AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

2026 Transition Plan for System Security

December 2026

Maintaining system security through the energy transition

Embargoed to 12.01am Tuesday 1 December 2026





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

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

AEMO is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

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Important notice

Purpose

AEMO is required to publish the NSCAS report, Inertia report, System strength report and system strength requirements, and the Transition Plan for System Security, specific to clauses 5.20.3, 5.20.5, 5.20.7, 11.143.14(f), 5.20C, and 5.20.8 of the National Electricity Rules. This publication provides a plan to maintain power system security in the National Electricity Market through the energy transition to a low- or zero-emissions power system. It further outlines the work AEMO is undertaking to improve this understanding and to specify the range of services that may be required. This publication is based on information available to AEMO as of 16 November 2026 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	1/12/2026	First release

Executive summary

The Australian Energy Market Operator (AEMO) operates the power system to maintain a secure and reliable supply of electricity for homes and businesses across the National Electricity Market (NEM). This system continues to evolve as renewable generation, batteries, large loads, and consumer energy resources (CER) continue to grow and as coal-fired generators approach retirement. The *Transition Plan for System Security* (TPSS) outlines AEMO's plan for how system security can be managed through the energy transition. It includes AEMO's latest assessment of system strength, inertia, and network support control and ancillary services (NSCAS) requirements in years ahead, and AEMO's Engineering Roadmap which summarises progress in improving technical understanding of what is required to operate a low emission power system.

Collective action for system security is supporting the energy transition

Over the past 12 months there has been collective action to support system security:

- Battery capacity on the transmission network has doubled to 9.1 gigawatts (GW), providing flexibility, firming for renewable generation, system security services, and supporting secure operation during periods of minimum system load.
- Investment has been committed for priority transmission infrastructure across the NEM, reactors in South Australia, and synchronous condensers in New South Wales to provide system security services as synchronous generators retire.
- In Victoria, VicGrid is actively procuring cost-efficient system security services to support secure operation as the generation mix changes.
- Engineering efforts have increased understanding of grid-forming (GFM) technologies and their potential to provide system security services.
- The Australian Energy Market Commission's (AEMC's) Access Standards Package 2 reforms and ongoing Operational Integration and Visibility rule change process are supporting the secure integration of large inverter-based loads through improved connections, operational visibility, information sharing and coordination.
- Arrangements to extend Eraring Power Station until April 2029 provide additional time for replacement generation, firming and system security capabilities to be delivered ahead of its retirement.
- The energisation of Project Energy Connect (PEC) strengthens the interconnected NEM and increases the ability to share energy and system security support between South Australia and New South Wales.

System security

A power system is secure when operated safely within defined technical limits, with the ability to withstand credible disturbances, return to secure operation, and restart following a widespread outage.

The National Electricity Rules (NER) outline shared responsibilities for AEMO, network service providers (NSPs) and NEM market participants to collectively ensure system security through the operation of energy systems and markets and planning frameworks.

Together, and with the support of industry, regulators and governments, progress has supported the NEM to accommodate growing renewable contributions, which reached a record of 80% of electricity generation over a 30-minute interval in September 2026. In South Australia, renewable supply regularly exceeds local demand, with progress towards capability to operate with zero synchronous generators online facilitated by the energisation of PEC.

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In addition, almost 10 GW of new generation and storage capacity was commissioned in 2026, household battery capacity increased more than 40% to 6.1 GW, and similar investment is expected in coming years through utility-scale and behind-the-meter generation and storage, electrification, data centre growth, and major transmission projects.

However, there are near-term headwinds to navigate

Security solutions are required ahead of coal exits, but often have long lead times for investment decision and delivery

The solutions required to operate the NEM without coal are largely known and resolvable through the deployment of synchronous condensers, GFM technology, network augmentation, and uplifted capabilities of new gas turbines when installed. The key challenge is ensuring that cost-effective solutions are delivered before the periods when coal stations decommit from the market, which may occur well in advance of announced retirement dates. Where enduring solutions are not available ahead of time, there may be extended windows where interim solutions are needed, increasing the likelihood of more costly market interventions to maintain system security.

Without proactive investment, there may be prolonged reliance on interim solutions

Energy infrastructure projects worldwide are experiencing delays in delivery and increases in costs. Navigating this for critical NEM infrastructure, such as for Snowy 2.0 and synchronous condensers, requires ongoing coordinated action across industry, governments, and AEMO.

Beyond any single event, the energy transition has significant interdependencies for progress. A change in the timing of one project can alter the requirements, risks or available mitigation for others, potentially creating reliability or system security gaps even where the broader transition pathway remains achievable. This highlights the importance of resilience in the transition plan: maintaining sufficient flexibility, alternative pathways, and appropriate lead times to respond when expected projects are delayed or system conditions change. It also reinforces the value of delivering cost-effective system security investments sufficiently ahead of operational need.

These sequencing risks are evident in two near-term transition points:

- **Yallourn** – proactive steps are underway to maintain system security at required operational levels following Yallourn Power Station's scheduled retirement in Victoria's Latrobe Valley. However, some of the required investment in system security assets has not yet progressed sufficiently to meet AEMO's commitment criteria. Without these assets in place, there would be periods of heightened risk in which operational intervention may be necessary to maintain system strength.

  Managing this risk will require interim system strength contracts with existing assets, measures to minimise overlapping unavailability of critical units, and operating measures to manage severe contingencies until enduring solutions are in place. AEMO is reviewing operational procedures and working with VicGrid to prepare for these conditions ahead of Yallourn's exit. If planned mitigating actions are not delivered in time, there may be an increased likelihood of more significant operational interventions being required to maintain system security, potentially including, in extreme circumstances, controlled de-energisation of parts of the network. This heightened risk would exist in the period between Yallourn's retirement and commissioning of the planned synchronous condensers, particularly when other critical synchronous units are unavailable.

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- **Eraring** – Eraring Power Station's revised retirement to April 2029 has provided additional time for new generation, storage and security infrastructure to enter New South Wales, improving readiness for its exit. Transgrid's Phase 1 synchronous condensers are on track to address most of the system strength and inertia requirements ahead of retirement, and Transgrid is pursuing contracts with existing assets to address the remaining needs. However, if replacement assets are delayed, high-impact operational intervention may be required to maintain security. Further, the 12-month delay to Snowy 2.0 illustrates the interdependencies across the transition: while it does not create an unresolved system security issue for Eraring's retirement, it has contributed to a newly forecast reliability gap in 2029-30, as outlined in the December 2026 *Update to the 2026 Electricity Statement of Opportunities* (ESOO Update). This reinforces the importance of timely delivery across the broader portfolio of committed and anticipated generation, storage and transmission, and of retaining sufficient flexibility to respond when individual projects are delayed.

  Timely delivery of planned and actionable network augmentations, including HumeLink, Hunter Transmission Project and Sydney Ring South will also be important following retirement of Eraring, as power flows into the Sydney-Newcastle load centre change. AEMO is continuing to jointly plan with Transgrid and EnergyCo to address the thermal capacity of the transmission network from the south of New South Wales ahead of operational timeframes.

While the timing of some coal closures is confirmed, asset retirement and the coordination of plant operation are ultimately decisions for asset owners. AEMO will continue to plan with the best available information and be prepared to support industry readiness for what may eventuate.

Increasing system complexity requires focused attention

As the power system transitions, security increasingly depends both on having necessary technical capabilities in place and for those capabilities to integrate efficiently together. The more diverse and complex mix of technologies in the power system is introducing new system behaviours and operating challenges that need to be identified, understood and actively managed. This is bringing greater focus to stability and operability requirements as the system evolves.

- **Stability** – transient and oscillatory stability is becoming an increasing focus as the characteristics of the power system change, as identified in AEMO's 2026 *General Power System Risk Review* (GPSRR). New voltage oscillations have been observed periodically in South Australia under low-demand conditions since November 2025, and ElectraNet, SA Power Networks, and AEMO are investigating the root causes and potential mitigations. Progress towards operation with zero synchronous generators online in South Australia will continue when these oscillations are resolved, as synchronous generators currently provide damping that reduces the oscillations to acceptable levels.

  AEMO's broader assessment of future power system damping requirements also identifies the potential for new or changed inter-area oscillations that will require ongoing assessment. Damping performance depends on how resources are located, controlled and tuned, not only on their availability, and AEMO and network service providers (NSPs) are uplifting modelling tools and capabilities to identify emerging stability risks and assess effective responses. Preserving appropriate design and control flexibility in new assets now, will help retain options to address evolving oscillatory stability risks.

- **Operability** – as the power system becomes more diverse, complex and dynamic, operability can no longer be assumed as an inherent outcome of market and system design – it must be deliberately developed alongside the physical system. AEMO is uplifting operability capabilities in collaboration with NSPs, including improved real-time visibility of system conditions, early identification of emerging technical limits, enhanced decision-support tools and emergency backstop

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capabilities. These investments in people, processes, and tools will strengthen situational awareness and support timely, informed and efficient operational decisions as system complexity increases.

This year's *Transition Plan for System Security* combines four AEMO transition planning programs, and highlights accelerated preparation is required for 2028 and 2029

System security assessments identify gaps in requirements and the commissioning of enduring solutions

AEMO sets the inertia and system strength requirements for each region of the NEM and then assesses Jurisdictional Planning Bodies' (JPBs') plans to meet these, as well as other power system security needs, through NSCAS – in many cases JPBs are transmission network service providers (TNSPs). Gaps are summarised in **Table 1**. A new security and reliability gap has been declared in New South Wales from summer 2029-30, following retirement of Eraring Power Station and progressive demand growth. System strength and inertia needs are re-affirmed for Victoria, primarily associated with the planned closure of Yallourn Power Station.

For all identified system strength and inertia deficits, along with thermal and reliability gaps and emerging risks across several regions, AEMO will continue to jointly plan with JPBs as solutions are progressed. While most identified system security gaps have solutions underway, interim measures, such as market intervention through directions, are likely to be required in some cases until permanent solutions are available.

Transition point planning identifies 'Moderate Readiness' for the majority of upcoming transition points, with significant change expected in 2028 and 2029

Transition point planning assesses the readiness of industry plans to maintain system security during market operation at key events and milestones and identifies actions for improved outcomes. **Figure 1** outlines the NEM Transition Point sequence. Key changes from 2025 transition points are summarised in **Table 2**.

The TPSS highlights 'Moderate Readiness' for the majority of transition points over the next 10 years. This means that, in most cases, actions to improve readiness are already being progressed, however moderate-impact interventions will likely be required to maintain system security. There may be opportunities to expand or accelerate actions to improve readiness.

An 'On Track' assessment, such as for the retirement of Gladstone Power Station in Queensland in 2029, indicates that planned actions are expected to maintain system security. An assessment of Unresolved Issues indicates that current plans are unlikely to be sufficient to avoid increased chance of high-impact interventions being required to maintain system security. Options for further preparatory actions and operational controls are narrow or not currently being actively progressed.

The 2026 TPSS highlights that several significant power system transitions are expected in close succession across calendar years 2028 and 2029. These include four announced synchronous generator retirements across the NEM and the planned connection of Central West Orana (CWO) Renewable Energy Zone (REZ) in New South Wales. The period may also include times when a second New South Wales coal station is offline and when South Australia operates for the first time with zero synchronous generators online. Additional preparation will also be required during 2029 ahead of the planned connection

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of Marinus Link in 2030, a monitored transition point for Tasmania and Victoria incorporating GFM high-voltage direct current (DC) converter technology.

Navigating this period will require a transition planning approach that can withstand foreseeable challenges in design and plausible delays in delivery, without prohibiting further progress in the transition. Success in doing so will provide firm foundations to prepare for the remaining coal-offline transition points of the next decade and for the first periods of no-coal operation for the NEM.

Type 2 Services are moving from framework development to delivery

Type 2 Transitional Services enable collaboration for demonstration of new technologies or new applications of existing technologies that may contribute to managing power system security. Five Statements of Need for Type 2 services were published in 2025 (in addition to two Type 1 services), and the framework for procurement has been established in 2026. The first contracts for Type 2 Services have now been signed for Minimum System Load and System Restart with High Distributed Photovoltaics, with ongoing feasibility assessments in process for other services. Market engagement has highlighted the need for staged feasibility work to be delivered for more complex trials before live trials can proceed.

AEMO's Engineering Roadmap has identified system strength, system restart, stability and operability as key focus areas for the next three years to advance technical understanding and progress capabilities

To give a single reference point for AEMO's broader system-wide future readiness activities, for the first time AEMO is incorporating its Engineering Roadmap workplans and reporting into the TPSS. The Engineering Roadmap outlines how remaining technical uncertainties for power system criteria will be reduced and capabilities uplifted. This work, alongside Type 2 Transitional Services, seeks to advance technical understanding for industry and explore innovative and unprecedented solutions for what is required to operate a low- or zero-emission power system. It also serves as a reference point for AEMO's collaboration with researchers. Engineering Roadmap workplans are summarised in **Figure 2**.

In addition to **Stability** and **Operability,** outlined above as emerging issues requiring focused attention, priority Engineering Roadmap workplans include the following:

- **System strength** – GFM inverters may be capable of making further contributions to system strength; however, uncertainties remain regarding the compatibility of their fault current characteristics with existing network protection systems. Together with NSPs, research organisations, and original equipment manufacturers (OEMs), AEMO is progressing initiatives to determine how GFM can contribute to the provision of minimum fault level requirements through power system modelling, laboratory testing, and Type 2 Transitional Services. These will collectively build the evidence base over coming years to inform future NSP procurement decisions.
- **System restoration** – AEMO is preparing for the commencement of the recently revised System Restart Standard in July 2027. Additionally, AEMO is analysing existing and future restart pathways to assess whether further consideration of the restart framework and underlying objectives is warranted in advance of future coal retirements. Engineering Roadmap efforts target identifying operational needs for existing and future restart scenarios, Type 2 Service Trials, and requirements to support network augmentation and interconnector-led restart capability, in parallel with reform.
- **DER** – distributed energy resources (DER), comprising both CER and larger distribution-connected resources, continue to shape power system operation with ongoing uptake of rooftop solar, storage and electric vehicles (EVs) and

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increasing demand side flexibility and coordination. Minimum system load (MSL) management in normal conditions is improving through better integration of battery storage and Transitional Services, though emergency backstop capabilities remain essential for management of plausible, onerous conditions. The DER workplan supports sector-wide collaboration through the National CER roadmap and focuses on technical enablers for DER integration across five priorities: visibility and predictability; whole-of-system planning and operational coordination; management of high-DER system conditions; cyber-physical resilience; and technical requirements and compliance.

- **Large loads** – AEMO is actively collaborating with industry and government to support the secure integration of large loads, including data centres. Reform activities include updated access standards, improved operational integration and visibility, and the Commonwealth Minister's proposed rule change to introduce data centre contracting obligations for firmed energy, including provisions for demand flexibility. These activities are complemented by the GPSRR assessment of large-load integration risks and the accompanying high-degree of data centre investment uncertainty.

Key takeaways:

- **Market participants** – collective action continues to be required in preparation for scheduled coal exits and upcoming transition points, with potential for co-investment in both reliability and security capability with planned new capacity and assets. Appropriate design and control flexibility should be included and preserved in new assets such as GFM inverters. AEMO notes the locational opportunities for new plant, as outlined in AEMO's *Enhanced Locational Information Report*, *Integrated System Plan* (ISP) and *Electricity Statement of Opportunities* (ESOO) – in particular plant with multiple degrees of flexibility such as gas turbines with clutches and black-start capability, and battery storage with GFM capability.
- **NSPs** – continued proactive, cost-effective investment and uplift is required to navigate upcoming transition points and manage evolving power system security requirements, in particular for stability, system strength, inertia, system restart, and operability. NSPs are encouraged to assess future operating limits and dynamic behaviour well in advance of operational timeframes, giving AEMO an early indication of the evolving technical operating envelope and helping signal where additional action, capability uplift, and investment may be needed. Uplifted network models and modelling tools will help assess oscillatory stability and GFM compatibility with protection systems, and there is opportunity to preserve appropriate flexibility in new assets such as synchronous condensers to support future system damping needs. Appendix A2[1] includes detailed assessments of system security shortfalls for each network region.
- **Governments** – continued support of market and network investment enables assets to be in place before transition points occur. There is opportunity for further consideration of power system security requirements alongside government investment and support for new capacity to lower the cost of the energy transition. This includes GFM capability for new battery energy storage systems (BESS), new black-start capability, clutches for new gas generators (as recently required with the New South Wales Government electricity roadmap), and emergency backstop capability to support increased CER integration. Part B includes region-specific system security information.

The consolidated reporting of the TPSS produces a wide range of information, assessments, and data. **Table 3** presents options for readers to navigate to selected topics of interest.

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[1] At https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

Figure 1 Summary of NEM transition points

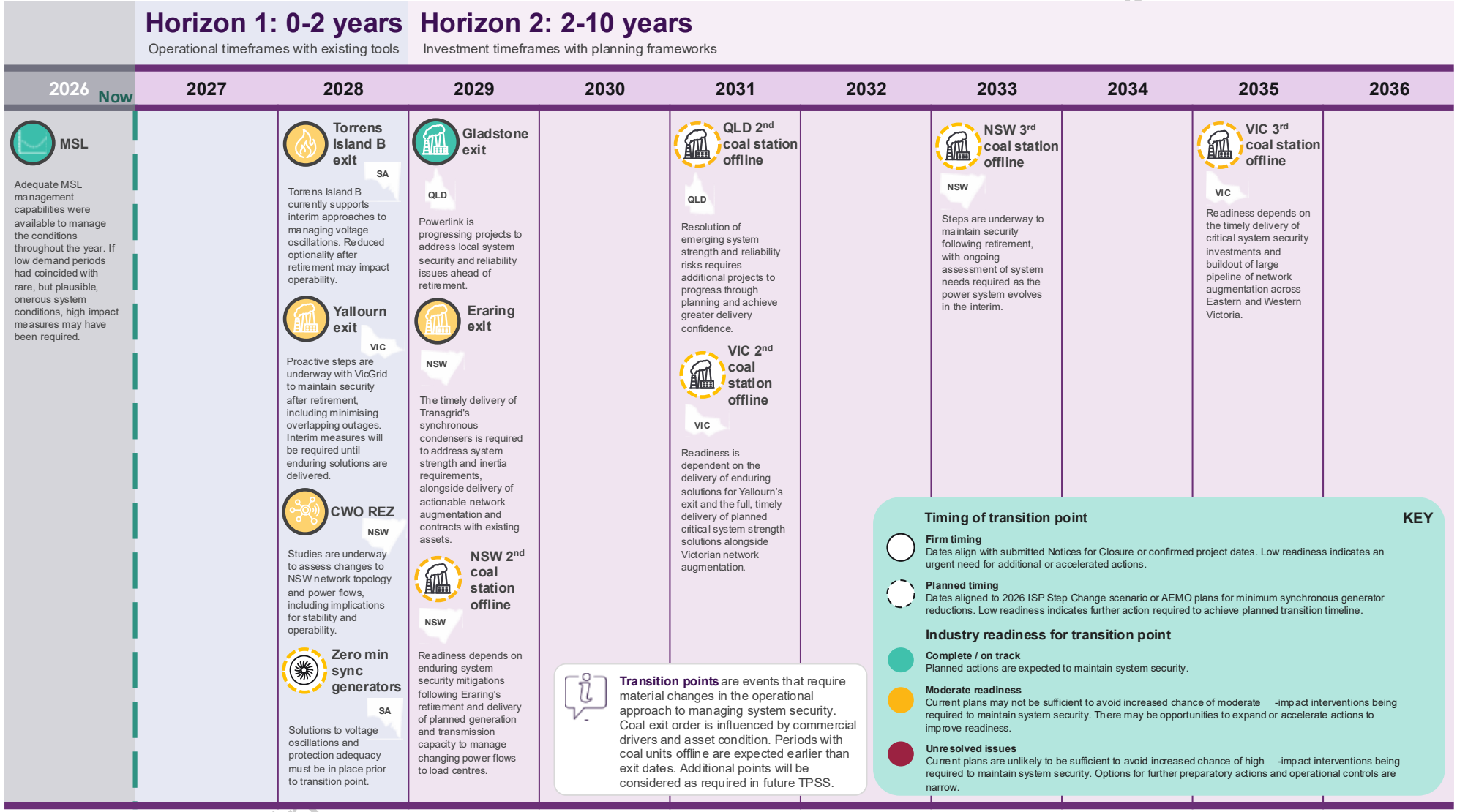

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Figure 2 Engineering roadmap

	Priority power system criteria	Engineering Roadmap target objectives
System strength	**Controlling the voltage waveform and maintaining minimum fault levels for protection.** The compatibility of inverter-based resources (IBR) and protection needs to evolve. There may be opportunities in future for grid-forming inverters (GFM) to contribute further to system strength at lower cost and lead times than synchronous condensers.	• Technical understanding and technology options for minimum three phase fault levels are aligned. • Efficient and accurate modelling techniques are available to represent IBR in fault level analysis. • An evidence base is developed for the compatibility of GFM BESS and network protection systems to inform NSP selection of technologies to address future needs.
Stability	**Remaining stable and synchronised when subject to small (oscillatory) and large (transient) disturbances.** There is a need to uplift capabilities to identify, model and respond to future local and wide-area stability issues in high-IBR, low synchronous generation conditions, including for recent voltage oscillations in South Australia.	• Small signal oscillatory stability models are accurate for high-IBR, low-synchronous generation conditions. • Local & inter area oscillations are adequately damped within appropriate operating limits. • Transient stability is managed in high-IBR / low-synchronous generation conditions.
System restoration	**The ability to re-start generation and re-energise load following a black system event** AEMO is analysing current operational capability and future restoration pathways. Opportunities include identifying locations for investment, ensuring operability under anticipated system configurations, building understanding of IBR capability to support restoration, and enabling network augmentation and interconnector restart.	• Restoration of generation and load is assured within technical limits under anticipated conditions. • Planning, policy, and Investment frameworks enable future restoration. • Required operational tools, capabilities and assets are progressively delivered to ensure system restoration from any anticipated fleet and network.
Operability	**The practical ability to operate the power system securely and efficiently using the capabilities available to operators and industry.** Operational capability must keep pace with increasing complexity, interacting system changes and growing demands on operators and support teams, requiring coordinated capability development across AEMO and NSPs.	• Operational foundations prioritise, coordinate and sustain capability development. • Strengthened capability to assess system risks, manage secure operating conditions, and enable effective operator decision-making through visibility, support and preparedness. • Future system and market readiness supported by forecasting, industry coordination and aligned reforms.
DER	**Integrating distributed energy resources into the power system, including consumer solar PV, batteries, and electric vehicles.** AEMO is supporting the National CER Roadmap through engineering activities that strengthen secure DER integration, address emerging system impacts and develop solutions for high-DER operation.	• DER is sufficiently visible and predictable to support forecasting, planning, security assessment and effective management of minimum system load. • DER is effectively coordinated across transmission and distribution planning and operation, enabling whole-of-system outcomes and efficient investment. • Cyber-physical resilience, technical standards and assurance arrangements enable DER to operate securely, perform as required and contribute to system needs.
Large loads	**Integrating large loads, such as data centres, into the power system in a way that supports security and reliability.** International experience demonstrates the potential for significant power system impacts. Appropriate technical, operational, and regulatory arrangements are needed with progress being made to support integration of these facilities.	• Technical performance requirements for the connection of data centres are identified and implemented. • Operational visibility and communication arrangements are in place to manage system security as data centre load increases. • Registration and system integration requirements are defined, and emerging reliability and system security issues are managed effectively.

