will consider the *Step Change* scenario early in 2022.

In this section:

- A map of the system security five-year outlook (Figure 30).
- Supply and demand outlook (Section 7.1).
- Assessment of system strength requirements and shortfalls (Section 7.2).
- Assessment of inertia requirements and shortfalls (Section 7.3).
- Assessment of NSCAS needs (Section 7.4).

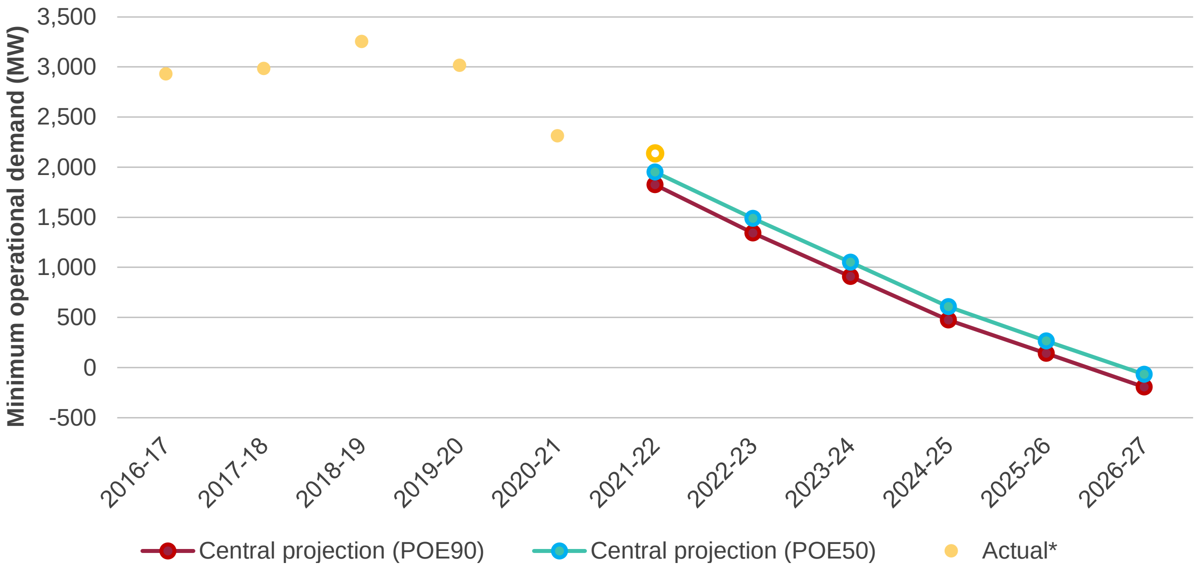
Figure 30 System security five-year outlook for Victoria



7.1 Supply and demand outlook

Minimum operational demand (sent-out[64]) in Victoria is forecast to become negative by 2026-27. This is a reduction of approximately 2,000 MW by 2026-27 when compared to 2021-22 in the 2021 ESOO Central scenario, as seen in Figure 31.

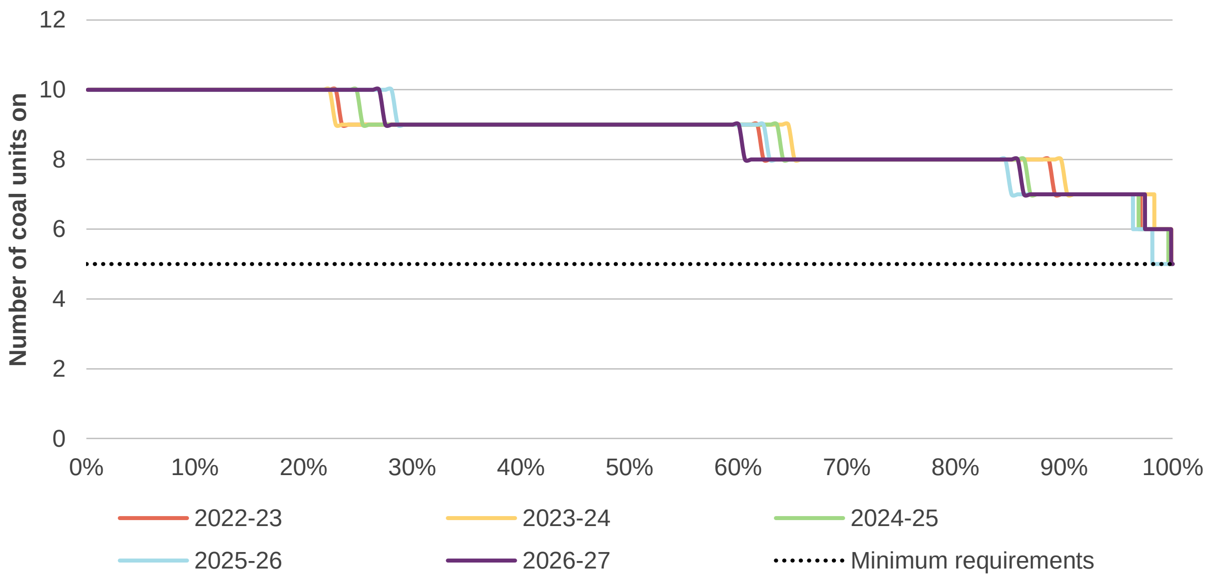
Figure 31 Actual minimum demand and 2021 ESOO forecast 90POE and 50POE summer minimum operational demand (sent-out) for Victoria (Central scenario)



* Record minimum demand occurred 28 November 2021 (2,136 MW sent-out), included as an outlined circle in this figure for illustrative purposes only as the year is still incomplete.

The number of coal generators projected to be online in Victoria across the year is not forecast to fall below current minimum combinations for more than 1% of the time for the five-year outlook period, as shown in Figure 32.

Figure 32 Number of coal units projected online under *Progressive Change* scenario, Victoria [A]

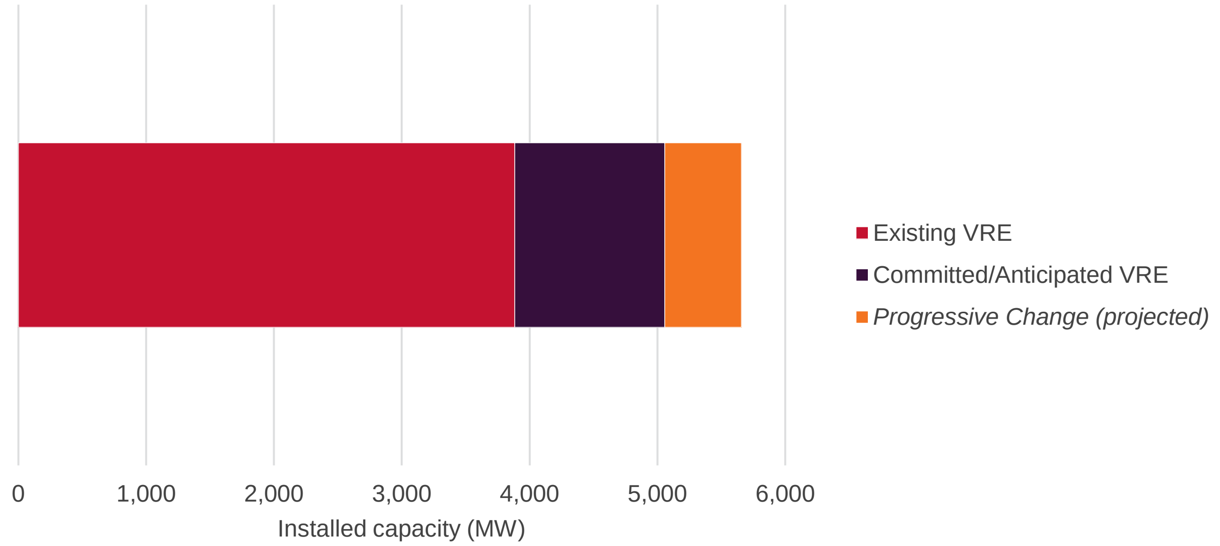


A. See Appendix A3 for further details about the minimum requirements.

[64] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

VRE generation modelled in Victoria for the system strength and inertia projections is shown in Figure 33. Victoria has just under 5,200 MW of existing, committed and anticipated VRE generation projects, as well as just over 600 MW of new VRE generation projected over the five-year outlook period for the *Progressive Change* scenario.

Figure 33 Victoria existing, committed and anticipated VRE generation projects and the *Progressive Change* projected VRE projects out to 2026-7



AEMO is working with Victorian network service providers to ensure sufficient emergency response measures are available in Victoria given ongoing decline in minimum demand. Given declining minimum demand in the state, the capability of the Victorian under-frequency load shedding (UFLS) scheme is under review[65].

[65] AEMO. *Phase 1 UFLS Review: Victoria.* August 2021. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

7.2 2021 System strength assessment

7.2.1 Requirements

AEMO updates the minimum fault level requirement at the Red Cliffs fault level node, and the system strength shortfall has now been met until the introduction of Project EnergyConnect

In August 2020, AEMO assessed the post-contingency minimum fault level requirement at the Red Cliffs fault level node as 1,000 MVA, subject to operating conditions. In its role as system strength service provider for the Victorian region, AEMO secured sufficient services from facilities in the West Murray area to meet the assessed Red Cliffs fault level requirement effective until 31 July 2022[66].

