2020 ISP Appendix 7. Future Power System Security

July 2020

Important notice

PURPOSE

This is Appendix 7 to the Final 2020 Integrated System Plan (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes this 2020 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its broader functions under the National Electricity Rules to maintain and improve power system security. In addition, AEMO has had regard to the National Electricity Amendment (Integrated System Planning) Rule 2020 which commenced on 1 July 2020 during the development of the 2020 ISP.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2020	Initial release

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2020 ISP Appendices

Summary

This Future Power System Security appendix reviews the requirements for system security services such as inertia, system strength, voltage control, and frequency control within the ISP optimal development path.

Focus is also given to detailing how these aspects are managed for the for South Australian region, as well as how to optimise these services into the future as part of REZ development.

- Power system security relies on many services that have historically been provided by thermal synchronous generation. New technologies and approaches to these services are required as the power system continues to transform and becomes increasingly dominated by small- and large-scale inverter-based resources (IBR).
- AEMO has performed engineering studies of the power system to identify future power system security requirements. The areas considered are voltage control, transient stability, system strength, frequency management, power system inertia, and dispatchability.
- The ISP recommends network investments that efficiently provide a range of power system security services. The design of REZs can deliver economies of scale by incorporating services for delivering system strength, inertia, and voltage control.
- The ISP looks out to 2042, outlining a dynamic whole-of-system roadmap for nationally significant and essential investments to ensure the efficient, secure and reliable operation of the power system, and incorporates the work of AEMO's Renewable Integration Study (RIS)[1]. The ISP assumes that RIS recommendations are ultimately implemented, while focusing on medium- and long-term solutions that go far beyond the RIS horizon.
- This ISP finds:
  - Many areas are already displaying low system strength issues, but by 2029-30 the retirement of thermal generators and high penetration of inverter-based devices would lead to lowering of system strength in South West Victoria, Northern New South Wales, and Central Queensland. Investments to system strength will be required, and new resources will need to provide for this within their designs.
  - Demonstrable improvements in system strength are expected in areas where new transmission is proposed as part of the optimal development path, for example in REZs in Northern New South Wales.
  - If a NEM minimum inertia level is considered, then by 2034-35 a shortfall of over 19 GWs could occur due to synchronous plant retirements and other remediating investments will be needed. This requirement should be assessed in conjunction with other system security requirements such as system strength in order to minimise total investments needed.
- Near-term, detailed assessments incorporating the latest minimum demand forecasts will be conducted as part of the 2020 System Strength, Inertia and Network Support and Control Ancillary Services (NSCAS) reports due to assess requirements and declaration of any new shortfalls by the end of 2020.

[1] AEMO. *Renewable Integration Study: Stage 1 Report*, at https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf.

A7.1. Introduction

This appendix is part of the 2020 ISP, providing more detail on the Power System Security requirements across various scenarios in the 2020 ISP (see 2020 ISP Section D3).

There are system security considerations beyond just ensuring sufficient capacity from generation and transmission networks[2], and these must be considered to ensure power system developments are operationally adequate and also secure and reliable.

As conventional synchronous generation retires, the suite of services such as system strength, inertia, frequency control, and reactive power support, will need to continue to be closely monitored and studied, as well as the efficacy of existing protection and control schemes. Coordination and locational optimisation for the acquisition of these services will be an important consideration as the power system transitions to higher levels of inverter-based resources within REZs.

Most of the system strength and inertia in the NEM today is provided incidentally

System strength and inertia are critical requirements for a stable and secure power system. A minimum level of each is required for the power system to operate in a stable manner, and for recovery following a system disturbance. The majority of system strength and inertia in the NEM today is provided by power stations that are approaching the end of their technical life, and many are expected to retire in the next 20 years of this ISP. The services they provide depend upon a range of factors including the level of interconnection of the system, protection equipment, and IBR capability. The projected closure or mothballing of these power stations within the planning horizon of this ISP signals an urgent need for the market to provide additional security services either through investment in new assets, retrofitting of existing assets, or contracting for service provision from potential providers.

The timing of regional shortfalls is closely linked to the timing of thermal power station closures and minimum demand projections which are highly uncertain

To meet regional system strength requirements, this ISP projects the need for significant further investment such as large synchronous condensers to be required to replace the regional services currently provided by thermal power stations. The timing and scale of regional system strength shortfalls depends on the timing of exits of thermal power stations (including any generation outages) and the minimum demands in each region (driven by increasing consumer-based IBR such as distributed PV). AEMO is currently reviewing minimum demand projections based on the latest trends and policy information. A steeper decline in the projection of minimum demand is anticipated and could bring forward the timing and increase the scale of these shortfalls. AEMO will report further on this in the 2020 Inertia Report and 2020 System Strength Report.

System strength remediation will become increasingly common over the next few years

In parallel with emerging regional system strength and inertia shortfalls to replace the services provided by thermal generators, IBR such as wind farms and solar PV connecting to weaker areas of the grid will also need to offset their impact on system strength through remediation (referred to as "do no harm").

In recent years, many new generator connections have increasingly been required to provide system strength remediation. Moving forward just a few years, most connections in the NEM are anticipated to need to fund solutions that remediate their system strength impact through the mid-2020s and beyond. Today, this

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[2] AEMO. *Power System Requirements*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

remediation is most typically in the form of synchronous condensers for small remediation requirements. Without remediation, and when the regional system strength is not sufficient, increasing numbers of generators would be constrained down or even off the system, so it is important to plan investments to address this increasing need in the most efficient manner.

Advanced grid forming controls on inverters (once demonstrated) may be able to reduce these do-no-harm requirements, or even form part of the solution. Other solutions such as generator contracting or conversion of generators to synchronous condensers will be viable if economical. It is critical that these developments be promoted and facilitated through market and policy reforms.

Strategic investments can play an important role in realising efficient and robust outcomes

It is important that consideration also be given to all needs and the relative benefits of differing technologies in meeting some, part, or many of the services needed, if not now, then in the future. For example, solutions to address inertia, frequency control, system strength and reactive control must be considered together, not independently. Some available technologies address multiple needs, which may be preferable as the investment choice in the near term, if efficient and economic. Alternative technologies that address needs are also developing and may be more economic in the future.

The development of inverter and control systems providing grid forming services could provide alternative options in part to addressing the requirements, and need to be considered when deciding on strategy for future investment – for example, decide now on technology solutions that best meet needs now, and assess alternatives in the future for future needs; or invest now in assets that provide a range of services for needs now and potential future needs.

For example, the inclusion of high-inertia flywheels on synchronous condensers which could be delivered by TNSPs to meet fault level requirements at key nodes could also provide the majority of the inertia required across the NEM in the coming 20 years. The cost of these flywheels is a small percentage of the cost for a synchronous condenser if it is part of the initial design and construction, whereas adding high-inertia flywheels after a synchronous condenser is already commissioned is often impractical or cost-prohibitive. If not included in the original plant, alternatives would be needed if inertia becomes a future additional requirement.

The four large synchronous condensers being installed in South Australia (see Appendix 3) are being fitted with high-inertia flywheels. This is a good example of a robust strategic investment that provides a wide range of system security services both for current needs and expected future requirements. ElectraNet estimated that the cost of adding flywheels represented only 3% of the total capital works[3].

The design of emerging REZs can benefit from ElectraNet's experience. Economies of scale can be realised by incorporating centralised synchronous condensers to deliver system strength, inertia, and voltage control to REZs. It is clear that a centralised synchronous condenser solution is currently more economic than a series of small solutions on a project-by-project basis. However, realising a coordinated and centralised solution is yet to be demonstrated under the existing regulatory framework, one that allocates responsibility for system strength across multiple parties who are in direct competition and at different stages of project development and financing.

As the NEM transitions to a grid increasingly dominated by IBR, AEMO is also placing an increasing focus on management of active power control and management of ramping events due to wind and solar (including DER) variability. This is increasingly affecting power system security safeguards such as under frequency load shedding schemes, and in some cases over frequency load shedding schemes.

[3] ElectraNet. *Addressing the System Strength Gap in South Australia*, at https://www.aer.gov.au/system/files/ElectraNet%20-%20System%20Strength%20Economic%20Evaluation%20Report%20-%2018%20February%202018.PDF.

The impact of reducing minimum demands

Periods of minimum demand place the greatest pressures on synchronous generation to decommit. As the amount of synchronous generation online reduces, the need for remediation of system services increases. Existing schemes to arrest under-frequency and over-frequency events can also be less effective under these conditions.

Intervention already occurs in South Australia and Tasmania to ensure system strength and inertia requirements are maintained, and in Victoria to reduce high voltages on the 500 kV network. When assessing options to address shortfalls, longer-term forecasts in minimum demand are key inputs to projecting the timing and scale of shortfalls, and where co-ordination or optimisation of solutions to address all the system services is warranted to deliver efficient outcomes for consumers. For example, it can be optimal to address a voltage control issue with a higher-cost dynamic reactive support option like a synchronous condenser instead of cheaper static reactive support such as a capacitor or reactor, if system strength shortfalls are also expected to materialise within a short period.

Revised minimum demand forecasts currently being finalised for the 2020 ESOO are anticipated to be lower than the minimum demands that were used in current system strength and inertia projections in this ISP. The revised minimum demand forecasts include the short term impact of COVID-19 and the latest trends in distributed PV sales, above those forecast in 2019. The projected decline in minimum demand will bring forward the timing and increase the scale of the identified shortfalls.

Due to the significance, once these revised forecasts are finalised, the system strength and inertia implications will be incorporated in the NSCAS shortfall outlook report, and the combined System Strength and Inertia Shortfall Outlook report, both due to for release late in 2020. These reports will revise the projections outlined in this ISP.

The Appendix is set out in the following sections:

- **A7.2 Renewable integration study (RIS)** – gives an overview of the interactions between the recent RIS study outcomes, and how these have fed into the ISP studies and results.
- **A7.3 System strength outlook** – AEMO has defined minimum three phase fault level requirements that need to be maintained at specific fault level nodes across the NEM to ensure the network is operated in a stable and secure manner. Projections and anticipated shortfalls of system strength are detailed, as well as the drivers of these shortfalls.
- **A7.4 Inertia outlook** – AEMO has defined minimum and secure inertia levels that need to be available in each NEM region in the event of that region operating as an island, to ensure the network is operated in a stable and secure manner. Projections and anticipated shortfalls of inertia are detailed, as well as the drivers and potential remediation of the shortfalls. The adequacy of the existing inertia framework is highlighted with reference to the recent RIS.
- **A7.5 REZ opportunities** – when assessing REZ network solutions there is also a need for consideration of system strength mitigation and associated costs. An example for a large-scale REZ with different network options and remediation strategies is presented. Results highlight the benefits of a coordinated approach to investments in transmission and system strength to minimise overall costs and reduce costs for consumers.
- **A7.6 South Australia in transition** – provides details on the growing system security challenges being experienced in the South Australian region as the penetration levels of distributed PV and IBR grow, and explores AEMO's planning assumptions relating to the South Australian region.

A7.2. Renewable Integration Study

AEMO's RIS takes a deeper review into the specific system implications and challenges associated with the integration of large amounts of variable inverter-based renewable generation and decentralised energy on the power system, as part of a multi-year plan to maintain system security in a future NEM with a high share of renewable resources.

The RIS Stage 1 report published in April 2020[4] is a complementary publication to the 2020 ISP; the Draft 2020 ISP established the core inputs for the RIS Stage 1 analysis, and the RIS Stage 1 report supplied insights into the 2020 ISP. AEMO envisages an ongoing feedback loop between the RIS and the ISP analysis and publications.

The majority of RIS Stage 1 insights were related to operational and short-term measures to ensure the security of the power system out to 2025, based on the technical limits of the power system to integrate renewables (not the economic limits). The RIS concluded that, in the coming five-year period:

- The NEM power system will continue its significant transformation to world-leading levels of renewable generation. This will test the boundaries of system security and current operational experience.
- If the recommended actions are taken to address the regional and NEM-wide challenges identified, including the required network upgrades as identified in the ISP, the NEM could be operated securely with up to 75% instantaneous penetration of wind and solar. The RIS did not examine the economics of the requirements, rather focused on what is needed, and concluded that, technically, this and even higher levels were possible if the appropriate investments were made – inherently reliant upon suitable reform of the market to be realised.
- If, however, the recommended actions are not taken, the identified operational limits will constrain the maximum instantaneous penetration of wind and solar to between 50% and 60% in the NEM.

The 2020 ISP outlines a dynamic whole-of-system roadmap for nationally significant and essential investments to ensure the efficient, secure and reliable operation of the power system. The ISP assumes the RIS recommendations are ultimately implemented, while also focusing on medium and long-term solutions that go beyond the RIS horizon.

A7.2.1 Key system security challenges from Stage 1 of the Renewable Integration Study

The RIS Stage 1 report identified a number of key challenges and explored system limits that impact wind and solar instantaneous penetration in the NEM power system, specifically:

- Limits that affect how much wind and solar PV generation can operate at any one time, and what the limits are NEM-wide and for individual regions.

[4] See Stage 1 report and appendices, with other RIS information and documents, at https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris.

- How close NEM regions are to these limits now, and how close they are expected to be by 2025.
- Actions that can overcome these barriers so the system can operate securely with higher penetrations of wind and solar generation.

While it identified recommended actions that would be required to meet the system's technical needs, it did not investigate the economics of proposed actions or all the specific mechanisms that could be implemented.

The RIS Stage 1 report has fed into the ISP and into the ESB's Post 2025[5] work and regulatory processes that the AEMC is progressing[6].

Recommended actions relating to system strength and inertia are shown in Table 1 below.

Table 1 Recommended RIS actions feeding into the ISP

RIS action	ISP section
Investigate the introduction of a system inertia safety net for the mainland NEM, under system intact conditions	The outcomes from consideration of a NEM minimum inertia level net are explored further in Section A7.4.2.
Improving the transparency of system strength across the grid	System strength outcomes are demonstrated in a number of ways in the ISP: • Expected available fault levels across the NEM (Figure 1). • Expected TNSP fault level node fault levels (Section A7.3.2). • Available fault levels and remediation amounts in identified REZs (see REZ scorecards in Appendix 5). • Publishing of results on an interactive map.
Promoting the development of scale-efficient renewable energy zones (REZs) that are designed for the connection of IBR	Appendix 5 discusses the development of REZs in the NEM.
Presenting evidence that coordinated system strength services can deliver positive net market benefits	Section A7.5 demonstrates the need to co-ordinate network upgrades and system strength remediation in order to be able to develop a least-cost solution.
Outlining an efficient strategy for the coordinated delivery of system strength services	This will be explored further in the 2020 Inertia Report and 2020 System Strength Report, expected for publication by the end of 2020. This will ensure incorporation of anticipated updates to minimum demand forecasts, and the exploration of additional sensitivities.

[5] COAG. *Post 2025*. At http://www.coagenergycouncil.gov.au/energy-security-board/post-2025.

[6] AEMC. *System Services Rule Changes*, at https://www.aemc.gov.au/rule-changes/synchronous-services-markets.

A7.3. System strength outlook

System strength is a measure of the ability of a power system to maintain and control the voltage waveform under normal conditions and to return to a steady state condition following a system disturbance[7]. Traditionally synchronous machines have provided, and continue to provide a source of system strength, while IBR generally require a level of system strength to be provided at the location they connect to in order to be able to operate.

Results from the both the Central and Step Change scenarios have been assessed. System strength projections have been provided for the fault level nodes for each of the regions.

AEMO will also publish standalone 2020 System Strength and Inertia Reports by the end of 2020. These reports will consider a wider range of sensitivities than considered in this ISP, as well as assessing system strength requirements and shortfall assessments for the next 10-year period.

This section:

- Notes the importance of system strength and the roles and responsibilities for its treatment (A7.3.1).
- Provides a NEM-wide system strength outlook (A7.3.2).
- Details the system strength outlook for each region (A7.3.3 to A7.3.7).

A7.3.1 Importance of system strength, and roles and responsibilities

The increasing integration of IBR across the NEM has implications for the engineering design of the future transmission system. As clusters of IBR connect in close proximity, generators will need to offset their impact on system strength, and TNSPs will need to ensure a basic level of fault current across their networks.

Key areas of system strength are discussed in detail in AEMO's white paper System Strength Explained[8], and include steady state voltage management, voltage dips, fault ride-through, power quality and operation of protection[9].

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

- AEMO is required to determine the fault level requirements across the NEM and identify whether a fault level shortfall is likely to exist now or in the future. The System Strength Requirements Methodology[10] defines the process AEMO must apply to determine the system strength requirement at each node.

[7] A system disturbance is an unplanned contingency on the power system, such as a high-voltage network fault (i.e. short-circuit) or an unplanned generator or large load disconnection.

[8] AEMO. *System strength in the NEM explained*, at https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[9] Protection maloperation can result in additional generation tripping during power system disturbances, loss of load due to maloperation of network equipment, and public safety risks if faults are not cleared.

[10] AEMO. *System Strength Requirements Methodology*, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

- The local TNSP is required to provide system strength services to meet the minimum three phase fault levels at relevant fault level nodes if AEMO has declared a shortfall.
- A connecting generator is required to implement or fund system strength remediation, such that its connection (or altered connection) does not have an adverse impact on system strength, assessed in accordance with AEMO's system strength impact assessment guidelines.

Regional system strength requirements

As covered in Section A7.3.2, AEMO has published guidelines with regards to system strength and mitigation requirements for new generation connections[11]. TNSPs are also required to maintain minimum fault levels at specified nodes within their networks. Should a shortfall be identified by AEMO, the TNSP is responsible for ensuring that system strength services are available to maintain the fault levels determined by AEMO. AEMO has published methodologies and assessments relating to TNSP responsibilities in maintaining minimum fault levels at specific fault level nodes[12].

As IBR continue to displace conventional generation, it will become increasingly important for TNSPs to coordinate system strength solutions. REZs that are strategically designed with system strength in mind will benefit from economies of scale to achieve optimal investment outcomes.

Local system strength remediation

Because some types of generation, including most solar and wind generators currently being developed and built, have not been designed to provide inherent contribution to system strength, REZs can be susceptible to low system strength conditions. Low system strength can impact the stability and dynamics of generating systems' control systems and the ability of the power system to remain in stable operation. Appendix 5 provides detail on REZs that are most susceptible to low system strength.

Based on projections in this ISP, many renewable developments contemplated in the 2020s are likely to require some level of system strength remediation for their connection, and from the 2030s onwards, most renewable developments would be expected to require system strength remediation. In addition, as existing thermal power stations exit, the inherent system strength (and a range of other system services) that the synchronous generators provided needs to be replaced.

Section A7.5 details outcomes highlighting that, when developing REZs:

- System strength planning can benefit from economies of scale.
- Coordinated solutions to providing system strength, to which generators contribute, are expected to be more economic than multiple small-scale solutions developed at each wind or solar farm[13].

A7.3.2 NEM-wide system strength outlook

The initial system strength requirements determined by AEMO in 2018 are currently under review, with detailed electromagnetic transient (EMT) studies now being utilised for all regions to refine the fault level requirements. Updates to some regions have been progressively published relating to where outcomes have highlighted shortfalls.

To date, AEMO has published[14] fault level shortfalls for:

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[11] AEMO. *System Strength Impact Assessment Guidelines*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Strength-Impact-Assessment-Guidelines.

[12] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

[13] Section 4.3.2 of AEMO's 2017 Victorian Annual Planning Report also previously included a worked example that demonstrated the benefits of system strength planning, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2017/2017-VICTORIAN-ANNUAL-PLANNING-REPORT.pdf.

[14] AEMO. *Notices of shortfalls in inertia and fault level*, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

- South Australia (Davenport 275 kV fault level node).
- Tasmania (George Town, Burnie, Waddamana and Risdon 220 kV fault level nodes).
- Queensland (Ross 275 kV fault level node).
- Victoria (Red Cliffs 220 kV fault level node).

Fault level requirements shown in these ISP projections are based on these latest studies, noting that these updated fault level requirements are still under review.

This ISP examined the projected outcomes from the Central and Step Change scenarios, because these project a higher IBR uptake and are expected to have greater likelihood of future system strength shortfalls.