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Table 1 Summary of network requirements, to be addressed by transmission network service providers

Region	Transmission Network Service Provider (TNSP) requirements
New South Wales (Transgrid) 	**Minor system strength deficits across New South Wales remain from 2028-29 with the expected delivery of Transgrid's 'Phase 1' synchronous condensers, inclusive of the revised Eraring Power Station retirement date.** Transgrid is actively pursuing additional market services to cover these minor deficits. These services may be required before 2028-29, depending on market conditions. **No inertia deficits have been identified** following the expected delivery of Transgrid's 'Phase 1' synchronous condensers, which will include flywheels to deliver inertia. **A reliability and security NSCAS gap has been declared in New South Wales from summer 2029-30,** driven by retirement of Eraring, and exacerbated by risk of delayed delivery of anticipated projects, potential decommitment of a second coal station and progressive demand growth. Supply to the Sydney, Newcastle and Wollongong load centre is limited by the thermal capacity of the transmission network from the south of New South Wales. AEMO will continue to jointly plan with Transgrid and EnergyCo on this matter. Transgrid is currently progressing the actionable Sydney Ring South project to address this gap, currently planned to be delivered in stages by 2033-34 at the earliest.
Queensland (Powerlink) 	**There are no emerging system strength deficits in Queensland** with the anticipated delivery of the four synchronous condensers designed to address the Gladstone Power Station retirement from 2028-29. **No inertia deficits have been identified** in Queensland. **Thermal and voltage risks in the Gladstone Region are expected to be managed following the retirement of Gladstone Power Station due to the delivery of the anticipated Central Queensland Synchronous Condensers project and Stage 1 of the Gladstone Project.**. Powerlink is progressing the Gladstone Project in two stages, with Stage 1 targeted for delivery by March 2029, ahead of the retirement of Gladstone Power Station. The anticipated Stage 2 will be required to further reinforce the network for additional generation retirements and future load growth.
South Australia (ElectraNet) 	**No system strength deficits have been identified, but an emerging oscillations issue has led to the inclusion of DPV forecasts in the efficient level of system strength to be considered by ElectraNet.** The oscillations issue may require further consideration under the system strength framework once ongoing testing and analysis reveals the nature and source of the oscillations. **No inertia deficits have been identified.** **The previously declared voltage control gap is actively being addressed**. ElectraNet is resolving this gap through the installation of new switched reactors in the Adelaide and South East regions and ongoing NSCAS contracts to be completed in 2027.
Tasmania (TasNetworks) 	**AEMO has confirmed that TasNetworks has sufficient contracts in place to meet system strength and inertia requirements until 2029-30, however deficits have been identified from 2029-30.** TasNetworks has several options to manage system strength and inertia requirements once the existing contracts end. **No gaps have been identified in relation to thermal loading or voltage control** at this time.
Victoria (VicGrid) 	**Emerging system strength deficits continue to be anticipated from 2028-29, primarily associated with the planned closure of Yallourn Power Station.** In addition to developing the planned synchronous condensers identified in its system strength regulatory investment test for transmission (RIT-T), VicGrid is actively contracting system strength from existing assets as an operational response, pursuing measures to minimise overlapping unavailability of critical units, and reviewing limits advice, to minimise likelihood and impact of severe contingencies before enduring solutions are in place. **An inertia deficit has been confirmed in Victoria from 2027-28 under the current sub-network allocation.** While the planned synchronous condensers (including flywheels) can provide some inertial support once in service, additional measures may be required under the current allocation. However, the NEM-wide inertia requirement is expected to continue to be met for at least the next three years through contributions across regions. AEMO is considering whether the current sub-network allocations should be updated to better account for existing inertia across the NEM and provide a durable basis for regional contributions as generators retire. This is important to avoid overinvestment before it is required from a whole-of-system perspective. At the same time, **Victoria's minimum regional interconnected inertia requirement is expected to increase from the level established in 2024**, reflecting significant growth in distributed PV. The appropriate requirement may vary with operational conditions, and VicGrid should account for the possible increase when planning future inertia services. **AEMO confirmed the existing thermal loading risks in Eastern and Western Metro Melbourne** to supply growing peak demand. VicGrid is progressing the Eastern and Western Melbourne reinforcement programs to manage these risks in anticipation of rapid demand growth and early retirement of a second coal station in 2032. **AEMO has also identified thermal and voltage control risks at Deer Park**. Powercor, VicGrid, Lumea and AEMO will continue to work on operational solutions to the emerging voltage risks at Deer Park under specific high load conditions to avoid pre-contingent load shedding, with enduring solutions to be delivered progressively from 2027-28 to 2030-31.

Table 2 Summary of transition point changes from 2025

Region	Summary of changes
New South Wales	CWO REZ is now treated as a transition point. Eraring's exit has been deferred two years, with improved readiness due to the accelerated delivery of synchronous condensers. The announced delay of Snowy 2.0, however, requires timely delivery of anticipated projects to address forecast reliability gaps. The 2026 ISP revised the date of the third coal station offline transition point to 2033 (from 2031).
Queensland	The 2026 ISP revised the date of the second coal station offline transition point to 2031 (from 2027) with readiness reduced to 'Moderate Readiness' due to dependence on a non-committed system strength service.
South Australia	The exit of Torrens Island Power Station B has been assessed as 'Moderate Readiness' (revised from being monitored in 2025). The planned date for Zero minimum synchronous generation operation has been deferred a year to Q4 2028.
Tasmania	Project Marinus Stage 1 has become 'anticipated' and continues to be a monitored potential transition point, and Stage 2 has become 'actionable'.
Victoria	Yallourn's exit date and readiness assessment of 'Moderate Readiness' are unchanged from 2025, while operational impacts have become clearer. The 2026 ISP revised the date of the third coal station offline transition point to 2035 (from 2033).
All regions	MSL events are not assessed as transition points in the 2026 TPSS, with information provided in Appendix A3.

Table 3 Ways to read the 2026 TPSS

If you are particularly interested in…	Start with…	Then explore…
The overall outlook for system security in the NEM	Part A, Sections 1, 3.1	Part B, first page of each region
How AEMO plans to maintain security through the transition	Part A, Section 2	Part B, pages 1-2 of each region
The system security outlook for a state or region	Part B, regional Section	Appendices 2 and 3
Readiness for upcoming coal retirements	Part A, Section 2.5	Part B, first page, then detail
Transmission system requirements and identified gaps	Part B, page 2 of region	Appendix 2
Engineering challenges and forward workplans, including for technologies and industry collaboration	Part C, select power system criterion	Part A, Section 2.4
Grid-forming inverters for system strength	Part C, Section 5	Part B, pages 1-2 of each region
DER-related issues, including minimum system load	Part C, Section 11	Appendix 3
Future system restart needs	Part C, Section 9	Appendix 4
Observed and evolving oscillatory stability challenges	Part A, Section 1.2	Part B, SA page 3, Part C, Section 8
AEMO's use and plans for Transitional Services	Part A, Sections 2.4, 3.2	
The operability of the NEM	Part A, Section 3.3	Part C, Section 10
The system security impacts of data centres	Part C, Section 12	
Research collaborations	Part C, Section 13	Part C, for further opportunities

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Part A. Transition planning

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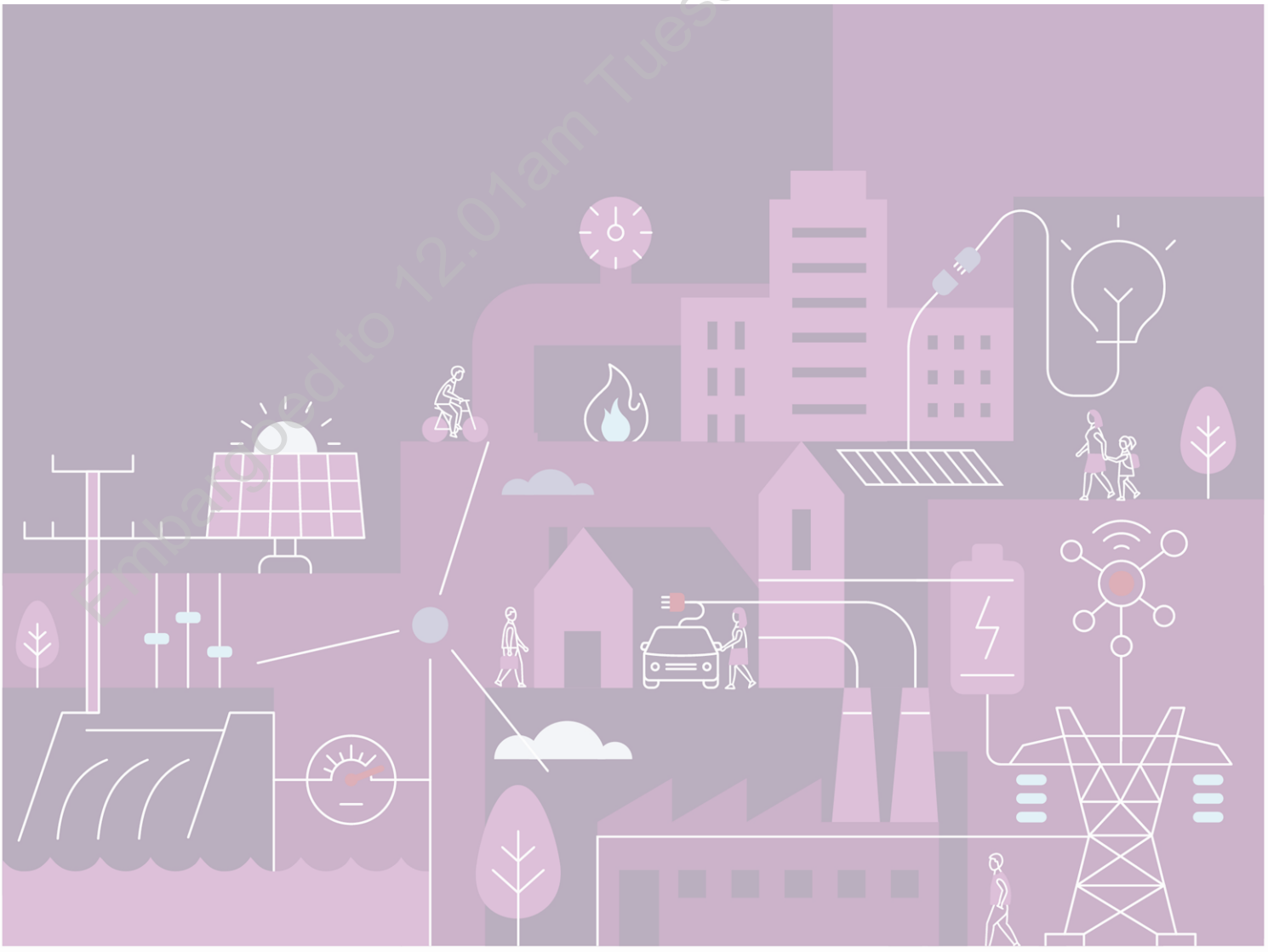

Part A. Transition planning

The TPSS provides AEMO's plan to maintain system security in the NEM over the coming decade. Since 2025, it incorporates the system strength, inertia and NSCAS reports[2] and, from 2026 onwards, AEMO's Engineering Roadmap[3] reporting, as shown in **Figure 3**. The consolidation of reporting follows stakeholder feedback that this will aid clarity of understanding and cohesion of action[4]. Structural changes from the 2025 TPSS are summarised in **Table 4**.

The report has three parts:

- **Part A. Transition planning** outlines the fundamental technical criteria – and critical importance – of system security and summarises AEMO's approaches for maintaining security through the transition.
- **Part B. Regional transition plans** presents detailed transition plans for each region of the NEM, assessing industry readiness for transition points.
- **Part C. System-wide developments and plans** provides an overview of AEMO's Engineering Roadmap workplans, which are prioritised initiatives to improve the understanding of remaining technical uncertainties in what is needed to maintain security in a low- or zero-emissions power system, including the latest developments on technologies and system services.

The report has four appendices, covering feedback from the Reliability Panel, system security requirements for transmission networks, and assessments of minimum system load conditions and locational suitability and indicative capacity gaps for system restart investments.

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[2] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[3] See https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap, noting the Engineering Roadmap FY2026 Priority Actions Report marked the end of priority actions reporting in favour of integration in the TPSS.

[4] See **Section 2.4.2** for a summary of stakeholder feedback and Appendix A1 for the letter providing feedback from the Reliability Panel, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a1.

Figure 3 Structure of combined security reporting in the TPSS

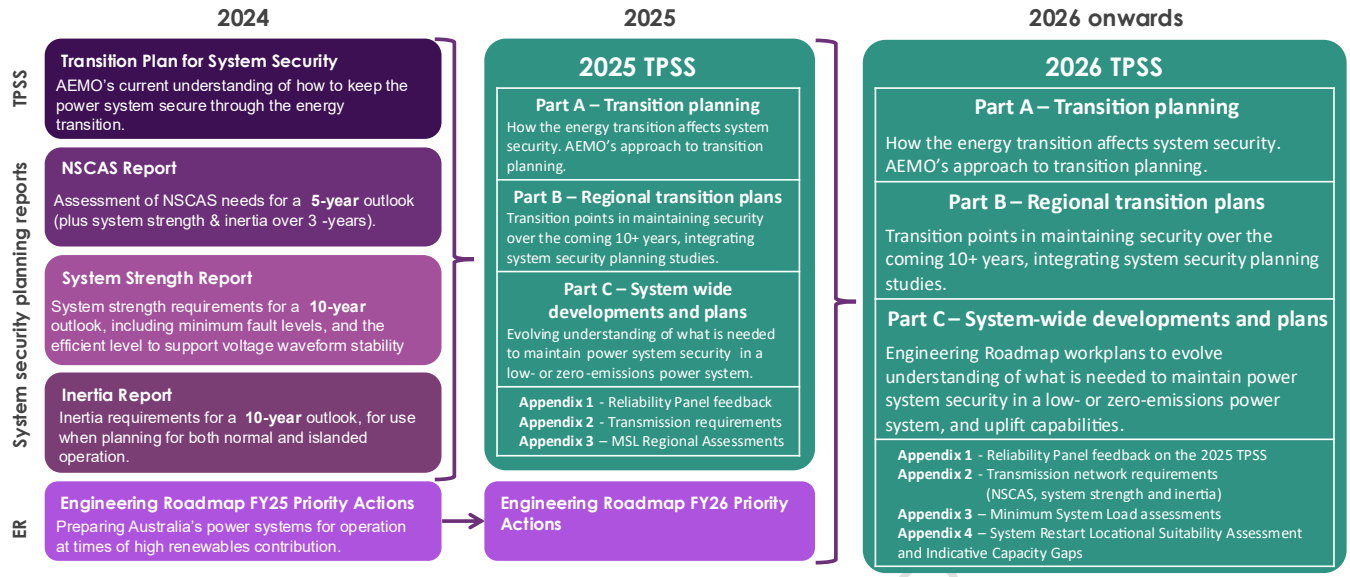

Table 4 Structural changes from the 2025 TPSS

Section	Summary of changes
Part A – Section 2 Error! Not a valid result for table.	Provides an overview of the four approaches to transition planning that contribute to the TPSS: system security assessments, transition point planning, the Engineering Roadmap, and Type 2 Transitional Services.
Part A – Section 2.4 Type 2 Transitional Services	Provides an update on progress of these new services, including establishing governance arrangements.
Part C – System-wide developments and plans	Part C has been restructured to more clearly present AEMO's Engineering Roadmap workplans to improve the technical understanding of system security in low-emissions power systems.

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1 How the transition affects system security

The NEM is in a period of transition: the generation mix is changing as coal retires; storage, networks and CERs are taking different and increasingly important roles; electricity consumption is expected to grow; and the way the system is planned and operated is changing.

Irrespective, the technical requirements, and critical importance, of system security are enduring. The ways in which security is managed must evolve to ensure security is maintained in an efficient and cost-effective manner, while managing increased operational complexity.

1.1 The technology mix is changing

The NEM's coal-fired generation fleet is progressively retiring. Ten coal-fired power stations have closed since 2012 and retirements have been announced for all but one of the remaining fleet, with about half of the fleet planning to retire in the coming 10 years and the rest by 2049 at the latest. To meet government policy objectives, AEMO's 2026 ISP *Step Change* scenario[5] projects an even faster shift, with around two-thirds of today's coal capacity closing by 2035.

These synchronous generators are being replaced by a pipeline of projects predominantly made up of inverter-based resources (IBR), such as wind turbines, solar, and batteries, including a large amount of distributed solar and batteries, including installations in homes and businesses. AEMO expects these trends to continue in coming decades, with the 2026 ISP reaffirming that *renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas* presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies. **Figure 4** highlights the change in technology mix projected in the 2026 ISP *Step Change* scenario[6].

Australia is not alone in navigating an energy transition. Changes in technology capabilities, engineering and regulatory approaches, and industrial supply chains are shared, global experiences. AEMO is committed to learning from these international experiences and is one of six founding members of the International System Operator Network (ISON)[7], which facilitates rapid knowledge-sharing and deployment of best practices and innovations.

Within this global context, the NEM, and the Wholesale Electricity Market (WEM) in Western Australia, are at the forefront of certain changes. Australian power systems feature some of the highest instantaneous and average contributions from wind and solar, with the NEM reaching a record 80.4% renewable energy contribution over a 30-minute interval ending 12:30 pm on 19 September 2026. **Figure 5** shows the NEM and WEM in relation to other leading large power grids and large island grids respectively[8]. **Figure 5** shows only wind and solar contributions, with the NEM instantaneous record therefore being 79% after accounting for the 1% contribution by hydro.

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[5] The *Step Change* scenario is considered by AEMO (with input from expert stakeholders) to be the most likely of the three possible futures assessed in the 2026 ISP. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

[6] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

[7] See https://www.aemo.com.au/initiatives/major-programs/international-system-operator-collaboration.

[8] Prepared for this report by Benjamin Kroposki of the National Laboratory of the Rockies.

Figure 4 Historical and projected capacity of synchronous and IBR generation and storage in the NEM, historical and in the 2026 ISP *Step Change* scenario, 2009-10 to 2049-50 (GW)

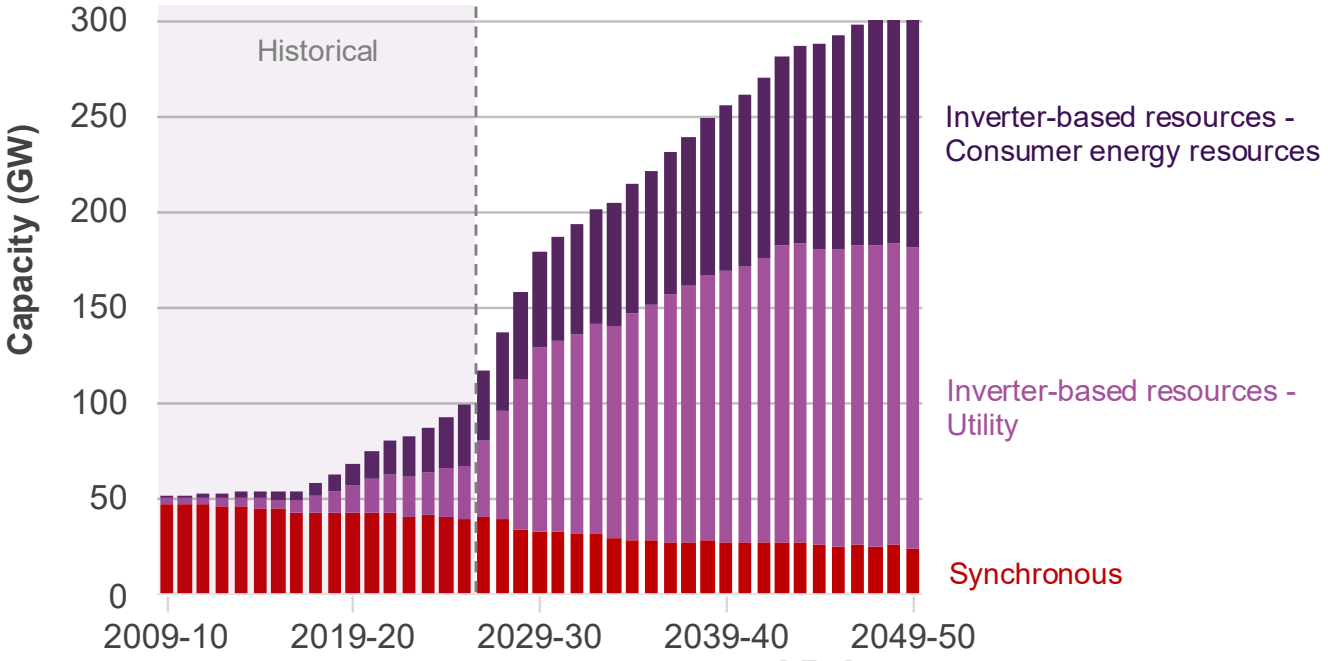
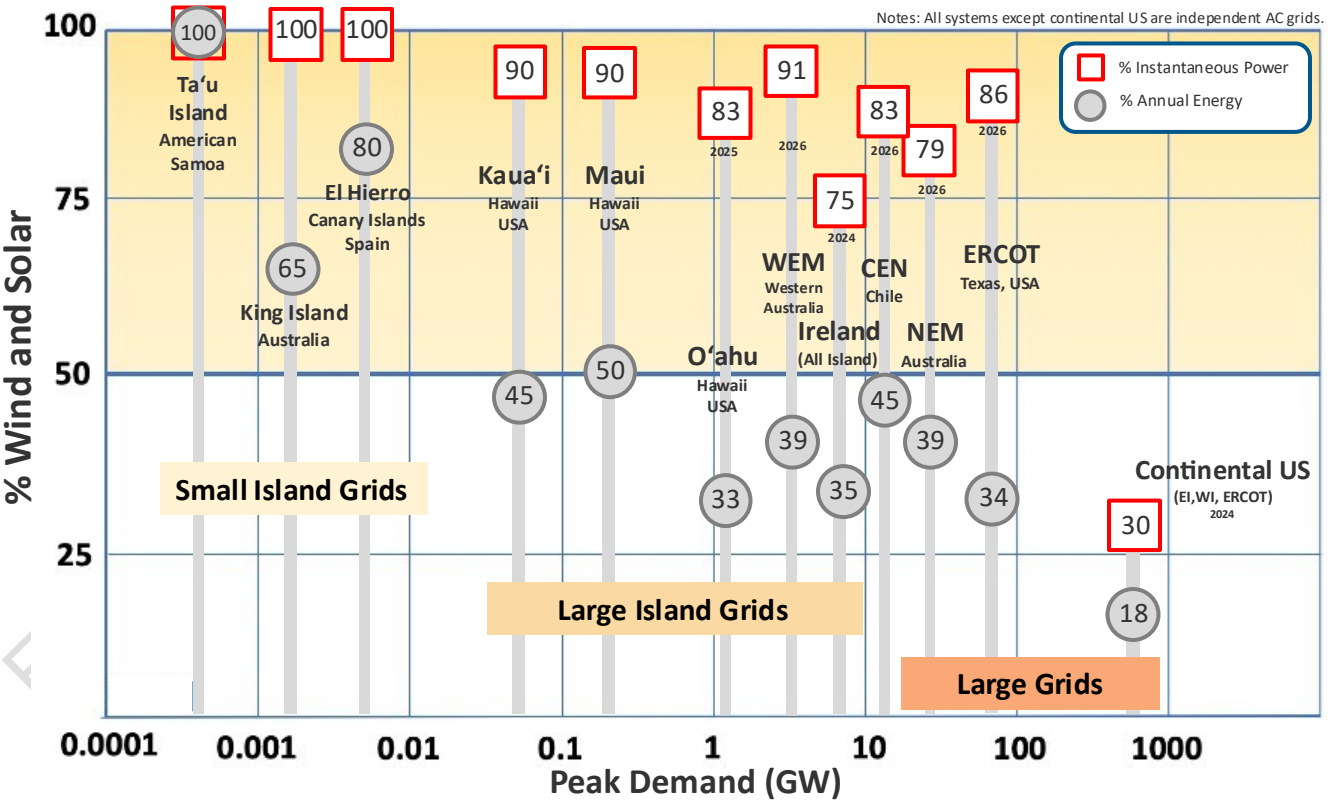