AEMO has now re-assessed the requirement for the period between 31 July 2022 and the commissioning of Project EnergyConnect. In its role as system strength service provider, AEMO has also completed an expressions of interest and tendering process and has secured services to meet the requirement and address the shortfall for that period.

The updated minimum pre-contingency requirement for Red Cliffs is 1,786 MVA and the post-contingency requirement is 1,036 MVA[67]. These requirements reflect changes to the power system, including the impact of synchronous condensers[68], and the impact of the secured services. Different requirements have also been derived for times when some generators are not online, and the system limits applied by the AEMO control room will need to accommodate these various operating conditions.

[66] AEMO. *Notice of change to system strength requirement and shortfall at Red Cliffs.* August 2020. Available via https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en.

[67] This assessment has been provided consistent with the declaration made in 2019 which included a success criterion of sub-synchronous voltage oscillations below 0.3% peak-to-peak at 8-10Hz, to fall within the flicker standard requirements. AEMO expects that over time this success criterion can be lowered across the NEM as inverter technology, experience and confidence in models improves.

[68] The updated requirements include the impact of all synchronous condensers in the relevant area, both those engaged for provision of system strength services, as well as others associated only with system strength remediation schemes for individual solar farms. A lower requirement may be applied under certain operating conditions, for example depending on the number of generating projects operating in the area.

Victoria requirements are held steady for now, except for the Red Cliffs update

Apart from the update to the requirements for the Red Cliffs fault level node, AEMO is not changing the remaining Victorian system strength requirements for now, but will reassess in 2022. Table 10 provides the requirements.

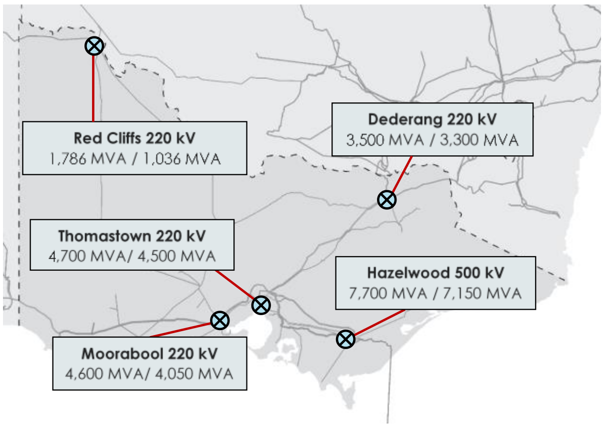
Table 10 Victoria system strength requirements

Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Dederang 220 kV	Remote from synchronous generation	3,500	3,300	Per December 2020 declaration.
Hazelwood 500 kV	Synchronous generation centre; close to Basslink DC link	7,700	7,150	Per December 2020 declaration.
Moorabool 220 kV	High IBR	4,600	4,050	Per December 2020 declaration.
Thomastown 220 kV	Metropolitan load centre	4,700	4,500	Per December 2020 declaration.
Red Cliffs 220 kV	High IBR; Remote from synchronous generation	1,786	1,036	Updated in this report based on 2021 studies to include the impact of synchronous condensers in the Red Cliffs area, both those engaged for system strength services, as well as others associated only with system strength remediation schemes for individual solar farms. This new requirement applies from 31 July 2022 onwards, with the December 2020 declaration to apply before that date. The requirements applied in the control room may vary depending on operating conditions, for times when some generators are not online.

A. 2020 System Strength and Inertia Report, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

7.2.2 Outcomes

Victoria



The existing system strength shortfall at Red Cliffs has now been closed, and no further system strength shortfalls are declared in Victoria.

Although the Victoria fault level nodes see projected reductions in fault level under the *Progressive Change* scenario, none are below the minimum requirements.

The system strength shortfall identified at Red Cliffs for the period after 31 July 2022 has been met by AEMO (as the Victorian system strength service provider) procuring services in the local area until the anticipated commissioning of Project Energy Connect.

The Victorian region analysis includes the planning assumption of the prior outage of a Hazelwood – South Morang 500kV line during low loading conditions for voltage control. Usually, this coincides with a lower number of synchronous generators online, and as such is considered to be a realistic operating condition.

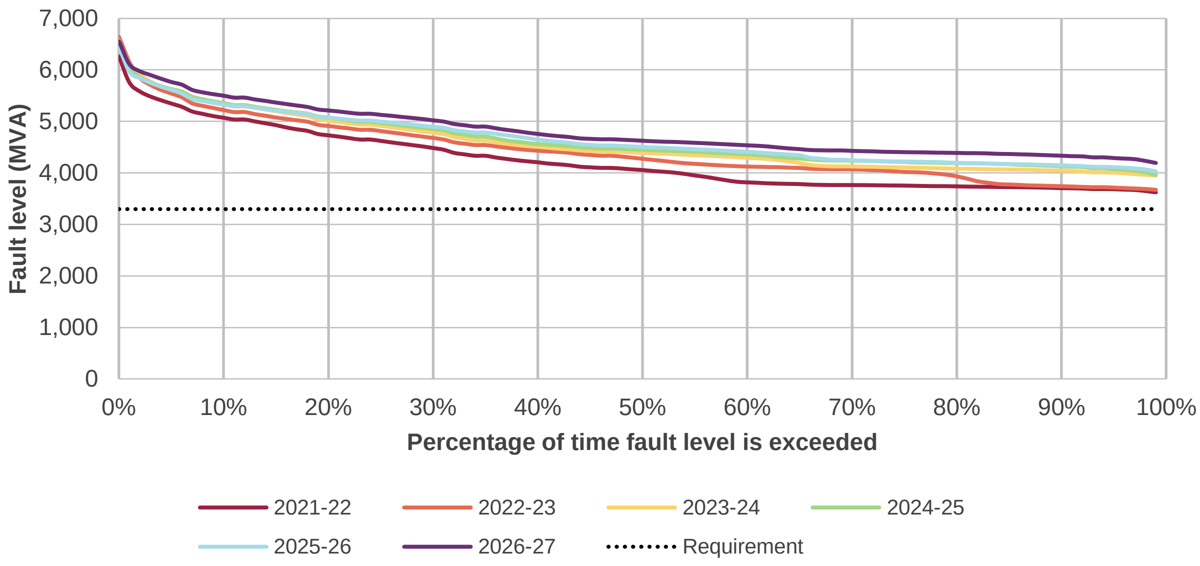
Analysis is continuing for the Thomastown node.

Projections (*Progressive Change*) and shortfalls

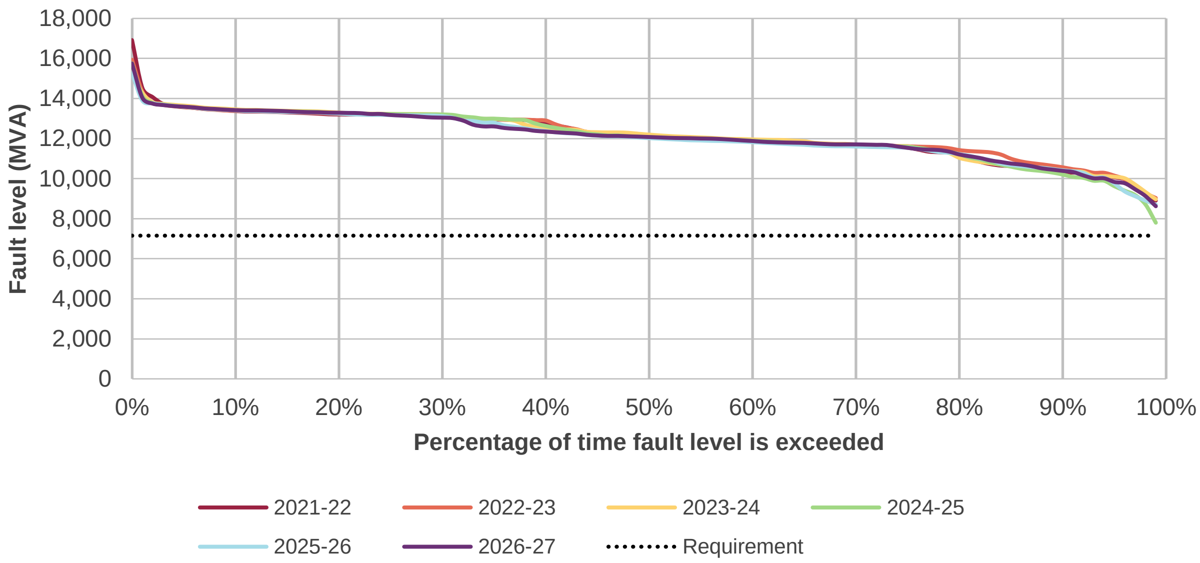
Node	**Projected minimum three phase fault level for 99% of the time**						**Shortfalls and comments** [A]
	2021-22	**2022-23**	**20223-24**	**2024-25**	**2025-26**	**2026-27**	
Dederang 220 kV	3,625	3,671	3,948	3,960	4,030	4,194	No shortfall
Hazelwood 500 kV	8,905	9,025	8,964	7,800	8,706	8,615	No shortfall
Moorabool 220 kV	4,499	4,593	4,591	4,379	4,460	4,670	No shortfall
Thomastown 220 kV	AEMO is undertaking detailed investigations for the Thomastown node and will provide an update in 2022.						
Red Cliffs 220 kV	1,042	1,043	1,045	1,592	1,989	2,070	No shortfall