In the 2020 System Strength and Inertia report, AEMO will update projections of system strength assessments with revised minimum demand forecasts that are currently being prepared for the 2020 ESOO. The 2020 System Strength and Inertia report will focus on the immediate 5-10 year outlook and review a wider range of sensitivities to assess the risks of potential system strength shortfalls in this period, and may declare additional system strength shortfalls to be addressed by TNSPs.

Results shown allow quantification of potential shortfalls, timings, and locations. Where new pumped hydro or other synchronous machines have been part of the optimal market modelling outcomes, generic contributions from these units have been derived and included in results.

Future fault level node definitions and fault level requirements

Projections of fault levels have been assessed using the latest fault level node and minimum fault level requirements. It is noted that these have been defined for the existing power system and locations of generation. As the generation and transmission systems develop, both the fault level nodes and fault level requirements will change. For example, where there are significant coal-fired generation retirements in a generation centre that is currently synchronous, it may be more appropriate to change the fault level nodes and their requirements than to try to maintain historic fault levels at the old fault level nodes. It is also anticipated that fault level node definitions will need to shift to where large clusters of new generation are being built, for example, closer to major REZs.

AEMO needs to undertake detailed system strength studies prior to the projected generation retirements to more accurately determine system strength mitigation options, or options to allow operation of the network at lower fault levels. This work must provide outcomes sufficiently ahead to enable the requisite economic assessments and procurement of equipment.

Procurement of system strength mitigation such as large synchronous condensers is expected to take at least 18 months to two years; there is a risk of being caught out by early generation retirements or failures, as these are aspects not easily forecast. In some locations, network upgrades may also be required to facilitate integration of synchronous condensers due to (local) increases in fault level.

Other technical solutions such as grid forming inverters associated with battery energy storage systems (BESS) are anticipated to be able to provide system services in the future and reduce the need for synchronous machines to provide fault current and inertia. Fault level requirements and potential remediation options will need to adapt to take new technologies into account.

Results from the Step Change scenario also highlight the need to appreciate the risks associated with early coal unit retirements.

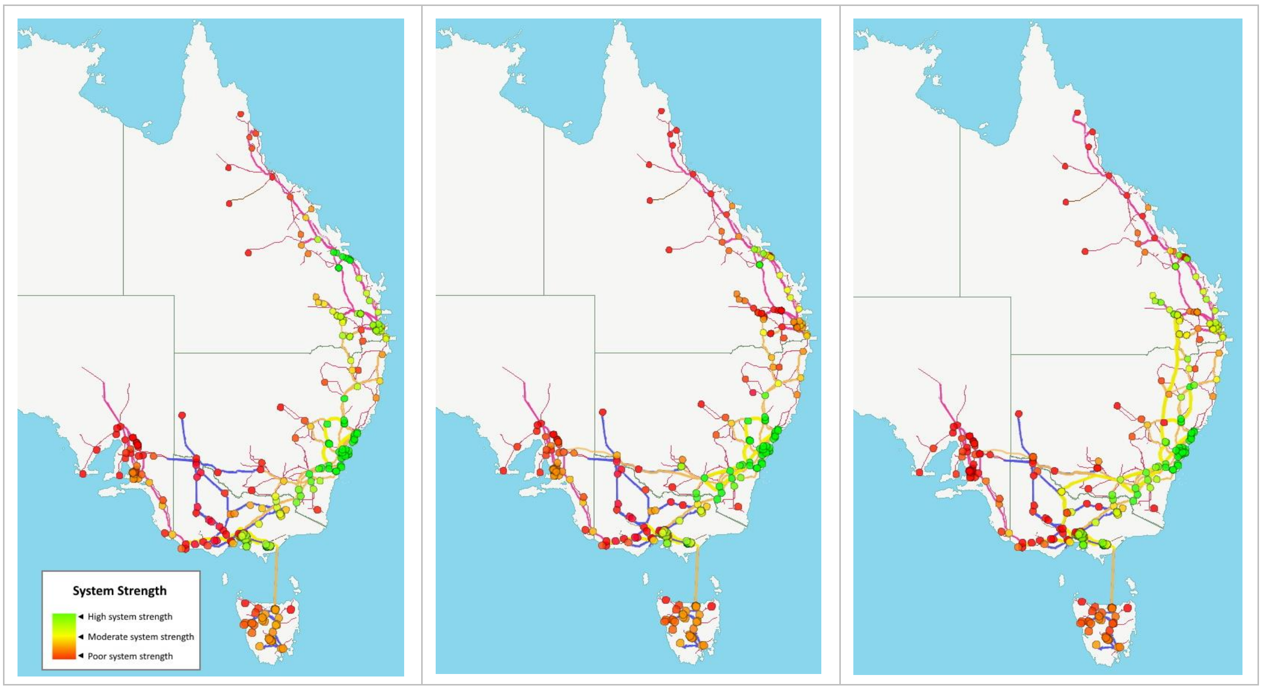
Available fault levels

For this ISP, AEMO used the Available Fault Level calculation methodology[15] to perform high level system strength impact assessments (see Figure 1), and the more comprehensive System Strength Requirements Methodology[16] for determining system strength requirements at fault level nodes (see the following sections).

Snapshot periods from the market modelling outputs with low levels of synchronous generation online have been analysed across the NEM for particular years.

Figure 1 demonstrates areas that already have low system strength, and projects where system strength is expected to decrease unless investments are made.

Figure 1 NEM-wide system strength outlook 2020-21 (left), 2029-30 (centre), 2034-35 (right), Central scenario



Note: For system strength analysis, the timing of VNI West was modelled as 2034-35, however the actual timing of this augmentation is subject to decision rules and could be as early as 2027-28.

In Figure 1:

- Results for 2020-21 show areas with existing low system strength such as Western Victoria, South West New South Wales, Northern Queensland, and Tasmania.
- In 2029-30:
  - The 330 kV transmission lines, as well as the synchronous condensers associated with Project EnergyConnect, will improve the system strength outlook around central South Australia, western Victoria, and south-west New South Wales. The upgrades being undertaken in the Western Victoria Transmission Network Project will also improve the system strength outlook in western Victoria, demonstrating the importance of taking into account network upgrades for system strength assessments.

[15] AEMO. *System Strength Impact Assessment Guidelines*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

[16] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

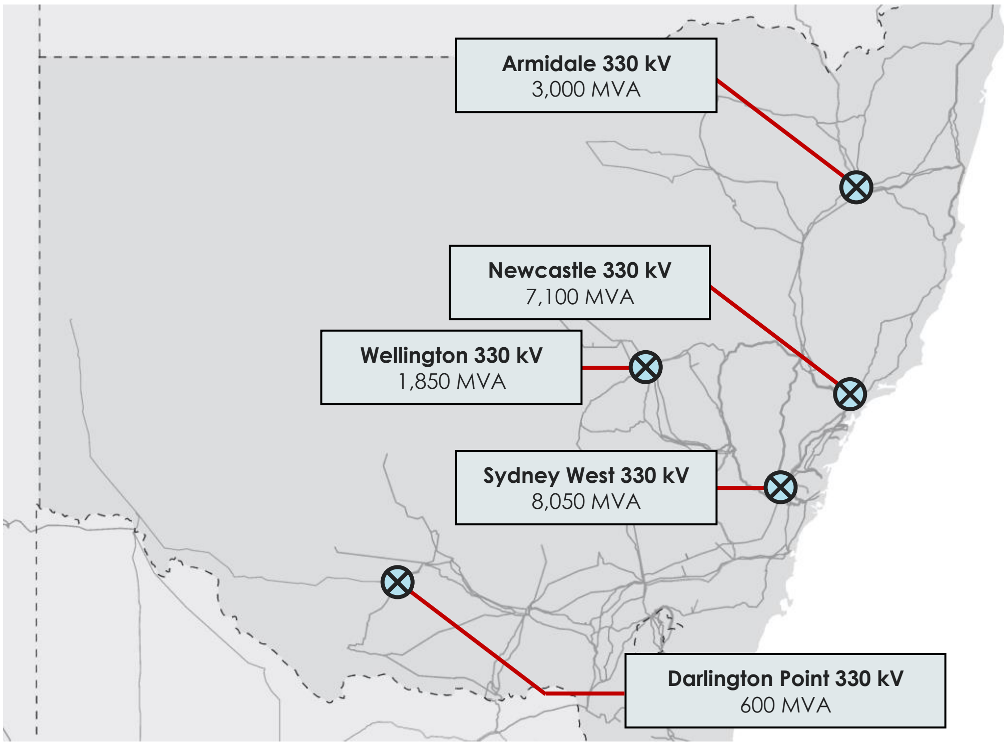
- High levels of new IBR are projected in the optimal development path, and these are expected to be required to include system strength remediation due to low system strength emerging or worsening in south-west Victoria, northern New South Wales and central Queensland.

- In 2034-35:
  - Retirement of thermal power stations such as Vales and Eraring will significantly reduce available system strength, including in central New South Wales.
  - Improvements in system strength are expected as a result of new transmission that is delivered as part of the optimal development path, for example, in REZs in northern New South Wales, and the second QNI interconnector. As projected additional IBR connect to these areas later in the timeframe, and additional coal plant retires, the available system strength will reduce.

A7.3.3 New South Wales system strength outlook

AEMO has determined the following fault level nodes for New South Wales. They represent a metropolitan load centre, a synchronous generation centre, areas with high IBR, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[17] outlines the process for determining the system strength requirement at each node.

Figure 2 New South Wales system strength (fault level) post contingent requirements



The ISP system strength assessments for New South Wales are outlined in Table 2 and Table 3. Fault level requirements shown are based on draft EMT studies that are ongoing. The ISP studies have found that:

- The proposed Project EnergyConnect (see Section 3) is projected to improve system strength in South West New South Wales, as the network upgrade includes synchronous condensers at Buronga and close to Darlington Point.

[17] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

- Following the exit of Vales Point, Mt Piper and Eraring Power Stations, there are projected shortfalls at the Sydney West and Newcastle fault level nodes.

Table 2 New South Wales projected system strength – Central scenario

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Armidale 330 kV	Figure 3	Yes	Yes	Yes	Increases following transmission network upgrades to QNI
Sydney West 330 kV	Figure 4	Yes	Yes	1,600 MVA potential shortfall †	Results from Vales Point closure in 2030, and Eraring in 2033
Wellington 330 kV	Figure 5	Yes	Yes	Yes	
Newcastle 330 kV	Figure 6	Yes	Yes	1,900 MVA potential shortfall †	Results from Vales Point closure in 2030, and Eraring in 2033
Darlington Pt 330 kV	Figure 7	Yes	Yes	Yes	

† Although AEMO projects that a shortfall may arise before 2035, a fault level shortfall is not formally declared at this stage.

Table 3 New South Wales projected system strength – Step Change scenario

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Armidale 330 kV	Figure 3	Yes	Yes	Yes	Increases following transmission network upgrades to QNI
Sydney West 330 kV	Figure 4	Yes	Yes	2,700 MVA potential shortfall †	Results from Vales Point closure in 2026, Mt Piper in 2032 and Eraring in 2033
Wellington 330 kV	Figure 5	Yes	Yes	100 MVA potential shortfall †	Remediation at Sydney West and Newcastle nodes will also resolve this shortfall.
Newcastle 330 kV	Figure 6	Yes	Yes	2,700 MVA potential shortfall †	Results from Vales Point closure in 2026, Mt Piper in 2032 and Eraring in 2033
Darlington Pt 330 kV	Figure 7	Yes	Yes	Yes	

† Although AEMO projects that a shortfall may arise before 2035, a fault level shortfall is not formally declared at this stage.

The following figures show the projected fault level duration curves for each fault level node in New South Wales against the minimum fault level requirement, highlighting:

- A forecast step increase at Darlington Point when Project EnergyConnect is commissioned in 2023-24, because of the new synchronous condensers associated with the upgrade. TransGrid's preferred route for Project EnergyConnect is now anticipated to be a direct path from Buronga to Wagga Wagga, rather than via the existing Darlington Point substation[18]. While an increase in fault level is still expected at the

[18] TransGrid. *Transmission Annual Planning Report*, at https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf.

Darlington Point substation, it will not be as high as the projections shown. Further analysis will be included in the 2020 System Strength and Inertia Report.

- A projected step increase at Armidale when the projected QNI Medium and North West New South Wales REZ upgrades are commissioned.
- A forecast trend of decreasing system strength across New South Wales due to the retirement of synchronous generation and the transition to IBR.
- Large shortfalls at the Newcastle and Sydney West 330 kV buses by 2035 in the Step Change scenario due to accelerated coal unit retirements.

Figure 3 Projected Armidale 330 kV fault level duration curves, Central and Step Change scenarios

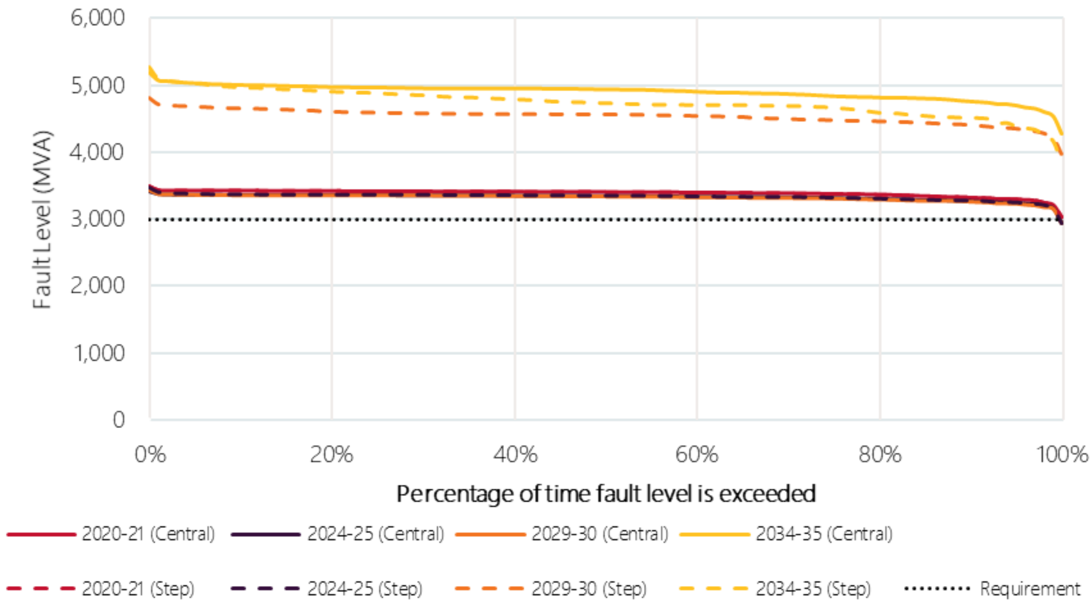


Figure 4 Projected Sydney West 330 kV fault level duration curves, Central and Step Change scenarios

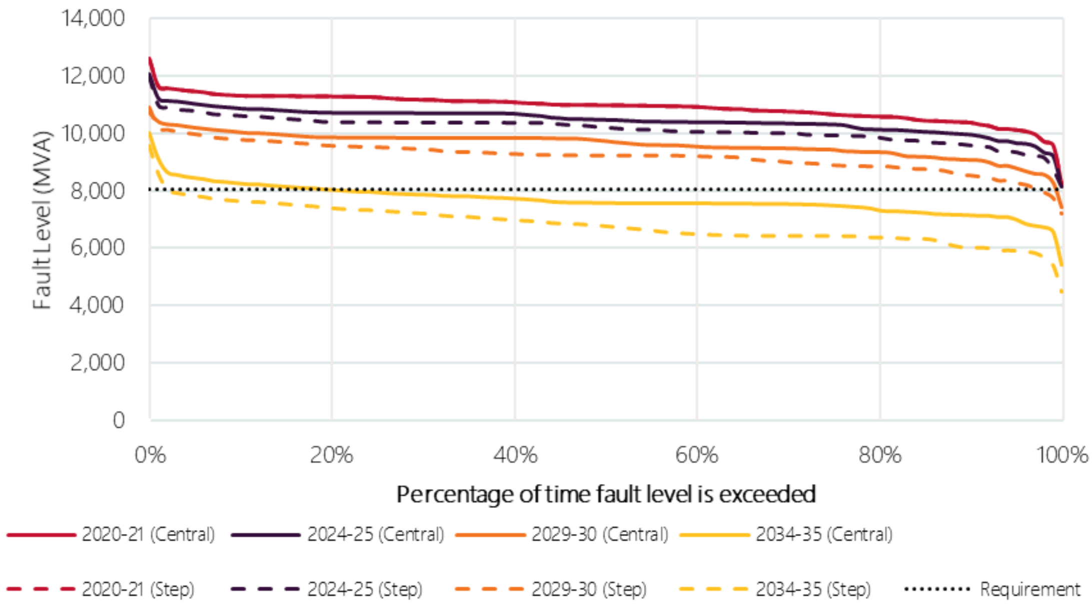


Figure 5 Projected Wellington 330 kV fault level duration curves, Central and Step Change scenarios

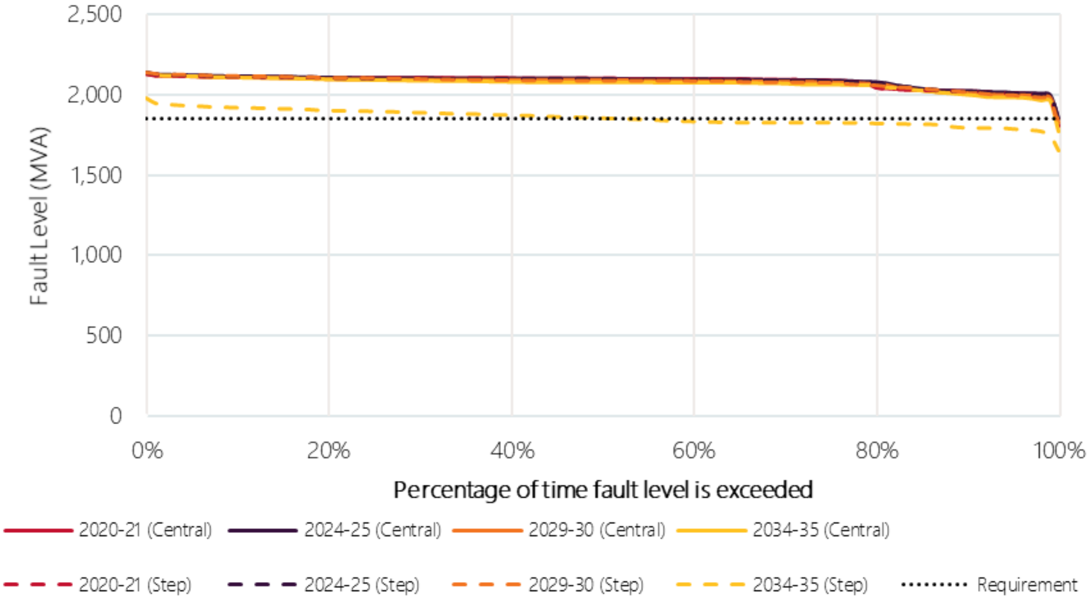


Figure 6 Projected Newcastle 330 kV fault level duration curves, Central and Step Change scenarios