Figure 5 Record contributions of wind and solar to total supply in grids globally

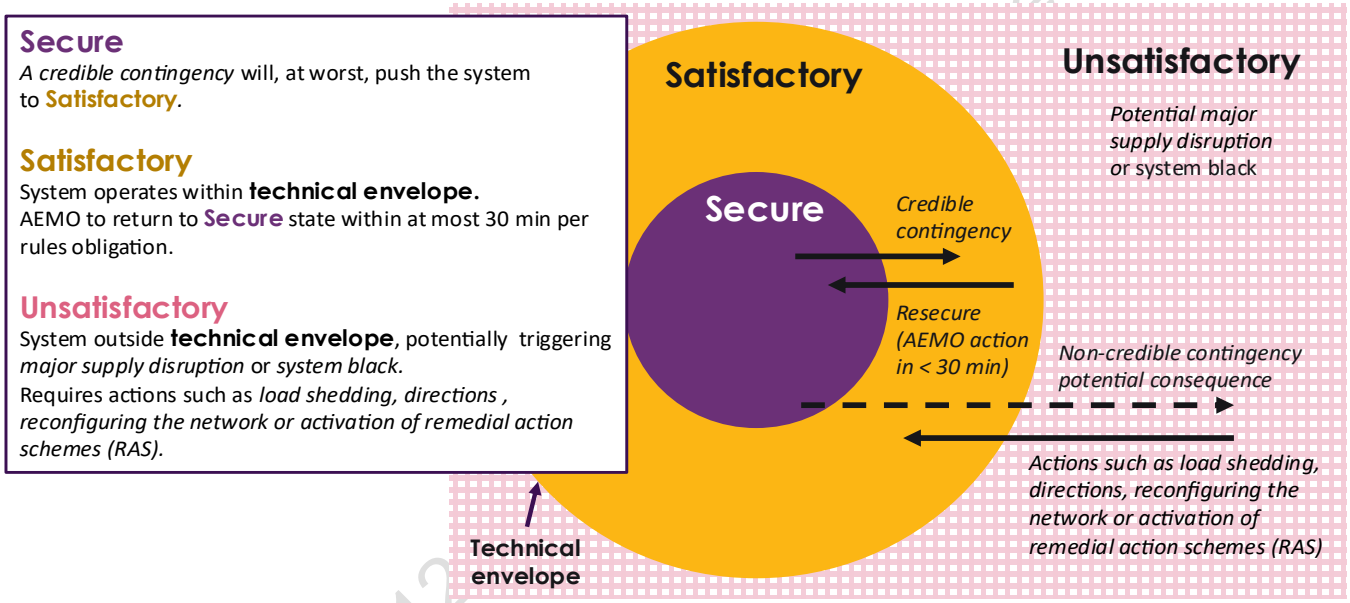


1.2 The technical requirements for security are enduring

While the NEM is undergoing significant structural change as the technologies that generate, store and use electricity evolve, the requirements that define a *secure* operating state remain unchanged. The *power system* is in a *secure operating state*[9] if, in AEMO's reasonable opinion, the system is in a *satisfactory operating state*[10] and will return to a *satisfactory operating state* following the occurrence of any *credible contingency event* or *protected event*. A *satisfactory operating state* is one in which frequency, voltage, current flows, and all connected plant are operating within their defined limits[11].

Following any contingency event (regardless of whether it is a credible or non-credible contingency) AEMO is obliged to take all reasonable actions to return the *power system* to a *secure operating state* as soon as it is practical to do so and, within at most 30 minutes. **Figure 6** shows the relationship between secure and satisfactory states.

Figure 6 Relationship between secure, satisfactory and unsatisfactory operating conditions



AEMO's power system security responsibilities in the NEM are set out in the National Electricity Rules (NER)[12] and System Standards[13], and implemented through guidelines and procedures[14].

While noting that security is a property of the system, not its parts, AEMO's *Engineering Roadmap*[15] assesses security using five criteria: system strength, frequency and inertia, voltage control, transient and oscillatory stability, and system

[9] At https://energy-rules.aemc.gov.au/ner/714/690835#4.2.4.

[10] At https://energy-rules.aemc.gov.au/ner/714/690835#4.2.2.

[11] At https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper.

[12] At https://energy-rules.aemc.gov.au/ner/429/187180#4.3.1.

[13] Standards for the performance of the power system as set out in NER Schedule 5.1a, and power system security standards determined by the Reliability Panel, defined in NER 8.8.1(a)(2).

[14] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation and https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.

[15] At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

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restoration. These criteria are used throughout this report to assess the current and future security of the power system, with detailed descriptions in **Table 5**.

The box below the table provides additional background on voltage oscillations, which are a category of oscillatory stability that is becoming increasing challenging for power systems in Australia and globally. Transient and oscillatory stability is assessed in detail in the 2026 TPSS, including in the **Part B. Regional transition plans** and in a dedicated Engineering Roadmap workplan Part C, **Section 8**.

In addition to being *secure*, the power system must be *reliable* – having energy resources and network capacity to balance supply and demand 99.998% of the time – and *operable* – such that operators can effectively respond to dynamic changes in the power system to keep the system in a secure state. The TPSS incorporates these aspects through the resource adequacy and operability power system criteria described in **Table 5**.

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Table 5 Power system criteria and their contributions to security

System criteria	Contributions to system security
System strength	System strength is the ability of the power system to maintain and control the voltage waveform at any location during both steady-state operation and following a disturbance. This definition reflects AEMO's *Power System Requirements*[A]. The current system strength management framework consists of two complementary requirements, set out in NER S5.1a.9 and implemented through AEMO's *System Strength Requirements Methodology*[B]: • minimum three-phase fault level (system security requirement), and • stable voltage waveforms (efficient level to host forecast IBR). Each requirement plays a distinct role: minimum fault levels are required for reliable protection operation and system security, while stable voltage waveforms support the secure operation and connection of IBR. These requirements are assessed at designated System Strength Nodes (SSNs) and may be further refined as technology and understanding evolve. Throughout this report, including **Part B. Regional transition plans** and Appendix A2[C], the requirements are distinguished wherever system strength is discussed.
Frequency and inertia	In an alternating current (AC) power system, such as the NEM, frequency reflects the balance between active power generated and consumed. AEMO is responsible for managing power system frequency in accordance with the Frequency Operating Standard (FOS)[D]. For system security, a particularly important characteristic is how rapidly the frequency changes in response to a disturbance, referred to as the rate of change of frequency (RoCoF), and, relatedly, how quickly and reliably the fleet of connected generators adjust their power output to stable levels. The RoCoF is inversely proportional to the inertia[E] of the system, which includes the physical inertia of the spinning masses inside synchronous machines and the emulated 'synthetic' inertial response that IBR may be programmed to produce. Inertia impacts the overall system dynamic performance, particularly frequency stability, and interacts with other forms of stability, both local and system-wide. Inadequate frequency control and excessive RoCoF can cause plant disconnection and/or plant damage.
Voltage control	Voltage control is the ability to maintain network voltage profiles and variations within defined limits under normal and contingency conditions, across a range of demand levels. This primarily involves managing 'reactive power', measured as Volt-Ampere reactive (Var). This is the component of electrical power associated with out-of-phase voltage and current waveforms that supports the electric and magnetic fields required by AC equipment and plays a key role in maintaining power system voltage. This requires coordinated use of generator reactive capability, network reactive plants, and other voltage control devices to support secure power transfer and voltage stability. System strength, as indicated by three-phase fault level, influences voltage sensitivity to changes in reactive power, with lower fault levels generally resulting in larger voltage step changes following the switching of large reactive power devices. Adequate dynamic reactive headroom is maintained to ensure acceptable voltage outcomes across the system in the event of a contingency. Reactive power margin is maintained based on prevailing system loading conditions, network topology, and the severity of the most onerous credible contingency. Voltage instability can lead to cascading outage situations with loss of load or tripping of transmission lines and other network components through protection action, potentially triggering generator loss of synchronism and frequency instability. In real time, AEMO primarily utilises the automated VAr Dispatch Scheduler (VDS) system to dispatch TNSP and generator reactive power devices in the NEM to meet specified voltage control objectives[F].
Transient and oscillatory stability	Power system stability is defined as "the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact"[G]. Transient and oscillatory stability relate specifically to maintaining stability through

System criteria	Contributions to system security
	large transients, which may occur during contingency events, and stability against oscillations, which can arise from natural modes, control interactions, and forced oscillations[H] (see box below). Stability requires the presence of synchronising torque and damping torque, historically provided by synchronous machines, and the ability of IBR to reach a state of equilibrium after the power system disturbance[I]. It also requires controls to dampen inter-area stability issues, which will need to evolve as the synchronous generators that currently provide these controls retire, and the nature of oscillations change with new system configurations. Additionally, this requires sufficient voltage waveform stability to ensure new oscillation modes associated with the stability of grid-following inverter-based plant are managed.
System restoration	Despite best endeavours, the power system can, on rare occasions, experience cascading failures resulting in loss of supply to large portions of the power system. Following this, control room operators in the NEM require the ability to restore the power system through the execution of a system restart pathway. Black start generators and restart pathways used in operation during a restart are determined on the day based on available plant and network assets, but preferred pathways and key system restart ancillary service (SRAS) providers are agreed in advance with NSPs and generators[J].
Operability	Operability is the ability to achieve and maintain a secure operating state by managing the power system effectively as conditions change. It depends on the technical characteristics of the power system and the people, processes, information, models, tools and digital systems needed to plan, monitor and operate it in coordination with industry. Operability integrates the other power system criteria by enabling operators to anticipate changing conditions, assess the system against its technical operating envelope and take timely action to maintain security and reliability. This includes forecasting and outage coordination, determining and monitoring secure operating limits, assessing contingencies, scheduling and dispatching resources, and coordinating operational responses across AEMO, NSPs and market participants.
Resource adequacy	Having a sufficient overall portfolio of energy resources and network capacity to achieve the real-time balancing of supply and demand 99.998% of the time. Potential constraints include thermal limits of the network, reliability of sufficient electricity generation capacity, and considerations of their fuel adequacy.

A. AEMO's *Power System Requirements* document, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.
B. AEMO's *System Strength Requirements Methodology, at* https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf.
C. See Appendix A2, https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.
D. At https://www.aemc.gov.au/regulation/electricity-guidelines-and-standards.
E. At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf.
F. Refer to Section 14 of AEMO Power System Security Guidelines for further information, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.
G. See *Power System Dynamic Modelling and Analysis in Evolving Networks*, at https://www.cigre.org/GB/publications/green-books.
H. At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf.
I. At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf.
J. For more information, see Section 3.4 of AEMO's *Power System Requirements* document, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

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Power system oscillations

Management of power system oscillations is an established component of maintaining power system security. As the NEM transitions, changing generation technologies, network configurations, loads and control systems are expected to alter the nature and characteristics of oscillatory behaviour, increasing the importance of effective monitoring, analysis and mitigation. The following conceptual background provides an overview of these phenomena, which may be observed as oscillations in quantities such as voltage, current, power flow and frequency.

Power system oscillations are repeated variations in electrical and electromechanical quantities around an operating point. They are distinct from the fundamental 50 hertz (Hz) alternating voltage and current waveforms used to transfer electrical energy through the NEM. Oscillations can occur across a wide range of frequencies and may arise following a disturbance or from interactions between generators, IBR, loads, control systems and the transmission network.

Different physical and control phenomena can give rise to different forms of oscillatory behaviour. At lower frequencies, oscillations have traditionally been associated with the electromechanical dynamics of synchronous generators, including the exchange of energy between individual machines or groups of generators. These include

local modes, involving predominantly one generating unit or plant, and inter-area modes, involving groups of generators oscillating against one another across different parts of the power system. At higher frequencies, oscillatory behaviour may also arise from interactions involving IBR control systems, power-electronic devices, synchronous plant controls, network characteristics and other connected equipment. In some cases, interactions between control systems and the network can adversely affect the damping of an existing mode or introduce new oscillatory modes.

The existence of oscillatory modes is not inherently problematic. Following a disturbance, a stable power system may exhibit oscillations that diminish over time as energy associated with the disturbance is dissipated or controlled. The key consideration is therefore the damping of relevant oscillatory modes. Poorly damped oscillations may persist for an extended period, while negatively damped oscillations can increase in magnitude and potentially threaten secure operation. Depending on their frequency, magnitude and duration, poorly damped or unstable oscillations can adversely affect equipment and control-system performance, contribute to protection misoperation or equipment disconnection, and in severe circumstances contribute to cascading events and loss of supply.

The oscillatory characteristics of the NEM vary with the operating condition and can change as generation and load patterns, network topology, and the mix and configuration of connected plant change. The increasing contributions of power-electronic equipment introduce additional control interactions and timescales that need to be considered alongside the electromechanical modes traditionally associated with synchronous generation.

Effective management therefore requires capabilities to identify relevant oscillatory modes, assess their damping and underlying causes, monitor their behaviour as operating conditions change, and implement appropriate mitigations where required. Mitigation may include imposing operating limits (via constraints) especially during network outage events, tuning or coordination of plant control systems, use of stabilising controls such as Power System Stabilisers (PSS), or other plant control and network solutions specifically designed to improve damping performance. Where appropriate monitoring and controls are not available to effectively manage oscillatory behaviour, more conservative operational constraints may need to be applied, which may increase costs for consumers.

A detailed workplan for oscillatory stability is presented in **Section 8**.

1.3 System security is a shared responsibility

Managing each power system criterion is a complex task. The roles and responsibilities for maintaining security are similarly complex, with AEMO, JPBs (who are often TNSPs), NSPs, market participants, investors, governments, and regulators all having roles to play. While specific arrangements will evolve, such as through ongoing regulatory reform[16], the responsibilities will remain shared.

Error! Reference source not found. provides a breakdown of stakeholder actions involved in setting technical requirements, assessing economic options, and operationally delivering services to manage security criteria. It highlights key dependencies between these activities. For example, AEMO relies on JPBs limits advice to define the technical operating envelope within

[16] See Security Frameworks Enhancement rule change process, at https://www.aemc.gov.au/rule-changes/security-framework-enhancements.

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which the power system must operate. It also highlights the risk that procurers may be unable to secure sufficient services from providers, such as where there are insufficient sources of black start services.

Figure 7 Roles and responsibilities in maintaining security assets in the long-term interest of consumers

	Technical requirements		Economic assessments		Operational delivery	
System strength	**JPBs*** Internal studies of needs. Set limit advice, including min fault level. Assess connections.	**Market Participants** Assess whether to self-remediate system strength impacts or pay JPB.	**JPBs*** Assess options to invest or procure from market participants. Generally, involves RIT-T.	**Market Participants** New generators may self-remediate or pay system strength charge to JPB.	**Market Participants** Where contracted by JPB, provide minimum level of system strength (currently synchronous machines only) and efficient level of system strength using Grid-forming (GFM) inverters and/or synchronous machines.	
	AEMO Sets requirements based on JPB limits advice and AEMO studies. Identifies gaps. Assess connections.		**AER** Assesses/reviews JPB proposed/actual expenditure.		**AEMO** Calculates requirements and schedules JPB contracts	**JPBs*** Contract services and co-ordinate with contracted providers
Frequency & inertia	**AEMC** Sets Primary Frequency Response (PFR) obligations.	**AEMO** Sets inertia requirements. Identifies gaps.	**AEMO** Procures frequency services through FCAS markets.	**JPBs*** For inertia, assess options to invest or procure from market participants. Generally, involves RIT-T.	**AEMO** Calculates FCAS reserve enablement through NEMDE, send signals to plant.	**JPBs*** Provide inertia from synchronous machines; synthetic inertia response from GFM.
	Reliability Panel Set Frequency Operating Standard (FOS).	**JPBs*** Internal studies of needs. Assess connections.		**AER** Assesses/reviews JPB proposed/actual expenditure.	**Market Participants** Generators provide primary frequency control via governors and control systems (mandatory). Provide additional frequency control services (where enabled via FCAS).	**Market Participants** Where contracted by JPB, provide inertia from synchronous machines; synthetic inertia response from GFM.
	AEMO Identifies Frequency Control Ancillary Services (FCAS) requirements and levels. Identifies PFR requirements. Assess connections.					
Voltage control	**JPBs*** Internal studies of needs. Determine limits advice. Assess connections.	**AEMO** Network Support and Control Ancillary Services (NSCAS) assessments. Review limits advice. Assess connections.	**JPBs*** Assess options to invest or procure from market participants. Generally, involves RIT-T.	**AER** Assesses/reviews JPB proposed/actual expenditure.	**JPBs*** Dynamically connect and disconnect their equipment. **Market Participants** Maintain Generator Performance Standard requirements	**AEMO** Manages voltage collapse risks through constraint equations. Schedules and manages NSP and Market Participant voltage regulating and reactive plant.
			AEMO Procurer of last resort through NSCAS contracts if satisfied gap will remain after TNSP action.			
Transient & oscillatory stability	**JPBs*** Internal studies of needs. Determine limits advice. Assess connections.	**AEMO** May study and plan through NSCAS. Review limits advice. Assess connections.	**JPBs*** Invest to improve stability. Generally, involves a RIT-T. **AEMO** Procurer of last resort through NSCAS contracts if satisfied gap will remain after JPB action.	**AER** Assesses/reviews JPB proposed/actual expenditure.	**Market Participants** Meet ride through, recovery and damping requirements in their performance standards.	**AEMO** Manages transient stability risks through constraint equations.
System restoration	**NER** Set System Restart Ancillary Services (SRAS) objective.	**Reliability Panel** Set System Restart Standard.	**AEMO** Procures Black Start Services (BSS).	**AEMO** If required, procures Restoration Support Services (RSS)	**Market Participants** All generators have local black start plans. Some provide contracted SRAS (BSS & RSS).	**JPBs*** Supply AEMO a local black system procedure. If required, augment network to facilitate restart pathways.
	JPBs* Determine SRAS procedures.	**AEMO** Determine SRAS procedures.				

*Jurisdictional Planning Bodies, which are often TNSPs

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Operational action is an essential part of managing uncertainty and unexpected events. For some transitional needs, operational interventions may be more cost-effective for consumers than an enduring solution, depending on the expected duration of the need, the costs of available options, and the system security risks. However, repeated or sustained reliance on directions, conservative constraints or other interventions may indicate that market, network, technical or operational arrangements are not consistently delivering the capabilities required for secure operation. These actions can increase costs or distort market outcomes and do not, in themselves, provide enduring solutions to the underlying system need. Their use and associated costs can nevertheless help inform the assessment of whether further investment or changes are warranted.

AEMO notes that distribution network service providers (DNSPs) also have critical system security responsibilities. DNSPs are becoming increasingly important actors for managing system security in a high DER power system. As discussed in **Section 11**, AEMO is working closely with DNSPs on the capabilities required to do this, with associated roles, responsibilities and operational coordination requirements being considered in the National CER Roadmap[17].

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[17] See https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5.

2 How AEMO is planning to maintain system security through the transition

The TPSS presents the work AEMO does to prepare and plan for system security through the transition to a low-emissions power system. This includes setting planning requirements, assessing industry readiness to meet system needs at transition points, and building understanding and capabilities to improve future operations.

The TPSS draws on four AEMO programs for preparing for the transition:

- **System security assessments** set the requirements for a range of power system criteria, and assess whether JPB plans are sufficient to meet these requirements as well as against other power system needs.
- **Transition point planning** assesses the readiness of industry plans to maintain system security at key events and milestones, and identifies actions for improving outcomes.
- The **Engineering Roadmap** program contributes to improving the technical understanding of challenges and opportunities for maintaining security in low-emissions power systems and uplifting associated capabilities. It also serves as a reference point for AEMO's collaboration with researchers.
- **Type 2 Transitional Services**, in collaboration with industry, enable trials of new technologies, or new applications of existing technologies, that may contribute to managing power system security.

Figure 8 illustrates how these complement each other to provide a holistic strategy for maintaining security through the transition. The remainder of this section provides further details on each program.

In addition to these activities, which are focused on security under expected operating conditions, including credible contingencies, AEMO conducts the GPSRR[18], which provides a proactive assessment of power system resilience[19] related to high-impact, low-probability events that could cause cascading failures or major supply disruptions.