A. The system strength outcomes for Victoria are assessed on a post-contingent basis.

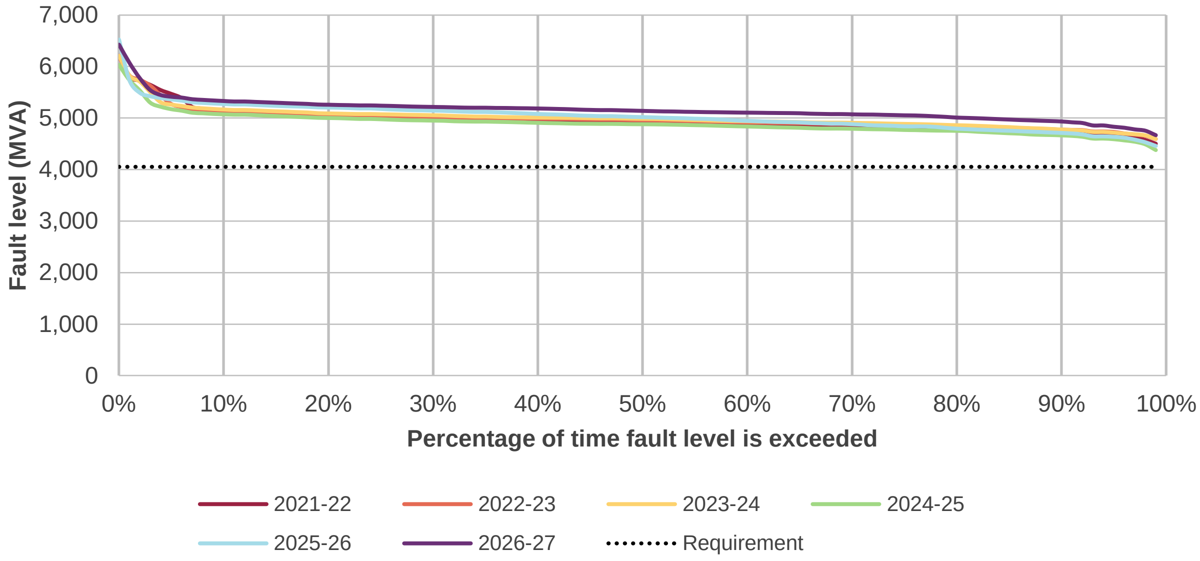
Dederang 220 kV



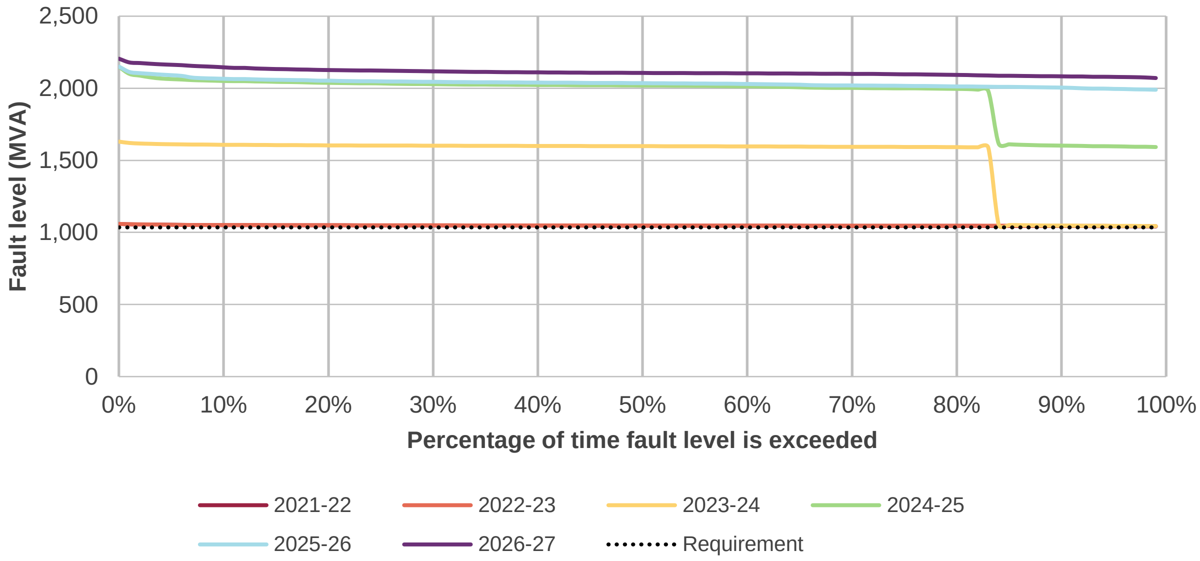
Hazelwood 500 kV



Moorabool 220 kV



Red Cliffs 220 kV



* Increasing fault level projections at Red Cliffs coincide with Project EnergyConnect stage 1 and stage 2 network augmentations.

7.3 2021 Inertia assessment

Victoria

Under the *Progressive Change* scenario, AEMO projects that inertia in Victoria will decline below the minimum threshold level and the secure operating level throughout the coming five-year outlook period. However, as Victoria islanding from the remainder of the NEM is not considered likely, no shortfall is able to be declared under the current framework.

Future decommitment of large synchronous generators during low demand periods may cause a reduction in online inertia in the Victoria region.

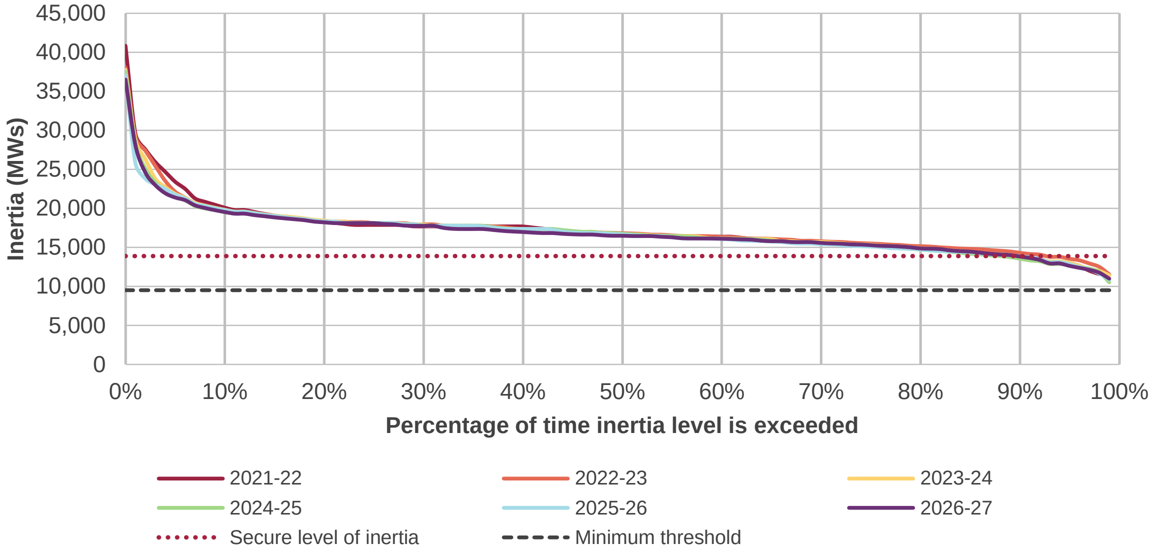
Inertia requirements

	2020	2021	
Secure operating level of inertia (MWs)	13,900	13,900	The secure operating level and minimum operating level of inertia for Victoria are held steady at the values determined in December 2020. These have been calculated including fast frequency response capability provided by the Victorian Big Battery.
Minimum operating level of inertia (MWs)	9,500	9,500	Declaration of any inertia shortfall for a region must also consider the likelihood of islanding. Islanding of Victoria alone remains unlikely, consistent with AEMO's 2020 and 2018 assessments. This finding is largely driven by the diversity and number of AC interconnectors that exist between Victoria and the adjacent regions.
Net distributed PV Trip (MW)	-	-	
Risk of Islanding	Not Likely	Not Likely	Net distributed PV trip has not been incorporated in this assessment, and the secure operating level is not provided as a ratio of synchronous inertia and fast frequency response or Fast FCAS, because islanding is not considered likely and so a shortfall will not be declared.

Inertia projections (*Progressive Change*)

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Available inertia for 99% of the time (MWs)	11,468	11,548	11,416	10,511	10,860	10,993

Figure 34 Projected inertia for the five-year outlook, *Progressive Change* scenario, Victoria



7.4 2021 NSCAS assessment

AEMO did not identify any NSCAS gap in Victoria, assuming pre-contingent switching of the Hazelwood – South Morang 500 kV transmission line for voltage control.

Context

AEMO assessed voltage control in Victoria over the five-year outlook period, including future committed transmission projects, committed generators, announced generator retirements, and forecast change in demand. This 2021 NSCAS review incorporated changes identified through AEMO's review of planning assumptions for voltage control (more information is provided in Appendix A2). In addition, the minimum synchronous machine requirement associated with the system strength requirements is adhered to for these studies[69].