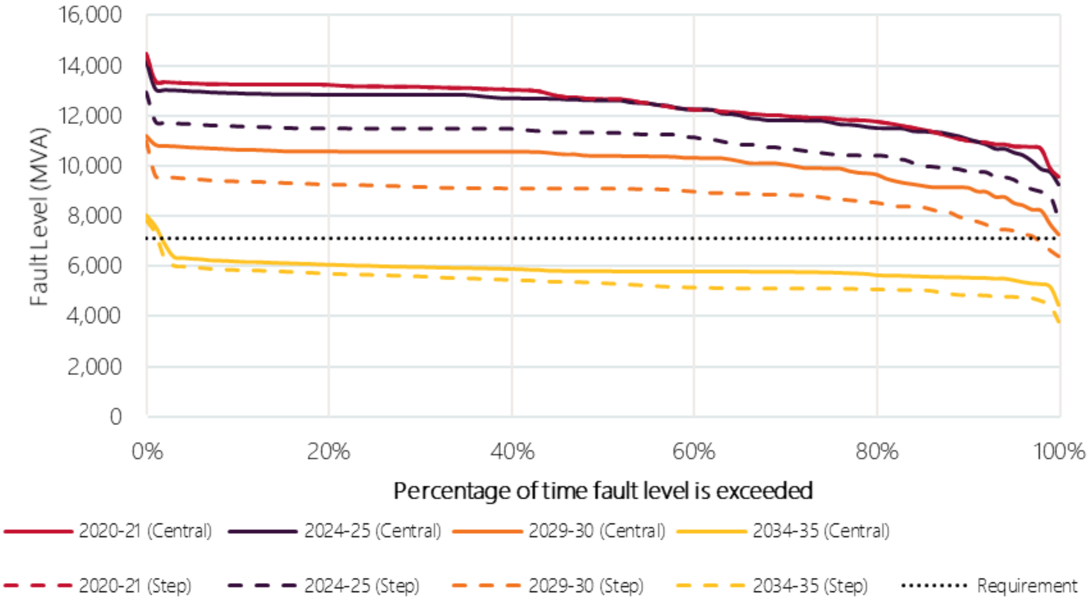
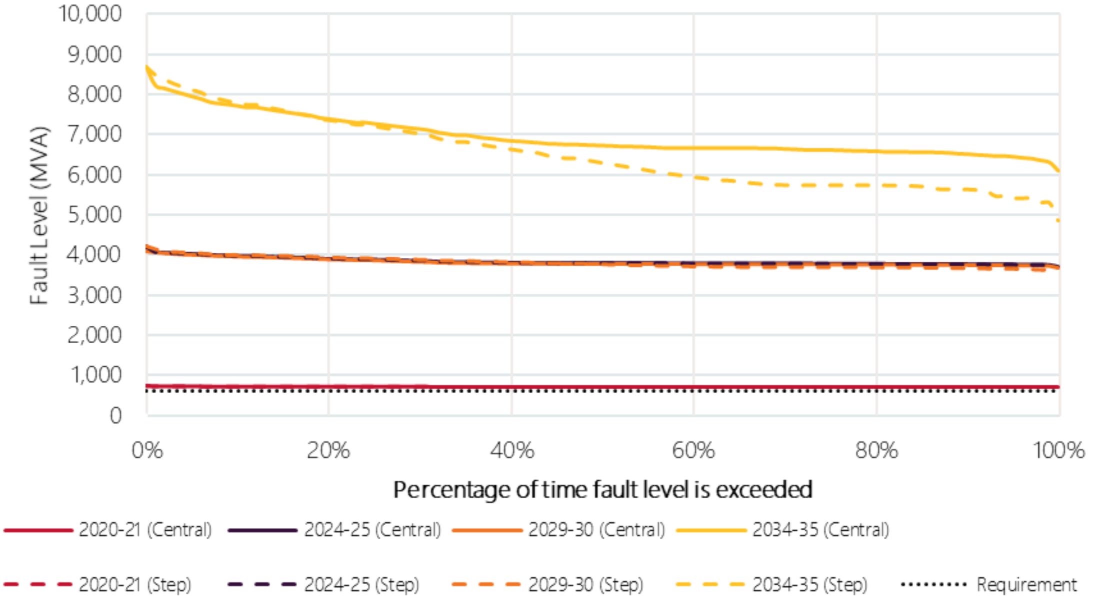


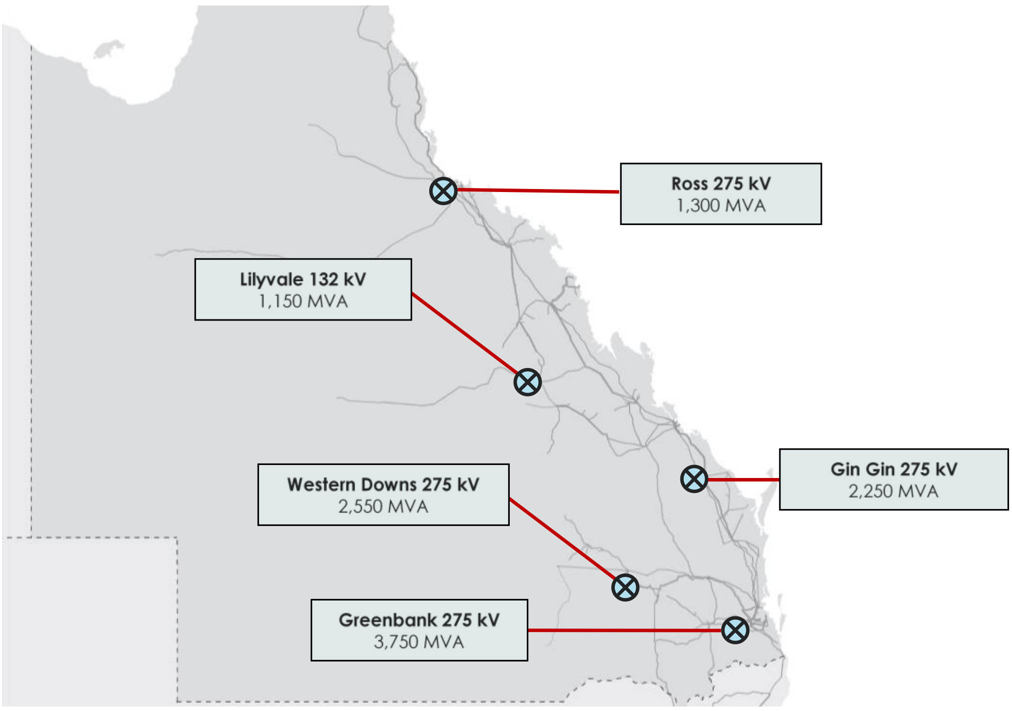
Figure 7 Projected Darlington Point 330 kV fault level duration curves, Central and Step Change scenarios



A7.3.4 Queensland system strength outlook

AEMO has determined the following fault level nodes for Queensland. Together they represent a metropolitan load centre, a synchronous generation centre, areas with high IBR, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[19] outlines the process for determining the system strength requirement at each node.

Figure 8 Queensland system strength (fault level) post contingent requirements



[19] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

The ISP system strength assessments for Queensland are in Table 4 and Table 5. These studies are based on the fault level requirements published as part of the Ross shortfall declaration[20]. Powerlink is currently in the process of finalising the system strength services in order to meet the declared gap at Ross.

These studies have found that across Queensland, there is a projected trend of decreasing system strength due to the retirement of synchronous generation and the transition to IBR, particularly in the Step Change scenario, which projects Callide B retiring in 2029, three Gladstone units retiring by 2025, all Tarong units in 2026 and Tarong North in 2027.

Table 4 Queensland projected system strength – Central scenario

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Western Downs 275 kV	Figure 9	Yes	Yes	Yes	
Greenbank 275 kV	Figure 10	Yes	Yes	Yes	
Ross 275 kV	Figure 11	Shortfall	Shortfall	Shortfall	Existing shortfall. Powerlink currently finalising system strength services to meet the current gap.
Gin Gin 275 kV	Figure 12	Yes	Yes	Yes	
Lilyvale 132 kV	Figure 13	Yes	Yes	Yes	

Table 5 Queensland projected system strength – Step Change scenario

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Western Downs 275 kV	Figure 9	Yes	Yes	Yes	
Greenbank 275 kV	Figure 10	Yes	Yes	400 MVA potential shortfall †	Results from Tarong units retiring in 2026 and Tarong North in 2027
Ross 275 kV	Figure 11	Shortfall	Shortfall	Shortfall	Existing shortfall. Powerlink currently finalising system strength services to meet the current gap.
Gin Gin 275 kV	Figure 12	Yes	70 MVA potential shortfall†	350 MVA potential shortfall †	Results from three Gladstone units retiring by 2025, and Callide B in 2029
Lilyvale 132 kV	Figure 13	Yes	Yes	100 MVA potential shortfall †	Results from three Gladstone units retiring in 2025, and Callide B in 2029

† Although AEMO projects that a shortfall may arise before 2025 or 2035, a fault level shortfall is not formally declared at this stage.

The following figures show the projected fault level duration curves for each fault level node in Queensland, highlighting:

[20] AEMO. *2020 Notice of Queensland system strength requirements and Ross node fault level shortfall*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-queensland-system-strength-requirements-and-ross-node-fault-level-shortfall.pdf?la=en&hash=398E515E24B7022406B6B391F269CBBB.

- A forecast step increase at Western Downs following the commissioning of the QNI medium upgrade in 2031-32.
- Reductions at Greenbank, Gin Gin and Lilyvale due to the retirement of synchronous generators, in the Step Change scenario.
- The existing shortfall declared for the Ross node persists across the study timeframes.

Figure 9 Projected Western Downs 275 kV fault level duration curves, Central and Step Change scenarios

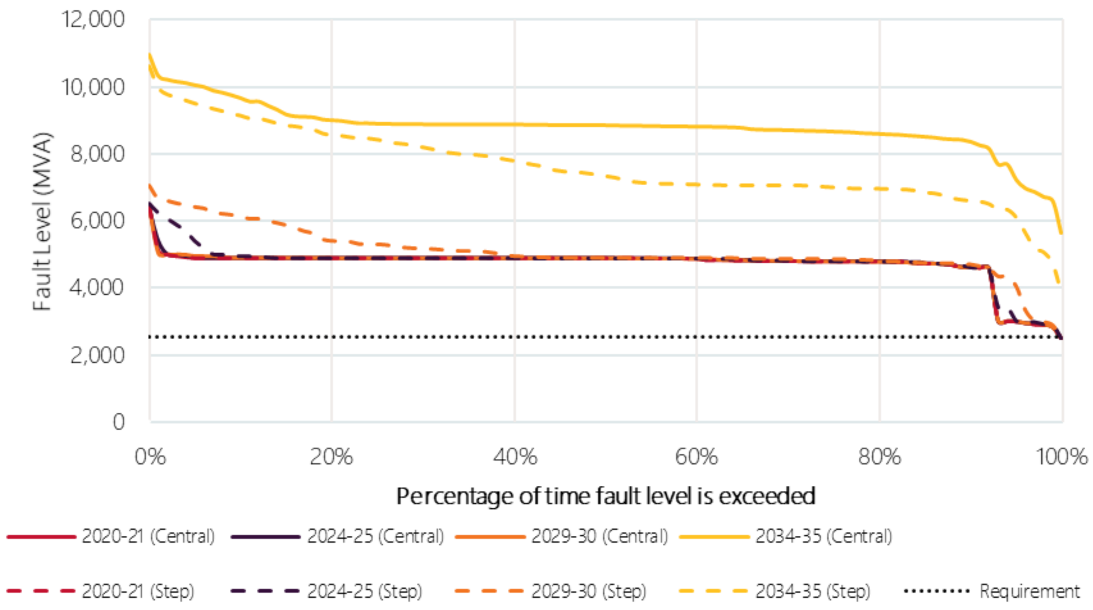


Figure 10 Projected Greenbank 275 kV fault level duration curves, Central and Step Change scenarios

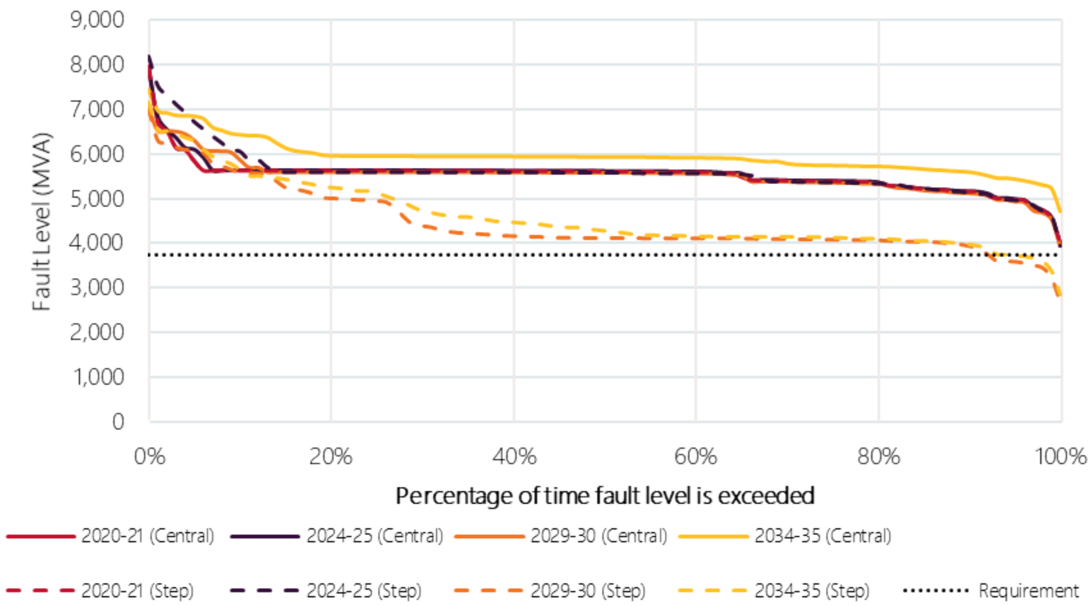


Figure 11 Projected Ross 275 kV fault level duration curves, Central and Step Change scenarios

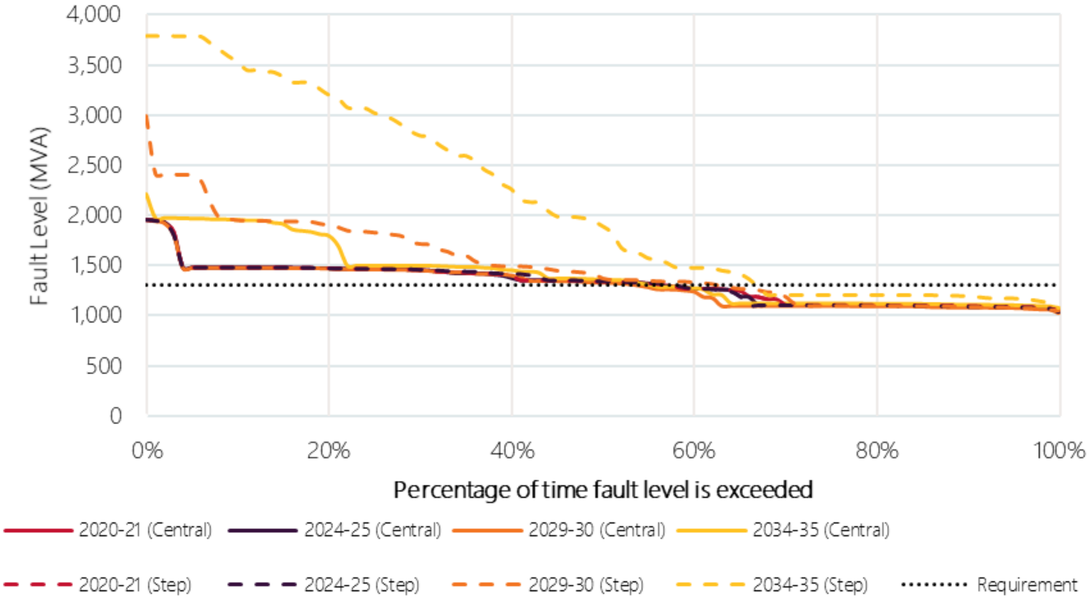


Figure 12 Projected Gin Gin 275 kV fault level duration curves, Central and Step Change scenarios

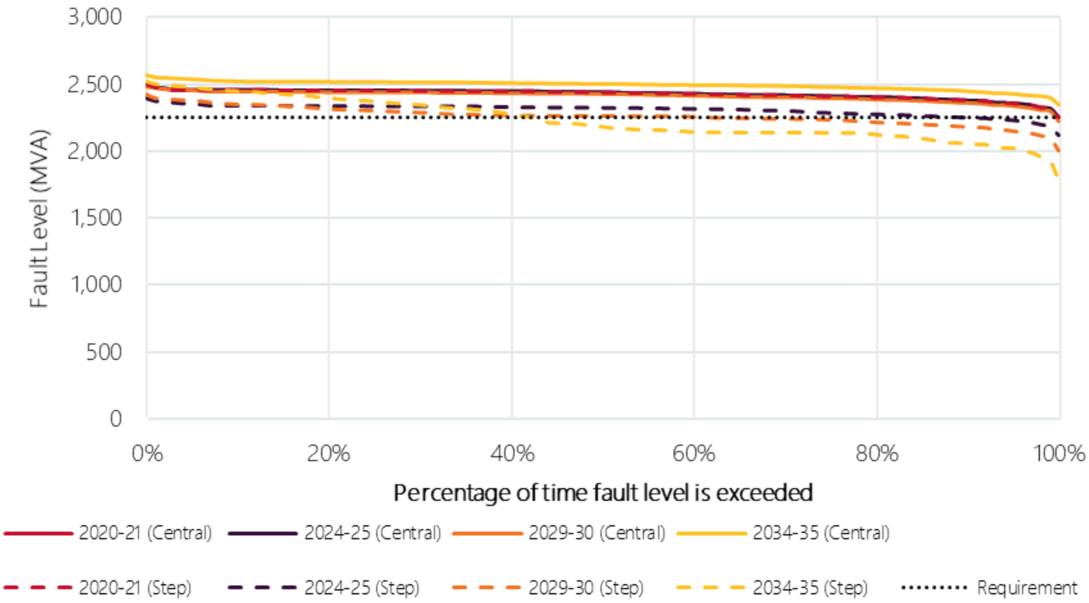
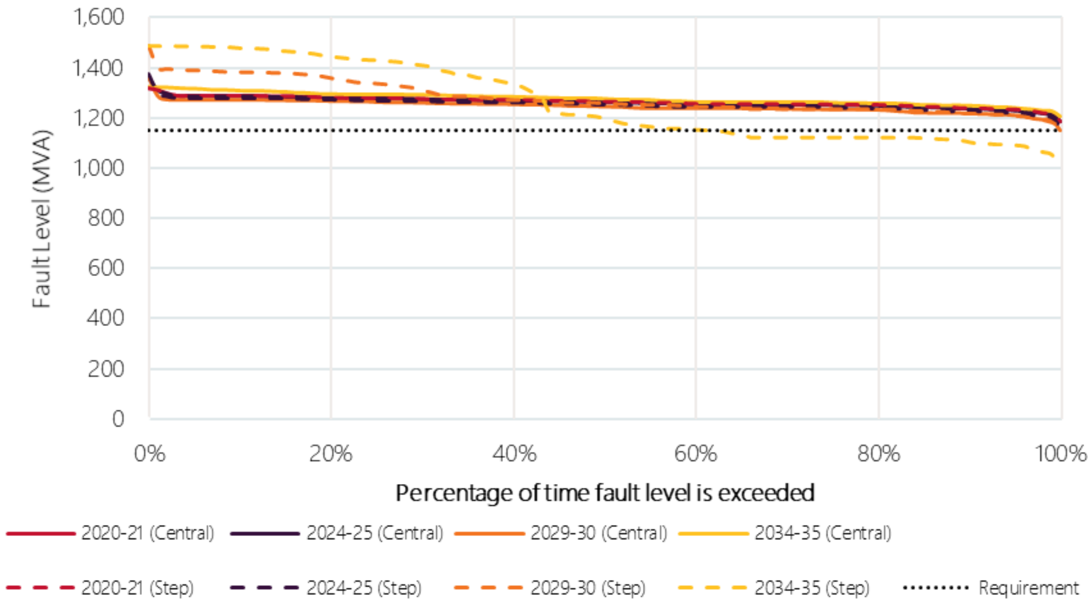


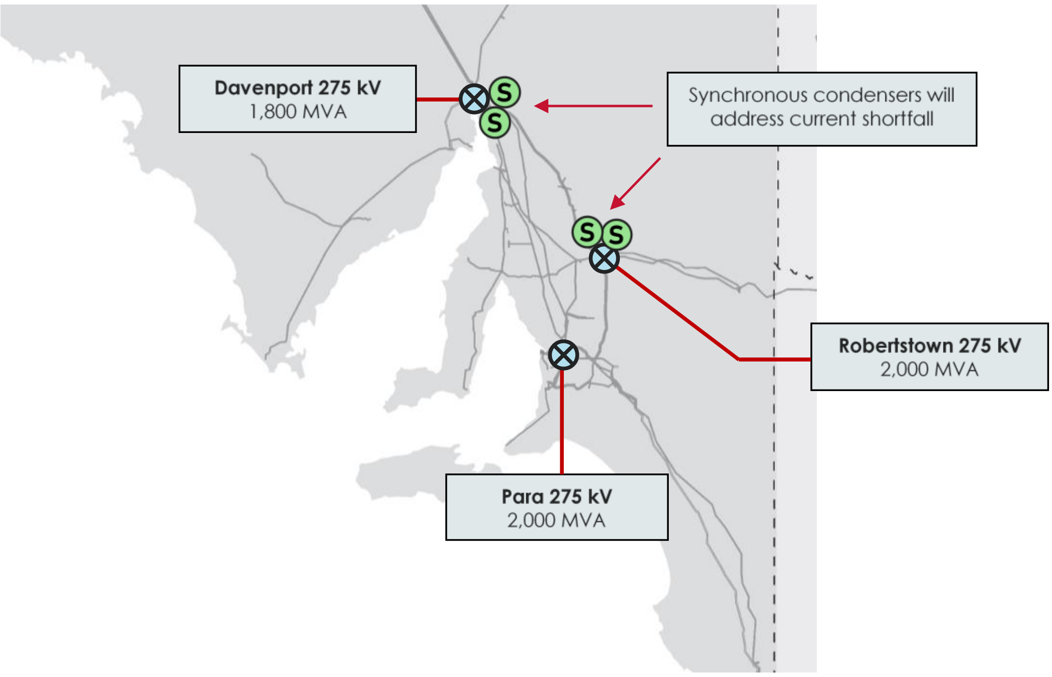
Figure 13 Projected Lilyvale 132 kV fault level duration curves, Central and Step Change scenarios



A7.3.5 South Australia system strength outlook

AEMO has determined the following fault level nodes for South Australia. They represent a metropolitan load centre, a synchronous generation centre, areas with high IBR, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[21] outlines the process for determining the system strength requirement at each node.