The GPSRR assesses events from an operational perspective, looking up to five years ahead. It considers mitigation measures that could be implemented in an operational timeframe such as protected events, remedial action schemes (RASs) or other suitable solutions. Some of the events considered by the GPSRR stem from transition points, such as reduced synchronous generation, where emerging system resilience issues may arise in addition to the system security or reliability issues addressed in AEMO's other reports. Other topics covered are unique to the GPSRR, such as the consideration of protected events to manage non-credible contingencies. **Figure 9** shows the TPSS' relationship to the GPSRR as well as the ISP and NEM ESOO.

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

[19] Power system resilience is the ability to limit the extent, severity and duration of system degradation following an extreme event.

Figure 8 Illustrative overview of the activities that contribute to the TPSS

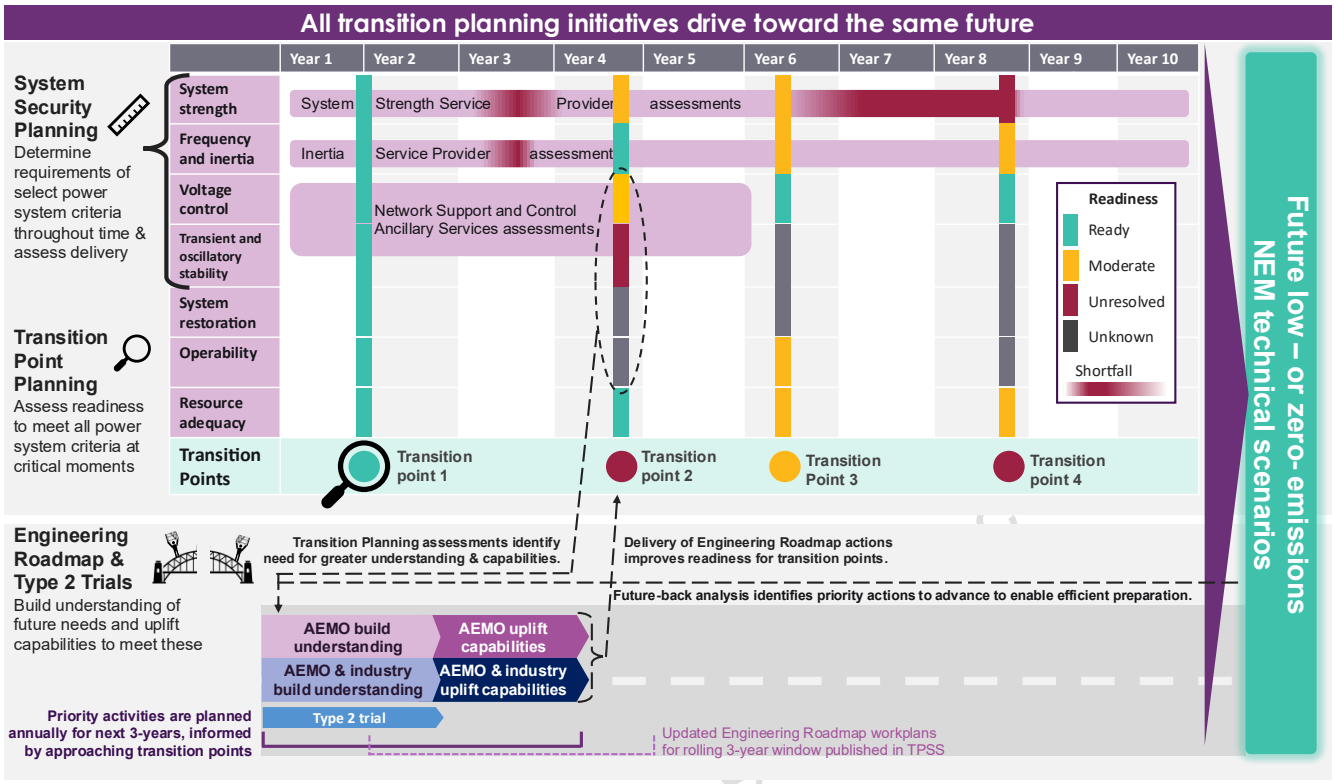
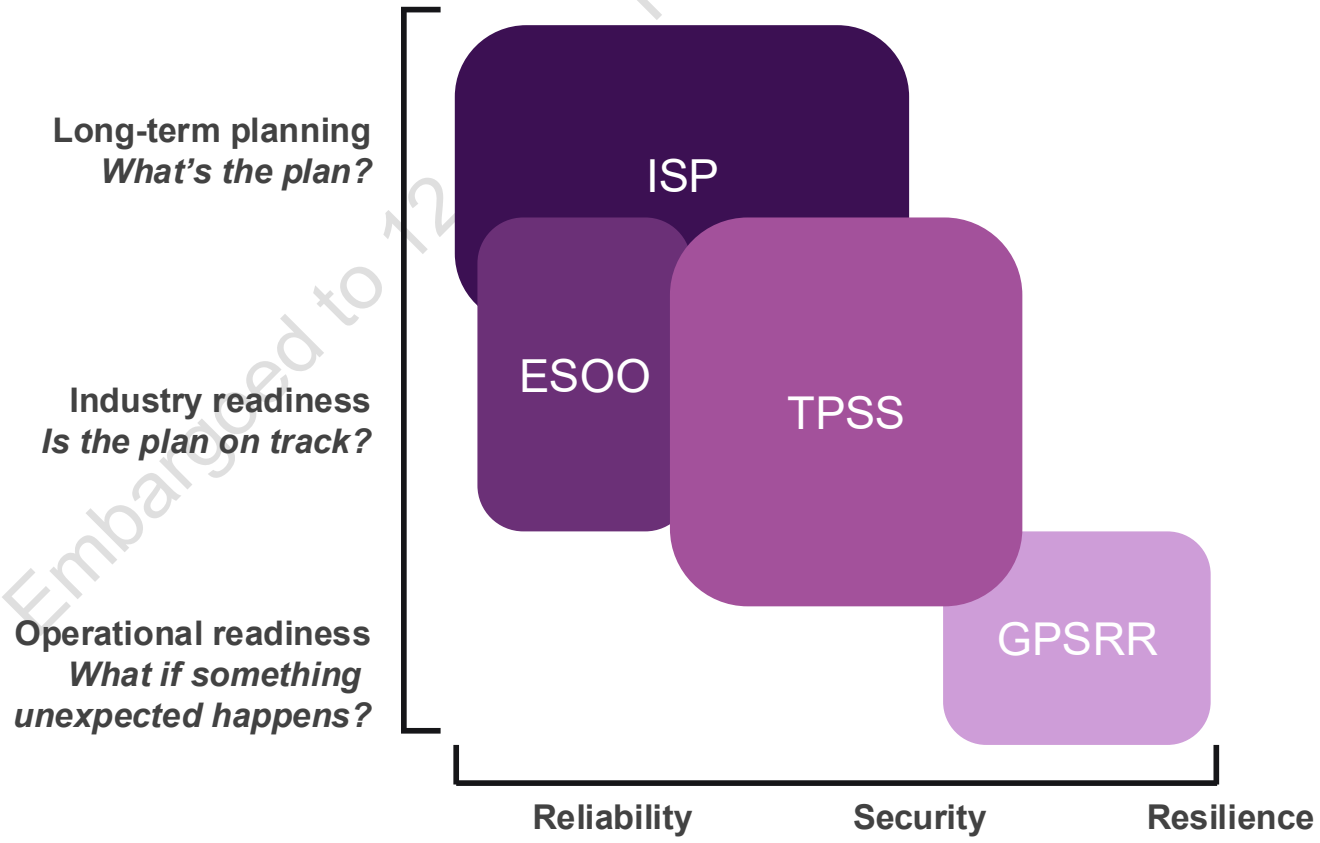


Figure 9 Illustrative relationship of the TPSS to the ISP, ESOO and GPSRR



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2.1 System security planning

AEMO system security assessments involve two primary functions: determining the inertia and system strength requirements[20], and using the NSCAS framework to identify any power system security or reliability service needs in the NEM and declare a gap where necessary[21]. The inertia and system strength requirements quantify the obligations of the JPBs, which are often TNSPs – in their role as System Strength Service Providers (SSSPs) or Inertia Service Providers – to procure sufficient inertia and system strength services. These requirements are binding and technology agnostic, applying equally to operating conditions with and without coal generation.

The NSCAS framework serves as a 'safety net' to ensure that no power system needs are missed through the planning processes JPBs undertake. The NSCAS framework covers services needed to maintain power system security and the reliability of the transmission network, or to maintain or increase its power transfer capability[22].

If any additional services are needed, AEMO may choose to declare a NSCAS gap. JPBs must consider any needs for which AEMO declares a gap, and provide AEMO with details of their proposed remediation activities. Where a JPB does not meet a declared NSCAS gap for reliability or security services in full, AEMO has last resort planning powers to procure services to meet that gap under NER 3.11.3 and 3.11.5. Appendix A2[23] contains the system strength, inertia and NSCAS assessments.

Notably, the NSCAS framework scope includes performing an assessment of the projected adequacy of system strength and inertia, but AEMO's last resort planning powers only extend to situations where the system strength requirements or inertia requirements have been revised upwards by AEMO and where the projected gap falls within the next three years. The AEMC is considering a rule change on system security frameworks, which includes the scope of AEMO's last resort planning power[24]. The NSCAS framework also does not extend to non-credible events.

2.2 Transition point planning

While the energy transition evolves through many concurrent and sequential events, some changes are particularly consequential for system security and operability. Transition point planning focuses on comprehensive analysis of a small number of priority **transition points**, which are events and milestones that AEMO, in collaboration with TNSPs, define as requiring material changes in the operational approach to managing power system security. This approach concentrates AEMO and industry efforts on understanding, and preparing for, the most crucial steps in the transition, which incorporate the cumulative impacts of more minor changes that occur in the periods between transition points[25].

The timing of when transition points ultimately occur may be uncertain, depending on commercial and/or policy decision making, as well as economic and environmental factors. The timing presented in the TPSS represents AEMO's assessment of dates to plan for, based on current information, noting that conditions equivalent to specific transition points could be experienced ahead of the transition point, for instance due to unplanned outages. For system security, the specific date of

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[20] See NER 5.20.4, 5.20.5, 5.20.6, 5.20.7, 5.20B.2, 5.20C.1.

[21] See NER 5.20.2, 5.20.3.

[22] For further details, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/final-nscas-description-and-quantity-procedure-determination.pdf.

[23] See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

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

[25] As specified in NER 5.20.8(b)(1).

transition points tends to be less critical than the sequencing of events relative to other critical infrastructure, such as the delivery of network augmentations and synchronous condensers, and energisation or decommitment of other generators.

For each transition point, AEMO assesses the **readiness level** of industry plans to deliver a power system that will maintain each power system criterion within secure limits at the time of the transition point (see box below). AEMO provides relevant stakeholders with the results of analysis, risk assessments, and mitigation options in regular engagements. For transition points in the nearer term (0-2 years), AEMO's transition planning activities focus on operational readiness, coordinating with industry, preparing procedures, constraints, operational tools, and procuring system services where required. Where transition points are in the more distant future (2+ years) AEMO's focus is on identifying solutions that may require long lead time preparations, including cost-effective investments and capacity uplift.

Readiness levels assessments consider the configuration of the power system expected at the time of the transition point, including future infrastructure developments based on the likelihood they will be in place before the transition point – in most cases adopting the committed, anticipated and actionable projects (defined in **0**) from the 2026 ISP. AEMO considers transition points with:

- **Firm timing** – dates aligned with submitted Notices for Closure or confirmed project dates. Low readiness indicates an urgent need for additional or accelerated actions.
- **Planned timing** – dates for coal stations being offline aligned to when stations' final unit is decommitted in the 2026 ISP *Step Change* scenario, or AEMO plans for minimum synchronous generator reductions. ISP *Step Change* dates are used as reference points for the pace at which the provision of system security must evolve to meet government policy objectives at least cost, and the changing operational patterns of generators. Low readiness indicates further action is required to achieve the assessed transition timeline. Ratings can change materially as projects progress, market outcomes change and evidence improves.

AEMO uses four readiness levels for each power system criterion and for transition points overall:

- **On track (green)** – planned actions are expected to maintain system security.
- **Moderate readiness (amber)** – current plans may not be sufficient to avoid increased chance of moderate-impact interventions being required to maintain system security. There may be opportunities to expand or accelerate actions to improve readiness.
- **Unresolved issues (red)** – current plans are unlikely to be sufficient to avoid increased chance of high-impact interventions being required to maintain system security. Options for further preparatory actions and operational controls are narrow.
- **Not yet assessed (grey)** – power system criterion cannot be assessed because of a high sensitivity on yet to be specified future system conditions or has not yet been prioritised for assessment because AEMO judges it to be low risk. Uplift in AEMO's analysis capabilities may improve the breadth and depth of future assessments.

Generally, the transition point rating will reflect the least ready rating of the underlying system criteria, however there may be circumstances where an overall rating is influenced by the aggregate materiality of underlying risks or factors outside of the system criteria assessments. Where transition points lie close to real-time operations, low readiness levels indicate that AEMO may need to take substantial, and sometimes severe, operational measures to ensure security. Where transition points lie further into the future, low readiness levels indicate substantial shortcomings in plans to prepare for the transition point and/or challenges in the delivery of planned mitigations.

2.2.1 Transition point selection

Of the many significant events expected to occur over the coming 10 years, AEMO identifies a prioritised set of transition points for detailed analysis. To date, these have come from three types of events:

- major changes to the asset mix, technical envelope, or configuration in the NEM, such as retirement of large synchronous generators, closure or entry of large loads, material investment in new assets to provide security services, or network augmentations, such as new transmission lines and new control schemes,
- threshold events, such as projected seasons where operational demand could drop below minimum levels, and
- operational shifts as changes in available security mechanisms allow relaxation of constraints such as minimum numbers of online synchronous generators.

Table 6 describes the events that have been prioritised for analysis in the 2026 TPSS.

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Table 6 Types of events assessed as transition points in 2026 TPSS

Event	Description
Decommitment of significant synchronous generator	Generator decommitment describes extended or regular unavailability of generation units in the market, such as through daily de-energisation (two-shifting), seasonal mothballing, prolonged forced outages, and retirement. Transition points focus on generators whose operations have significant impact on security in their region. This primarily reflects their size relative to region (for example, Torrens Island Power Station B power station represents a significant component of South Australia's synchronous generation capacity) but may also include influence of location or ancillary systems, such as power system stabilisers. AEMO distinguishes between stations based on whether they have submitted a Notice of Closure (required 3.5 years in advance). This difference is reflected in the transition point names: • "Station exit" – indicates a station with a Notice of Closure. These are typically within the nearer-term horizon and assessments of readiness consider the practical actions in place in advance of a set exit date. Any low readiness levels indicate an urgent need for accelerated action and/or preparation for interim solutions such as contracting and operational interventions. • "Station potentially offline" – indicates the date at which the 2026 ISP *Step Change* scenario projects retirement of a station's last unit. They intentionally represent a generalised sequence for each region rather than specific coal power station closures. These typically occur in the longer-term and assessments of readiness consider ongoing and planned actions ahead of the specified date. Low readiness levels typically indicate that existing and planned actions are at risk of not being delivered in full ahead of the date and/or that further actions are required in order for the system to be ready to follow the coal retirement schedule identified by the ISP as optimal for meeting consumer needs and government policy objectives. In some instances, plans may still be under development, particularly for transition points projected to occur late in the next decade.
Reduction in minimum synchronous generation units	To maintain system security, TNSPs and AEMO currently require a minimum number of synchronous generators to be online in each region. While reductions in such requirements are significant changes in the operation of the system, each one need not be treated as a transition point because the timing and conditions for enacting such changes to operating protocols are within AEMO's and TNSPs' sphere of control (and may be reversible). The reduction of minimum synchronous generation units in South Australia is treated as a transition point in the 2026 TPSS because of the internationally unprecedented nature of running a power system of this scale with only one synchronous generation unit (the transition point completed in September 2025) and with zero (the transition point scheduled for 2028).
Energisation of REZ	REZ design and integration are managed through dedicated processes and are not in general assessed as transition points. CWO REZ is an exception because it is the first large-scale REZ to have commenced construction in the NEM and is large and complex, with a concentrated mix of solar, wind, GFM BESS and high-inertia synchronous condensers. The timing of CWO REZ also coincides with a period of unprecedented change in the New South Wales power system, as well as generation mix across the broader NEM, giving weight to the decision to undertake a transition point assessment. Assessing CWO REZ as a transition point creates opportunities to identify and share key learnings that can be applied as part of future REZ developments.

In 2025, AEMO included transition points for MSL, including an 'Unresolved Issues' rating for Queensland due to the shortfall in capabilities to manage rare, but plausible, onerous system conditions. Periods of MSL occur when distributed generation, particularly passive rooftop photovoltaic (PV), significantly reduces demand on the transmission system below

the minimum stable operating levels of the synchronous generators required for system security (the minimum synchronous generation units requirement), and levels required for balancing supply and demand and maintaining inter-area flows within limits.

In 2026, the outlook for MSL management in typical system normal conditions has improved, with ongoing uplift in MSL management capabilities, increased demand, and lower minimum secure operating levels. While risks remain in rare, onerous system conditions, these have not been included as transition points because MSL is a transition challenge with progress on a continual trajectory rather than as a step change. **Section 11** details the work AEMO and industry are progressing in MSL management and AEMO's MSL outlook[26]. As the transition continues, AEMO will continue to monitor and evaluate emerging challenges, including MSL and other events, for potential inclusion as future transition points. In 2026, for example, Marinus Link Stages 1 and 2 are monitored transition points.

2.2.2 Scenarios considered for transition point readiness assessments

The assessments of transition point readiness, presented in Part B, consider a variety of scenarios that are most challenging for each respective power system criterion[27]. They draw on many studies performed across AEMO, including the system security assessments whose detailed results are provided in Appendix A2[28] and whose methodologies are published in standalone reports[29]. They also draw on wider planning and forecasting studies – including the ISP, ESOO and *Gas Statement of Opportunities* (GSOO) – whose inputs and assumptions are consulted on through the *Inputs, Assumptions and Scenarios Report* (IASR)[30], and whose scopes are consulted on through dedicated methodology documents. Where necessary, these are complemented by additional targeted analysis, which in 2026 included power system studies of oscillatory stability and system restoration under future scenarios (the latter are presented in Appendix A4[31]).

Table 8 provides a high-level overview of the conditions that are most challenging for each power system criterion and the scenarios and assumptions therefore used in planning assessments. Specific details are provided in **Part B. Regional transition plans**[32]. The table notes how the scenarios often draw on outputs from related planning activities, particularly the demand forecast and infrastructure delivery assessments in the ISP – defined in **0**.

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[26] See Appendix A3, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.

[27] For an overview of when studies are performed, in relation to transition points, see Part A Section 2.2.3 in the 2025 TPSS.

[28] See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

[29] For system strength methodology, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf. For inertia methodology, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf. For NSCAS methodology, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf.

[30] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[31] See Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.

[32] See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

Table 7 Definitions of committed, anticipated, actionable and government scheme projects

Category	Definition
Committed	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's *Cost Benefit Analysis Guidelines*.
Anticipated	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's *Cost Benefit Analysis Guidelines*.
Actionable	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ISP's optimal development path (ODP) and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable.
Actionable project progressing under a jurisdictional framework	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Government schemes	Generation and storage projects specifically supported by government schemes that have clear delivery mechanisms.

Table 8 Overview of the scenarios and information sources considered for transition point assessments

Power system criteria	Challenging conditions assessed	Scenarios and assumptions used in planning assessments
System strength	• Minimum demand conditions are typically most challenging because synchronous generators are likely to be offline or operating at low levels. • Peak demand with low synchronous generation and high IBR generation.	• Committed and anticipated projects with government schemes and actionable projects as sensitivities. • Market dispatch and power flows from ISP *Step Change* scenario, inclusive of two-shifting operation where applicable based on 50% probability of exceedance (POE) demands. • Maximum demand based on ISP *Step Change* 10% POE. • Minimum demand based on ISP *Step Change* 90% POE. • Contracted system strength services. • Credible contingencies, and non-credible under GPSRR analysis as required. • Prior outage scenarios. • Line-switching actions as used operational during low demand conditions.
Frequency and inertia	• Trip of largest generator during peak demand. • Trip of largest generator or largest load during minimum demand (high DPV).	• Committed and anticipated projects with government schemes and actionable projects as sensitivities. • Market dispatch and power flows from ISP *Step Change* scenario, inclusive of two-shifting operation where applicable based on 50% POE demands. • Maximum demand based on ISP *Step Change* 10% POE. • Minimum demand based on ISP *Step Change* 90% POE. • Contracted inertia services. • Credible contingencies, including expected largest contingencies. • Prior outage scenarios. • Islanded requirements.
Voltage control	• Maximum demand with relevant credible contingencies. • Minimum demand due to either lightly loaded transmission lines producing reactive power or reverse power flows from distribution network.	• Assess year 1 and year 5 and any other year on ad hoc basis as required. • Committed and anticipated projects with government schemes and actionable projects as sensitivities. • Generator decommitments as per ISP *Step Change*. • Maximum demand based on ISP *Step Change* 10% POE. • Minimum demand based on ISP *Step Change* 90% POE. • Network operational limits modelled as present day capability. • System normal and ad hoc system typical conditions as well as expected N-1. • Reactive margins and voltage step change requirements.

Power system criteria	Challenging conditions assessed	Scenarios and assumptions used in planning assessments
Transient and oscillatory stability	• Challenges can be sensitive to specific operating conditions and network configuration. Examples include: – high demand conditions with high interconnector flows, – minimum demand conditions with high reactive power absorption,	• Committed and anticipated projects. • Minimum system strength unit combinations considered per region. • Generator decommitments as per ISP *Step Change*. • High import/export conditions where key interconnectors and cutsets are monitored. • Credible contingencies, and non-credible under GPSRR analysis as required.
System restoration	• Islanded restart conditions. • Adverse weather conditions, including low renewables availability. • Communication infrastructure failure. • Forced generating units or network equipment outages.	• Committed and anticipated projects with government schemes and actionable projects as sensitivities. • System restoration capability of remaining generation fleet following retirements. • Existing practices, procedures and requirements for system restart and restoration processes. • Future opportunities for restoration pathways, including network topology changes. • Capability of variable renewable energy (VRE) and BESS to support restoration processes. • Islanded options for system restorations, including subregional options.
Operability	• Consecutive days with high demand, low wind and solar generation, and low storage capacities. • Consecutive days with low demand, high DPV generation, and full storage. • Coincident network outages. • Tight conditions to meet operational requirements in real time. • Conditions that would stress test or overload control room capacity and capabilities.	• Committed and anticipated projects with government schemes and actionable projects as sensitivities. • ISP *Step Change* 10% POE across the NEM with high and low VRE. • Minimum demand based on ISP *Step Change* 90% POE. • Network operational limits modelled as present day capability. • Credible contingencies and resecure requirements post credible contingency. • Relevant generation and network outages. • Available control room tools and levers, including the expected future capability at the time of assessment. • Observability of the system in real time. • Preliminary future operational limit advice when available.
Resource adequacy	• High demand coincident with persistently low renewable conditions and low dispatchable generation. • Extended use of gas turbines to provide system strength and/or inertia. • Periods of extended outages of dispatchable generation, such as for maintenance, coincident with high demand.	• Committed and anticipated projects • Maximum demand coincidental with renewable drought conditions. • ESOO outcomes[A]. • GSOO outcomes. • Network and operational constraints, limitations under system normal and N-1. • Energy/resource limitations where applicable. • Lack of Reserve (LOR) requirements.