Results

Despite the rapid decline of Victorian minimum demand over next five years, AEMO did not identify any NSCAS gap provided pre-contingent switching of the Hazelwood – South Morang 500 kV transmission line occurs. This assumes the 3 new 100 MVAr reactors, as part of Victorian Reactive Power Support RIT-T[70] , are in service by mid-2022.

If any of the new 100 MVAr reactors are delayed, this could lead to NSCAS gaps arising as minimum demand continues to decline in spring 2022 and beyond. If delays to the commissioning of any reactors are identified in advance, analysis should be performed to determine if additional services need to be procured until the reactors are commissioned.

This assessment includes the pre-contingent line switching of the Hazelwood – South Morang 500 kV line, taking into account advice provided by AEMO Victoria Planning, noting:

- This 500 kV network was designed to transfer power from the historical configuration of power stations in the Latrobe Valley to the Melbourne load centre.
- Victoria Planning have advised that it is reasonable for planning purposes to make this assumption[71], and that adequate procedures are in place for AEMO's control room to implement this action.

Table 11 notes the scenarios assessed and the results of the assessment.

[69] Only five synchronous generators with least absorbing reactive capabilities at Latrobe Valley were switched in the low demand studies.

[70] Victorian Reactive Power Support RIT-T, available at https://aemo.com.au/initiatives/major-programs/victorian-reactive-power-support-regulatory-investment-test-for-transmission.

[71] AEMO. Notice of NSCAS Planning Assumption – Line Switching, Victoria. December 2021. Accessible via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

Table 11 Victoria NSCAS outcomes for scenarios assessed[72]

Time of day	Financial year ending	Demand (MW)	Inter-connector flows	Pre-contingent line switching assumption	NSCAS gap
Daytime	2026	220 MW	• High transfer from Victoria to Tasmania • Low transfer from Victoria to South Australia • High transfer from Victoria to New South Wales	Hazelwood – South Morang 500 kV transmission line	No NSCAS gap identified
	2026	180 MW	• High transfer from Victoria to Tasmania • Low transfer from Victoria to South Australia • Medium transfer from Victoria to New South Wales	Hazelwood – South Morang 500 kV transmission line	No NSCAS gap identified
Overnight	2026	3,280	• Low transfer from Tasmania to Victoria • Low transfer from South Australia to Victoria • High transfer from New South Wales to Victoria	Hazelwood – South Morang 500 kV transmission line	No NSCAS gap identified.
	2026	3,260	• High transfer from Tasmania to Victoria • High transfer from South Australia to Victoria • Low transfer from New South Wales to Victoria	None required	No NSCAS gap identified.

AEMO did not identify any NSCAS gaps for maximising market benefits in New South Wales.

Next steps

AEMO has not declared an NSCAS gap and so no NSCAS-related next steps are proposed. As noted above, further assessment may be needed if there are delays to the commissioning of any of the new reactors in 2022.

[72] For completeness, AEMO has considered the NSCAS assessment for Victoria without line switching. Since the TNSP, Victoria Planning, has advise that switching one 500 kV line in Victoria between Hazelwood and South Morang can be used to manage voltages during low loading conditions, AEMO has not presented the results here.

8 Next steps

AEMO has identified a number of system security shortfalls and gaps within the five-year outlook period as a result of the 2021 assessments. Table 12 summarises the requests to TNSPs to deliver services to provide system strength, inertia and NSCAS services.

If you wish to provide any comments or ask any questions about this report, please contact AEMO via planning@aemo.com.au.

AEMO and the TNSPs will undertake joint planning in 2022 and beyond to ensure that essential power system needs are met as the Australian energy transformation continues at pace.

Table 12 Services to be requested from TNSPs for system security shortfall and gap declarations

Region	Requests for system strength, inertia or NSCAS services
New South Wales	• AEMO will request that Transgrid make system strength services available to address a shortfall at Newcastle of 1,448 MVA, from 1 July 2026 until at least 31 December 2026. • AEMO will request that Transgrid make system strength services available to address a shortfall at Sydney West of 865 MVA, from 1 July 2026 until at least 31 December 2026. • AEMO has declared an immediate RSAS gap of 2 MVAr reactive power absorption in the Coleambally region. AEMO will continue to receive updates from TransGrid on the resolution of this matter.
Queensland	• AEMO will request that Powerlink make system strength services available to address a shortfall at Gin Gin, ranging from 44 to 65 MVA, from 31 January 2023 until at least 31 December 2026. • AEMO will request that Powerlink make inertia network activities (or inertia support services) available to address an inertia shortfall in Queensland, against the secure operating level, ranging from 186 to 5,831 MWs. AEMO will request that the activities (or services) be made available from 31 January 2023 until at least 31 December 2026. • AEMO will request that Powerlink advise when it will have arrangements in place to meet an immediate declared RSAS gap of 120 MVAr reactive power absorption in southern Queensland, increasing in size to 250 MVAr by 2026.
South Australia	• AEMO will request that ElectraNet make inertia network activities (or inertia support activities) available to address an inertia shortfall in South Australia, against the secure operating level, of approximately 28,800 MWs (or equivalent inertia support activities of 360 MW). AEMO will request that the activities (or services) be made available from 1 July 2023 until 31 July 2025 when inter-network testing of Project EnergyConnect is assumed to be complete. This request is in addition to the existing inertia shortfall declared in August 2020, the end date for which is now amended to be 30 June 2023. • AEMO will request that ElectraNet advise when it will have arrangements in place to meet an RSAS gap of 40 MVAr reactive power absorption in South Australia, contingent on removal requirements for a minimum combination of synchronous generating units to remain online in normal conditions.
Tasmania	• AEMO will request that TasNetworks make system strength services available to address a shortfall at all fault level nodes, in accordance with the ranges listed in Section 6.2.2, from 15 April 2024 until at least 31 December 2026. • AEMO will request that TasNetworks make inertia network activities (or inertia support activities) available to address an inertia shortfall in Tasmania, against the secure operating level, of a range between 2,163 to 2,714 MWs. AEMO will request that the activities (or services) be made available from 15 April 2024 until at least 31 December 2026.
Victoria	Nil

A1. Generator, network and market modelling assumptions

This appendix provides the assumptions used in this report relating to generators, transmission network augmentations, and market modelling for generator dispatch.

A1.1 Generator assumptions

Committed generation projects

The system strength and inertia projections, and the NSCAS assessment, consider existing generators already in service as well as any committed and committed* scheduled and semi scheduled generation projects from the July 2021 NEM Generation Information[73].

The system strength and inertia projections also consider anticipated projects captured in the July 2021 NEM Generation Information, as well any new generation projected to be built under the market modelling results for the *Progressive Change* scenario prepared for the Draft 2022 ISP[74].

During the NSCAS review, in October 2021, AEMO's NEM Generation Information page was updated. From the October update, only newly-committed or committed* generator projects that were considered likely to impact the outcome of the NSCAS assessment were added to the assessment.

Generation withdrawal and operation

The system strength and inertia projections in this report are aligned with the generator withdrawals and operation in the *Progressive Change* scenario in the Draft 2022 ISP[75].

The NSCAS assessments in this report are consistent with the announced generator retirements and generator end of technical life information provided on the AEMO NEM Generation Information webpage[76].

[73] AEMO. The July 2021 NEM Generation Information is available under the Archive section of AEMO's Generation information webpage. Available via https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Criteria for committed and committed* are explained in the Background Information tab of the spreadsheet.

[74] AEMO. Draft 2022 ISP. December 2021. Available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[75] Information on projected generator withdrawals and operation is available from the Draft 2022 ISP, available via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[76] AEMO. The expected generator closure spreadsheet is in the expected closure years section of the Generation Information webpage. Updated October 2021. Available via https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

A1.2 Transmission network augmentations

Table 13 provides the details and modelling date for the large committed and anticipated[77] transmission network augmentation projects included in the NSCAS assessments, and the system strength and inertia projections in this report[78]. Future transmission network augmentations are not included in the minimum system strength and inertia requirements. These projects are modelled consistent with the latest information provided by TNSPs.