Figure 14 South Australia system strength (fault level) post-contingent requirements



[21] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

The ISP system strength assessments for South Australia are in Table 6. These are based on draft EMT studies relating to fault level requirements once the new synchronous condensers are installed. This analysis is ongoing, but the studies have found that the new synchronous condensers at Davenport and Robertstown in 2020-21 are projected to address the current fault level shortfall.

AEMO is currently intervening in the market to ensure the system strength requirements in South Australia[22] will be met on a day-to-day basis until the synchronous condensers are installed.

Table 6 South Australian projected system strength – Step Change and Central scenario

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Davenport 275 kV	Figure 15	Shortfall	Yes	Yes	The current shortfall will be resolved when synchronous condensers are installed at Davenport and Robertstown (see section A7.6).
Para 275 kV	Figure 16	Shortfall	Yes	Yes	The current shortfall will be resolved when synchronous condensers are installed at Davenport and Robertstown
Robertstown 275 kV	Figure 17	Shortfall	Yes	Yes	The current shortfall will be resolved when synchronous condensers are installed at Davenport and Robertstown

The following figures show the projected fault level duration curves for each fault level node in South Australia, highlighting a forecast step increase across South Australia when the new synchronous condensers are commissioned in 2020-21, and also at Robertstown when Project EnergyConnect is commissioned in 2024-25. The projected system strength shows that requirements are expected to be met in the future.

[22] AEMO. *Limits Advice*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

Figure 15 Projected Davenport 275 kV fault level duration curves, Central and Step Change scenarios

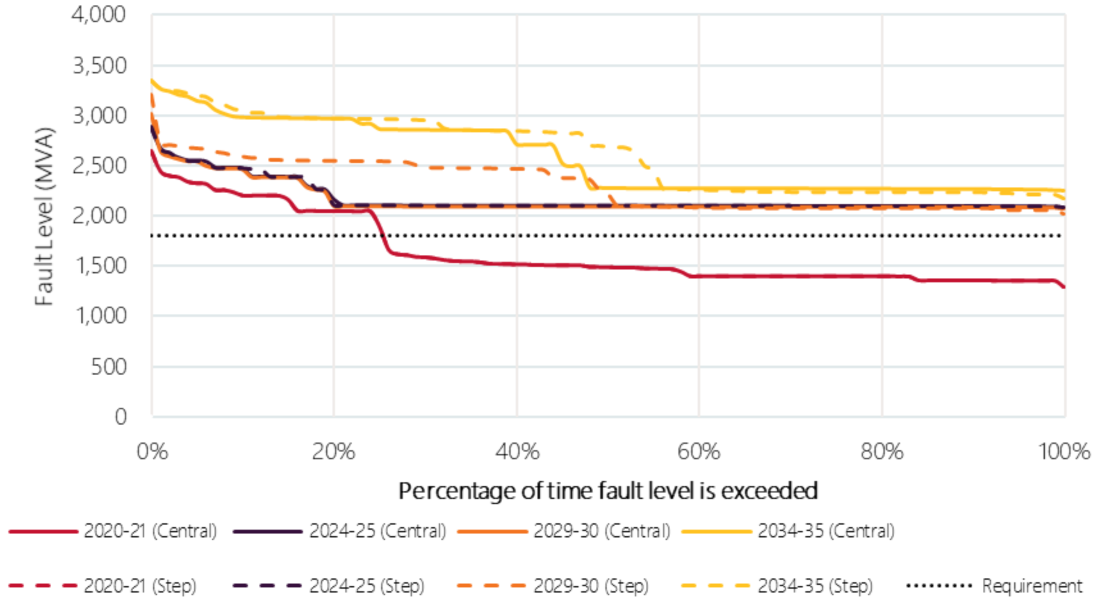


Figure 16 Projected Para 275 kV fault level duration curves, Central and Step Change scenarios

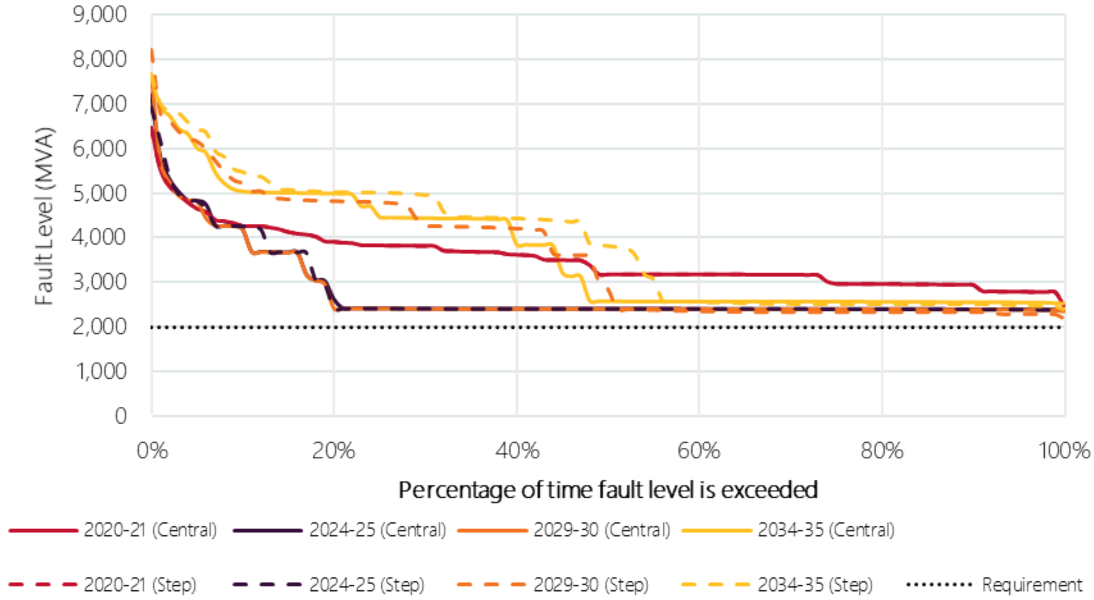
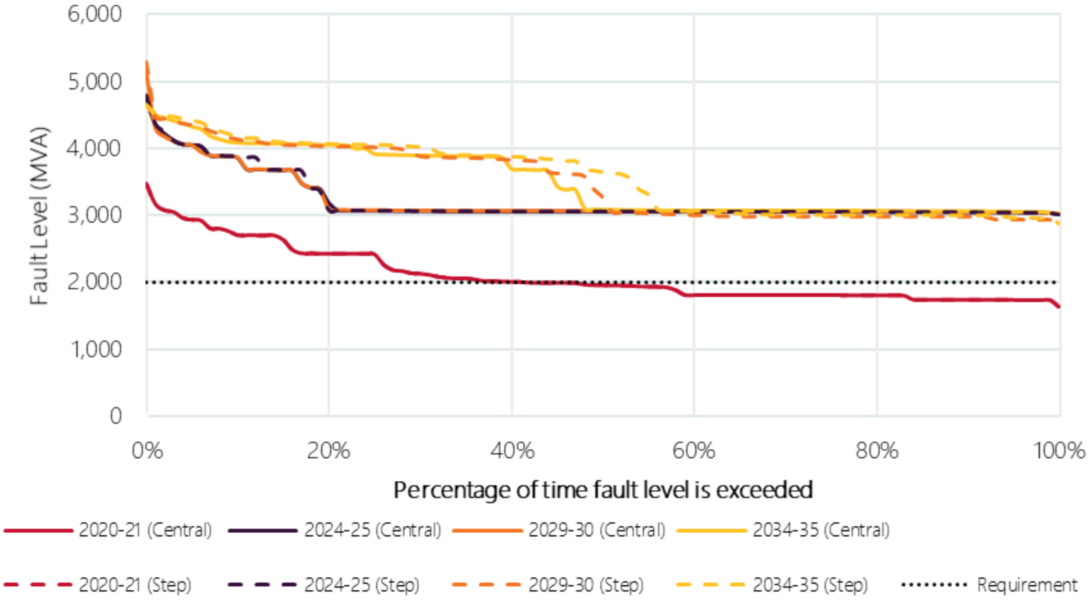


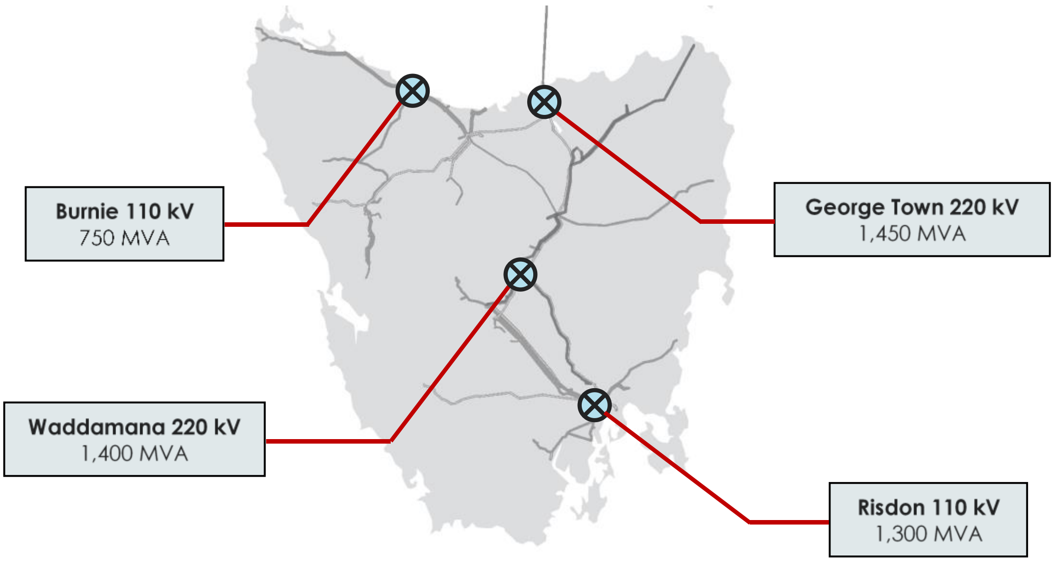
Figure 17 Projected Robertstown 275 kV fault level duration curves, Central and Step Change scenarios



A7.3.6 Tasmania system strength outlook

AEMO has determined the following fault level nodes for Tasmania. They represent a metropolitan load centre, a synchronous generation centre, areas with high IBR, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[23] outlines the process for determining the system strength requirement at each node.

Figure 18 Tasmanian system strength (fault level) system normal requirements



[23] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

The ISP system strength assessments for Tasmania are in Table 7. Fault level and inertia shortfalls were declared for Tasmania in November 2019[24], and fault level requirement numbers are based on these studies. TasNetworks has now procured sufficient system strength and inertia services to meet the declared gaps in the form of support contracts to be able to operate existing synchronous plant either at low output levels, or in synchronous condenser mode when required. These arrangements are expected to be reviewed prior to the contract end date of 2024. The fault level projections do not include the contribution from the support contracts arranged by TasNetworks.

Table 7 Tasmanian projected system strength – Step Change and Central scenarios

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
George Town 220 kV	Figure 19	Resolved with system strength services made available by TasNetworks.	Shortfall	Shortfall	
Risdon 110 kV	Figure 20	Resolved with system strength services made available by TasNetworks.	Shortfall	Shortfall	
Waddamana 220 kV	Figure 21	Resolved with system strength services made available by TasNetworks.	Shortfall	Shortfall	
Burnie 110 kV	Figure 22	Resolved with system strength services made available by TasNetworks.	Shortfall	Shortfall	

The following figures show the projected fault level duration curves for each fault level node in Tasmania. All the figures show a current shortfall, and worsening system strength into the future as IBR displaces synchronous generation; that is, the existing shortfall is currently projected to continue to occur for the long term and procurement of system strength services will need to continue.

[24] AEMO. *Notice of Inertia and Fault Level Shortfalls in Tasmania*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

Figure 19 Projected George Town 220 kV fault level duration curves, Central and Step Change scenarios

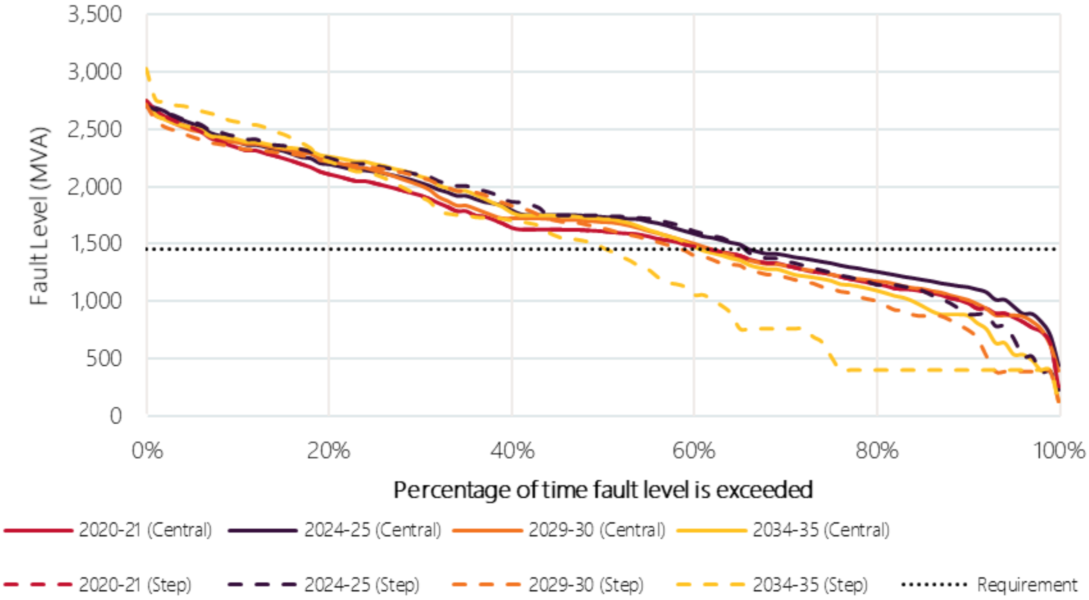


Figure 20 Projected Risdon 110 kV fault level duration curves, Central and Step Change scenarios

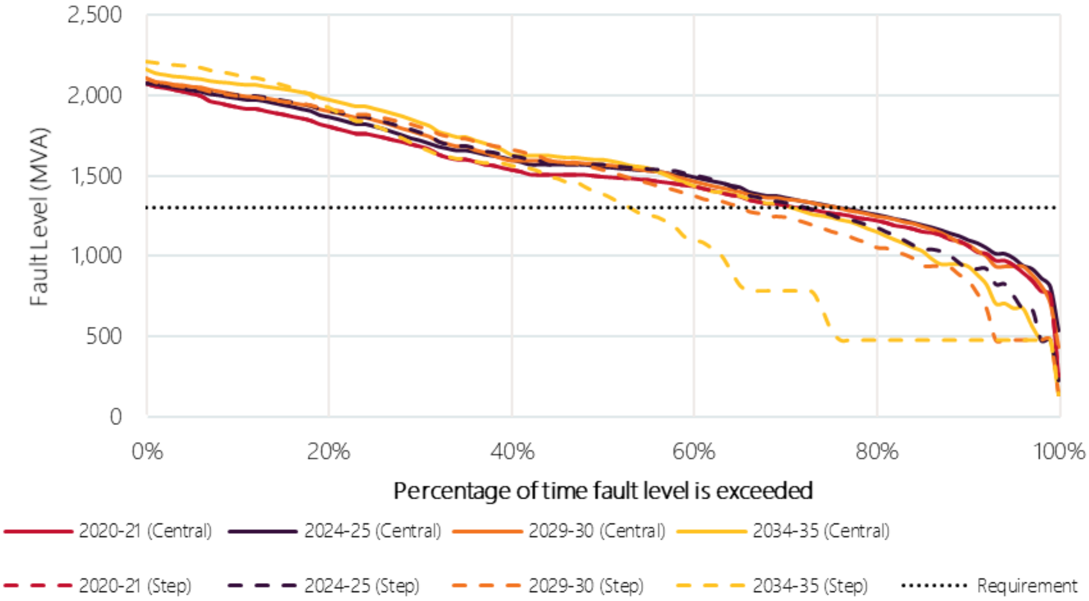


Figure 21 Projected Waddamana 220 kV fault level duration curves, Central and Step Change scenarios

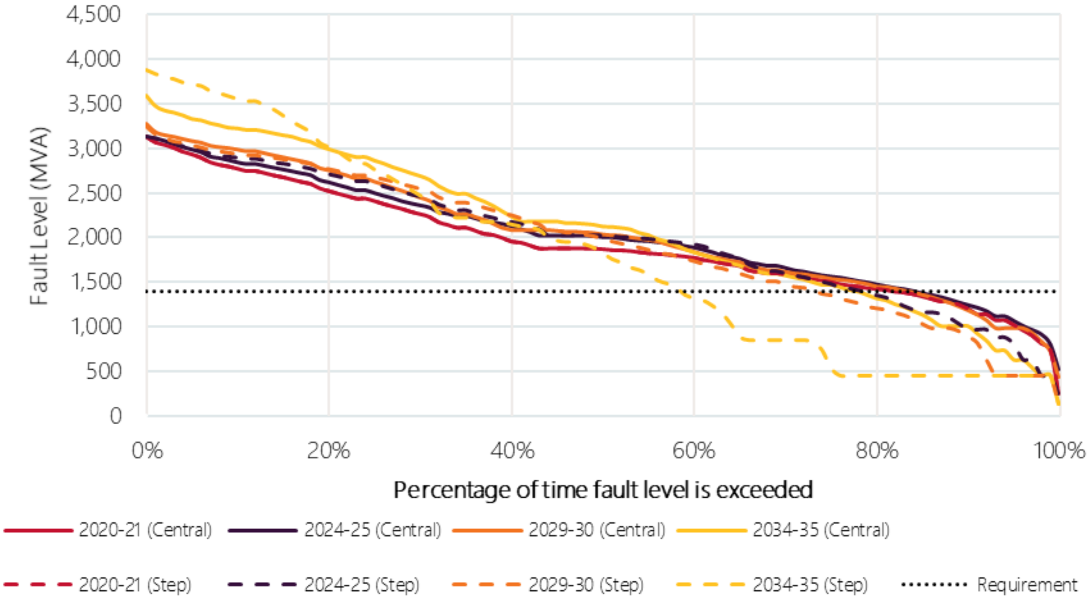
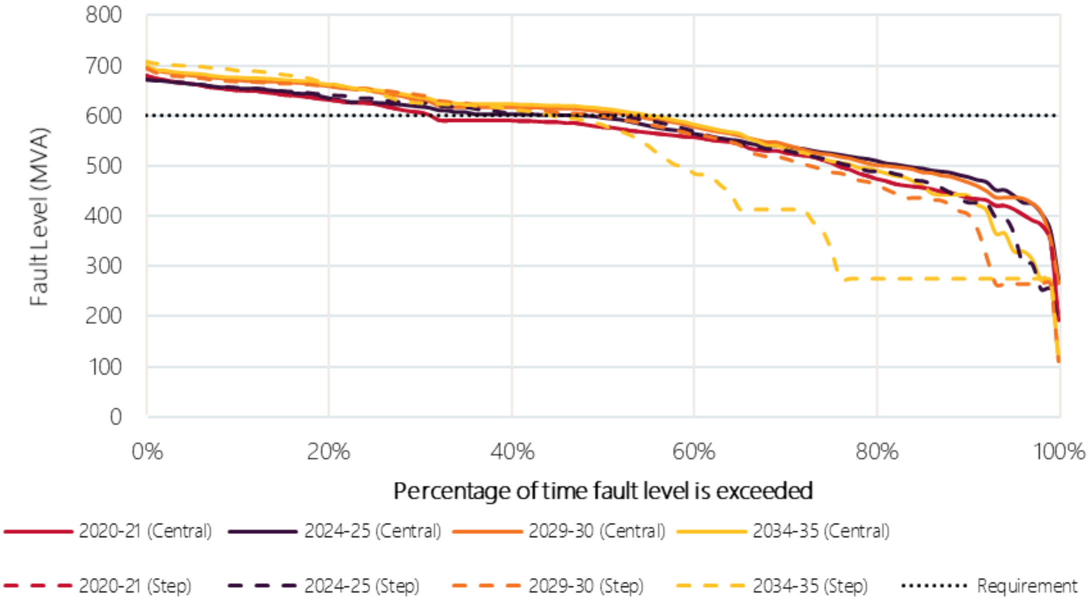