A. Note the December 2026 ESOO Update assumes a six-month delay for committed project and 12 months for anticipated projects, based on current market observations. AEMO intends to refine the alignment of security assessments and ESOO assumptions in this regard in 2027.

2.3 Engineering Roadmap

AEMO's Engineering Roadmap program adds a further layer to preparing for the transition, focusing on improving the technical understanding of what is needed to achieve power system security in a low- or zero-emissions power systems, including evolving technology and operational requirements, and uplifting capabilities to enable such operating conditions in the NEM. This aligns with the TPSS purpose of sharing the *"work AEMO is undertaking to improve … understanding"*[33].

[33] See NER 5.20.8(b)(2).

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This program is guided by the 2022 *Engineering Roadmap to 100% Renewables* report[34], which also sets out the power system criteria used in the TPSS (see Section 1.2). From 2022 to 2025, AEMO used a Priority Actions framework to deliver targeted projects to progress towards the preconditions identified in the 2022 report, receiving support from the Australian Renewable Energy Agency (ARENA) to accelerate this program of work from December 2023 to June 2025.

Consistent with stakeholder requests for greater visibility of AEMO's forward plans, AEMO in 2026 evolved the delivery of the Engineering Roadmap to be structured around rolling three-year workplans per power system criterion. This enables a closer alignment with transition point planning, with power system criteria that show consistently low readiness levels or are not yet assessed (shown in the dashed region in Error! Reference source not found., Section 2) being prioritised for resourcing, as well as alignment with Transitional Services. It also provides a reference point for AEMO's research priorities (see Section 12).

While activities are planned over a rolling three-year forward horizon, activities continue to be informed by the long-term transition to a low-emissions power system. AEMO will continue to reassess Engineering Roadmap priorities and resourcing on an annual cycle, updating workplans in future TPSS reports.

2.4 Type 2 Transitional Services

Transitional Services[35] are temporary additional services to assist AEMO in maintaining power system security in the transition to a low- or zero-emissions power system. AEMO may use Type 2 Transitional Services to trial the use of new technologies, or new applications of existing technologies, in managing power system security in a low- or zero-emissions power system. AEMO has implemented a Type 2 Services framework, which provides a structured process for identifying, assessing, procuring, and trialling Type 2 Transitional Services.

In October and November 2025, AEMO released five Statements of Need (SONs) for Type 2 Transitional Service trials. Over the past year, AEMO has focused on the following:

1. operationalising the Type 2 governance and procurement framework, including standardised guidelines for procurement phases and guidance on submission of unsolicited offers,
2. developing a Value for Money Framework, which provides an assessment methodology for AEMO to compare long-term value of trial knowledge and outcomes against up-front trial payments and potential ongoing service costs/payments – the framework will be used for both comparison of competing offers/tenders and assessing value against a minimum threshold to ensure that Type 2 transitional service agreements meet the Transitional Services Procurement Objective,
3. progressing market engagement and procurement of trials related to published SONs, and
4. identifying and prioritising other potential Type 2 Transitional Services.

The Type 2 Services framework allows AEMO to acquire services that might help accelerate the transition to a low or zero-emissions power system. By their nature – being new or novel – these services are inherently uncertain in the value they will deliver. AEMO has therefore carefully considered the potential benefits, costs and risks of these services for participants and consumers. To this end, AEMO has taken a measured approach to trial procurement and has focused on confirming trial

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[34] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.
[35] At https://energy-rules.aemc.gov.au/ner/714/690727#3.11.11.

feasibility, undertaking operational risk assessments and establishing a clear evidence base rather than expediting transitional service agreements. This is a risk management strategy to identify key delivery risks prior to committing significant funds on behalf of market participants.

2.4.1 Published Type 2 Transitional Services

Since publication of the five SONs, AEMO has conducted extensive market engagement to promote Type 2 Transitional Services opportunities and inform procurement processes for each SON. This includes webinars in December 2025 and January 2026, and an Expression of Interest (EOI) process for MSL Transitional Services from December 2025 to March 2026. In subsequent months, AEMO has held discussions with or received EOIs from more than 50 parties, including project developers/owners, OEMs and NSPs.

While general market interest in Type 2 Transitional Services has been strong, this process has demonstrated some learnings for the existing procurement processes, particularly relating to complex multi-party trials, which has led to slower procurement timelines than originally expected when the SON were published.

Table 9 summarises each trial and its current status, with further information on key learnings provided below.

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Table 9 Status of published Statements of Need for Type 2 Transitional Services

Type 2 Transitional Service	Description	Status
Black Start from IBR[A]	Evaluates IBR-based black start solutions to support system restoration in a low-emissions grid. Outcomes of the trial are expected to inform future restoration pathways, SRAS procurement and guide technology development.	Initial market engagement is complete and highlighted that further locational, technical and commercial analysis is required before AEMO can determine whether, where and how a trial should progress. The timing and approach for future procurement will be informed by the outcomes of the Engineering Roadmap System Restoration activities (see **Section 9**).
System Restart under High DPV Conditions[B]	Demonstrates emerging technologies and operational approaches capable of managing DPV/CER reconnection on the system restoration process, particularly where communications infrastructure is unavailable.	Following the Direct Request for Offer process, AEMO has entered into agreements for two Type 2 trials in South Australia: Common Smart Inverter Profile – Australia (CSIP-AUS) Fallback and Controlled Reconnection, and Enhanced Voltage Management (EVM). The trials are expected to be completed by June 2028.
Grid-Forming (GFM) Inverter Protection-Quality Fault Current[C]	Assesses whether GFM inverters can provide fault current of sufficient magnitude, duration, and composition (e.g. relevant positive and negative sequence components and waveform properties) for protection relays to operate correctly under diverse system operation and fault conditions.	Market engagement and feasibility assessment of identified potential trials is ongoing. AEMO has held workshops with one TNSP regarding a potential trial location. However, due to the TNSP's risk appetite and the limited opportunity to realise trial learnings ahead of its next investment decision, this opportunity did not progress to formal procurement.
Zero Synchronous Generation[D]	Demonstrates that IBR, either standalone or in conjunction with other grid support plant such as synchronous condensers, are able to maintain system security within a large isolated sub-network without requiring synchronous generation to be online. Insights from the trial are expected to inform future operational planning and technical requirements.	Market engagement and feasibility assessment of identified potential trials is ongoing. AEMO has been working closely with a TNSP and has undertaken workshops to identify and develop a specific trial location involving a proposed network island. This work is progressing towards detailed feasibility studies to assess the technical viability of the proposed trial and inform a decision on whether to proceed to formal Type 2 service procurement.
Minimum System Load Transitional Services[E]	Assesses novel approaches to management of MSL in conjunction with proposed Type 1 services, as discussed in **Section 3.2**.	Expression of interest (EOI) process in conjunction with MSL Type 1 closed in January 2026. An Invitation to Tender was issued for Type 2 MSL in April 2026.

Type 2 Transitional Service	Description	Status
		AEMO has contracted one Type 2 MSL trial to test whether aggregated commercial and industrial BESS can be coordinated through a virtual power plant platform to provide a predictable increase in operational demand. Learnings will be shared progressively from 2027, with the trial expected to be completed in 2028. Evaluation and negotiation continue on additional trials.

A. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/black-start-capability-from-ibr.
B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.
C. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial.
D. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/zero-synchronous-generation-trial.
E. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/msl-transitional-services.

2.4.2 Learnings from procurement process

With the progress in procurement of Minimum System Load and System Restart under High DPV Conditions Type 2 Transitional Services, AEMO has developed clearer expected learnings from these trials. These are summarised in **Table 10**.

Other published Type 2 trial SONs – particularly the Zero Synchronous Generation and GFM Inverter Protection-Quality Fault Current trials – are inherently more complex, as they require participation from multiple parties (for example, generators, customers, and NSPs) and involve unusual operating conditions (such as islanded sections of network).

Feasibility assessments are integral to the development of complex Type 2 trials. They enable AEMO to test whether potential trial configurations are technically, operationally and commercially viable, and whether the expected knowledge outcomes justify the proposed cost and delivery risks.

This work may identify that a particular trial configuration, site or delivery pathway is not suitable to progress. This is a valuable outcome, as it avoids AEMO committing market participant funds to a Transitional Services agreement that may subsequently prove undeliverable or unable to provide sufficient value. The resulting evidence can instead be used to refine the technical question, identify alternative pathways and improve the design of any future trials.

The activities related to complex multi-party trials are distinct from the standard opportunity identification, market engagement and procurement activities undertaken by AEMO for all Type 2 Transitional Services. These standard activities are undertaken through AEMO's existing operating arrangements. Complex trials may require additional trial-specific feasibility studies, technical investigations or other preparatory work before AEMO can determine whether it is appropriate to proceed to a Transitional Services Agreement.

Where these additional activities are required prior to execution of a Transitional Services Agreement, AEMO is exploring appropriate funding arrangements for prudent Type 2 pre-trial and trial-enabling activities, including both enduring and interim funding options.

While these complexities and challenges have taken longer to resolve than expected in the original procurement timelines published in late 2025, the assessment process has provided useful insights into technical pathways, technical and operational risks and stakeholder engagement that can be applied on future trials. These are also outlined in **Table 11**Table 10, which summarises key learnings from each trial.

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Table 10 Summary of key learnings from Type 2 Transitional Services processes

Trial	Learnings
Minimum System Load	AEMO has contracted with Momentum Energy for a Type 2 MSL trial to test whether aggregated commercial and industrial BESS can be coordinated through a virtual power plant platform to provide a predictable and repeatable response during minimum system load conditions. The trial will initially test the response through manual portfolio control and, pending the results, progress to automated coordination and integration with AEMO's operational systems. The trial will assess response reliability, measurement and verification methods, operational requirements and the potential scalability of the service. Learnings will be shared progressively from 2027, with the trial expected to be completed in 2028. AEMO is also evaluating and negotiating other potential Type 2 MSL trials and this process is expected to conclude before the end of 2026. The trial(s) will help identify which approaches may be suitable for future operational services rather than assuming each successful trial should become an ongoing operational service.
System Restart under High DPV Conditions	Following a Direct Request for Offer process, AEMO has entered into an agreement with SA Power Networks to conduct two Type 2 trials in South Australia: CSIP-AUS Fallback and Controlled Reconnection, and EVM. The trials will test whether DPV reconnection can be managed to support stable load formation and network energisation during system restart, including where normal communications may be unavailable. The trials will seek to demonstrate and test: • the effectiveness of CSIP-AUS[A] fallback and EVM[B] approaches, • whether these approaches can manage aggregated DPV behaviour during restoration, • their performance when internet-based communications are limited or unavailable, • the monitoring, coordination and operational arrangements required, and • whether the approaches could be scaled or incorporated into future system restart arrangements. Detailed planning, readiness assessment and bench testing will commence in early 2027, followed by controlled field testing subject to technical, operational and safety readiness requirements. The findings will inform future technical requirements, operating procedures and procurement approaches for system restart under high-DPV conditions.

A. CSIP-AUS is an Australian implementation profile of the IEEE 2030.5 communications protocol that enables standardised communication between distribution networks and compatible distributed energy resources, including operating instructions (such as zero-export or zero-generation commands) and fallback settings.
B. EVM is a network-based control method where DNSPs raise and maintain feeder voltage above inverter over-voltage protection thresholds to disconnect DPV inverters. In the context of restart, the same mechanism can be used to set network voltages above inverter reconnection thresholds to temporarily prevent or delay distributed energy resources from reconnecting during power-system restoration.

Table 11 Summary of key learnings from progressing complex and capital-intensive Type 2 trials

Trial	Learnings
Zero Synchronous Generation Trial	AEMO has identified a potential trial location which balances technical learning and potential for expanded trials with operational risk management. AEMO has undertaken workshops with one TNSP to identify required feasibility studies (e.g. asset review, protection studies, separability of auxiliary supplies) prior to formal Type 2 service procurement. Stakeholder engagement and planning work will continue in parallel with the initial feasibility studies. If the feasibility studies and value for money assessment indicate that the trial is capable of and sufficiently valuable to progress to an executed transitional service agreement, AEMO expects more detailed modelling and hardware-in-the-loop testing to be critical activities to understand equipment capability, expected outcomes and risks. The ultimate live trial(s) will be used to validate the modelling outcomes in an operational environment.
GFM Inverter Protection-Quality Fault Current Trial	For the GFM Inverter Protection-Quality Fault Current trial, market engagement and feasibility work have helped clarify the technical and practical requirements for a live trial. AEMO commissioned DEL Engineering, a specialist protection engineering contractor, to provide independent technical advice on how protection engineers assess fault current from IBR and identify the characteristics most important for dependable and secure protection scheme operation as IBR contributions increase. The DEL report[A] identified that protection performance depends on the characteristics of the fault current response, rather than fault current magnitude alone, and identified areas requiring further modelling, testing and live trial validation. The DEL work has therefore helped establish the technical basis for the trial and refine the characteristics and protection issues that subsequent modelling, hardware-in-the-loop testing and live trials should investigate. Investigations to date indicate that modelling and independent hardware-in-the-loop testing will provide most of the technical learning. However, live testing on a high-voltage network may provide valuable additional validation of the findings from modelling and independent hardware-in-the-loop (HIL) testing. Engagement to date indicates that TNSPs generally prefer passive monitoring of naturally occurring faults rather than deliberately applying faults to their networks. A preferred trial location was identified, and AEMO worked with the relevant TNSP to examine the proposed trial, protection requirements and operational risks. Whilst the TNSP has decided not to proceed with live testing at the location, the process provided valuable learning on the role and value of live testing within the broader evidence-building process. The TNSP concluded that the expected learning

Trial	Learnings
	from a single live test did not justify the site-specific system security risk. The trial would also not materially inform its investment decisions within the required timeframe. Given the range of inverter technologies, control configurations and protection schemes across the NEM, a single live trial would not provide a complete evidence base; rather, its value may be greatest as targeted field validation that can be compared with modelling and hardware-in-the-loop results to build confidence in how well these methods represent real-world protection performance. Future investigations could therefore form part of a broader, repeatable evidence-building and assessment framework combining specialist analysis, modelling, hardware-in-the-loop testing and targeted live validation across a wider range of technologies and network conditions. This also provides an opportunity to align future Type 2 activities with complementary Engineering Roadmap and industry initiatives, including UNSW's PROFILES Project, which commenced in July 2026 and is scheduled to conclude in Q4 2029, with field evidence potentially used to benchmark laboratory and HIL results. Such a coordinated approach would maximise the value of any future Type 2 Transitional Service and contribute to the broader evidence base for Protection-Quality Fault Current, alongside the system strength workplan outlined in TPSS Section 5.
Black Start from IBR	Market engagement to date has indicated that IBR black start capability sufficient to meet the existing Statement of Need is generally not incorporated into current BESS project designs, meaning there are limited opportunities to deliver the trial using existing installations. Delivering this capability is therefore likely to require material plant upgrades or consideration in the design of new projects. A key learning is that, where significant capital investment is required, the trial opportunity should be aligned with a credible longer-term system need rather than driven primarily by existing asset availability. AEMO therefore intends to align any future trial procurement with outcomes from the Engineering Roadmap system restoration activities (refer to Section 9). For example, this may include modelling to identify priority locations and capabilities where GFM IBR could provide enduring system restart value before undertaking targeted engagement with existing and proposed projects. A more detailed market update is available on the AEMO Black Start Capability from IBR webpage[B].

A. At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/impact-of-ibrs-on-power-system-protection.pdf.
B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/black-start-capability-from-ibr

2.4.3 Unsolicited Offers for Type 2 Transitional Services

Under NER 3.11.11(f)(5), the unsolicited offer pathway provides an opportunity for industry participants to proactively bring forward ideas for potential Type 2 trials or services for AEMO's consideration. The intent is to encourage industry to identify opportunities that could generate learning and capability for the broader benefit of the NEM, rather than limiting trial development to opportunities initiated by AEMO. AEMO has established a dedicated website with guidance on information to be included in expressions of interest and unsolicited offers[36].

In the past year, no unsolicited offers were submitted to AEMO for assessment.

2.4.4 Proposed Type 2 Transitional Services

AEMO's near-term focus remains on completing existing procurement processes, progressing several of the Type 2 Transitional Services identified through the SON published in 2025 but not yet underway (primarily the GFM Inverter Protection-Quality Fault Current Trial and Zero Synchronous Generation Trial).

AEMO expects to continue progressing the published SON while considering additional Type 2 opportunities as technical priorities and suitable trial pathways are identified through workstreams described in the TPSS.

Transient and oscillatory stability remains a priority area for potential future Type 2 Transitional Services. While inter-area oscillation damping was identified as a potential Type 2 opportunity in 2025, experience from the development of the initial trials has reinforced the importance of establishing a sufficiently robust technical evidence base before defining and

[36] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/submit-an-unsolicited-proposal-for-type-2-transitional-services.

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procuring a trial service. AEMO will therefore continue the technical analysis outlined in the Transient and Oscillatory Stability section of Part C (Section 8), including improving modelling capability, assessing damping performance under high-IBR conditions and identifying potential mitigation options. This work will inform whether a Type 2 trial is required and, if so, the system need, technologies, operating conditions and knowledge outcomes that should be targeted.

Within the next two-year period, AEMO anticipates procuring up to four new Type 2 Transitional Services across the SONs already published and/or priority focus areas. AEMO will only enter into Type 2 Transitional Service agreements where they are considered prudent and efficient having regard to the relevant procurement objectives maintaining power system security, achieving emissions reductions targets, and minimising costs to end users.

2.5 Preparing for no-coal operation in Victoria and New South Wales

As an example of how the four programs work together in practice, and address stakeholder requests, this section outlines how AEMO is preparing no-coal operation in Victoria and New South Wales, noting that no-coal operation is not expected to occur in Queensland within the 10-year horizon while Tasmania and South Australia already operate with no coal.

Table 12 summarises the insights and planning information that the programs provide for each power system criterion. Collectively, these provide AEMO with confidence that the technical needs for no-coal operation are sufficiently well understood to enable requirements to be set far enough ahead of time that procurement of assets and services can occur efficiently. While targeted technical uncertainties remain – as the operation of large power systems without synchronous generation is internationally unprecedented – they are increasingly concentrated in areas such as the compatibility of IBR and protection equipment, transient and oscillatory stability, system restoration and operability. The Engineering Roadmap workplans outline how AEMO is prioritising resourcing to address these residual uncertainties.

Specifically, AEMO has increasing confidence that the requirements for operating Victoria and New South Wales with no coal online, which the ISP projects could occur under credible contingencies in 2032 and 2033 respectively, are known and resolvable. These requirements are defined in technology agnostic ways, as outlined in **Table 12**, with the few remaining uncertainties being progressed in the workplans outlined in Part C. System-wide developments and plans. The challenge will be in the timely delivery of these requirements by industry, which is not currently assured.

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Table 12 Summary of how transition planning is preparing each power system criterion for no-coal operation

System criteria	Planning processes for maintaining security under no-coal conditions
System strength	Compensating for the loss of system strength from coal decommitments is one of the largest steps in preparing for operation with fewer and zero coal units online. In preparation of credible no-coal conditions: • AEMO has specified the minimum three phase fault level requirements that enable the correct operation of protection systems, stable voltage control systems, and the power system to remain stable[A]. Presently only synchronous fault current is considered sufficient to enable the correct operation of protection systems (see Section 5). These requirements represent the needs of the future system. Jurisdictional planning bodies, as SSSPs have responsibility for ensuring these levels are met, which, at present, may occur through a mix of market dispatch of synchronous generators, operation of SSSP owned synchronous condensers, and SSSP contracting of synchronous machines, with work underway to assess whether these options can be expanded to include GFM (see Section 5). • AEMO can also take action to ensure that the minimum secure levels can be met in the near term through its last resort planning functions in the NSCAS framework, but only in cases where AEMO has increased the requirements and a shortfall is projected within three years. • Additionally, AEMO's planning process identifies the efficient level of system strength, which may include GFM, required from SSSPs to enable future IBR connections without stability or synchronisation issues.
Frequency and inertia	• Batteries are continuing to grow their role as the dominant providers of frequency control ancillary services (FCAS), increasing from 56% in Q3 2025 to 75% Q3 2026[B].