Table 13 Large transmission network upgrades included in each assessment

	Augmentation detail	Modelling date (Calendar year)	Included in assessment
South Australia system strength remediation	The South Australia system strength remediation project includes the installation of two high inertia synchronous condensers at Davenport 275 kV substation and two high inertia synchronous condensers at Robertstown 275 kV substation. Each of the four synchronous condensers provide 575 MVA nominal fault current and 1,100 MWs of inertia and are expected to be commissioned by mid-2021.	In service	NSCAS assessment, system strength and inertia projections
QNI minor	QNI Minor is the upgrade of the existing interconnector with uprating to increase thermal capacity of the existing transmission lines and installation of additional new capacitor banks and Static Var Compensators (SVCs) to increase transient stability limits on the Queensland to New South Wales interconnector.	Early 2022[A]	NSCAS assessment, system strength and inertia projections
VNI Minor	VNI Minor is an upgrade of the existing Victoria – New South Wales interconnector with the installation of an additional 500/330 kV transformer, uprating to increase thermal capacity of the existing transmission, and installation of power flow controllers in NSW to manage the overload of transmission lines.	2022 [B] (Victoria side) 2023 (New South Wales completion date)	NSCAS assessment, system strength and inertia projections
South Australia Eyre Peninsula Link	This project will replace the existing 132 kV lines between Cultana and Port Lincoln with a new double circuit line. This includes a new double circuit line from Cultana to Yadnarie built at 275 kV but energised at 132 kV and a new double circuit 132 kV line from Yadnarie to Port Lincoln.	2022	NSCAS assessment, system strength and inertia projections
Powering Sydney's future	This project is to install a new 330 kV cable between Beaconsfield and Rookwood substations. Derate the existing 330 kV cable and service reactor between Beaconsfield and Sydney South from 300 kV to 132 kV.	Fully completed in 2022	NSCAS assessment, system strength and inertia projections
Western Victoria transmission network	The Western Victoria transmission network project is split into two stages. Parts of stage 1 are already complete. Remainder of Stage 1: • Uprate Bendigo – Kerang 220 kV line and Kerang- Wemen – Red Cliffs 220 kV lines Stage 2: • A new substation north of Ballarat • Cut-in the Ballarat-Bendigo 220 kV line at new substation North of Ballarat • A new 220 kV double-circuit transmission line from substation north of Ballarat to Bulgana (via Waubra) • Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to a new 220 kV line connecting the substation north of Ballarat to Bulgana • Cut-in the existing Ballarat-Moorabool No.2 220 kV line at Elaine Terminal Station.	Late 2021 (Stage 1) 2025 (Stage 2)	NSCAS assessment, system strength and inertia projections

[77] Definitions of committed and anticipated transmission network projects can be found in Section 3.10 of AEMO's *2021 Inputs, Assumptions and Scenarios*, July 2021, accessible via https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en, and Appendix B of the AER's *Cost Benefit Analysis Guidelines*, August 2021, accessible via https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[78] Where relevant, assessments also include smaller augmentations or changes, such as installation of capacitors, decommissioning of transformers, and replacements of transformers.

	Augmentation detail	Modelling date (Calendar year)	Included in assessment
	• A new 500 kV double-circuit transmission line from Sydenham to the new substation north of Ballarat • 2 x 500/220 kV transformers at the new substation north of Ballarat • 4 x 50 MVAr 500 kV reactors, one at each end of the new 500 kV lines.		
Project EnergyConnect	Stage 1: • A new Robertstown to Bundey 275 kV double-circuit line strung one circuit initially. • A new Bundey to Buronga 330 kV double-circuit line strung one circuit initially. • A new Buronga to Red Cliffs 220 kV double-circuit line strung one circuit only. • A new 330/275 kV substation and a 330/275 kV transformer at Bundey. • A new 330/220 kV substation, a 330/220 kV transformer and a 330 kV phase shifting transformer at Buronga. • Static and dynamic reactive plant at Bundey and Buronga. Stage 2: • Second 275 kV circuit strung on the Robertstown–Bundey 275 kV double-circuit line. • Second 330 kV circuit strung on the Bundey–Buronga 330 kV double-circuit line. • A new 330 kV double-circuit line from Buronga to Dinawan. • A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating initially at 330 kV.79 • Two additional new 330/275 kV transformers at Bundey. • A new 330 kV switching station at Dinawan. • Additional new 330 kV phase shifting transformers at Buronga. • Additional new 330/220 kV transformer at Buronga. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • Static and dynamic reactive plant at Bundey, Robertstown, Buronga and Dinawan. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.	Stage 1 2023 Stage 2 2024[C]	NSCAS assessment, system strength and inertia projections
Central-West Orana renewable energy zone (REZ) Transmission Link	The Central West Orana REZ link includes extension of the 500 kV and 330 kV network in the Central-West Orana region of New South Wales.	2024[D]	System strength and inertia projections [D]

A. The date captured in the table for QNI minor is the expected in-service date. AEMO, consistent with the ESOO and the 2021 inputs assumptions and summary report, assume the full capacity available from 1 July 2022 onwards to allow time for inter-network testing.
B. The dates captured in the table for VNI minor is the expected in-service date. AEMO, consistent with the ESOO and the 2021 inputs assumptions and summary report, assume the full capacity available from September 2023 onwards to allow time for inter-network testing.
C. The date captured in the table for Project EnergyConnect is the expected in-service date. AEMO, consistent with the ESOO and the 2021 inputs assumptions and summary report, assume the full capacity available from July 2025 onwards to allow time for testing.
D. Central West Orana is modelled for the system strength and inertia projections. AEMO did not assess this for NSCAS, as generation projects connecting with the project will assist with management of voltages. Since voltages issues are localised, generation locations are pertinent to this analysis. AEMO will revisit this in the NSCAS assessment next year.

[79] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

A1.3 Market modelling of generator dispatch

AEMO undertakes integrated energy market modelling to forecast future investment in and operation of electricity generation, storage and transmission in the NEM[80].

Projected generation dispatch from the *Progressive Change* scenario results for the Draft 2022 ISP have been used for the 2021 system strength and inertia assessments. These market modelling results:

- Cover the six financial years from 2021-22 to 2026-27.
- Are based on the *Progressive Change* scenario generator and transmission build outcomes for the Draft 2022 ISP. However, due to overlapping assessment timelines, the *Progressive Change* outcomes used for the 2021 system strength and inertia assessments are closely aligned to the final *Progressive Change* results in the Draft 2022 ISP, but not identical.
- Generator dispatch projections are 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[81].
- Apply the Central minimum demand 50POE projection from the 2021 ESOO.
- Apply projections of planned maintenance and outages for each generator. This includes selection of a reasonable planned maintenance and outage projection, with extreme outliers discarded where they would materially skew results for the shortfall assessment[82].
- Consider potential for additional coal seasonal decommitments, informed by forecast wholesale prices.

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

As noted in Section 2.1, projected generation dispatch from market modelling has been used in the 2021 system strength and inertia studies but not in the 2021 NSCAS studies. Results from the Draft 2022 ISP process were not available in time to be used for the NSCAS review. Instead, the NSCAS studies apply generation dispatch patterns consistent with the minimum synchronous machine dispatch combinations used for the system strength requirements (further details are available in Appendix A3). The generators in these combinations were dispatched at low generation levels to reflect minimum demand conditions and allow investigation of voltage control issues associated with low reactive power absorption available from synchronous generators. These combinations were confirmed against recent actual dispatch patterns for times of minimum demand.

[80] AEMO. Market Modelling Methodologies. July 2020. Available via https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

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

[82] Maintenance events are assumed to be distributed throughout the year such that they do not limit generating capacity at times when it is most required. Over time, as synchronous generation declines, this may be an optimistic assumption.

A2. Assumptions for voltage planning studies

AEMO's 2020 NSCAS review confirmed that in some regions of the NEM the power system is approaching the edge of its design envelope[83] and that traditional network planning assumptions used to consider network investment requirements may no longer be fit for purpose. The planning framework was originally conceived in the context of increasing maximum demand and so may not always provide the levers needed to plan for very low demand periods.

Throughout 2021, AEMO conducted a planning assumptions investigation, including consultation with TNSPs' planning and operations specialists. Table 14 provides the amended assumptions implemented to ensure that the system is planned to more efficiently maintain reliability and security within manageable operational risks.

These updated planning assumptions are intended to ensure that system security and reliability gaps are appropriately surfaced and allow transparent consideration of the full suite of options to address the gaps. These assumptions do not preclude the use of any particular options to address a gap. For example, pre-contingent line switching may be assessed as a solution to address a gap, along with a range of other technology neutral options. AEMO anticipates that this assessment by TNSPs would include prudent assessment of operating risks and, as applicable, costs and benefits.

Table 14 Amended planning assumptions for voltage control studies

Topic	Previous assumption	Updated assumption
1. Line switching for voltage control during system normal and providing for a secure operating state	Assume one line per region can be switched out of service pre-contingent for voltage control.	Assume no pre-contingent line switching for NSCAS assessments unless there is some regionally specific justification which has been agreed with AEMO in its functions as National Planner and Market Operator. AEMO expects that line switching would be considered by the TNSP when assessing solutions to any identified voltage control needs. This assumption has been updated following a public consultation to amend AEMO's NSCAS description and quantity procedure[84].
2. Tuning voltage control plant	Use all available voltage control plant adjustments in desktop planning studies, until a secure solution is reached.	Use newly developed AEMO loadflow tuning procedure for planning study voltage control assessments. This procedure incorporates advice from the AEMO control room and from TNSPs' operations specialists. The procedure is intended to limit both "over-tuning" and "under-tuning" in planning study voltage assessments.
3. Pre-contingent reactive headroom on SVCs	Restrict pre-contingent SVC reactive ranges to those stipulated in operating manuals and guides. Where no limits are specified, SVCs can use their full reactive capabilities pre-contingent.	Align pre-contingent SVC reactive ranges applied in planning assessments to those stipulated within the relevant operating manuals and guides. Where pre-contingent SVC reactive ranges have not been specified, either restrict to the lesser of +/-50 MVAr or +/-20% of rating, or to values as advised by the TNSP/RTO. AEMO expects that the TNSP would consider tuning of relevant reactive plant when assessing solutions to any identified voltage control needs.