Figure 22 Projected Burnie 110 kV post-contingent fault level duration curves, Central and Step Change scenarios

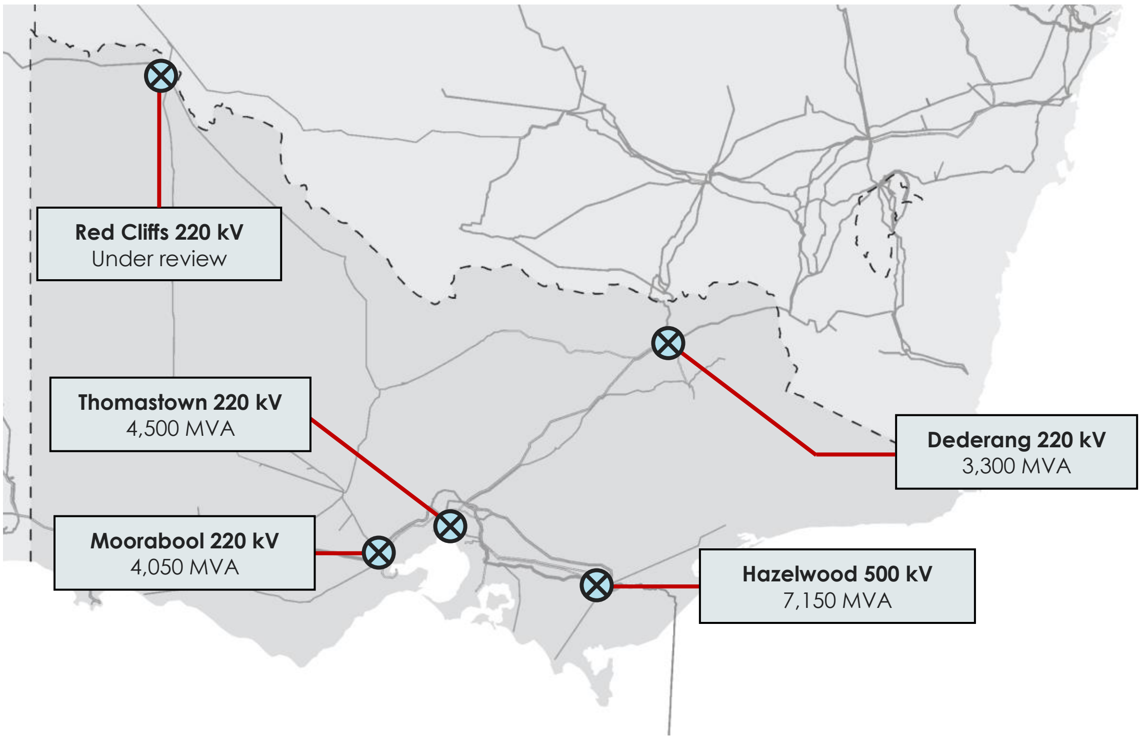


A7.3.7 Victoria system strength outlook

AEMO has determined the following fault level nodes for Victoria. They represent the metropolitan load centre, a synchronous generation centre, areas with high IBR, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[25] outlines the process for determining the system strength requirement at each node.

[25] AEMO. *System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls*, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

Figure 23 Victorian system strength (fault level) post-contingent requirements



The ISP system strength assessments for Victoria are outlined in Table 8 and Table 9. This analysis was based on the fault level requirements derived from the EMT studies undertaken to determine the minimum stable synchronous generation combinations for the Victorian region[26].

AEMO is currently progressing updated requirement studies for the Red Cliffs fault level node, as well as the procurement of interim system strength services to meet the declared shortfall. On completion of these studies, an update will be published.

ISP Results show:

- Following the closure of Yallourn Power Station (announced by EnergyAustralia to be staged between 2029 and 2032[27]), a shortfall is projected at the Hazelwood fault level node. Sufficient fault level is required at this node to ensure stable operation of the Basslink HVDC interconnector.
- In the Step Change scenario, there is a projected early retirement of the Loy Yang A power station in 2027/28, leading to larger shortfalls to be projected.

[26] AEMO. *Limits Advice*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

[27] AEMO. *Generating Unit Expected Closure Year*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Table 8 Victorian projected system strength – Central scenario*

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Thomastown 220 kV	Figure 24	Yes	Yes	500 MVA potential shortfall †	Results from Yallourn Power Station retirement by 2033
Moorabool 220 kV	Figure 25	Yes	Yes	Yes	
Dederang 220 kV	Figure 26	Yes	Yes	Yes	
Hazelwood 500 kV	Figure 27	Yes	Yes	100 MVA potential shortfall †	Results from Yallourn Power Station retirement by 2033

† Although AEMO projects that a shortfall may arise before 2035, a fault level shortfall is not formally declared at this stage.
* AEMO is currently progressing updated requirement studies for the Red Cliffs fault level node, not included in this table.

Table 9 Victorian projected system strength – Step Change scenario*

Fault level node	Duration curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2035	
Thomastown 220 kV	Figure 24	Yes	Yes	1,400 MVA potential shortfall †	To be resolved in conjunction with Hazelwood fault level shortfall remediation.
Moorabool 220 kV	Figure 25	Yes	Yes	500 MVA potential shortfall †	To be resolved in conjunction with Hazelwood fault level shortfall remediation.
Dederang 220 kV	Figure 26	Yes	Yes	Yes	
Hazelwood 500 kV	Figure 27	Yes	Yes	3,500 MVA potential shortfall †	Results from Yallourn Power Station retirement by 2030, and Loy Yang A retirement by 2028.

† Although AEMO projects that shortfalls may arise before 2035, fault level shortfalls are not formally declared at this stage.
* AEMO is currently progressing updated requirement studies for the Red Cliffs fault level node, not included in this table.

The following figures show the projected fault level duration curves for each fault level node in Victoria (except for Red Cliffs), highlighting:

- A projected shortfall at Hazelwood, Moorabool and Thomastown as a result of staged Yallourn retirement (from 2029-31 in the Central scenario and 2026-27 in the Step Change scenario) and staged Loy Yang A retirement from 2027 in the Step Change scenario. This will be further reviewed as part of the 2020 System Strength report.

Figure 24 Projected Thomastown 220 kV fault level duration curves, Central and Step Change scenarios

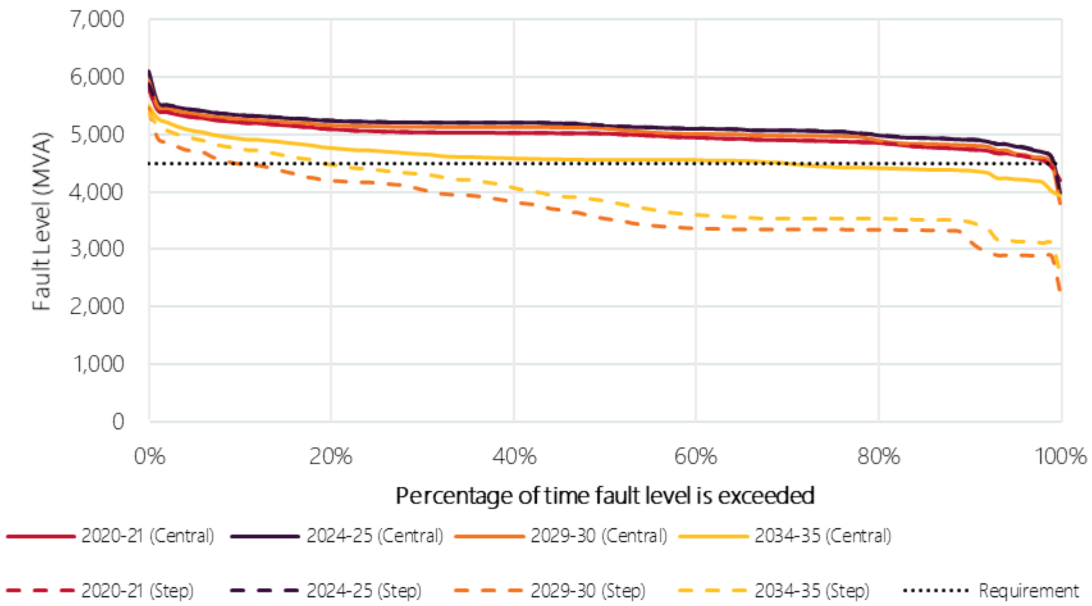


Figure 25 Projected Moorabool 220 kV fault level duration curves, Central and Step Change scenarios

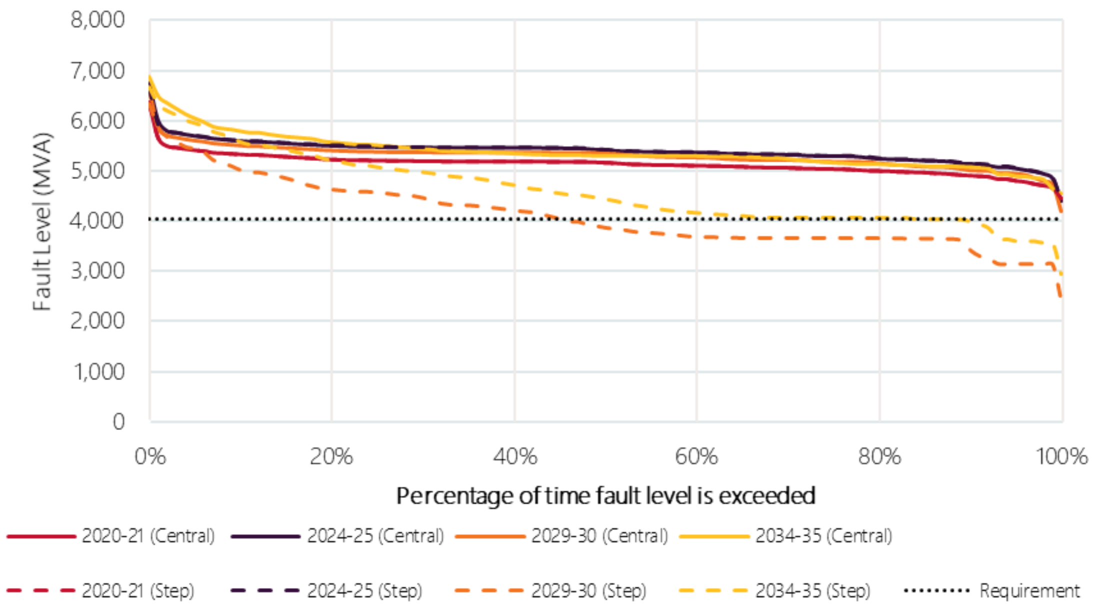


Figure 26 Projected Dederang 220 kV fault level duration curves, Central and Step Change scenarios

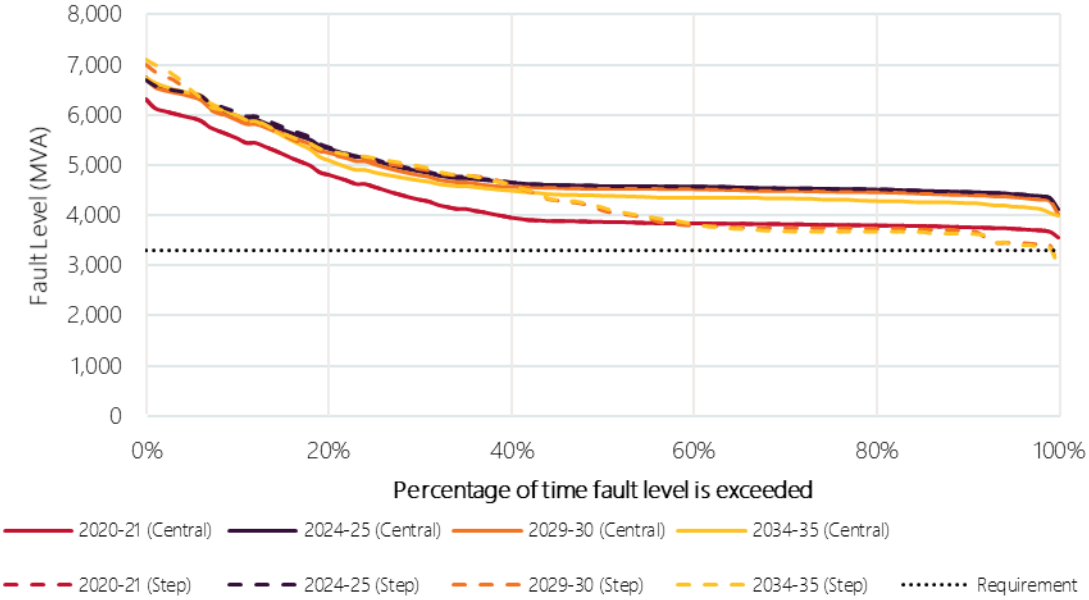
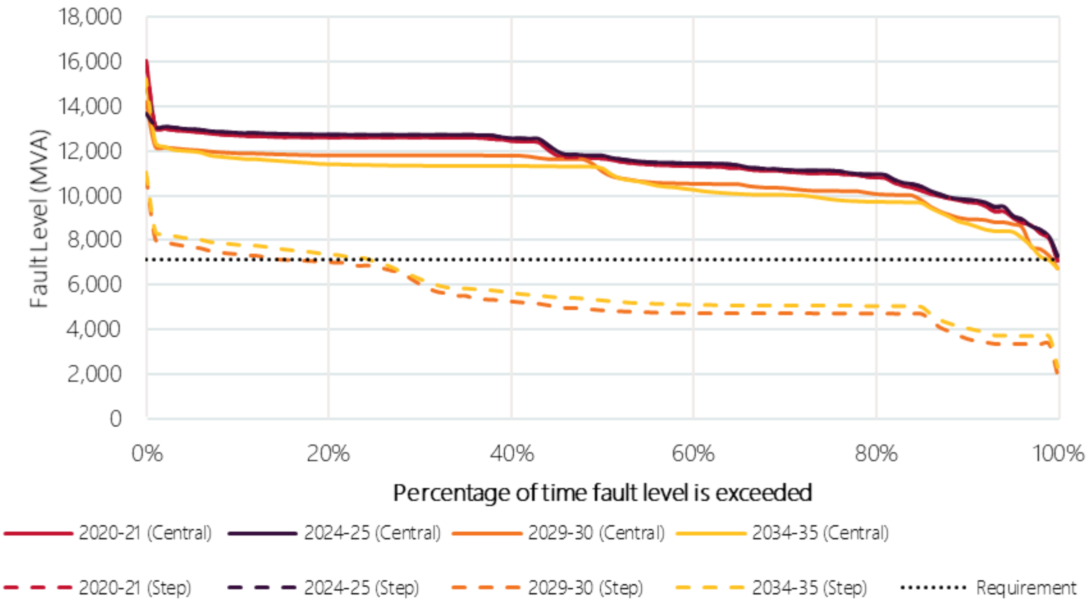


Figure 27 Projected Hazelwood 500 kV fault level duration curves, Central and Step Change scenarios



A7.4. Inertia outlook

Power systems with high inertia can resist large changes in the power system frequency arising from contingency events that lead to an imbalance in supply and demand. Experience in regions where inertia shortfalls have already been declared has demonstrated the importance of exploring alternatives to the traditional provision of inertia in the NEM, and this is an ongoing area of investigation for AEMO and TNSPs.

Results from the both the Central and Step Change scenarios have been assessed. Typical inertia values have been assigned to new generation planted by the market model,

AEMO will also publish a standalone 2020 System Strength and Inertia report by the end of 2020. This report will consider a wider range of sensitivities than considered in this ISP, as well as assessing inertia requirements and shortfall assessments for the next 10-year period. This section:

- Notes the importance of inertia and the roles and responsibilities for treatment of minimum inertia levels (A7.4.1).
- Provides a NEM-wide inertia outlook (A7.4.2).
- Details the inertia outlook for each region (A7.4.3 to A7.4.7).

A7.4.1 Importance of inertia, and roles and responsibilities

Maintaining an appropriate level of synchronous inertia, or its equivalent, is crucial for ensuring overall power system security.

AEMO is required under the NER to calculate (in accordance with the published methodology) and publish the satisfactory and secure requirements for synchronous inertia for each NEM region when it is islanded.

The NER also requires that AEMO assess and declare whether an inertia shortfall is identified to enable the TNSP to procure inertia. If an inertia shortfall is declared, the TNSP must procure services to fill it by the agreed timing.

AEMO is required to operate the power system to meet the frequency operating standards using services provided by the local TNSP. In 2018, AEMO determined two levels of inertia for each NEM region that must be available for dispatch when a region is at credible risk of islanding, or islanded:

- The Minimum Threshold Level of Inertia is the minimum level of inertia required to operate an islanded region in a satisfactory operating state.
- The Secure Operating Level of Inertia (SOLI) is the minimum level of inertia required to operate the islanded region in a secure operating state.

AEMO can agree to adjustments to the minimum threshold level of inertia or the secure operating level of inertia if inertia support activities (such as the provision or procurement of Fast Frequency Response (FFR)) will result in lower levels of synchronous inertia being necessary to meet system security requirements.

These requirements are solely focused on regional requirements when the region is at risk of islanding, or operating as an islanded system. Large amounts of IBR (both VRE and DER) are projected to replace the energy and capacity from synchronous generation such as coal plant when it retires. This will lead to reducing synchronous inertia across the NEM overall. This means that need for minimum levels of inertia services for system security may require new market arrangements, such as system-wide levels of inertia.

A7.4.2 NEM mainland inertia outlook

The Inertia Requirements define the minimum levels of inertia required to operate each NEM region as an island. These defined levels of inertia are only required to be online when a region is at risk of islanding, or islanded. While islanded, the frequency operating standards (FOS) allow the frequency to deviate between 49.0 Hz and 51.0 Hz for the largest credible contingency, and the inertia requirements have been calculated on this basis.

While NEM regions are interconnected, the FOS require that the frequency be maintained between 49.5 Hz and 50.5 Hz for the largest credible contingency. This is a more stringent requirement and can only be maintained with sufficient levels of FCAS and inertia online. As coal units retire, total inertia reduces across the NEM, and the FCAS required is anticipated to increase.

One of the key recommendations from the recent RIS Stage 1 report[28] is to introduce a minimum inertia level safety net for the mainland NEM , as the existing inertia frameworks do not cover this system security requirement. The initial proposed values from the RIS are shown in Figure 28. The minimum inertia level shown refers to the 45,350 MWs expected to be online as a result of minimum generator system strength combinations.