System criteria	Planning processes for maintaining security under no-coal conditions
	• AEMO's system security assessments set regional and system-wide inertia requirements including consideration of credible contingencies, islanding risks, network conditions and available fast frequency response. • Forecast shortfalls are identified to inform the timely procurement by JPBs as Inertia Service Providers. The *Inertia Requirements Methodology*[C] provides a technology-agnostic pathway for synchronous and approved non-synchronous equipment, including GFM BESS providing synthetic inertia, to contribute towards inertia requirements. AEMO's published synthetic inertia study[D] has informed the testing methodology used to quantify this contribution. This framework enables future planning assessments to consider approved synthetic inertia capability alongside synchronous generators and synchronous condensers, subject to the equipment's demonstrated operating envelope and relevant system conditions.
Voltage control	• The long-term development pathways for maintaining voltage control are established through the ISP[E], TNSP annual planning reports, Regulatory Investment Tests for transmission, and AEMO-TNSP joint planning and operational activities. AEMO's NSCAS assessments study how voltage control requirements and capabilities change throughout the coming five years, identifying any emerging gaps and helping to ensure those gaps are addressed through the appropriate frameworks. AEMO conducted scenario based steady state analysis of an assumed 2035-36 no-coal configuration for Victoria and New South Wales, assessing voltage profiles and generator reactive margins under selected normal and contingency conditions. Given the long-term horizon, the findings are indicative and will be refined as the future system configuration becomes clearer. • Collectively, the voltage assessments help identify where voltage control challenges may emerge and informs the areas that AEMO, jurisdictional planning bodies and industry should investigate further.
Transient and oscillatory stability	• Future network augmentations, coal decommitments, and the connection of synchronous condensers, IBR and inverter-based loads (IBL) will materially influence transient and oscillatory stability. It is difficult to assess these impacts accurately over a 10-year horizon, because they depend on future operating conditions, network configurations, and control-system design and tuning. Maintaining stability therefore requires efficient assessment of stability impacts of approaching system changes, as well as rapid identification and response to unforeseen shifts in stability characteristics, including control-system tuning or other system solutions. • AEMO and industry preparations are therefore focused on uplifting monitoring and modelling capabilities, including of IBR and IBL, as well as the processes for collaborative retuning of plant (see Section 8). AEMO analysis also suggests low-regret options for managing future oscillatory stability needs include early consideration of damping capability in new synchronous plant, such as power oscillation damper (PODs), and clarifying obligations on IBR to participate in retuning post commissioning, should the need arise. While detailed control design and tuning require sufficiently defined network and plant configurations and substantial engineering assessment, opportunities to preserve future capability can be considered before these studies are complete.
System restoration	• In the current system, some coal units are black-start generators capable of self-energising without the external network energised, but more commonly are the second or third generator in a restoration pathway, providing critical system security services to strengthen a growing island until the whole region is restored to normal operation. Retirement of coal and some gas generators will remove currently relied upon system restart capability in the system, requiring new viable pathways to be developed using technologies expected to be in the system post-coal. Additionally, coal currently provides early bulk generation as it ramps up during restoration. New system restart technical strategies will be needed to accommodate coal retirement and incoming generation, both IBR and synchronous, to ensure locational considerations and restoration support are appropriately managed. • As described in Section 9[F], AEMO and industry preparations are focused on understanding viable technical strategies under low- and no-coal systems to achieve feasible restoration of each region within the technical envelope of the power system to achieve normal operation and regain reliability. Examples include energising firm generation, enabling operators to choose network elements to energise based on VRE forecasts, or targeting critical network elements to resynchronise with neighbouring regions. • Efforts aim to achieve this by investigating the capabilities of IBR to support energisation, the distances that gas and smaller hydro generation can stably energise, and informing network augmentations like targeted reactor placement or point-on-wave switching for critical transformers.
Operability	Operating with no coal generation online will require operational capabilities across AEMO and industry to evolve alongside the changing technical characteristics of the power system. Operability depends on the collective capability of AEMO, NSPs, and market participants to forecast, assess, monitor, and manage the power system under increasingly dynamic and unfamiliar conditions, supported by clear responsibilities, effective information exchange, and coordinated operational action. AEMO's Operability workplan (Section 10) identifies and prioritises the required uplift in operational forecasting, modelling, look-ahead security assessment, real-time monitoring and decision support, procedures, simulation and operator training. Complimentary industry capability is being supported through AEMO's Power System Modelling Strategy[G], the Transmission System Operational Capability Framework[H] and work under the National CER Roadmap[I] to clarify future distribution-system roles, responsibilities and operational capabilities. Together, these initiatives support clearer responsibilities, more effective information exchange and coordinated operational responses across AEMO, NSPs and market participants. This provides a structured pathway for preparing AEMO and industry operating arrangements for credible no-coal conditions. Operability under these conditions has not yet been fully demonstrated, and confidence will increase progressively as future operating conditions are better defined, priority capabilities are delivered and AEMO and industry operators rehearse representative high-IBR, low-inertia and compound scenarios.

System criteria	Planning processes for maintaining security under no-coal conditions
Resource adequacy	Reliability gaps are identified by annual ESOO assessments, which forecast expected unserved energy (USE) over a 10-year outlook period based on announced closure dates of coal station exit. Where reliability gaps emerge against the relevant Reliability Standard[J], this indicates opportunities for market participants, investors, governments and other jurisdictional bodies to invest in new generation, storage, demand-side or other enabling infrastructure to maintain a reliable supply of electricity in the NEM. Where the ESOO forecasts a reliability gap in the third year of the assessment outlook AEMO is required to request the AER to make a T-3 reliability instrument under the Retailer Reliability Obligation[K] (RRO). This is designed to provide early signals to the market, allowing sufficient time for investment in or contracting of new capacity to address emerging reliability gaps. In a region where an existing T-3 instrument is in force and reliability gap continues to be forecast one year out then AEMO is required to request the AER make a T-1 reliability instrument. Complementing the ESOO, the ISP projects the additional generation, storage and transmission network capacity needed beyond committed and anticipated projects to maintain reliable and secure supply as coal-fired generation exits, while meeting government policies. This inherently requires planning for periods of no-coal operation towards the end of the planning horizon. Annual GSOO assessments provide a similar assessment of gas resource or infrastructure development opportunities in East Coast gas network infrastructure. The GSOO is a 20-year forecast of adequacy of gas supplies in central and eastern Australia to meet domestic and export demand for gas, including gas used in generating electricity in the NEM and in the Northern Territory. Collectively, the ISP, ESOO and GSOO assessments inform industry delivery of new electricity and gas supply capacity ahead of no-coal operation.

A. See Appendix A4, https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.
B. See https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q3-2026.pdf.
C. See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf .
D. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf.
E. See ISP Appendix A4 on system operability, Appendix A5 on network investments and Appendix A7 on system security.
F. Additionally, see Appendix A4.
G. See https://www.aemo.com.au/consultations/current-and-closed-consultations/power-system-modelling-strategy-consultation.
H. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.
I. See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/electricity-working-group/consumer-energy-resources-sub-working-group/national-cer-roadmap.
J. The ESOO measures reliability risks relative to two standards determined by the Reliability Panel. The Interim Reliability Measure (IRM) is a measure of expected USE in any region of no more than 0.0006% of energy demanded in any financial year. The IRM applies for the purposes of the Retailer Reliability Obligation (RRO) until 30 June 2028, after which the reliability standard of no more than 0.002% applies.
K. See Chapter 4A of the NER.

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3 Maintaining security is becoming more operationally challenging

Many power system phenomena can change extremely rapidly pushing the system towards the limits of the technical operating envelope. Their management therefore requires the use of automated systems – embedded in generators, transmission infrastructure, loads and control centres – in addition to operational procedures and planning.

Beyond immediate automated responses, manual actions may also be required from operations staff in AEMO, NSP and market participant control rooms. *Operability* is the ability to achieve and maintain a secure operating state by managing the power system effectively as conditions change. It integrates the other power system criteria through the people, processes, information, models, tools and digital systems needed to assess the system against its technical operating envelope, anticipate changing conditions, and take timely operational action.

The NEM remains secure and operable today, but the operating environment is becoming more dynamic, decentralised and less predictable. System security services historically provided as an inherent feature of synchronous generation increasingly need to be separately sourced, forecast, monitored and actively managed. Operators and operational support teams must also manage more variable generation and demand, increasingly complex operating limits, greater volumes of operational information and more frequent interactions between transmission and distribution networks. The growing number of connected facilities and market participants also increases operational coordination requirements. Timely responses across this larger participant base increasingly depend on automated information exchange and coordinated response arrangements, rather than individual control room contact with each participant during an incident.

The principal operability challenge is not any individual technology or operational issue, but the combined effect of these changes and the risk that operational capability does not keep pace with system complexity. If capability does not evolve alongside the power system, more conservative operating limits and/or operational interventions may be required to maintain security, reducing operational flexibility and increasing costs. Additionally, the system may become less resilient to high impact low probability events, increasing the likelihood of significant consequences for power system security and reliability following these rare events. AEMO's plans for strengthening operational capability are presented in Section 10.

NSPs may also need to invest in significant operational capability uplifts, including improvements to operational processes information exchange and supporting systems. Operational coordination and responsibilities across AEMO, TNSPs and DNSPs are also evolving, requiring these capabilities to work effectively together. Section 11 includes details of AEMO's contributions to the National CER Roadmap workstream to *Redefine roles for market and power system operations*[37], particularly working to formalise distribution system roles and responsibilities. In addition, AEMO has collaborated with TNSPs to develop and publish the *Transmission System Operational Capability Framework*[38] that identifies priority future TNSP competencies and capabilities. These initiatives support clearer operational responsibilities, more effective information exchange and stronger coordination across AEMO, NSPs and market participants, which will be crucial for future system operability.

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[37] See consultation page at https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5.

[38] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.

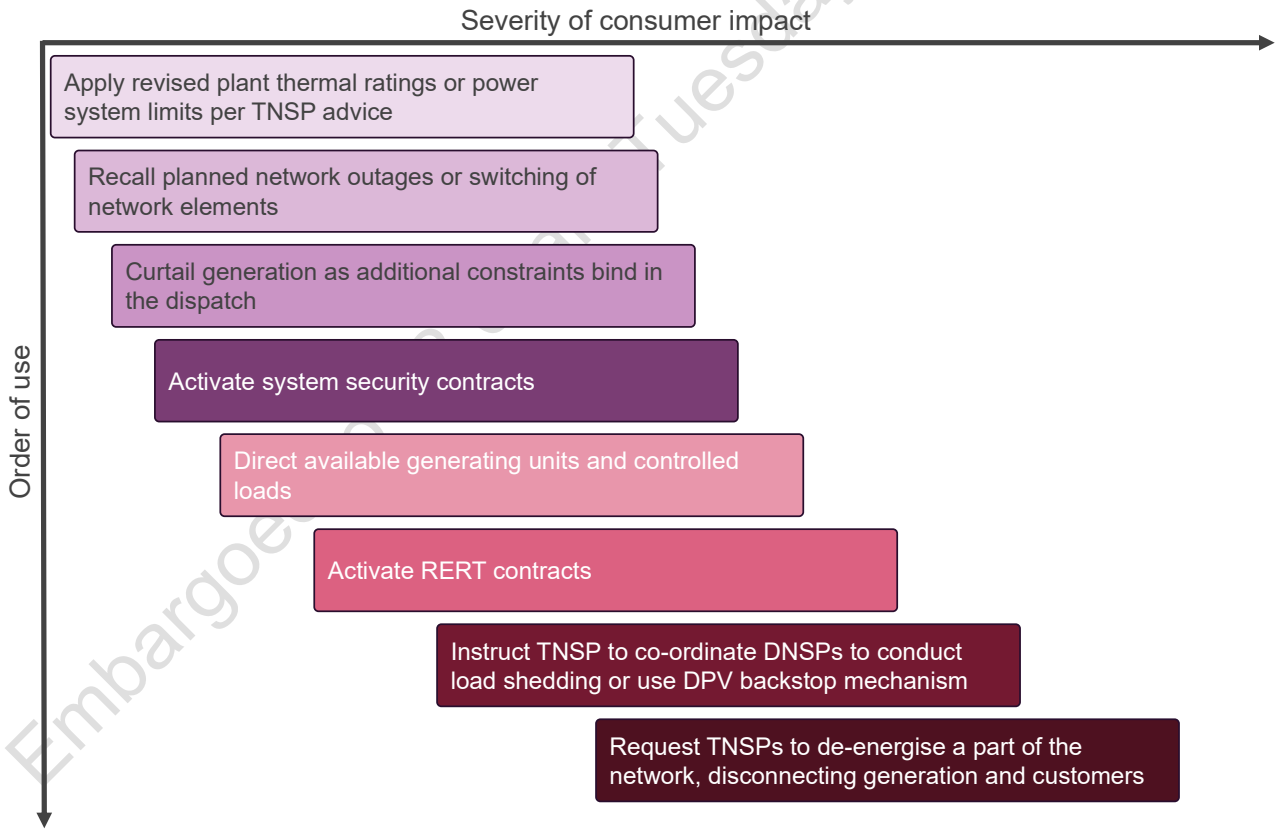
3.1 AEMO's operational toolkit

Sufficient system security services support the NEM in maintaining a secure operating state and returning to secure operation following a credible contingency. Where normal market outcomes do not provide the resources or services needed, AEMO may need to intervene to maintain or restore secure operation (see Section 1.2). The actions that AEMO may need to take are listed in **Figure 10**, in priority order[39].

AEMO selects from this operational toolkit according to prevailing system conditions, the available response time, and the effectiveness of available options. Actions may include adjusting constraints or network configurations, activating contracted security services (such as through NSCAS, NSP contracts, and Type 1 Transitional Services), coordinating with NSPs and market participants, issuing directions, curtailing generation or, as a last resort, de-energising parts of the network, leading to disconnection of generation and customer supply. Maintaining system security in accordance with the NER is paramount. Where practicable, AEMO seeks to do so while minimising disruption to market outcomes and costs to consumers.

As system complexity increases, the effectiveness of AEMO's operational toolkit will also depend on timely information, trusted models and forecasts, effective decision support, clear procedures and coordinated industry action.

Figure 10 AEMO's operational tools for maintaining system security



[39] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.

3.2 Type 1 Transitional Services

Type 1 Services are those needed to fill an identified security need within the next two years to support the power system during times of uncertainty during transitional periods, or to fill identified gaps that cannot be otherwise provided by an inertia network service, a system strength service, a market ancillary service or an NMAS.

Information on how AEMO intends to move away from using these contracts is outlined in the description of each proposed service below.

3.2.1 Published Type 1 Transitional Services

In November 2025, AEMO published two SONs for Type 1 Transitional Services across the NEM – one for MSL services in New South Wales, Queensland, South Australia and Victoria, and one for Grid Reference in South Australia, as shown in **Table 13**.

Table 13 Status of published Statements of Need for Type 1 Transitional Services

Type 1 Transitional Service	Description, including how AEMO intends to move away from using this service	Status
Procurement of MSL services for flexible load and temporary resecuring service – in New South Wales, Queensland, South Australia and Victoria	A wide EOI was released for Transitional Services to address MSL risks[A]. Those services offered that fit the framework for Type 1 Transitional Services have been negotiated and contracted for in Queensland, South Australia and Victoria. AEMO sees an intermittent need for these services in NEM mainland regions to manage network constraints, including interconnector flows. The need for the service in each region will be dependent on the prevailing power system conditions. AEMO will continue working with NSPs and other stakeholders to ensure appropriate safeguards are in place and explore new approaches through Type 2 trials.	Contracted in Victoria, Queensland and South Australia
Procurement of synchronous generators to provide grid reference in South Australia upon completion of NSCAS contracts	A minimum of at least one synchronous generator is currently required under system normal conditions in South Australia, while more than one may be required when the system is experiencing low operational demand, minimal resecure availability or under outage conditions, for example when islanding is a credible risk. AEMO has contracted with synchronous generators connected at the 275 kV network in South Australia for Type 1 Transitional Services, to provide generation at their minimum output when other synchronous generators are not generating[B]. This service will ensure a single synchronous generating unit or equivalent is kept online until AEMO has confirmed the conditions under which power system security can be maintained in South Australia with zero synchronous generation online. AEMO is working with ElectraNet to finalise requirements for the move to zero synchronous generators (refer to Part B. Regional transition plans).	Contracted three facilities

A. In MSL2 conditions, the power system is one credible contingency away from requiring immediate action from AEMO and DNSPs to increase demand. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services.
B. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service.

3.2.2 Learnings from procurement process

Type 1 procurement has highlighted the challenges of securing services from specific providers by specified dates. Limited alternative suppliers and strict timeframes can constrain procurement requirements and pricing negotiations. Establishing a risk-based cost benchmark, reflecting market intervention uncertainty and provider risks and costs, enabled AEMO to assess value for money and decline offers above the acceptable baseline.

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While current provider availability has supported AEMO's ability to challenge pricing, this flexibility could diminish with changing conditions. Future procurements will account for these constraints when assessing price, contractual requirements and delivery risks.

3.2.3 Proposed Type 1 Transitional Services

AEMO has not currently identified needs for Type 1 Transitional Services in addition to those listed above, however as a general estimate AEMO intends to enter into up to 10 Type 1 Transitional Services agreements over the coming two-year period. It is anticipated that any given SON may lead to more than one agreement.

3.3 Operational metrics

AEMO employs data metrics to measure, track and assess trends in operational risks as the power system transitions to a supply mix that is dominated, at times, by geographically dispersed IBR. Monitoring network performance through operational data enables AEMO to identify emerging shortfalls in power system security margins and evaluate the impact of uplift activities, reform, or network augmentation projects, ensuring that AEMO maintains the capabilities needed to securely operate the power system.

The extent of operational activity required to manage the system securely is shown in **Figure 11** and **Figure 12** via the duration and number of directions, and duration of security contract enablement. As **Figure 11** shows, high volumes of directions to gas generators have been issued in South Australia over recent years to meet the requirements for minimum synchronous generation units online. These are typically most necessary during periods of low demand and high IBR output.

In 2020 and 2021, up to four synchronous units operated under direction, with directions in place for 86% of intervals in 2021. Installation of four synchronous condensers in November 2021 allowed AEMO and ElectraNet to implement new limits advice, enabling system operation with a minimum of two synchronous units online. Since then, further technical investigation has enabled this requirement to be reduced to one synchronous generator under certain operating conditions. With contracted NSCAS agreements operational in 2025, and subsequently grid reference transitional service (GRTS) contracts that replaced these arrangements in 2026, these services are now dispatched via the System Security Management tool ahead of issuing directions, providing a more dependable mechanism for operational management. With completion of PEC Stage 2 in November 2026, AEMO and ElectraNet are progressing studies to build technical evidence in support of secure operation with zero synchronous generating units – this transition point is described in Part B. Regional transition plans, together with dependencies on resolving newly observed oscillations.

Recent years have also seen more directions issued in New South Wales and Victoria to maintain system strength. These regions are reliant on large synchronous units, with coal generators currently providing the majority of system strength support. Where unplanned generator or transmission outages reduce fault levels below secure requirements, AEMO has had to direct fast-start gas or hydro units online, or direct off IBR plant. As coal stations retire in New South Wales and Victoria, any shortages in security investments delivered ahead of transition points would increase reliance on interim solutions to maintain system security, such as through contracting, or directions, to keep existing synchronous units online.

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Figure 11 Duration of directions and contract enablement in South Australia, 2017 to 2026

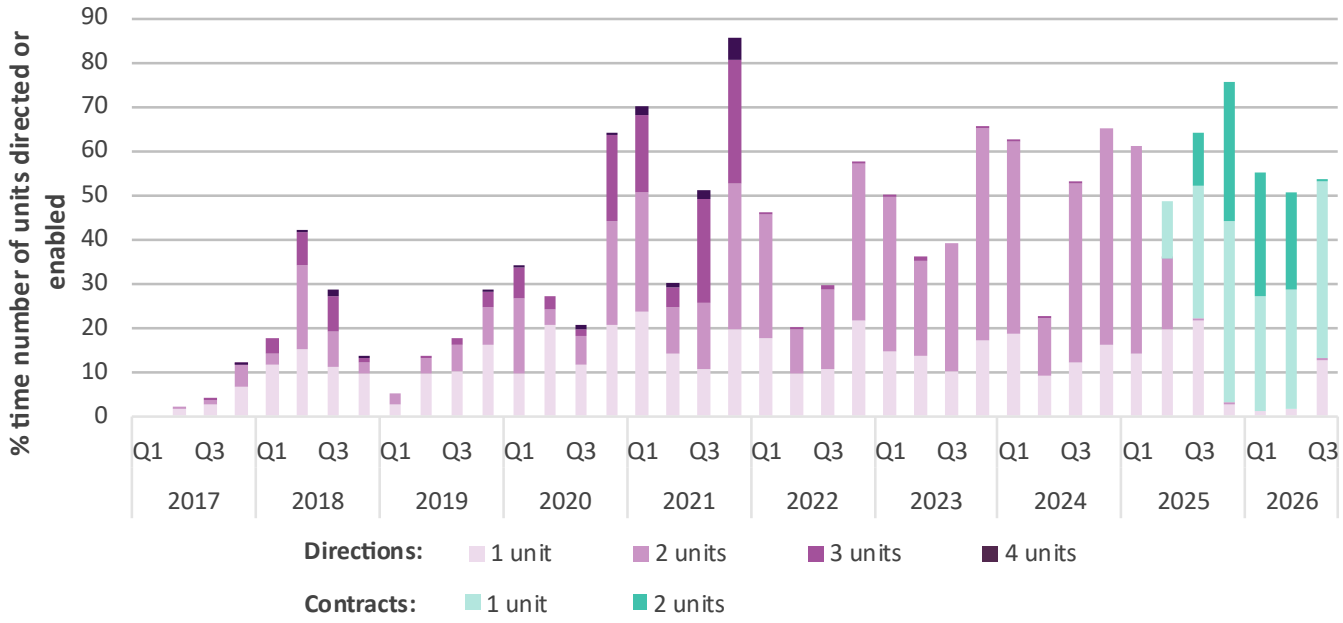
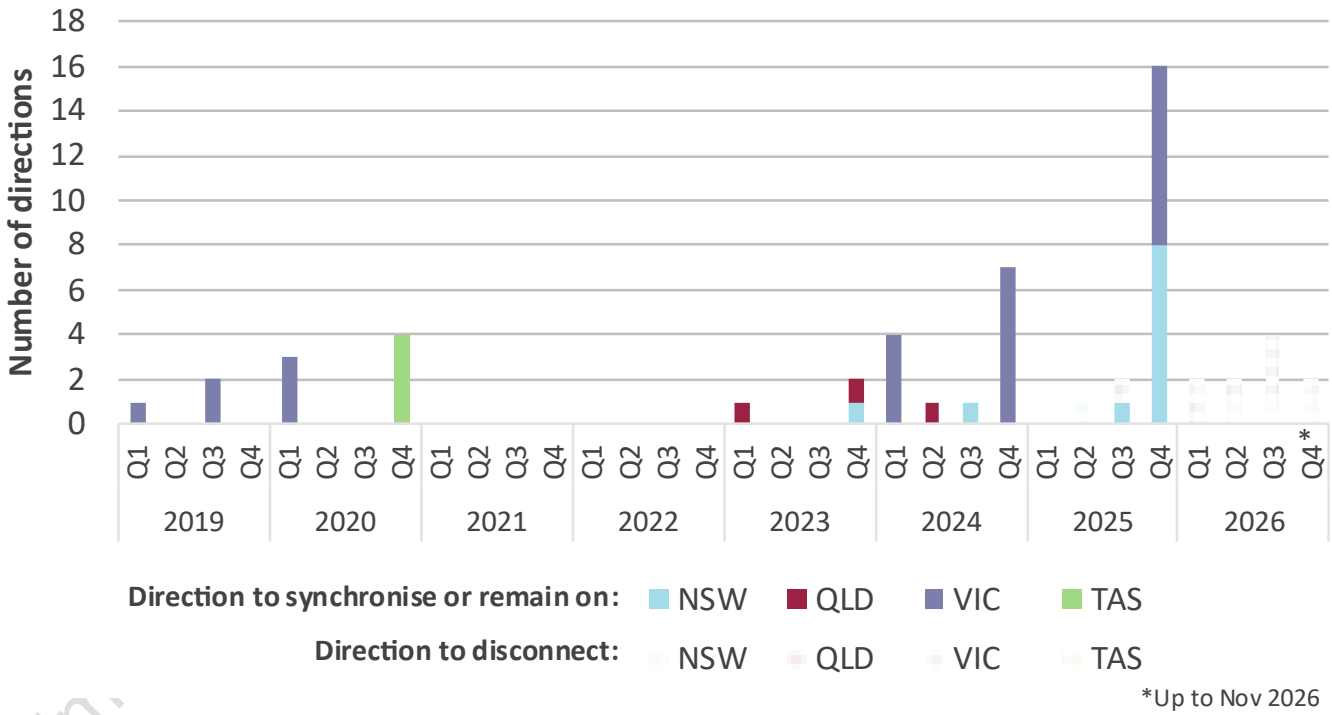