[83] AEMO. *2020 NSCAS Report*. December 2020. Available via https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-NSCAS-Report.

[84] AEMO. 'Network Support and Control Ancillary Services Description and Quantity Procedure Consultation'. Accessed in December 2021. Available via https://aemo.com.au/consultations/current-and-closed-consultations/network-support-and-control-ancillary-services-description-and-quantity-procedure-consultation.

Topic	Previous assumption	Updated assumption
4. Post-contingent Reactive headroom on SVCs	Allow SVCs to use full range of reactive capability after a contingency.	Unchanged.
5. Reactive power demand trends	Hold reactive power values steady, using most recent actual value.	Following advice from TNSPs and distribution network service providers (DNSPs) that reactive power demand may be changing at the same time as real power demand declines, AEMO investigated this assumption using as much available data as possible and in consultation with TNSPs, DNSPs and a university. Observed trends include declining day and night time MVAr, and overnight shifts to capacitive reactive demand, particularly for connection points which include high penetrations of residential customers. As a result, AEMO has applied the following process for reactive power projections for the 2021 NSCAS review: • Divide each region of the NEM into sub-regions. • Trend historical demand (MW and MVAr) over the five-year outlook period. • Divide seasonally and by lowest 10% minimum demand days. • Take a regression of the MVAr values to project MVAr demand for the coming five-year outlook period. • Apply projections to sub-regions where these trends show a change, and where these sub-regions are predominantly residential and commercial loads.

A3. EMT studies for system strength

This appendix notes details for the electromagnetic transient (EMT) studies undertaken for the minimum fault level requirements included in this report, consistent with the System Strength Requirements Methodology[85]. For this December 2021 assessment, the Red Cliffs minimum fault level requirements have been updated, and all other requirements are held steady against previous determinations[86].

The following sections provide details on treatment of minimum synchronous machine dispatch combinations, contingencies considered, success criteria, and model setup for the assessment undertaken to update the requirements at Red Cliffs.

Minimum synchronous machine dispatch combinations

AEMO uses minimum synchronous machine dispatch combinations to derive the minimum fault level requirements for each region. These combinations are verified using EMT analysis to ensure that power system stability and system standard criteria are met. Table 15 provides the public references available for existing combinations.

Table 15 References for minimum synchronous machine dispatch combinations

Region	Reports	Reference
Queensland	Appendix 3 of the *2020 System Strength and Inertia Report* A sub-set particularly relevant for North Queensland are listed in *Transfer Limit Advice – System Strength NQLD v8*	AEMO Planning for operability, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
New South Wales	Appendix 3 of the *2020 System Strength and Inertia Report*	AEMO Planning for operability, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability
Victoria	Appendix 3 of the *2020 System Strength and Inertia Report* Further details in *Transfer Limit Advice – System Strength VIC and SA v40*	AEMO Planning for operability, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
South Australia	Appendix 3 of the *2020 System Strength and Inertia Report* Further details in *Transfer Limit Advice – System Strength VIC and SA v40*	AEMO Planning for operability, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
Tasmania	Appendix 3 of the *2020 System Strength and Inertia Report*	AEMO Planning for operability, available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability

[85] AEMO. *System Strength Requirements Methodology.* July 2018. Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[86] AEMO system strength assessments are available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

Contingencies

AEMO calculates the minimum three phase fault levels for system intact conditions (pre-contingency) to represent the normal operating conditions secure level of system strength required to be available, as well as the post-contingency value in most cases[87]. The credible contingencies considered to calculate these values represent single power system element outage resulting in the highest fault level reduction at each fault level node, and are provided in Table 16.

Table 16 Contingencies considered to calculate minimum three phase fault levels requirements at fault level nodes

Region	Fault Level Node	Contingency considered
New South Wales	Armidale 330 kV	Tamworth – Armidale 330 kV line
	Darlington Point 330 kV	Wagga – Darlington Point 330 kV line
	Newcastle 330 kV	Liddell – Newcastle 330 kV line
	Sydney West 330 kV	Sydney West – Sydney North 330 kV line
	Wellington 330 kV	Wollar – Wellington 330 kV line
Queensland	Gin Gin 275 kV	Woolooga – Gin Gin – Calliope River 275 kV line
	Greenbank 275 kV	One Millmerran Power Station unit
	Lilyvale 132 kV	Lilyvale – Broadsound 275 kV line
	Ross 275 kV	• Ross – Strathmore 275 kV line • Townsville Power Station 132 kV feeder (if Townsville Power Station is in service) • Mt Stuart Power Station 132 kV feeder (if Mt Stuart Power Station is in service)
	Western Downs 275 kV	Braemar 275/330 kV transformer
South Australia	Davenport 275 kV	One Synchronous Condenser at Davenport
	Para 275 kV	One Synchronous Condenser at Robertstown
	Robertstown 275 kV	One Synchronous Condenser at Robertstown
Tasmania[A]	Burnie 110 kV	Burnie 220 kV – Sheffield 220 kV line
	George Town 220 kV	N/A
	Risdon 110 kV	N/A
	Waddamana 220kV	N/A
Victoria[B, C]	Dederang 220 kV	South-Morang Transformer 500 / 330 kV
	Hazelwood 500 kV	Hazelwood – South Morang 500 kV line
	Moorabool 220 kV	Transformer 500 / 220 kV
	Red Cliffs 220 kV	Red Cliff – Wemen 220 kV line
	Thomastown 220 kV	Thomastown – Keilor 220 kV line

A. AEMO and TasNetworks use pre-contingency values to inform the operational arrangements for system strength requirements in Tasmania. These nodes have specific local requirements which must be met for the pre-contingent levels, namely to do with maintaining Basslink requirements, switching requirements for local reactive plant, and some power quality requirements for metropolitan load centres.
B. One of two 500 kV transmission circuits in Victoria (Hazelwood – South Morang 500 kV line 1 or Hazelwood – Rowville 500 kV line 3) are assumed to be out of service during system strength studies, as these circuits may be switched off during low loading conditions for voltage control.
C. A range of contingencies were assessed to revise the Red Cliffs 220 kV minimum fault level requirements in this report, as noted in the Red Cliffs model setup section below.

[87] The post-contingency level (associated with a given pre-contingency level) is associated with the network landing in a satisfactory state following the occurrence of any credible contingency. These are not secure fault level requirements for prior or planned network outage condition.

Success criteria

The criteria used to assess system strength outcomes through EMT studies are outlined below.

- Generators, as well as relevant regional interconnectors, remain online.
- All online generators return to steady-state conditions following fault clearance, unless they are intentionally tripped as a part of the contingency.
- The power system frequency is restored to within the normal operating frequency band (49.85-50.15 hertz [Hz]).
- The transmission network voltage profiles across the region return to an acceptable range.
- Post fault voltage oscillations are adequately damped. At present, AEMO assesses whether the sub-synchronous peak-to-peak voltage oscillation magnitude is below an upper limit of 0.3% at 8 – 10 Hz. Increasingly AEMO is applying a stricter limit and in future expects to move the limit as low as is possible while also allowing for the limitations of modelling methods.

EMT model setup – Red Cliffs

In this report, AEMO declares an update to the pre- and post-contingency minimum fault level requirements at the Red Cliffs 275 kV node. The contingencies tested for this assessment were:

- Red Cliffs – Kiamal: Two phase to ground fault (2ph-G) and disconnection of Red Cliffs – Kiamal line.
- Red Cliffs – Buronga: Two phase to ground fault (2ph-G) and disconnection of Red Cliffs – Buronga line.
- Ballarat – Waubra – Ararat: Two phase to ground fault (2ph-G) and disconnection of Ballarat – Waubra – Ararat line.
- Kerang – Bendigo: Two phase to ground fault (2ph-G) and disconnection of Kerang – Bendigo line.
- Darlington Point – Wagga: Two phase to ground fault (2ph-G).
- Balranald – Darlington Point: Two phase to ground fault (2ph-G) and disconnection of Balranald – Darlington Point line.
- Darlington Point Synchronous Condenser: 2ph-G fault on the HV transformer terminals and disconnection of Darlington Point synchronous condenser at Buronga and inter-trip of Darlington Point Solar Farm.
- Finley Synchronous Condenser: 2ph-G fault on the HV transformer terminals and disconnection of Finley synchronous condenser at Buronga as well as an inter-trip of Finley Solar Farm

All inter-trips, runback schemes and special protection schemes relevant for the contingencies above were also included in the assessment.

The updated fault level requirement includes a minor increase due largely to the inclusion of local synchronous condensers in the calculations – both those engaged for system strength services, as well as others associated only with system strength remediation schemes for individual solar farms. Fault level projections used to assess system strength shortfalls are adjusted accordingly to ensure that a shortfall is not declared to cover system strength remediation which is already being addressed by a responsible generator. The requirements applied in the control room may vary depending on operating conditions, for times when some generators are not online.

A4. EMT studies for inertia

This appendix notes details for the assessment method for electromagnetic transient (EMT) studies undertaken for the inertia requirements determined in this report.

Overarching assessment method

AEMO conducts EMT studies to determine the minimum threshold level of inertia and secure operating level of inertia required for each inertia sub-network in the NEM. These studies are undertaken consistent with the Inertia Requirements Methodology[88]. To calculate inertia requirements for a region, it is assumed that a region is an electrical island and all necessary services must be sourced from within the region.