Results from the Step Change market modelling outcomes show operation below the NEM minimum inertia level by 2029-30, and by 2034-35 show periods where Victoria could start to have no synchronous inertia from generation online, and an overall NEM inertia shortfall of 19 GWs.

Experience from already declared inertia shortfalls in South Australia and Tasmania has demonstrated the procurement of two different types of inertia services, due to the differences in the generation in the two regions:

- In Tasmania, existing synchronous generation (predominantly hydro generation) can be utilised either at low output levels or placed in synchronous condenser mode when required.
- In South Australia, flywheels have been added to new synchronous condensers being installed for system strength remediation.

Consideration of these as options for the rest of the NEM shows:

- Even if all existing hydro plant in the NEM (excluding Tasmania) and new ISP planted pumped hydro was considered, the proposed minimum inertia level could not be met at all times.
- As in South Australia, new synchronous condensers installed for system strength mitigation will require flywheels, based on this being a more economic outcome than trying to utilise gas plant for long periods of time.
- Based on the potential need for synchronous condensers that may be required for system strength remediation across the NEM, a significant level of inertia could ultimately be delivered with low additional costs.

During recent island operation of the South Australian region, the ability for FFR from inverter-based devices to reduce the need for traditional FCAS and associated synchronous inertia also highlights other options that are now becoming available through the use of advanced inverter control systems. The ability of FFR and grid forming controls to provide a fast injection of active power will increasingly be an important feature for secure operation at lower inertia levels, minimising the need for synchronous inertia and traditional FCAS, and potentially also reducing the proposed minimum inertia requirement.

In the Central scenario, over 5,000 MW of batteries are projected to be installed across the NEM by 2040, indicating scope for a potentially significant contribution to system security.

[28] AEMO. *Renewable Integration Study: Stage 1 Report*, at https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf.

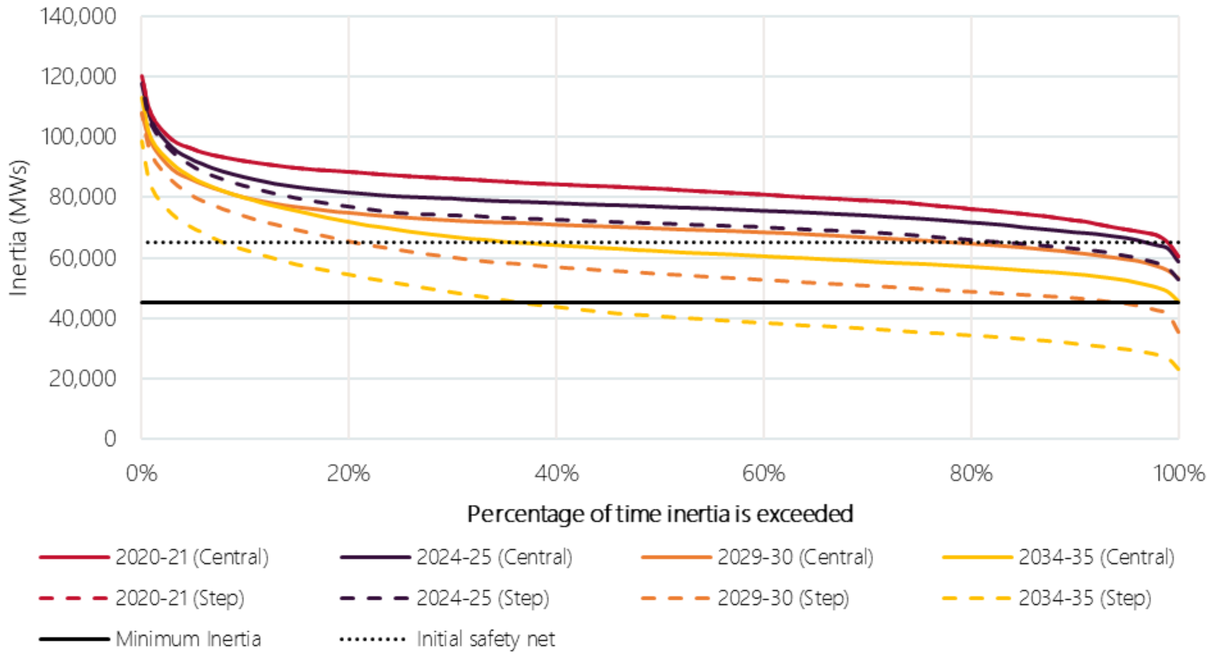
Figure 28 shows projected mainland inertia over the coming 20 years, under both the Central scenario (solid lines) and Step Change scenario (dashed lines). Inertia provided by new pumped hydro generation when online is already included in the projections.

Options for procurement of additional inertia could also include:

- Existing generation to be contracted to run for periods of low inertia.
- Hydro plant, gas generation to operate in synchronous condenser mode when not generating.
- Replacement of retiring or new static var compensators (SVCs) with synchronous condensers with flywheels.
- Synthetic inertia from IBR.

AEMO continues to monitor development of FFR and synthetic inertia (for example, virtual synchronous machines), and their impact/ability to reduce or contribute to inertia requirements.

Figure 28 NEM mainland inertia outlook (Tasmania excluded), Central and Step Change scenarios



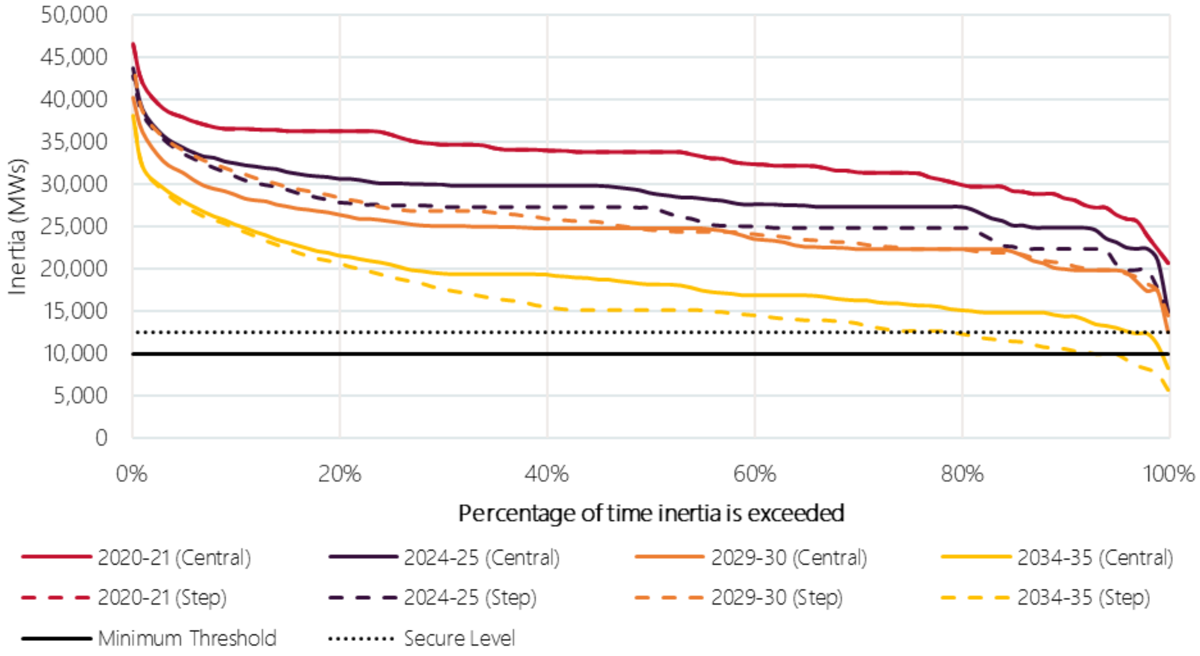
A7.4.3 New South Wales inertia outlook

As significant levels of coal plant retirement occur, the inertia available in New South Wales is forecast to reduce. There is still projected to be sufficient inertia for the minimum requirements prior to 2035.

If remaining coal plant is able to operate more flexibly (de-synchronise during the middle of the day), or retires earlier than expected, then the inertia online can be expected to reduce earlier than the times shown here.

The need to ensure sufficient inertia is online only applies when the region is operating as an island, or during a credible risk of islanding, which is seen to be a very low probability for New South Wales due to the number of AC interconnector circuits to other regions.

Figure 29 Projected inertia in the New South Wales grid, Central and Step Change scenarios

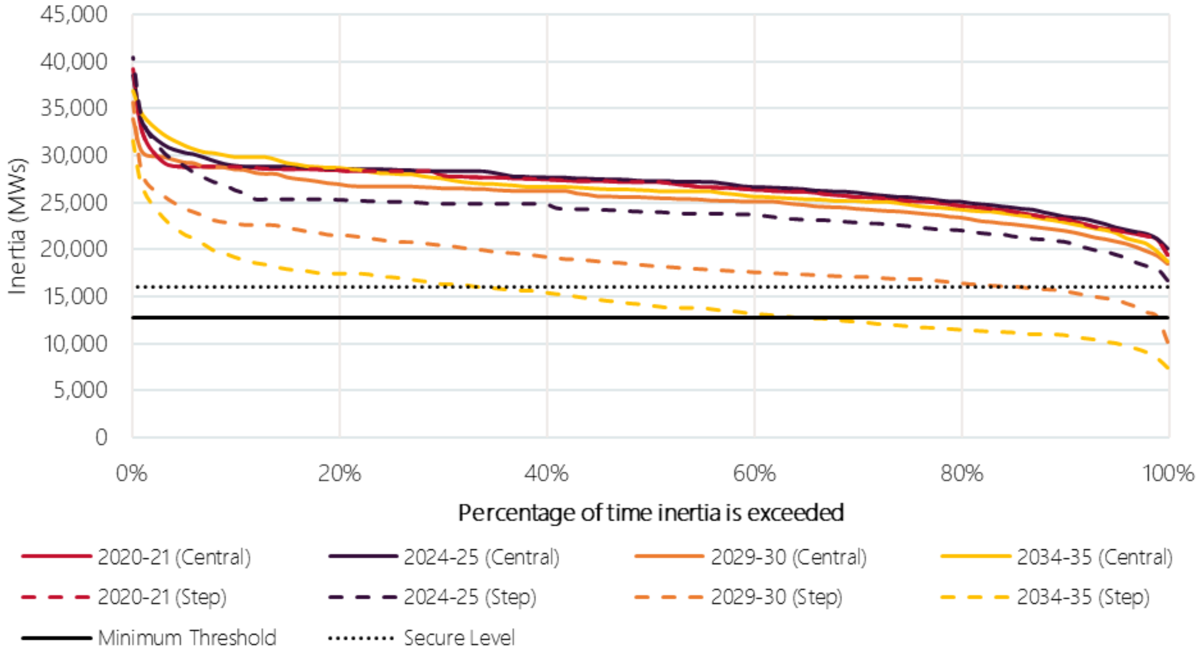


A7.4.4 Queensland inertia outlook

While some coal plant retirements have been assumed, there is still forecast to be sufficient inertia for the minimum requirements until 2034-35 in the Central scenario. In the Step Change scenario with accelerated coal retirements, there are significant periods where inertia could be below the requirement. If remaining coal plant can operate more flexibly (de-synchronise during the middle of the day), or retires earlier than expected, then the inertia online can be expected to reduce earlier than the times shown here.

The need to ensure sufficient inertia is online only applies when the region is operating as an island, or during a credible risk of islanding. For Queensland this currently occurs during outages of either QNI circuit.

Figure 30 Projected inertia in the Queensland grid, Central and Step Change scenarios



A7.4.5 South Australia inertia outlook

AEMO declared a system strength shortfall for South Australia in 2017[29], resulting in ElectraNet procuring four synchronous condensers for installation in the South Australian region.

AEMO also declared an inertia shortfall for the South Australian region as part of the 2018 NTNDP[30]. To partially meet this gap, high inertia flywheels have been included in the design of the synchronous condensers being procured to address system strength shortfalls. The results shown in Figure 31 include the 4,400 MWs inertia to be provided by the synchronous condensers fitted with flywheels.

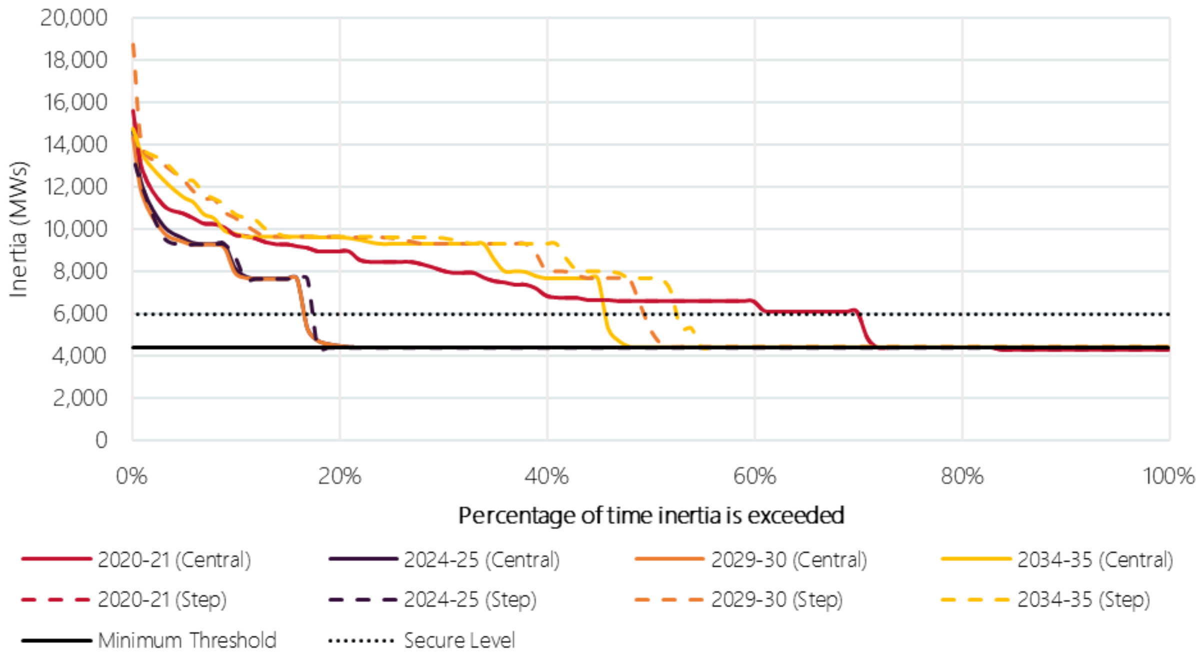
The need to ensure sufficient inertia is online only applies when the region is operating as an island, or during a credible risk of islanding. For South Australia this currently occurs during outages of either Heywood Interconnector circuits, or nearby 500 kV circuits in Victoria.

These results project significant periods after 2024-25 where the only synchronous inertia online is by the synchronous condensers fitted with flywheels. This occurs after Project EnergyConnect is commissioned, and no gas plant are required to be online. The commissioning of Project EnergyConnect will result in two double-circuit HVAC links and one HVDC link to other NEM regions, meaning the risk of having to operate as an island will be significantly reduced.

[29] AEMO. *Update to the 2016 NTNDP*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2017/second_update_to_the_2016_ntndp.pdf?la=en&hash=A9EE910B7DA3C1D88927871630C02B48.

[30] AEMO. 2018 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

Figure 31 Projected inertia in the South Australia grid, Central and Step Change scenarios



The inertia requirements for the South Australian region are presently under review. The updated requirements will reflect:

- Findings from the South Australia islanding events in early 2020[31].
- Anticipated levels of distributed PV generation.
- The implications of declining minimum demand in the region[32].

A key outcome from this updated review has been to consider the estimated increase in contingency size due to tripping of distributed PV systems as a result of transmission network faults. At low inertia periods, FFR from battery energy storage systems has been shown to be crucial in being able to meet frequency operating standards.

It is anticipated that the 2020 inertia requirements for the South Australian region will require inertia support activities such as dedicated FFR going forward to reduce synchronous inertia requirements. This is an example of how newer technologies are being harnessed to support and reduce the need for slower, more traditional technologies.

The impact of distributed PV tripping will be further explored for other regions as part of the 2020 System Strength and Inertia Report.

[31] AEMO. *Preliminary Report – Victoria and South Australia Separation Event 31 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-31-jan-2020.pdf?la=en. Also South Australia islanded via a credible contingency on 2 March 2020, see Market Notice 74613, at https://aemo.com.au/en/market-notices?marketNoticeQuery=74613&marketNoticeFacets=.

[32] AEMO. *Renewable Integration Study Stage1 Appendix A: High Penetrations of Distributed Solar PV*, p36, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en.

A7.4.6 Tasmania inertia outlook

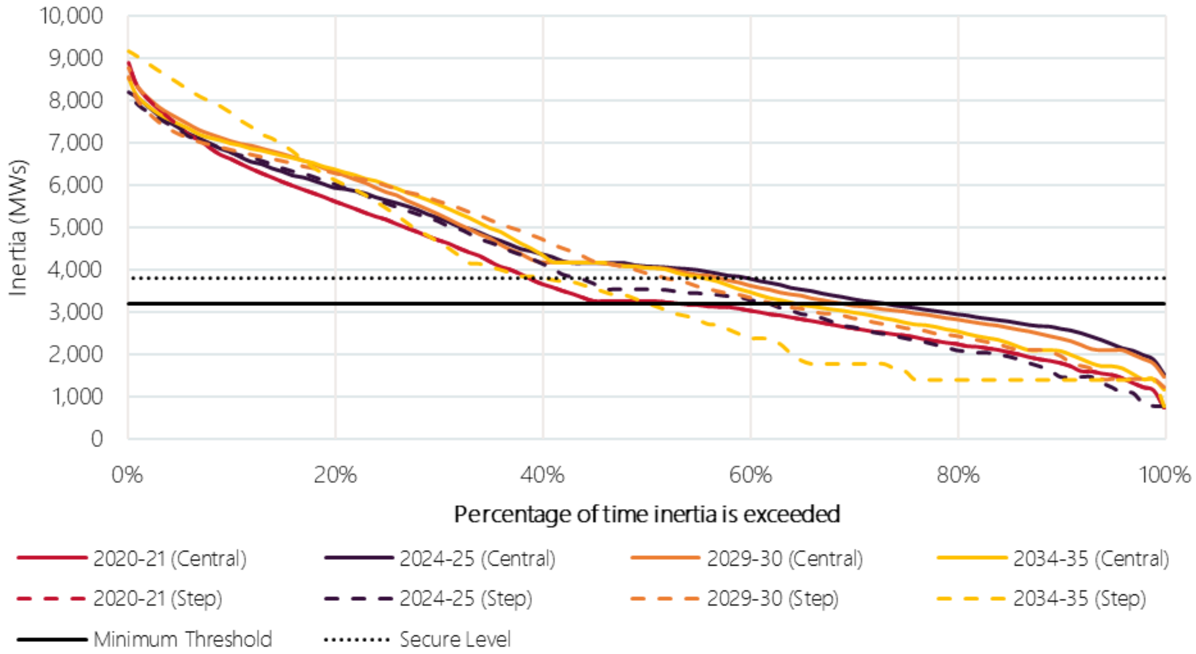
Tasmania is connected to Victoria by an asynchronous HVDC link, so for the purposes of inertia assessments is considered to be operated as an island at all times. This means the inertia requirements also need to be met at all times.

The results below project the inertia expected to be online from the dispatch of hydro plant. Operation of hydro plant in synchronous condenser mode can be utilised to increase the amount of online synchronous inertia. These results are consistent with the system strength and inertia gap declared by AEMO for the Tasmanian region in 2019[33].

TasNetworks has now procured sufficient system strength and inertia services to meet the declared gaps in the form of support contracts to be able to operate existing synchronous plant either at low output levels, or in synchronous condenser mode when required. These arrangements are expected to be reviewed prior to the contract end date of 2024.

Results shown in Figure 32 only show inertia online when dispatched for the energy market, and not including the expected additional inertia able to be procured. Projections highlight the inertia services are likely to be required for the long term, past the currently contracted end date.