Figure 12 Number of directions in New South Wales, Queensland, Victoria and Tasmania, 2018 to 2026



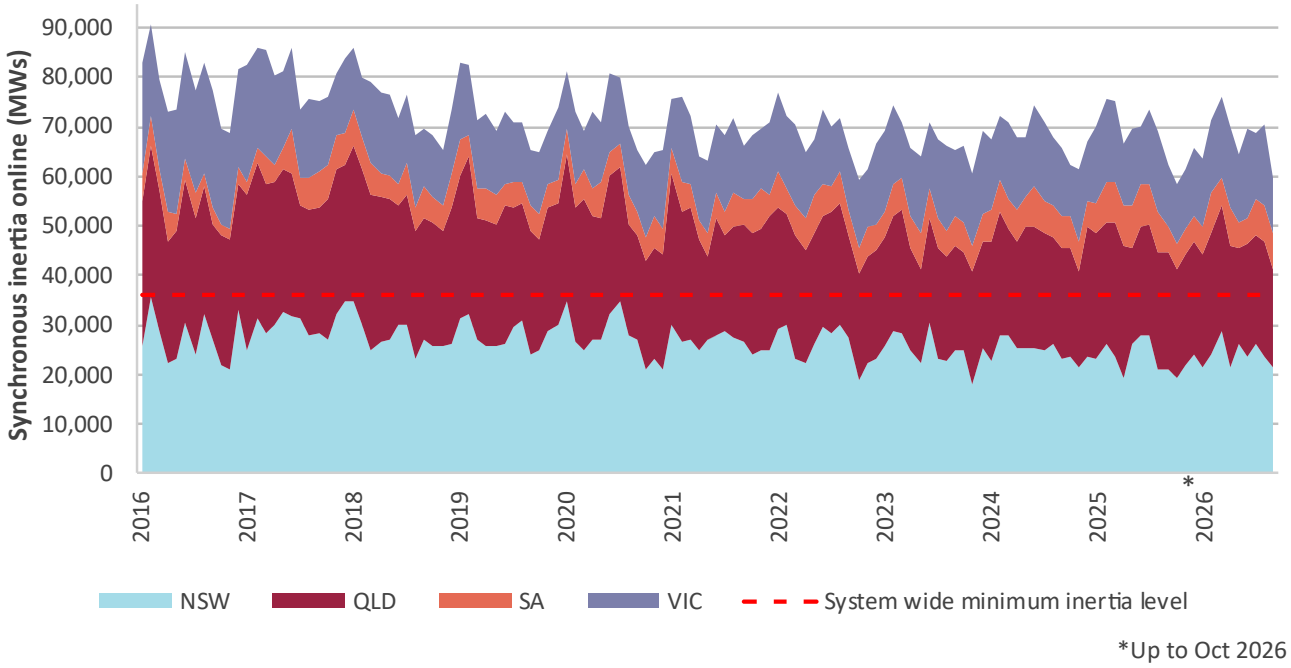
*Up to Nov 2026

AEMO monitors the availability of system security services in real time to assess the need for intervention or enablement of system security contracts. Work is underway to develop additional metrics for monitoring long-term trends in system security services, including historical levels of system strength from synchronous machines.

Figure 13 shows a gradual decline in the levels of synchronous inertia available over recent years. As coal units retire or decommit, the inertia services they provide must be replaced to maintain levels above regional and mainland minimum requirements. From 2 December 2027, JPBs (often TNSPs) will be obligated to procure against sub-regional network inertia

allocations, representing their contribution to meeting the system-wide inertia level. Most JPBs are planning to procure inertia through a combination of synchronous inertia from synchronous condensers and synthetic inertia support provided by GFM BESS, noting that to date no synthetic inertia has been procured in the NEM or WEM (see Section 6 for details of the how AEMO and industry are planning to operationalise synthetic inertia responses).

Figure 13 Minimum monthly synchronous inertia for mainland NEM regions, 2016 to 2026 (MWs)



MWs: megawatt seconds.

The growing operational complexity of managing the power system is reflected in the volume of control room alarms[40]. **Figure 14** shows that the average number of alarms per operator has peaked to as high as 180 alarms every 60 minutes. This is 15 times higher than the recommended maximum manageable number of alarms per operator outlined in ANSI/ISA18.2 standards[41].

The growing number of alarms reflects the power system's technical operating envelope shifting, and increasing numbers of market participants, network constraints, outages, RASs and system contingencies. While not all alarms may reflect material issues, each must be assessed alongside the growing volume of real-time information. This increases the cognitive load for operators and reduces situational awareness.

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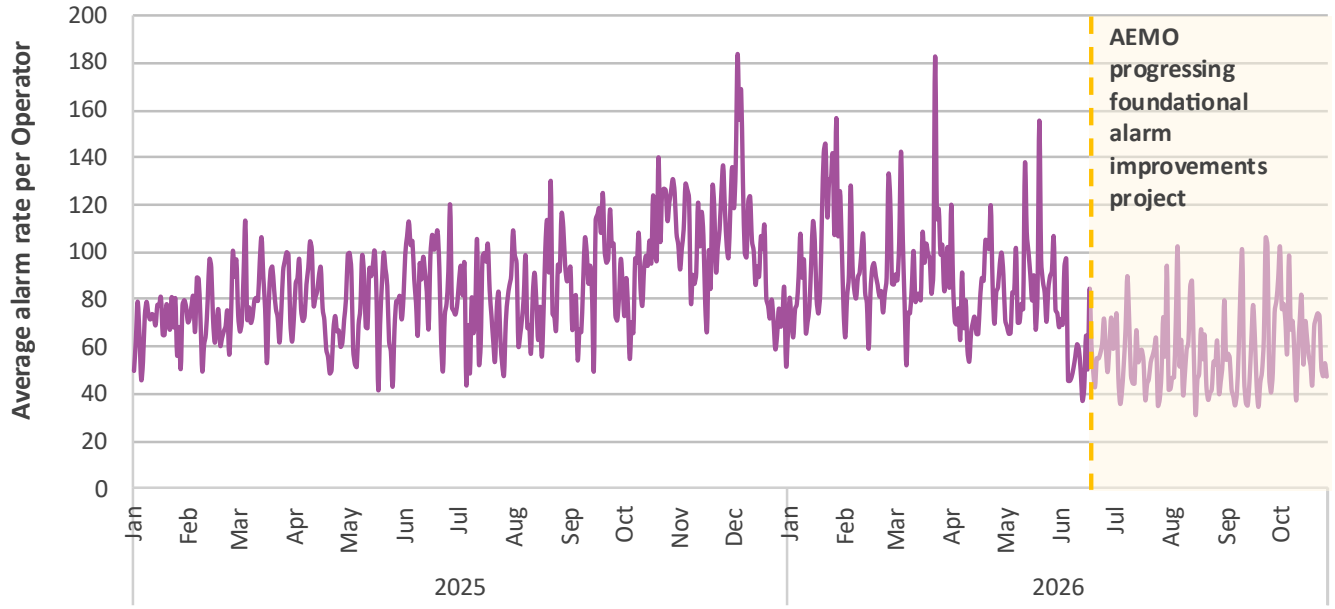
[40] AEMO's alarms system monitors equipment status across the NEM and informs operators of incidents. AEMO defines an alarm as a system event which requires an action from network controller. The intent of alarms is to provide operators with clear and concise critical information and allow them to respond effectively to maintain power system security and reliability. The above metrics of alarms received by AEMO controllers only includes alarms from AEMO's Energy Management System (EMS). Controllers may also receive additional alarms from other market management systems which often require action.

[41] The recommended average maximum manageable alarm rate per operator console is defined as 12 alarms per hour.

AEMO has commenced work to rationalise alarms and prioritise material control room information. This has led to a significant reduction in average alarm rates since June this year. To address the sustained volume of control room alarms and associated operator cognitive load, AEMO has considered two complementary initiatives:

- The progressing foundational alarm improvements project is focused on establishing the underlying alarm-management foundations, including alarm rationalisation, and improved prioritisation of operationally material alarms. The project also includes removal or reclassification of alarms that are actually Events or Notifications (which are only for operator awareness and do not require any action) but are currently, incorrectly, reported as alarms. This will also support a more consistent alarm philosophy and clearer escalation of conditions requiring operator attention, reducing the risk that material events are obscured by incorrectly classified, excessive, or poorly prioritised alarm activity.
- Building on this foundation, the intelligent alarming and decision support initiative will explore more advanced automation and analytics to help identify, prioritise and contextualise alarms, including greater correlation of related events and system conditions. This is intended to improve the signal-to-noise ratio presented to operators, support faster situational awareness and enable more effective operator decision-making (see Section 10).

Figure 14 60-minute average alarm rate per operator, January 2025 to October 2026



AEMO also tracks the maximum contribution[42] of renewable energy and battery discharge to instantaneous demand (over any 30-minute interval). This has steadily increased to the current record of 80.4%, shown in **Figure 15**, supported by uptake of DPV alongside utility-scale renewables development.

[42] Peak renewable contribution is calculated using the renewable share of total generation. This measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for DPV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery discharge and DPV. Total generation = large-scale generation + estimated PV output.

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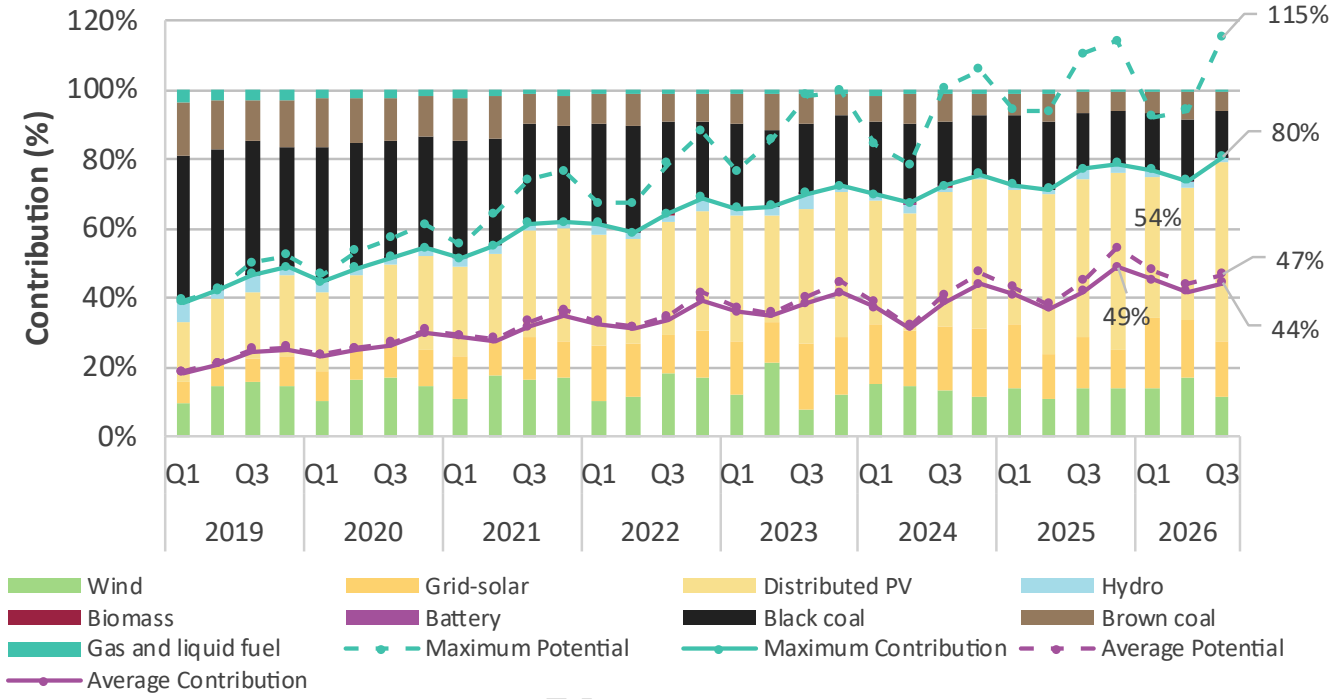
Figure 15 also shows that potential[43] renewable contribution has exceeded 100% at times, in periods when available renewable supply, before network curtailment[44] and/or economic offloading[45], could have met all NEM demand. While coal-fired units remain online, their relatively high minimum stable output levels (MSOLs) limit the aggregate contribution of renewables. As these units retire and their system security services are replaced by sources with low or zero MSOL, the maximum level of renewable contribution will increase further.

Figure 15 Maximum 30-minute contribution of renewables to NEM demand, 2019 to 2026



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[43] Renewable potential in an operating interval refers to the total available energy from VRE sources, even if not necessarily dispatched, and actual output from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

[44] Curtailment refers to a generator being dispatched below its economic availability (output available at offer prices below the regional reference price [RRP]) due to the operation of network- or security-related constraints.

[45] Economic offloading refers to a generator being dispatched below its maximum availability, because some, or all, of its output was bid into price bands greater than the RRP; that is, it was undercut by competitors offering their output at a lower price.

4 Stakeholder engagement and feedback

4.1 AEMO's engagement approach

The TPSS is developed through an iterative process that draws on AEMO's technical analysis and operational experience, system security planning and other engagement with NSPs, and feedback from governments, market bodies, industry participants, consumer representatives and other interested stakeholders. Engagement undertaken for each TPSS is tailored to specific issues and stages of development. AEMO uses established industry forums, targeted briefings and workshops to seek input, test emerging analysis and build stakeholder understanding of the findings. Information shared through targeted engagement is managed with regard to confidentiality, security and competition law considerations.

AEMO's engagement approach for the 2026 TPSS is structured around three stages:

1. **pre-release** – to seek input on the report's scope, priorities and emerging analysis,
2. **release** – to explain the findings, implications and actions arising from the report, and
3. **post-release** – to understand stakeholder interests and gather insights to inform the development of future reports.

4.2 Pre-release engagement

Development of the 2026 TPSS was informed by feedback received on the 2025 TPSS and engagement undertaken throughout 2026. Early engagement focused on the report's scope and structure, transition point assessments, Engineering Roadmap priorities, and the information stakeholders require to support planning, investment and operational preparedness. AEMO engaged through discussions with the Reliability Panel, governments, NSPs, industry associations, consumer representatives and established technical and planning forums. It also included engagement undertaken through AEMO's system security planning activities and targeted engagement supporting relevant technical analysis.

Following publication of the 2025 TPSS, AEMO invited written feedback from interested stakeholders. AEMO received seven formal submissions, from the Australian Energy Council (AEC), CS Energy, Electrification and Energy Systems Network (EESN), Reactive Technologies, SMA Australia and Syncline Energy, as well as a submission from the AEMC's Reliability Panel[46]. These submissions have been published on AEMO's website[47]. Feedback received through these submissions, together with engagement throughout 2026, informed the development of the 2026 TPSS. **0** summarises how stakeholder feedback informed the content of the 2026 TPSS and how this has been reflected in the report.

Experience from the 2025 TPSS feedback process has also informed AEMO's approach to future engagement. AEMO intends to place greater emphasis on targeted workshops and other two-way engagement in the development of future reports, enabling stakeholders to test emerging analysis, ask questions and provide feedback.

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[46] As required under the NER; see https://energy-rules.aemc.gov.au/ner/767/817641#5.20.8. See Appendix A1, https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a1.

[47] At https://www.aemo.com.au/energy-systems/major-publications/transition-plan-for-system-security-tpss/2025-transition-plan-for-system-security.

Table 14 Summary of stakeholder feedback to inform the 2026 TPSS

Stakeholder feedback	How it influenced the 2026 TPSS
Bring system security reporting together and clarify the relationship between AEMO publications	The 2026 TPSS incorporates Engineering Roadmap reporting, building on the earlier consolidation of the system strength, inertia and NSCAS reports. Section 2.1 also explains the distinct but related roles of the TPSS, ISP, ESOO and GPSRR.
Be clearer about what has changed, emerging risks and the actions underway	The report identifies major changes since the 2025 TPSS and provides updated transition point assessments, preparatory actions and Engineering Roadmap workplans.
Provide information that supports planning, investment, regulatory and operational decisions	The report provides greater visibility of transition point readiness, identified risks, preparatory activities and planned technical work. AEMO will continue to consider opportunities to improve the transparency of inputs, assumptions and methodologies (as in **Table 8**).
Maintain a technology-neutral and performance-focused approach	The Engineering Roadmap and Transitional Services sections focus on the capabilities and services required to maintain system security, including how new technologies and novel applications of existing technologies may contribute.
Engage earlier and more consistently with networks, governments, market bodies and technology providers	AEMO commenced engagement earlier in the development process and used established planning and technical forums, Reliability Panel engagement, jurisdictional briefings and targeted discussions to test the report's proposed scope, priorities and emerging findings.
Explain the consumer relevance of system security more clearly	The report provides additional discussion of the relationship between system security risks, operational interventions, investment and consumer outcomes. AEMO will also consider how broader communication and education material can provide accessible explanations for non-technical audiences.

4.3 Release and post-release engagement

AEMO is keen to ensure that all engagement is fit for purpose, interactive and centred on building a common understanding of emerging issues and insights into specific stakeholder interests. At release, AEMO intends to provide opportunities for stakeholders to understand the key findings of the 2026 TPSS, their implications for industry preparedness, and the actions identified across the transition plans and Engineering Roadmap workplans This will include an industry webinar, recorded and published on AEMO's website, as well as an accessible language infographic.

Following release, AEMO will undertake targeted workshops with NSPs, market participants, governments, industry associations, technology providers and consumer representatives. These workshops will aim to leverage participation from members of existing forums, where practical, and seek feedback on:

- emerging system security risks and transition point readiness,
- the levels used for assessing transition point readiness,
- prioritisation of Engineering Roadmap activities to build technical understanding and industry capabilities,
- the technical capabilities, services and preparatory actions required from AEMO and industry,
- potential flow through impacts for industry stakeholders and consumers, and
- opportunities for collaborative problem solving to identify potential mitigation pathways.

AEMO will use this feedback, together with its ongoing technical, planning and operational engagement, to inform the scope and development of the 2027 TPSS. Stakeholders may also provide feedback on the 2026 TPSS at any time through futureenergy@aemo.com.au and can subscribe to receive updates through AEMO's website[48].

[48] At https://www.aemo.com.au/subscribe/aemo-subscription-form.

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Part B. Regional transition plans

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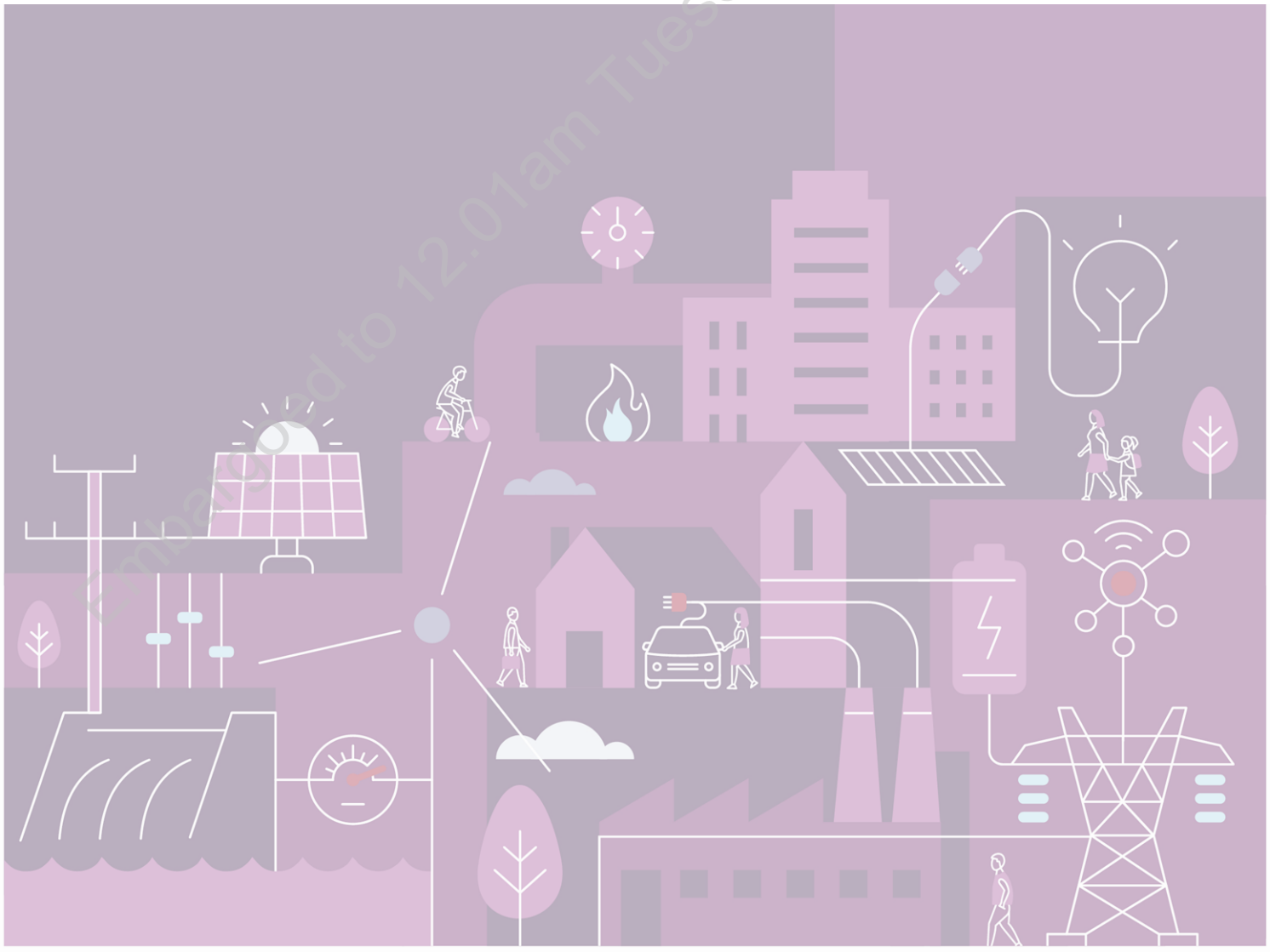