For this report, the secure operating levels of inertia for Queensland and South Australia have been assessed in accordance with the assessment method described in this section. The minimum threshold levels of inertia for those regions, as well as all requirements for all other regions, remain at the levels set in previous AEMO publications.

This section notes the treatment of assumptions, contingencies, size of distributed PV disconnection, treatment of primary frequency response requirements and success criteria for the studies.

Assumptions

Assumptions for the EMT model for inertia requirements studies include:

- Committed, committed*, commissioned and retired generation as per the July 2021 NEM Generation information[89]. On a case-by-case basis, some committed or existing utility-scale battery systems and synchronous condensers are included in the requirements studies, but only where they are considered to be part of the typical dispatch being considered for that study.
- Output from online generators can be reduced to limit the size of the contingency. However, this reduction should not compromise the lower frequency control capability of the generator. The generator should have sufficient foot room to reduce their generation in response to high frequency events.
- Registered frequency control ancillary services (FCAS) for large generators and loads is modelled in accordance with their individual registrations[90] as at August 2021. When a generator is online, it must provide at least its registered FCAS[91].
- Disconnection of distributed PV as a result of a nearby disturbance is modelled as an increase in the size of the contingency. In this report, 'distributed PV' is referring to PV generation connected to the distribution network that is either estimated by the Australian Solar Energy Forecasting System (ASEFS2)[92] (smaller than 100 kW) or is non-scheduled PV generation smaller than 30 MW.

[88] AEMO. 2018 Inertia Requirements Methodology. June 2018. Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[89] AEMO. The July 2021 NEM Generation Information is available under the archive section of AEMO's Generation information webpage. Available via https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Definitions of committed and committed* are available in the Background Information tab.

[90] AEMO. NEM Registration and Exemption List. Accessed December 2021. Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration.

[91] It should be noted that registered FCAS is for 0.5 Hz arresting band while island arresting band is 1 Hz.

[92] AEMO. Australian Solar Energy Forecasting System. Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

- The amount of distributed PV and load disconnection used in the analysis in this report was determined through dynamic loadflow studies using PSS/E, not through EMT studies. The disconnection in response to a nearby contingency event was estimated as a percentage of the total distributed PV and underlying load in the region, and that percentage was then applied to the latest demand and PV projections used in the *Progressive Change* scenario. More details are provided in a dedicated section below.
- The frequency dead bands for generators and utility-scale battery systems are set consistent with the latest adjustments declared by affected generators to comply with the primary frequency response (PFR) requirements. More details are provided in a dedicated section below.

Contingencies

The secure operating level of inertia is assessed by considering the minimum synchronous machine dispatch combinations that provide sufficient frequency control and inertia within a region, including ensuring that the system remains in a satisfactory operating state following a credible contingency. Several contingencies are studied, with the secure operating level determined based on the worst-case contingency identified through the EMT analysis.

In recent years AEMO has considered the credible contingencies which must be assessed to understand frequency disturbances and inertia requirements within an islanded system to be as follows:

- Loss of an online generator, plus the coincident unintended disconnection of distributed PV[93].
  - Although the amount of generation from an online generator may be able to be reduced to lower the contingency size when the region is islanded (subject to other system conditions), reduction below a certain level for thermal plant is not possible due to minimum stable operating point requirements.
  - The size of distributed PV disconnection would be largely uncontrolled and would depend on factors such as the amount of distributed PV generation at the time as well as proximity to the initiating generator contingency. The largest net loss of distributed PV has been applied to a subset of the credible contingency events studied for each region as not all contingency events will result in a severe enough voltage depression to trip off distributed PV.
- Loss of the largest transmission-connected load which can be considered as a credible loss (in some cases, this means a subset of the overall site load).

[93] Distributed PV refers to PV that meets AEMO's Australian Solar Energy Forecasting System[93] (ASEFS2) total installed capacity, which only includes capacities less than 100kW. AEMO, ASEFS2, accessible via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

Size of distributed PV disconnection

To estimate the net impact of a distributed PV disconnection, the demand modelled for the region is scaled up to reflect the estimated additional demand on the system after the distributed PV is disconnected. This value is only included in the modelled credible contingency if it is a daytime contingency event, and if that contingency event would create a sufficient voltage depression to initiate distributed PV disconnection.

The most onerous distributed PV disconnection in South Australia occurs for the trip of a Torrens Island B Power Station unit, due to the short electrical distance between the Torrens Island generating system and the Adelaide metropolitan area, where much of the distributed PV is installed. For Queensland, the most onerous distributed PV disconnection occurs for the trip of a Tarong Power Station unit, due to the short electrical distance between the Tarong generating system and the Brisbane metropolitan area where much of the distributed PV is installed.

To calculate the distributed PV disconnection and underlying load sizes used for this report, AEMO applied the Central disconnection factors documented in the 2020 ESOO[94] to the latest *Progressive Change* forecast. The net distributed PV disconnection sizes were forecasted for each half hourly interval and the largest disconnection size was applied to the relevant generator contingency. The equation for disconnection of net distributed PV is given here:

$$Disconnection(MW) = PV_{disc\%} * PV_{Total} - Load_{disc\%}[OPSOPVLITE + AUX]$$

Where:

$PV_{disc\%}$	is the distributed PV disconnection factor from the 2020 ESOO
PV_{Total}	is the distributed PV generating at the time in the region (total distributed PV installed * capacity factor[95])
$Load_{disc\%}$	is the load disconnection factor from the 2020 ESOO
OPSOPVLITE	is the underlying load in the region (Operational as sent out (OPSO) + PV generated at the time)
AUX	is the generator auxiliary load in the region at the time

Beyond 2021-22, it is assumed that net disconnection will not increase, as it is assumed that distributed PV units installed after the end of 2021 will have improved disturbance ride-through capabilities from the updated AS/NZS 4777.2:2020 standard[96]. Should there be any issues related to implementation of the new standard such that inverters are observed to continue to disconnect in power system disturbances, these assumptions will need to be revisited in future inertia requirement assessments.

[94] AEMO, 2020 ESOO, Appendix A5.1, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. AEMO will seek to update these figures when possible.

[95] The maximum capacity factor typically applied (based on historical observations) is 70%.

[96] AEMO. AS/NZS 4777.2 – Inverter Requirements Standard. Accessible via https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/as-nzs-4777-2-inverter-requirements-standard.

Primary frequency response requirements

The continuous primary frequency response (PFR) of generators can be used to maintain an aggregate level of responsiveness in the power system to relatively small and ongoing, incremental changes in frequency.

In March 2020, the AEMC introduced mandatory PFR requirements for scheduled and semi-scheduled generators. This was specified as an interim arrangement to begin in June 2020 and sunset in June 2023 to allow for further work to be done to understand power system requirements and consider enduring PFR arrangements. In September 2021, the AEMC released a draft rule determination for these interim PFR requirements to continue beyond the June 2023 sunset date. A final determination on this rule change is due in July 2022[97].

AEMO is currently coordinating changes to generator control systems in accordance with the mandatory PFR rule. The rollout of these arrangements began in late September 2020 and has taken place in tranches, starting with the largest generators (maximum capacity greater than 200 MW). Rollout is continuing, particularly for semi-scheduled generation.

Under these mandatory PFR arrangements, generators have been progressively implementing changes[98] to their control systems, as specified in AEMO's interim PFR requirements[99], to:

- Provide an automatic, locally detected active power response to changes in frequency outside a narrow frequency deadband.
- Disable any control features that act to suppress a unit's active power response to a frequency disturbance, within the plant's stable operating range.

For the purposes of the EMT studies performed to assess inertia requirements for this report, generators are assumed to comply with their mandatory primary frequency response requirements[100].

Success criteria

The success criteria for determining if an islanded region returns to a satisfactory operating state[101] following a credible contingency include:

- Frequency is maintained within the arresting frequency bands for each specific operating condition studied[102]. Consistent with good engineering practice, an operating margin of 0.1 Hz has been considered while determining the requirements. As an example, arresting frequency above 49.1 Hz is considered even though the floor of the operational frequency tolerance band is 49.0 Hz[103].

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[97] AEMC. Primary frequency response incentive arrangements consultation webpage, accessible via https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

[98] Updates on the rollout of the mandatory PFR rule are available at AEMO's Primary Frequency Response webpage, accessible via https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response.

[99] AEMO. Interim Primary Frequency Response Requirements. June 2020. Accessible via https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf.

[100] Application of these requirements in the EMT studies reflects the fact that the mandatory PFR requirements do not guarantee generator headroom. As such, in the EMT studies, inverter-based resources are not assumed to hold headroom and not assumed to provide raise response.

[101] Clause 4.2.2 of the NER.

[102] For the purposes of this work only the arresting band is considered which is in line with the 2018 Inertia Requirements Methodology. The arresting bands are provided in the Frequency Operating Standards, available through the AEMC website via https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

[103] As per Table A.1: Frequency bands in the Frequency operating standard - effective 1 January 2020, available through the AEMC website via https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

- The occurrence of a credible contingency should not result in the activation of automatic load or generation shedding schemes and consequent load or generation loss.
- The high voltage transmission network voltages across the region return to nominal voltages[104].
- All online generators return to steady-state conditions following fault clearance, unless they are intentionally tripped as part of the contingency.
- All online generations remain connected and return to new steady-state conditions, except those who are part of the contingency considered or included in any special control or protection scheme.