Figure 32 Projected inertia in the Tasmania grid, Central and Step Change scenarios



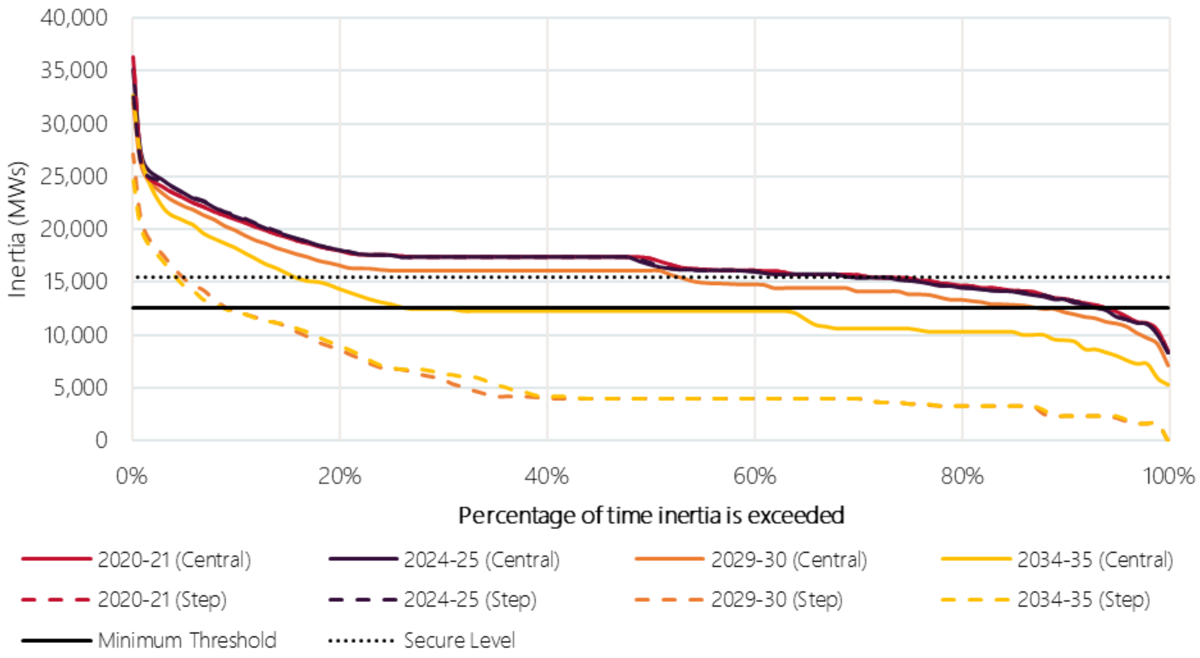
A7.4.7 Victoria inertia outlook

The need to ensure sufficient inertia is online only applies when the region is operating as an island, or during a credible risk of islanding, which is seen to be a very low probability for Victoria due to the number of AC interconnector circuits to other regions

While the inertia dispatched in Victoria is forecast to be below the minimum threshold for significant periods even in 2020-21, the low risk of islanding means there is currently no declared shortfall.

[33] AEMO. *Notice of Fault Level and Inertia Shortfall*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

Figure 33 Projected inertia in the Victoria grid, Central and Step Change scenarios



Results for the Step Change scenario for Victoria highlight significant periods after 2029-30 with inertia in the Victorian region below the minimum threshold, due to coal retirements. Co-incident with these low levels of inertia are expected system strength shortfalls. Consideration of both inertia and system strength, as well as other system services such as voltage control, will be required in assessing solutions.

A7.5. Renewable Energy Zone opportunities

AEMO's analysis of the system security requirements of REZs has provided the following insights:

- For a REZ, construction of a lower-cost network option could lead to higher system strength mitigation requirements. This is an important insight when considering the optimal network topology to deliver a REZ.
- While system strength remediation costs can be significant, they are shown in the example provided in this section to be only 2-3% of the total costs. However, the proportion of costs could be higher, depending on the fault level headroom existing at the REZ network location.
- A centralised coordinated solution to system strength can lead to lower-cost outcomes by accessing the benefits of economies of scale for solutions, especially for large clusters of IBR in REZs. AEMO estimates that if all generation proponents were required to individually mitigate their own plant's impact behind individual connection points, total system strength mitigation costs could more than 30% higher than over a coordinated approach.
- Network upgrades associated with the identified ISP projects will strengthen the network and reduce the amount of remediation that would otherwise be required to deliver the prioritised REZs.
- There may be opportunities to optimise overall fault level mitigation by considering both the regional TNSP fault level requirements and localised generator connection remediation options at the same time. The retirement of major thermal power stations will significantly diminish regional system strength in large steps and must be addressed irrespective of new connections.
- Emerging advances in implementation and configuration of inverter control systems has the potential to significantly reduce system strength remediation.

This section provides an introduction to considering system strength investments, presents options for estimating costs of delivering system security requirements for REZs, and then summarises the treatment of system strength costs for REZs in the ISP.

A7.5.1 Introduction to system strength investments

As existing synchronous generation progressively retires, new generation capacity is projected to mostly be inverter-based generation. Due to the significant size of these new generation projects, new or upgraded transmission network, as well as system strength remediation, will likely be required. The concept of establishing REZs to coordinate this generation investment brings an opportunity to deliver robust system security services.

While under current Rule requirements there are separate responsibilities for system strength for TNSPs and newly connecting generators, remediation will be required for both parties in similar timeframes as synchronous generation retires. There may be opportunities to optimise fault level mitigation by considering both the regional TNSP fault level requirements and localised generator connection remediation options at the same time.

Using the ISP market modelling outcomes, projections of available fault levels at proposed REZ locations have been calculated, and potential system strength remediation requirements and costs then determined.

These REZ fault level remediation costs have been calculated based on:

- Fault levels at the defined fault level nodes being maintained by the TNSP (that is, mitigated if required when generation retires).
- A requirement for all inverter-based generation to operate down to a short circuit ratio of 3 at the connection point[34]. The fault level at the connection point needs to be maintained at this level even after a single credible contingency.
- All proposed ISP network upgrades being included in the calculations.

Two alternative solutions for system strength mitigation were determined:

- A larger centralised synchronous condenser solution.
- A series of local solutions where connecting generators provide their own smaller synchronous condensers connected behind the generator connection point.

A7.5.2 Assessing costs for system strength investment options

Example results below are based on a study of two network options for the Central-West Orana REZ in New South Wales. The results compare the costs of centralised system strength remediation against the cost of project-by-project remediation. One option was for a radial network extension, and the second option was a higher cost looped arrangement. Both options allow connection of up to 3 GW of inverter-based generation.

Table 10 REZ system strength remediation cost example

	Costs – radial network option ($m)	Costs – looped network option ($m)
Transmission network costs	570	650
System strength remediation costs[A] – centralised[B] REZ solution	290	115
Generation costs (including connection costs)	4,600	4,700
Total	5,460	5,465
System strength costs with remediation on a project by project basis	370	185

A. Synchronous condenser costs have been estimated from responses from a number of manufacturers, and from recent projects in the NEM, for a variety of synchronous condenser sizes. These are high-level estimates only.
B. A centralised solution is shared across generators, taking advantage of economies of scale

Results highlight that:

- A lower-cost network design (before considering system strength needs) could lead to higher system strength requirements, and overall higher system costs.
- System strength remediation costs can be significant but are shown in this example to be 2-3% of the optimal total REZ costs. For a sub-optimal network design, this increases to approximately 7%.

[34] The short circuit ratio is the ratio of the fault level at the generator connection point (in MVA), compared to the total cumulative rating of all the inverters associated with the project (in MW or MVA). It can generally be assumed there is sufficient system strength where the ratio is 3 or above. Advances in technology and operating arrangements may allow a lower rule of thumb to be applied in future.

- A centralised coordinated solution can lead to lower cost outcomes. Total system strength costs increased by over 30% when system strength remediation is not centrally coordinated.
- Improving inverter control systems can significantly reduce system strength remediation costs. AEMO's analysis indicates that system strength remediation costs are approximately halved if inverters can operate reliably at a short circuit ratio of 2 rather than 3.

Under the existing system strength frameworks, some optimal outcomes are not easily achievable:

- TNSPs are not exposed to the generator system strength mitigation costs, and the connecting generators cannot easily co-ordinate central solutions or influence network build decisions.
- Generators may not initially have any incentive to make use of well-tuned inverter control systems, resulting in less headroom for later generating units trying to connect.

The AEMC is currently investigating the system strength frameworks to consider some of these issues[35].

A7.5.3 System strength remediation costs in the ISP

Available fault levels and potential system strength mitigation for all REZs are detailed as part of the REZ scorecards in Appendix 5. Generator system strength remediation costs are not explicitly stated in ISP economic analyses. As the results above show, when well-coordinated, these costs can be as low as 2-3% of the overall project costs, and well within the error margins of the total project cost estimates[36].

A well-planned centralised system strength solution will assist in ensuring that remediation requirements are planned in advance. This can avoid lengthy commissioning periods where generator output is limited due to unforeseen system strength issues.

[35] AEMC. *Investigation into system strength frameworks in the NEM*, at https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

[36] The accuracy of generator costs used by AEMO is approximately ±30%. See *2019 Cost Costs and Technical Parameter Review*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-cost-and-technical-parameters-review-report-rev-3.pdf.

A7.6. South Australia in transition

New system security risks are emerging in in South Australia and expected to grow over time. The risks are being driven by the changes to power system characteristics resulting primarily from the increasing uptake of distributed PV. To secure the South Australia power system, AEMO expects:

- New constraints will be required on Heywood interconnector flows to manage increasing contingency sizes relating to coincident tripping of DER.
- A need for online inertia and conventional frequency control services by contracting a total of up to 400 MW[37] of FFR from IBR such as batteries or solar farms by 2025.

These measures are required to enable AEMO to maintain power system security, avoid load shedding for credible contingencies and reduce the likelihood of a system black event. The delivery of Project EnergyConnect would:

- Deliver a wide range of market benefits (captured by ISP modelling) that outweigh its cost.
- Significantly reduce the likelihood of operating South Australia as an electrical island, and therefore mitigate the need to procure FFR to manage islanded operation.
- Resolve the need to maintain headroom of the Heywood interconnector for credible contingencies in South Australia.
- Reduce the likelihood of operating in conditions where a separation is credible and therefore reduce the impact of limits that manage those conditions.

This section:

- Introduces the South Australian network situation (A7.6.1).
- Provides an overview of Project EnergyConnect (A7.6.2).
- Discusses current South Australian power system requirements (A7.6.3).
- Explains emerging South Australian system security needs (A7.6.4).
- Summarises the planning assumptions applied for South Australia (A7.6.5).
- Notes the potential impact of Project EnergyConnect on system security in South Australia, and potential alternatives if Project EnergyConnect were not to be delivered (A7.6.6).

A7.6.1 Introduction

The South Australian network has traditionally been reliant on synchronous generation sources to provide system strength, inertia, and voltage and frequency control.

[37] The estimated requirement for 400 MW of FFR is inclusive of any amount of FFR already contracted by any party to provide this service. The total amount of large-scale BESS existing or committed in South Australia is approximately 205 MW.

Over the past few years however, the South Australia power system has changed substantially, due to increased penetration of distributed PV and the commissioning of large-scale grid-connected IBR including BESS and wind and solar farms.

The South Australia power system dynamics will continue to change over the coming years due to a further increase in the uptake of distributed PV and grid-connected IBR, and the substitution of online synchronous generation with four new synchronous condensers in ElectraNet's transmission network.

Within the NEM, as well as internationally[38], South Australia is at the forefront of being able to transition away from operating a secure grid that is reliant on synchronous generation within the region.

The interplay between the limitations of the existing and new generation sources is resulting in emerging system security risks. At the same time, the capabilities inherent in some of the newer technologies are also providing opportunities for some technologies to provide partial solutions.

Ensuring a smooth transition occurs in an economical manner, without unduly putting the grid at risk in regions like South Australia in the face of emerging system security issues is one of the key challenges facing the industry.

A7.6.2 Project EnergyConnect

To address these challenges, ElectraNet and TransGrid have proposed[39] a new double-circuit HVAC interconnector between South Australia and New South Wales referred to as Project EnergyConnect. This will increase the number of HVAC transmission lines between South Australia and the rest of the NEM from two (the Heywood double-circuit line) to four (the Heywood and Project EnergyConnect double-circuit lines).

This proposal also includes a minor upgrade to the Victorian network and a Special Protection Scheme (SPS) to prevent cascading loss of interconnection with the NEM for loss of either HVAC interconnector. Project EnergyConnect is proposed to be commissioned in 2023-24 with a staged delivery from late 2022.

It will also provide greater flexibility and increased reliability to the South Australian power system and address a number of South Australian system security challenges, both existing and emerging, as renewable penetration reaches very high levels.

Following commissioning of Project EnergyConnect, the South Australia power system will be designed to remain connected to the rest of the NEM following a double-circuit loss of either the Heywood interconnector or Project EnergyConnect. Furthermore, the increase in imports necessary to compensate for a non-credible loss of generation or a credible loss of a metropolitan generator and distributed PV can be distributed across both interconnectors, significantly reducing the possibility of triggering protection schemes.

For these reasons, Project EnergyConnect will significantly reduce the likelihood of South Australia separating from the rest of the NEM.

AEMO's modelling indicates that a primary benefit of Project EnergyConnect is fuel cost savings – the project improves competition in South Australia by enabling low-cost generation to displace GPG.

A7.6.3 Current South Australian power system requirements

At present, a minimum local commitment of large synchronous generating units is needed in South Australia to provide essential power system services, including:

- System strength (and fault current).
- Inertia (to limit Rate of Change of Frequency [RoCoF]).

[38] AEMO. *RIS International review*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

[39] ElectraNet and TransGrid are currently preparing a Contingent Project Application. https://www.electranet.com.au/projects/south-australian-energy-transformation/

- Frequency control and operating reserves.
- Voltage control.

The 2018 ISP identified that the most efficient development pathway for South Australia to address these requirements was to include high-inertia synchronous condensers and Project EnergyConnect. The synchronous condensers are able to provide voltage control, fault current and inertia. Project EnergyConnect is able to ensure operating reserves are available, as well as allow for the transfer of frequency control services, inertia and additional system strength from other NEM regions.

System strength (and fault current)

At present, local commitment of large synchronous generating units is required in South Australia to maintain system strength[40]. In October 2017, AEMO declared a fault level shortfall in South Australia[41]. ElectraNet is commissioning four large synchronous condensers to meet this fault level shortfall[42]. These units are designed as a cost-effective, no-regrets way to address the declared shortfall that currently exists in the system.

However, this solution does not address all of the requirements for system security in South Australia for the future:

- The synchronous condensers address the declared minimum fault level gaps (and provide inertia) only for up to an estimated 2,000 MW of inverter-based generation online. Additional steps were expected to be required to provide for more inverter-based generation to be able to be online, dependent on the location of the plant and its characteristics. The "do no harm" rules relate to new connecting utility-scale generation to ensure that their connection does not detract from system strength.
- This does not guarantee that system strength in other areas will be sufficient, or that the system be able to be returned to a secure operating state during outages. Critical outages such as a prior outage of a synchronous condenser, Para SVC, or a Tailem Bend – South East 275 kV line, are expected to require additional measures to be in place.
- This does not address other potential system security requirements, such as voltage control, damping of oscillations and short-term power quality.
- This does not address future potential system strength declines in the metropolitan area with over 1 GW of DER, primarily comprising distributed PV with much less sophisticated control systems than utility-scale IBR.

Inertia (and RoCoF)

In response to a ministerial direction issued under the *Essential Services Act 1981 (SA)*, AEMO has implemented constraint equations to limit Heywood flow to a level that ensures South Australian RoCoF is less than 3 Hz/s for the non-credible trip of the Heywood Interconnector[43], to mitigate the risk of a state-wide blackout from a double-circuit contingency event.

AEMO has determined the inertia requirements for South Australia[44] and declared an inertia shortfall in South Australia[45]. ElectraNet's proposed synchronous condenser solution (due to be delivered in late 2020) has been designed to provide additional synchronous inertia (4,400 MWs) to address the minimum synchronous

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[40] AEMO. *System strength requirements methodology. System strength requirements and fault level shortfalls*; July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[41] AEMO. *Second Update to the 2016 NTNDP*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[42] ElectraNet. *Strengthening South Australia's Power System*, at https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

[43] AEMO. *Electricity Market Notice 55358*, 12 October 2016, at https://www.aemo.com.au/Market-Notices.

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

[45] AEMO. *2018 NTNDP*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

component of the inertia shortfall and will improve the RoCoF constraint by up to approximately 500 MW in both interconnector flow directions.

Frequency control

Traditionally, frequency control was provided through the headroom available from online synchronous generators. Primary frequency control in South Australia has been reduced by the increasing penetration of wind and solar generation, resulting in fewer synchronous generators being online.

The current FOS[46] set out that following a multiple contingency event, AEMO should use reasonable endeavours to return the frequency to between 49.85 Hz and 50.15 Hz within 10 minutes. The loss of the Heywood interconnector is one such event.

Further, the NER require that AEMO must use reasonable endeavours to:

- Control the power system frequency (NER 4.4.1(a)).
- Ensure the FOS are achieved (NER 4.4.1(b)).
- Ensure adequate facilities are available and are under the direction of AEMO to allow the managed recovery of the satisfactory operating state of the power system. (NER 4.4.2(d)).

Additionally, as noted above, the South Australian Government has made a ministerial direction to limit RoCoF to 3 Hz/s[47].

Emergency frequency control schemes (over frequency generation shedding [OFGS] and under frequency load shedding [UFLS]) are also in place to assist with frequency recovery following non-credible contingency events. AEMO is currently investigating the requirement for defining an additional Protected Event relating to the non-credible contingency of the Heywood interconnector. This is due to the declining levels of load available for UFLS in the South Australia region[48] as distributed PV increases. A potential outcome of this protected event, if shown to be economical, may be to also implement additional limits on Heywood flow into the South Australia region at times of low UFLS availability.

AEMO's capability to restore frequency in South Australia following a separation event requires online services that provide:

- **Inertial response** (instantaneous) – inherent response from synchronous machines and associated masses to arrest deviations in frequency. This can be reduced through the use of FFR, for example the use of advanced power electronics associated with inverter connected generators and battery energy storage systems or switched demand responses.
- **Primary frequency control** (within a few seconds) – active power controls act in a proportional manner to respond quickly to measured changes in local frequency and arrest deviations through changes in their active power output in a timeframe longer than that of the inertial response). It is automatic and not an outcome of centralised system control and begins immediately after a frequency change beyond the specified level is detected.
- **Secondary frequency control** – automatic generation controls (AGC) and manual dispatch commands act to restore frequency to 50 Hz and relieve providers of primary frequency control.
- **Operating reserves** – The capability to respond to large continuing changes in energy requirements.

Since NEM start (1998), the Heywood interconnector has experienced a non-credible separation event approximately once every two to three years, with the frequency of events being higher over the past five years. Additional interconnection and provision of sufficient frequency control is critical to manage the

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[46] Reliability Panel AEMC. *Frequency Operating Standards*, at https://www.aemc.gov.au/sites/default/files/2019-04/Frequency%20operating%20standard%20%E2%80%93%20effective%201%20January%202020.pdf.

[47] Note that this is different from the Protected Event rule which would treat the contingency as credible for purposes not strictly related to frequency restoration (such as transient stability, FCAS).

[48] AEMO. *Draft 2020 Power System Frequency Risk Review*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/psfrr-stage-1.pdf?la=en.

potential risk of a system black event following this event. In the absence of additional interconnection (which of itself reduces the likelihood of separation events by establishing two double circuit ties instead of just the one), AEMO's reasonable endeavours to maintain the FOS in South Australia will include the pre-contingent provision of some minimum level of these services.

While emerging technologies (for example, advanced inverter functionality such as virtual synchronous machines) may eventually be capable of providing some of these services, they are not yet proven to be scalable for operation in a large islanded system the size of South Australia, and there is no comparable demonstration of this at this scale anywhere in the world. The existing batteries in South Australia are not yet able to provide all these essential services.

Wind and solar generation have proven their capability to provide a level of frequency control but cannot provide firm operating reserves (due to resource availability) and are not currently active in the FCAS markets.