[104] Criteria for voltage is up to 10% higher or lower than nominal voltage.

A5. Challenges not addressed by existing frameworks

The present frameworks for system strength and inertia do not address certain types of operational challenges that are arising in the NEM.

The current planning framework does not contemplate declaration of an inertia or system strength shortfall unless shortfalls are considered reasonably likely to occur more than 1% of the time[105].

AEMO's forecasting projects that in rare periods within the five-year outlook period which lie outside of the planning framework's ability to address, operational demand could drop to levels that may challenge AEMO's ability to securely operate parts of the NEM with sufficient system strength, inertia and frequency control. Further, on these rare occasions, even last resort emergency action may be challenging to implement. This is because the demand could be too low to operate within the presently defined limits advice, including minimum synchronous machine combinations at the required levels.

AEMO is continuing to explore these issues and the risks involved, and is working with network service providers to develop suitable mitigation strategies.

NEM mainland in periods of minimum operational demand

AEMO's System Strength Requirements Methodology[106] does not contemplate assessment of a system strength shortfall until it is likely to occur for at least 1% of time. Similarly, AEMO does not contemplate declaration of an inertia shortfall until it is likely to occur for at least 1% of time. It is implicitly assumed that for the remaining times over the year, other measures will be available to allow AEMO to maintain sufficient system security services, including directions in respect of available facilities if necessary.

AEMO has identified that within the five-year outlook period, there may be trading intervals where emergency last resort measures will be needed to secure system services, and in some instances, even these may be challenging to apply. This is because:

- AEMO estimates that there is a requirement for a minimum of 4 to 6 GW of operational demand across the NEM mainland to be able operate the various minimum unit combinations at the minimum dispatch levels so as to deliver the necessary levels of system strength, inertia and frequency control. This is based on the present operational toolkit[107,108,109].

[105] This is consistent with "typical patterns of dispatched generation" as per NER 5.20B.3 and 5.20C.2.

[106] AEMO. System Strength Requirements Methodology. July 2018. Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[107] To operate the NEM mainland (the interconnected system of Queensland, New South Wales, Victoria and South Australia), with the present operational toolkit, AEMO maintains a minimum of 26-32 synchronous generating units online (in specific unit combinations) to provide adequate levels of inertia and system strength. This includes the specified minimum synchronous generating unit requirements of 5-8 units in Victoria, 7–9 units in North and Central Queensland and 2 units in South Australia, as well as minimum unit requirements in other regions. It is also necessary to dispatch these units above their minimum loading levels to allow sufficient headroom and footroom for delivery of sufficient raise and lower frequency control services.

[108] AEMO. Transfer Limit Advice – System Strength in SA and Victoria. October 20201. Available via https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[109] Powerlink. North Queensland System Strength Constraints. August 2021. Available via https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/nQueensland-system-strength-constraints.pdf?la=en.

- The NEM mainland is projected to have periods with total operational demand below 4 to 6 GW by 2024 or 2025, depending on the forecast scenario. When operational demand falls below this threshold, it may no longer be technically possible to maintain online the present minimum synchronous unit combinations that deliver adequate system strength, inertia and frequency control services, unless deliberate preparatory actions are planned and taken.
- Initially, periods with NEM mainland operational demand below 6 GW are projected to be very rare, occurring around 0.01% of the time in 2023-24, growing to approximately 0.4% of the time in 2026-27. These periods will typically occur around midday on public holidays or weekends with conditions of mild temperatures and clear skies. Initially, NEM mainland operational demand below these thresholds may only occur on a single day of the year, projected to grow to periods occurring on approximately 14 different days by 2026-27.

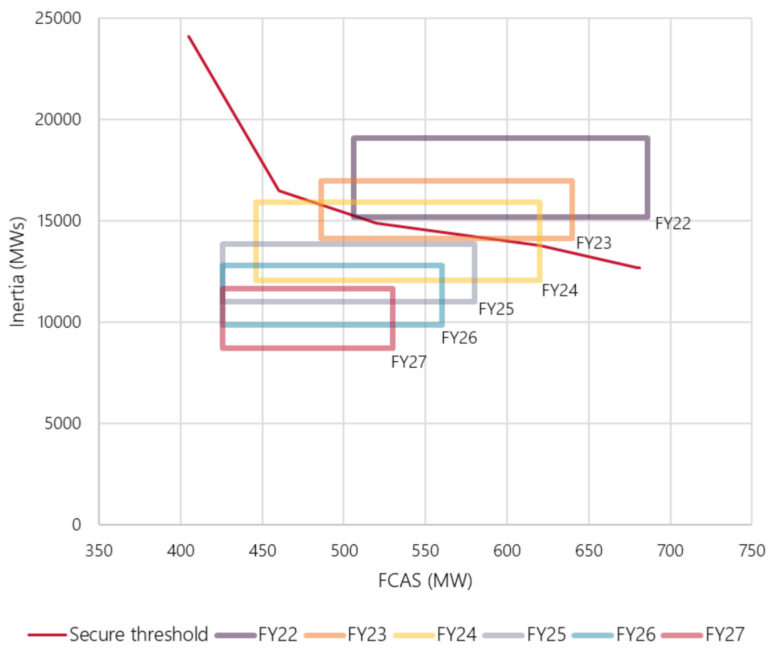
An example considering inertia in minimum demand periods

As an illustrative example, Figure 35 shows the secure threshold for Queensland. The boxes show the levels of inertia and FCAS that can be delivered in the minimum operational demand periods in each year, based on the present operational toolkit.

Reducing operational demand will limit the number of inertia and FCAS providers that can operate, so the boxes move downwards over time. The boxes are projected to fall entirely below the secure threshold from 2024-25 onwards, meaning it may not be possible to operate the Queensland island with sufficient inertia and frequency control from this date onwards in periods of minimum operational demand, even with unit directions, unless preparatory and other emergency actions are taken.

It should be noted that the secure threshold limits could be partially or fully met should batteries with fast frequency response capability be engaged.

Figure 35 Range of inertia and Fast Raise FCAS that can feasibly be dispatched in minimum demand periods with present operational toolkit (Queensland) [A, B]



Boxes are based on minimum demand projections for the *Progressive Change* scenario 50POE scenario, and present and committed inertia and FCAS providers in Queensland.

The range within each box represents different unit combinations that could be directed online at minimum demand. The optimal combination may not be available due to plant outages or other operational limits.

This figure does not show impact of some measures which could help address these issues, for example restricting generation from large generators to reduce contingency size.

Note: The secure threshold curve would move to the left if fast frequency response from utility-scale batteries were included, potentially alleviating the requirements and risks.

Periods where operational demand in Queensland is too low to allow operation of unit combinations that deliver sufficient inertia and FCAS are projected to occur rarely: up to 0.3% of the time in 2022-23, increasing to 0.2% to 4% of the time by 2026-27[110].

Inertia for combined regions

The NER currently specify that inertia requirements are analysed in single regions individually when they are either islanded or at credible risk of islanding, and that the likelihood of islanding is a key factor in determining whether a shortfall of inertia is likely to exist. AEMO is not permitted to determine inertia networks that span more than one NEM region, meaning it is not possible to declare an inertia shortfall for combined regions.

This may mean that there is insufficient inertia to securely operate larger islands that could form, such as a Victoria and South Australia island, or a Queensland and New South Wales island. Historically, separations have occurred between Victoria and New South Wales[111], so these combinations of regions are considered operationally plausible. In addition, the regulatory framework does not provide for requirements or shortfalls for inertia to be declared for the NEM mainland as a whole.

Preparatory actions to manage very low demand periods

Preparatory actions to manage the rare very low demand periods that fall outside of normal system operations, and where directing units online is not operationally feasible, could include consideration of:

- Network service procurement and/or investment in alternative sources of inertia, system strength and frequency control – including fast frequency response from batteries – thereby enabling satisfactory provision of these services with fewer synchronous generating units online[112].
- Approaches that increase customer demand and incentivise demand response, and as an emergency last resort action, emergency curtailment of distributed PV. AEMO has recommended that an emergency backstop distributed PV curtailment capability is considered for all new distributed PV installations[113,114]. To align with customer preferences, other investments may also be appropriate, including storage, to minimise any possible need for this last resort mechanism.

AEMO is continuing to explore these issues.

[110] Based on the *Progressive Change* Scenario 50POE forecast and the different possible unit combinations.

[111] AEMO (September 2020) Final Report – New South Wales and Victoria Separation Event on 4 January 2020, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en&hash=A35535D1D6AD14F9967B13C822A37A07.

[112] It may also be possible to somewhat reduce the number of synchronous units required to deliver adequate system strength in periods with very low levels of inverter-based generation operating, which may delay the onset of these challenges, but is unlikely to mitigate them entirely.

[113] AEMO (August 2021) 2021 Electricity Statement of Opportunities, Section 6.1, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf?la=en&hash=D53ED10E2E0D452C79F97812BDD926ED.

[114] AEMO (August 2020) 2020 Electricity Statement of Opportunities, Section 7, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.