A7.6.4 Emerging South Australian system security needs

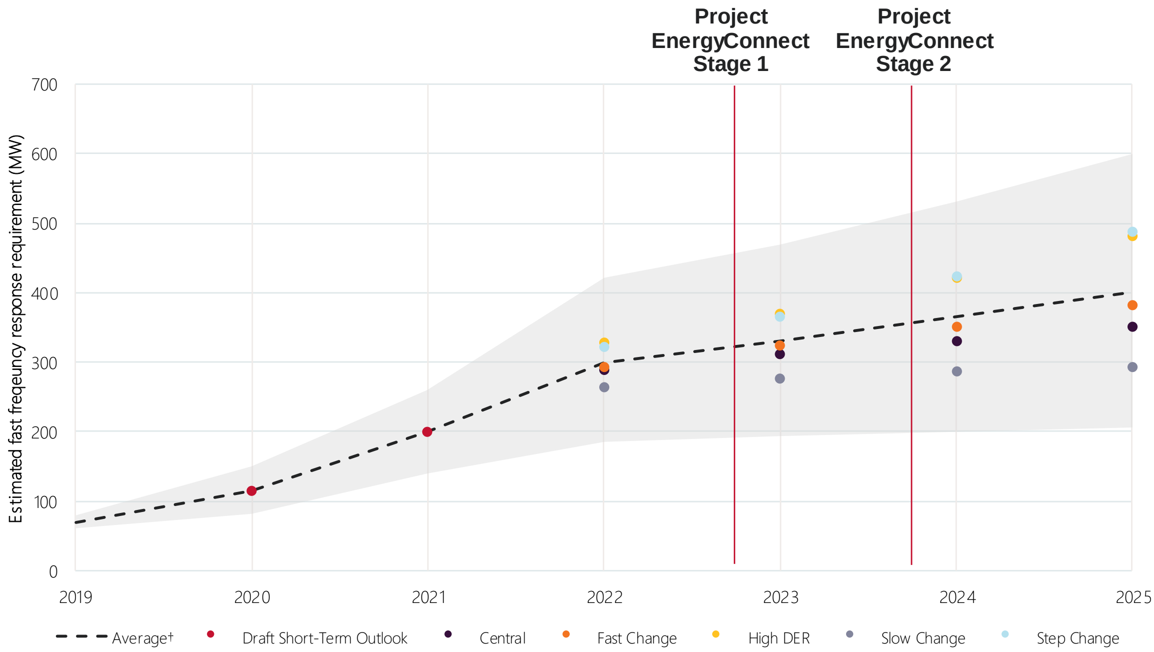
A growing need for Fast Frequency Response (FFR) to address islanding risk

Increasing amounts of FFR will be required to maintain power system security as the South Australian power system continues to change with increasing penetration of distributed PV. This FFR is required to maintain the FOS while the size of credible contingencies grows and inertia reduces.

Through power system modelling and monitoring, AEMO has demonstrated that large amounts of distributed PV can disconnect following a credible fault that also disconnects a large synchronous generator in the Adelaide Metropolitan area[49]. As distributed PV penetration continues to increase, the size of this contingency will grow. The anticipated implementation of a stricter voltage ride-through standard (AS/NZS 4777) in 2022 is expected to slow but not completely stop this increase.

Figure 34 shows projected FFR requirements in South Australia over time.

Figure 34 Projection of FFR required to efficiently operate South Australia during island conditions



† Averaged numbers are rounded to the nearest 5 MW due to limitations in sizing BESS.

[49] AEMO. *RIS Appendix A:High Penetration of Distributed Solar PV*, at https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf.

This projection considers the efficient mix of FFR as a substitute for additional synchronous inertia to operate South Australia as a synchronous island. The requirements for FFR need to be sized for what is needed during islanded conditions, because this is the most onerous operating condition – even though it might be very rarely used. This is because, when islanded, Heywood interconnector flow cannot be varied to reduce the need for FFR. These outcomes align with AEMO's findings in determining South Australia inertia requirements.

The delivery of Project EnergyConnect is projected to fundamentally change the FFR requirements in South Australia. When determining the inertia shortfall for a region, AEMO must consider the likelihood of that region becoming islanded[50]. As a part of Project EnergyConnect, ElectraNet has proposed an interconnector special protection scheme which will be designed to prevent a double-circuit failure from cascade tripping the parallel interconnector. Once this scheme is implemented and determined to be robust, AEMO expects that there will be no ongoing regional inertia shortfall for South Australia.

Compounding the increased challenges associated with operating the South Australia Power System as an Island is the recent increase in the duration and number of instances South Australia has separated from the rest of the NEM. A recent separation event lasted 17 days[51].

Recent and emerging constraints on the Heywood interconnector

On 24 April 2020, AEMO implemented constraint equations to manage power system security in South Australia based on limits advice received from ElectraNet on 7 April 2020. These updated limits include the impacts of distributed PV disconnection on voltage and transient stability limits[52]. This limit advice has also been incorporated in the stability constraints used for ISP market modelling.

As the penetration of distributed PV continues to increase in South Australia, new limits are expected to emerge. In relation to increasing distributed PV penetration, AEMO's studies demonstrate that the secure operation of the South Australia power system under different conditions can be approximately expressed as a function of five key factors:

- The output of the online metropolitan synchronous generation which may be tripped by the contingency under consideration.
- The amount of power being imported into South Australia through Heywood interconnector.
- The amount of distributed PV generating.
- Underlying consumer demand[53] in South Australia.
- Available FFR to be injected as a positive value (referred to as Fast Active Power Response (FAPR) when configured to respond to an emergency control scheme rather than a frequency deviation)[54].

While some of these factors can be adjusted via the central dispatch process, allowing for some level of economic optimisation, some key factors are not easily controlled in real time.

In system normal configuration and during a single Heywood circuit configuration, the risk of load shedding and system black event can be minimised by limiting Heywood import into South Australia. Specific levels of Heywood import and enabled FAPR can be co-optimised in constraint equations based on network and market conditions.

[50] Clause 5.20B.3(b)(2) of the NER.

[51] AEMO. *Preliminary Report – Victoria and South Australia Separation Event, 31 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-31-jan-2020.pdf.

[52] This includes the following constraint equations: V::S_NIL_MAXG_1, V::S_NIL_MAXG_2, V::S_NIL_MAXG_3, V::S_NIL_MAXG_SECP_1, V::S_NIL_MAXG_SECP_2, V^^S_NIL_MAXG_1, V^^S_NIL_MAXG_2, V^^S_NIL_MAXG_3, V^^S_NIL_MAXG_SECP_1 and V^^S_NIL_MAXG_SECP_2.

[53] Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as distributed PV.

[54] In the context of this appendix, FFR refers to a rapid power change that can be activated and delivered in sub-second timeframes in response to a frequency deviation. The same service is referred to as FAPR when activated as a part of a special protection scheme.

The following equations show that there is a trade-off between the level of Heywood import into South Australia and the amount of FAPR provided[55]. The higher the import into South Australia, the more FAPR is needed to keep the system secure, all other things being equal. AEMO has determined the following equations that are likely to emerge as distributed PV penetration continues to grow[56]:

- **System normal** – the following equation can create headroom on the Heywood interconnector to ensure that a credible contingency does not result in exceeding the 850 MW satisfactory limit[57] (including a 50 MW operating margin).
  - Heywood import ≤ FAPR – Metro Generator Size – Net Distributed PV Loss + 800.
- **Credible risk of separation** – during outages that place the Heywood interconnector at high risk, interconnector flow should be limited such that a credible contingency does not result in a cascade trip of Heywood.
  - Heywood import ≤ FAPR – Metro Generator Size – Net Distributed PV Loss + 400.
- **Islanded** – when operating in an island, FFR is required to rapidly re-balance supply and demand in response to a contingency event (effectively limiting the contingency size so that the FOS can be maintained).
  - FFR ≥ 0.95 × (Metro Generator Size + Net Distributed PV Loss).

AEMO recommends that these constraints be included in modelling of future power system behaviour, including market modelling.

The delivery of Project EnergyConnect is expected to remove the system normal constraint outlined above. Constraints for credible risk of separation and islanded conditions are not expected to be required, due to the extremely low likelihood of operating in those conditions after delivery of Project EnergyConnect.

Project EnergyConnect will reduce the need for FFR and avoid new constraints on the Heywood interconnector

The delivery of Project EnergyConnect is projected to:

- Significantly reduce the likelihood of operating South Australia as an electrical island, and therefore mitigate the need to procure FFR to manage islanded operation.
- Resolve the need to maintain headroom of the Heywood interconnector for credible contingencies in South Australia.
- Reduce the likelihood of operating in conditions where a separation is credible and therefore reduce the impact of limits that manage those conditions.

A7.6.5 Summary of planning assumptions

For the forward-looking timeframes being assessed as part the ISP, it is acknowledged that there are many uncertainties that can influence the outcome of studies, and it is not seen to be feasible to review all combinations of potential variables. Planning assumptions are often made in order to reduce the complexity of interactions or fidelity of studies in order to practically be able to determine an outcome.

If potential issues are not picked up and investments flagged in the planning timeframes, costly operational interventions can result that may take many years to rectify. Taking no action due to uncertainty or waiting for new solutions to hopefully develop is also likely to result in this outcome.

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[55] For constraints relating to system normal and credible separation risk, FFR must be configured to respond to an emergency control scheme rather than responding to a frequency event.

[56] In the context of these equations, Net Distributed PV loss = (0.4 × Distributed PV generation) – (0.2 × Underlying demand).

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

Given all the uncertainties relating to changing generation technologies and demand levels, regulatory requirements, operational measures, and other emerging security issues for the South Australian region, an assessment of likely gas plant operation for the South Australian network has had to be undertaken for the projections.

The planning assumptions applied in this ISP relating to operation of gas generation in the South Australian region are summarised in the following table and detailed in the subsequent sections. These assumptions are re-assessed as new information comes to light, and further studies undertaken. The assumptions presented are planning assumptions, not operational advice. It is expected that more detailed studies will be able to be undertaken closer to actual implementation dates and include requirements for all operating conditions.

Table 11 Planning assumptions for the ISP

Power system requirement	At least four synchronous generating units	At least three synchronous generating units	At least two synchronous generating units	At least one synchronous generating unit	No synchronous generating units
SYSTEM NORMAL, REQUIREMENT FOR POWER SYSTEM SECURITY					
System strength & fault current	NOW				SYNCONS / ENERGY CONNECT
Operating reserves for ramping			NOW / SYNCONS		ENERGYCONNECT
SYSTEM NORMAL REQUIREMENT TO SURVIVE 1-IN-3 YEAR SEPARATION EVENT†					
Grid formation				NOW / SYNCONS	ENERGYCONNECT
Inertia and RoCoF				NOW‡	SYNCONS / ENERGY CONNECT
Primary frequency control				NOW / SYNCONS	ENERGYCONNECT
Secondary frequency control			NOW / SYNCONS		ENERGYCONNECT
Operating reserves for energy balance			NOW / SYNCONS		ENERGYCONNECT
SYSTEM NORMAL MINIMUM REQUIREMENT					
Minimum requirement	NOW		SYNCONS		ENERGYCONNECT

† A "non-credible" separation event has occurred approximately once every two to three years since NEM start. With Energy Connect, the separation risk would be reduced.
‡ RoCoF risk is currently managed with a 3 Hz/s RoCoF constraint on the Heywood interconnector.

Current system – before synchronous condensers and Project EnergyConnect

As described, GPG currently plays a vital role in South Australia, and without other developments, ongoing operation of GPG is essential for reliability and security of the future power system.

Currently, a minimum commitment of synchronous generation in South Australia is required in real-life operations to maintain system strength. As these minimum requirements are critical for system security in the South Australian region, where the market does not deliver these minimum requirements, AEMO will direct participants (and continues to be forced to do so in the live market) to ensure that this minimum requirement is met. Accordingly, any modelling of the power system must recognise these real limits.

While there were many feasible combinations of units that could satisfy the minimum system strength and inertia requirements, AEMO's planning studies, based on typical operational outcomes, distilled this limit to a least-cost implementation that required five units from Torrens Island B (TIPS B), Pelican Point, Osbourne or

Quarantine 5 online above minimum generation at all times to ensure supply adequacy for system strength purpose, with the 3 Hz RoCoF constraint in place and only one synchronous interconnector (Heywood). For the purposes of the ISP, this was sufficient to assess and develop the resultant development plans. Other combinations of generating units can and do apply operationally to meet this requirement, but do not change the outcomes of the ISP in any material manner. Updated combinations that can provide equivalent outcomes are described in the transfer limits advice for South Australia system strength[58].

After synchronous condensers, and prior to Project EnergyConnect

The concept of "system normal" as an entirely intact power system is rarely reflected in practice as a static condition – generation and transmission are often coming into and out of service. The resultant "new system normal" state then needs to be maintained in or quickly returned to a secure operating state.

AEMO's planning assumptions in this ISP were that, to the extent practicable, the power system should remain in a secure operating state for all system normal conditions. Furthermore, the FOS should be maintained and black system should be avoided for any reasonably foreseeable contingency event (for example, a non-credible South Australia separation event that has occurred approximately one in every two to three years since NEM start).

This ISP re-affirms that the installation of four synchronous condensers (including flywheels) would address the identified system strength gap and the minimum synchronous component of the declared inertia shortfall. However, AEMO did not assume that the four synchronous condensers would address all requirements for system security in South Australia. Rather, AEMO's approach was consistent with ElectraNet's economic case for the synchronous condensers[59], which assumed a requirement to keep two large synchronous generators online at all times.

For this ISP, AEMO assumed that following the installation of the four synchronous condensers (including flywheels) and prior to the implementation of Project EnergyConnect, at least two large synchronous generator units in South Australia would be required online at all times[60]. AEMO's detailed studies have shown that this is a minimum requirement for security of South Australia. AEMO has assumed this requirement for the following reasons:

- Operating reserves for ramping.
- Secondary frequency control following a separation event.
- Operating reserves for energy balance following a separation event.

Operating reserves for ramping

AEMO has reviewed historical wind and demand ramping events, which highlight the need for operating reserves to be provided to prevent overloading of the Heywood interconnector. For example, over a 30-minute period, South Australia can experience up to an unforecast 600 MW deficit in energy balance (for example, a sudden drop in wind generation)[61]. Without local operating reserves, this deficit will be balanced by increased flow on the Heywood interconnector. At full registered import capacity, the Heywood interconnector has a 200 MW headroom before breaching its satisfactory limit and risking separation.

While some fast start plant can support this need, there is a delay in bringing units online through the dispatch process (10 to 25 minutes depending on the bidding of fast-start plant). Two large synchronous

[58] AEMO. *Transfer Limit Advice – South Australia System Strength*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf.

[59] ElectraNet. *Addressing the System Strength Gap in SA – Economic Evaluation Report*, at https://www.aer.gov.au/system/files/ElectraNet%20-%20System%20Strength%20Economic%20Evaluation%20Report%20-%2018%20February%202018.PDF.

[60] Noting that a synchronous unit comprising of a combined Gas Turbine and Steam Turbine are treated as single unit if trip of one results in trip or de-loading of the other.

[61] AEMO. *RIS Stage 1 Appendix C: Managing variability and uncertainty*, at https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

generators can provide approximately 500 MW of ramping services over a 30-minute period, which is enough to prevent breaching the satisfactory limit on Heywood for an un-forecast ramping event.

Secondary frequency control following a separation event

Following a one in two-to-three year non-credible South Australia separation event, AEMO is required to restore frequency in South Australia to the 49.85 to 50.15 Hz range within 10 minutes – see Section A7.6.3. The ability to achieve this requires secondary frequency control services (such as contingency FCAS). Modelling confirmed that at least two large synchronous generators would be required online prior to a separation event to achieve this standard. These services cannot reliably be provided by fast-start plant within the stabilisation and recovery timeframes required in the FOS.

Operating reserves for energy balance following a separation event

Following a one in two-to-three year non-credible South Australia separation event, assuming the system frequency has been stabilised through adequate provision of secondary frequency control, operating reserves will then be required to maintain energy balance.

For example, load and intermittent generation will continue to change from minute to minute. In the event of a separation event, AEMO can begin to bring fast-start plant online to provide operating reserves and to begin to restore load that was shed by the UFLS system. In the 10 to 25 minutes it can take to bring these fast-start units online, if the system does not have sufficient operating reserves to be able maintain the supply-demand balance as generation and load varies minute to minute, frequency will continue to vary and other measures may be needed to preserve frequency within the limits while the units are brought online, potentially including the undesirable action of shedding further customers.

At least two large synchronous generating units, online prior to a separation event, with sufficient operating reserves to maintain energy balance during subsequent operations (which may include, for example, variation of demand or rapid changes in wind generation), would be needed to support the orderly restoration of load.

After synchronous condensers and Project EnergyConnect

For this ISP, AEMO assumed that the minimum number of synchronous generation units required online could be reduced further following the implementation of the synchronous condensers (including flywheels) and Project EnergyConnect where all key elements of the South Australian power system were intact.

Similar to the previous case, these planning assumptions did not assume that Project EnergyConnect combined with the four synchronous condensers would address all of the requirements for system security in South Australia for the future under all circumstances.

It was assumed that additional measures would be required for outage conditions, protected events[62], or where AEMO declared abnormal operating conditions. Detailed studies, to be undertaken in parallel with commissioning of synchronous condensers and the implementation of Project EnergyConnect, will determine the operational requirements for managing the power system during outages, protected events, or abnormal operating conditions.

For the planning assumptions used in the modelling of this ISP, AEMO assumed the minimum requirements, including a reduction of synchronous generating units to zero, where both HVAC interconnectors were intact, there were no critical outages within the state, normal operating conditions prevailed, and additional measures were in place and effective to arrest and remediate any potential further declines in system strength (such as connecting generation and increasing distributed PV) from the current state.

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[62] AEMO. *2018 Power System Frequency Risk Review Final Report*, at http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/PSFRR/2018_Power_System_Frequency_Risk_Review-Final_Report.pdf.

A7.6.6 Conclusion

Over recent years, the dynamics of the South Australia power system have changed substantially as a result of increased distributed PV generation and large-scale grid-connected batteries and solar farms. In particular, the large uptake in distributed PV has substantially increased the region's power system security challenges. These challenges will continue to grow as more transmission- and distribution-connected IBR are installed.

As explained in Section A7.6.4, there is a growing need for FFR in South Australia to minimise the risk of load shedding and black system events during system normal configuration and when at credible risk of separation, and to allow the FOS to be maintained if the South Australian system is islanded.

The ISP identifies Project EnergyConnect as a low-regret and actionable project in the optimal development path. Project EnergyConnect will provide a second HVAC double-circuit interconnector between South Australia and the rest of the NEM and reduce the risk of islanding. It will also provide greater flexibility and increased reliability to the South Australia power system and address a number of South Australia system security challenges.

A primary market benefit from delivering Project EnergyConnect is fuel cost savings – the interconnector enables South Australia GPG to be displaced by cheaper energy sources. If Project EnergyConnect does not proceed, additional investment in FFR will be needed to meet system security challenges in South Australia that would otherwise be solved by Project EnergyConnect. These system security challenges are in addition to the market benefits modelled in this ISP and are separate to the supply risk and fuel cost matters considered in Appendix 6. In the absence of Project EnergyConnect, approximately 300 to 500 MW (or an average of 400 MW) of FFR will be required to securely operate South Australia as an island in 2025.

The delivery of Project EnergyConnect is projected to:

- Deliver a wide range of market benefits (captured by ISP modelling) that outweigh its cost.
- Significantly reduce the likelihood of operating South Australia in an electrical island, and therefore mitigate the need to procure approximately 400 MW of FFR to manage islanded operation.
- Resolve the need to maintain headroom of the Heywood interconnector for credible contingencies or protected events in South Australia.
- Reduce the likelihood of operating in conditions where a separation is credible, and therefore reduce the impact of limits that manage those conditions.

The delivery of Project EnergyConnect would result in fuel cost savings by providing competition to GPG in South Australia and would significantly reduce the scale of system security investments needed to securely operate the South Australia power system. Project EnergyConnect will provide increased interconnection between South Australia and the rest of the NEM, greater flexibility, and increased reliability to the South Australia power system. AEMO's assessments indicate that the Project EnergyConnect will substantially reduce or potentially eliminate a large number of South Australia system security challenges.