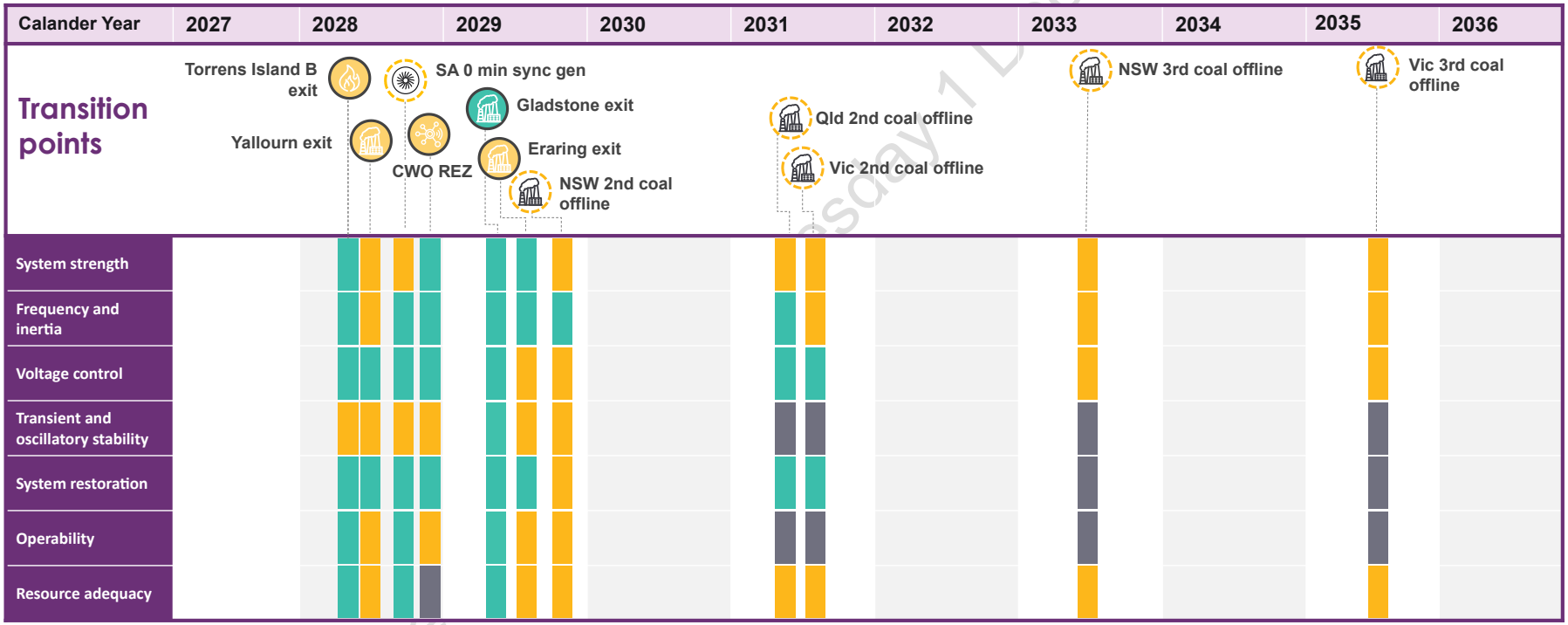
Part B. Regional plans for maintaining security through the transition to a low- or zero-emissions power system

Part B identifies and assesses industry readiness for specific transition points (events that require material changes in the operational approach to managing system security) in each NEM region.

The 2026 TPSS assesses 11 transition points across seven power system criteria, with readiness level findings summarised in the figure below.

For each region, Part B contains:

- an overview page, including operational metrics that give a snapshot of current conditions,
- a summary of regional system security assessments, including system strength, inertia and NSCAS findings, and
- detailed readiness assessments for each identified transition point, including publicly available data on infrastructure developments and in-flight actions.



KEY

Timing of transition point

Firm timing
Dates align with submitted Notices for Closure or confirmed project dates. Low readiness indicates an urgent need for additional or accelerated actions.

Planned timing
Dates aligned to 2026 *ISP Step Change* scenario or AEMO plans for minimum synchronous generator reductions. Low readiness indicates further action required to achieve planned transition timeline.

Industry readiness for transition point

Complete / on track
Planned actions are expected to maintain system security.

Moderate readiness
Current plans may not be sufficient to avoid increased chance of moderate-impact interventions being required to maintain system security. There may be opportunities to expand or accelerate actions to improve readiness.

Unresolved issues
Current plans are unlikely to be sufficient to avoid increased chance of high-impact interventions being required to maintain system security. Options for further preparatory actions and operational controls are narrow.

Not yet assessed
Power system criterion cannot be assessed because of a high sensitivity on yet to be specified future system conditions or has not yet been prioritised for assessment because AEMO judges it to be low risk.

Embargo Tuesday 1 December 2026

New South Wales

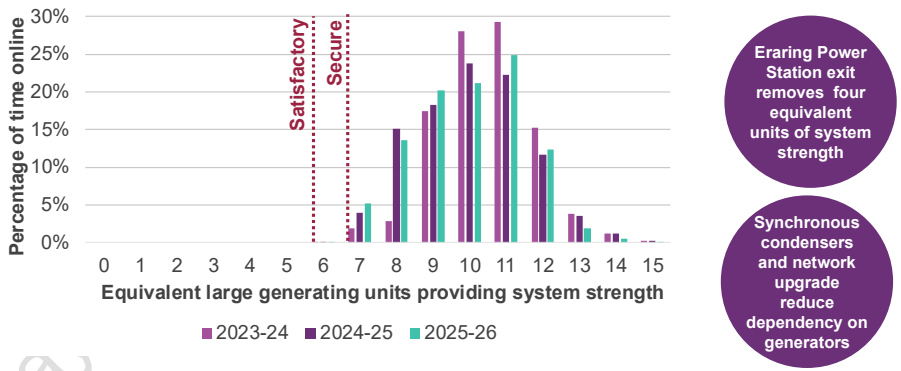
Context

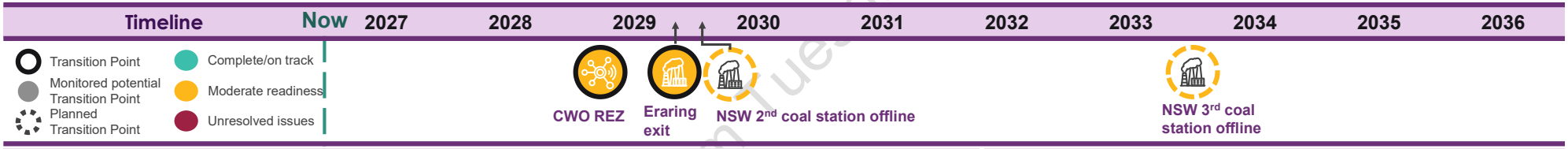
The New South Wales power system is evolving rapidly, supported by the NSW Electricity Infrastructure Roadmap[B]. Multiple transitions are expected from late 2028 through 2029, including the retirement of Eraring, the connection of the CWO REZ and commissioning of its first synchronous condensers, and the projected decommitment of a further coal generator. The delayed completion of Snowy 2.0 further complicates this period.

The 2026 ISP[A] *Step Change* scenario projects a third coal generator to decommit in 2033, leaving only two coal units available. Under credible operating conditions, New South Wales capabilities will need to be available at the right time and increasingly provided by a mix of storage, synchronous condensers and other generation and network assets; noting increasing costs of synchronous condensers add challenges on procurement efforts[C].

***Since the 2025 TPSS**: Eraring's exit has been deferred two years and readiness has improved due to accelerated delivery of synchronous condensers. The 2026 ISP revises the date of the third coal station offline transition point to 2033 (from 2031). Snowy 2.0 has also been delayed 12 months, resulting in forecast reliability gaps, as indicated in AEMO's December 2026 ESOO Update, although reliability is expected to remain within the reliability standard if all committed, anticipated and government-supported generation, storage and transmission projects are delivered on time and in full. CWO REZ is included as a transition point, and South West REZ Network Infrastructure Project has been authorised by the Consumer Trustee.*

Maintaining system strength above security limits is increasingly challenging





Security challenges

To ensure adequate system strength post Eraring retirement, Transgrid, with support from the New South Wales Government, has been accelerating the delivery of the system strength RIT-T Phase 1 synchronous condensers to be in-service prior to Eraring retirement. Transgrid's preferred portfolio to meet system strength requirements includes delivery of Phase 2 synchronous condensers, however its Material Change in Circumstances report[C], triggered primarily by a material increase in synchronous condenser costs, indicates these are currently not commercially feasible. The preferred portfolio from Phase 2 onwards, or an appropriate alternative, will need to be confirmed and delivered in a timely manner to support planned coal station decommitment.

As further coal generators retire and are replaced by remote renewable generation, power flow patterns to major load centres will change. Network augmentations and local dynamic reactive power support may be required to maintain adequate voltage levels. Changes in transient and oscillatory stability may also have an impact in power transfer capability.

Changes in network configuration, equipment mix and operating conditions may influence future dynamic limits, potentially affecting transfer capability across New South Wales network. Understanding how these limits may evolve allows potential restrictions to be identified early, providing sufficient time to assess mitigation options and implement efficient solutions before they become operational constraints. The outlook for Minimum System Load (MSL) has improved, with no MSL transition point identified and no MSL3 events forecast[D].

Preparatory actions

- **Transgrid** to continue timely delivery of its preferred or equivalent portfolio of system strength solutions, with Phase 1 delivered ahead of Eraring retirement.
- **Transgrid** to progress on actionable ISP network augmentations.
- **Transgrid** to provide planning limits to support operational readiness assessments prior to operational timeframes and enable the timely identification and implementation of any required mitigation measure.
- **AEMO and TNSPs** to progress the transient and oscillatory stability workplan[E] of the Engineering Roadmap to improve understanding of the future power system dynamics.
- **EnergyCo**, **ACEREZ**, **Transgrid** and **AEMO** to facilitate the timely delivery of REZ infrastructure, including system strength and generation components.
- **Market Participants** to progress timely delivery of committed and anticipated generation and storage projects.

A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
B. See https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap.
C. For more information, see https://www.transgrid.com.au/media/m5ycbumc/260825_transgrid_system-strength_final-mcc-report-1.pdf.
D. Refer to Appendix A3 for further details, https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.
E. Refer to Section 8.2 for further details.

New South Wales security assessment

Now	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036

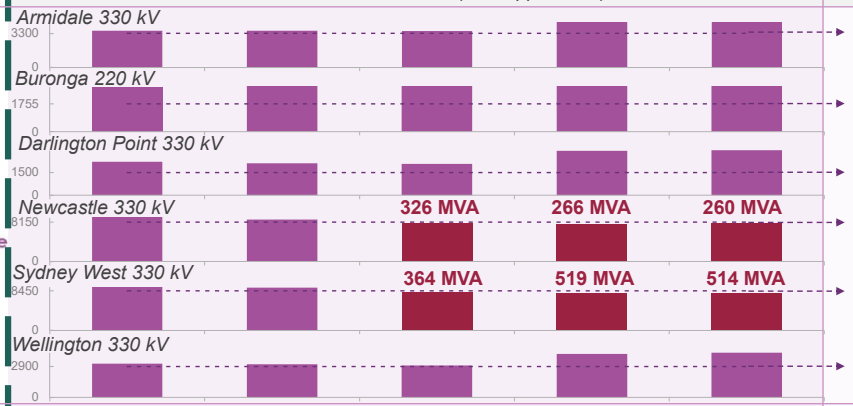
Assessment horizon

NSCAS assessment *(See Appendix 2)*

Long-term assessment

System strength – *nodal assessment*
(minimum fault current in megavolt amperes [MVA])





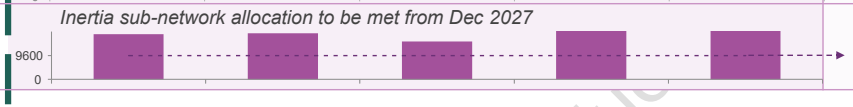
Minor system strength deficits have been identified even with the delivery of the Phase 1 synchronous condensers. Transgrid are pursuing additional options such as contracting generation to manage these minor deficits.

Long Term, system strength procurement is managed by the RIT-T process.

Transgrid have published the Material Change in Circumstances (MCC), which has updated the preferred option, but also raised some concerns about the commercial feasibility of the Phase 2 synchronous condensers.

The preferred option identified in the MCC includes contributions from grid forming inverters to the minimum fault level requirements, subject to confirmation of technical feasibility.

Inertia (MWs)



Through the delivery of synchronous condensers with significant inertia, there is low risk of inertia deficits.

Other system attribute assessments

Thermal limits

AEMO has confirmed a reliability and security NSCAS gap

This gap has been declared in 2029-30 and is driven by retirement of Eraring and exacerbated by risk of delayed delivery of anticipated projects, potential decommitment of a second coal station and progressive demand growth. Supply to the Sydney, Newcastle and Wollongong load center is limited by the thermal capacity of the transmission network from the south of New South Wales.

The AEMO is declaring a NSCAS RSAS gap with a trigger date of 1 November 2029 and an NSCAS tender date of 1 May 2028. This trigger date has been set for the beginning of NEM summer post Eraring retirement.

Transition points

CWO REZ

Eraring exit

NSW 2nd coal station offline

NSW 3rd coal station offline

Requirements | Available level | Deficit

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Central-West Orana Renewable Energy Zone (CWO REZ)

Dec 2028

New South Wales

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability

Not Applicable

- Resource adequacy

Context

REZs facilitate the transmission network development necessary to enable coordinated development of bulk renewable generation and storage. The CWO REZ is approximately 20,000 square kilometres centred by Dubbo and Dunedoo[A]. Its scale and technical complexity will materially change New South Wales network topology and operational characteristics, warranting inclusion as a transition point.

Connecting to the NEM via two double circuit 500 kV lines terminating at Barigan Creek Switching Station, CWO REZ will initially export up to 3 GW of transfer, increasing to 4.5 GW following Hunter Transmission Project (HTP) commissioning. Longer-term capacity of 6 GW is intended following further transmission buildout.

Thirteen variable renewable energy (VRE) and storage projects have been granted access rights, totalling 7.15 GW capacity[B]. Seven 240 megavolt amperes (MVA) synchronous condensers will provide system strength, voltage support and approximately 12,775 MWs of inertia. Together, these assets represent the NEM's largest transmission development and coordinated deployment of IBR and synchronous condensers to date.

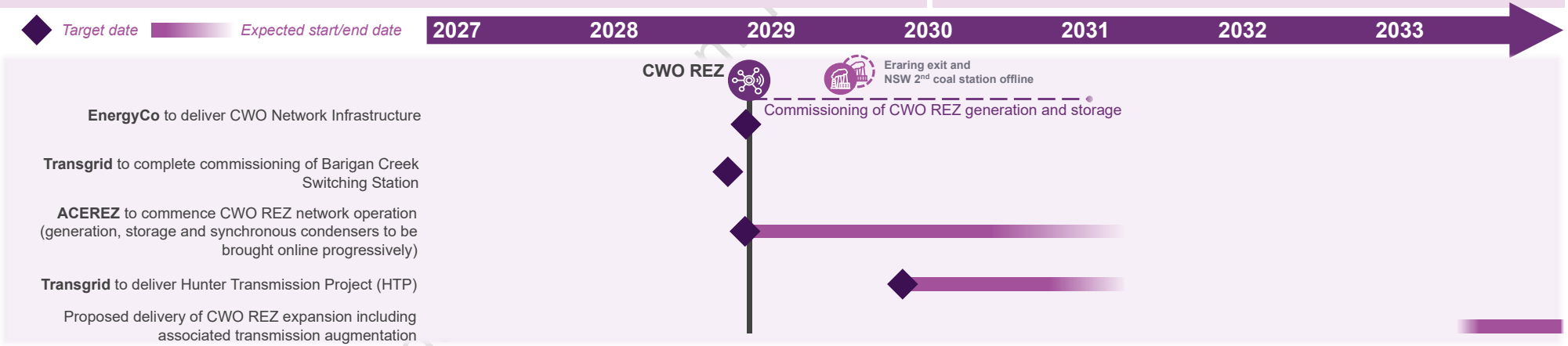
Impact

CWO REZ represents a material change in power flow patterns, voltage control arrangements and dynamic system behaviour of the New South Wales and NEM power systems.

Preparatory actions

CWO REZ integration involves significant engineering to address system security implications, with findings that can inform future decision-making in the NEM:

- **AEMO** to continue connections assessments to evaluate CWO REZ generator performance across a range of operating conditions and contingency events.
- **ACEREZ** to continue integration studies to identify issues or changes to the power system characteristics that need collective engineering effort to resolve.
- **EnergyCo, AEMO, Transgrid** and **ACEREZ**, via formal governance arrangements, to continue coordinating planning, connection and integration requirements between parties, to ensure secure and timely connection of the REZ.
- **AEMO, ACEREZ** and **Transgrid** to ensure operational readiness of CWO REZ, including integration into AEMO's Energy Management System (EMS), limits advice development, AEMO constraints library, settlements process, NEM Dispatch Engine (NEMDE) and contingency analysis.
- **Transgrid** and **EnergyCo** to complete timely delivery of transmission augmentation to enable full CWO REZ export capability including HTP and CWO REZ Network Infrastructure Project[C].



A. For more information, see https://www.energyco.nsw.gov.au/our-projects/central-west-orana-rez/about.
B. AEMO now considers the Hunter Transmission Project anticipated, as it is progressing towards meeting at least three of the five committed project criteria.
C. For more information, see https://www.energyco.nsw.gov.au/industry/access-schemes#rights-energyco-access-rights-register--june-2026.xlsx.
D. For more information, see https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

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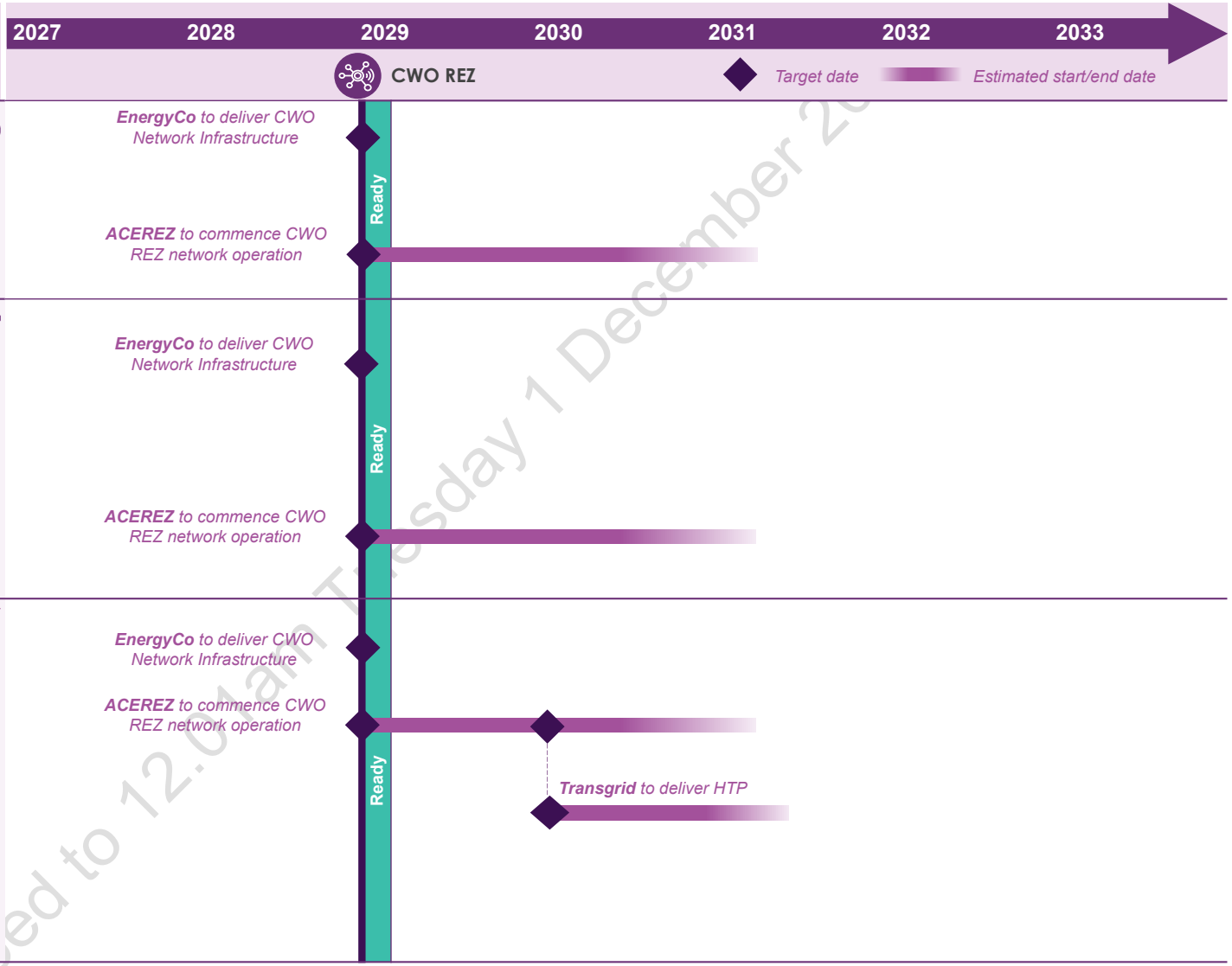
Central-West Orana Renewable Energy Zone (CWO REZ)

New South Wales

Moderate readiness



System strength

The CWO REZ incorporates seven synchronous condensers that will provide a strong electrical reference to the connected IBR. The units will a provide synchronous fault current contribution and dynamic reactive power that supports voltage. This delivers the system strength required for each generator connection point within the REZ and contributes to minimum three phase fault current for the broader New South Wales network.

Frequency and inertia

The CWO REZ Network Operator is not the designated system security service provider for New South Wales and is therefore not required under NER system security frameworks to deliver specific inertia outcomes. The procured synchronous condensers were specified with heavy flywheels, providing a significant amount of inertia to New South Wales and contributing to broader frequency performance.

AEMO is undertaking further assessment to understand the dynamic performance implications of concentrating significant inertia and frequency response from synchronous condensers and IBR within the remote radially connected REZ. Related considerations are discussed in the transient and oscillatory stability section below.

Voltage control

CWO REZ has a voltage control strategy that has been endorsed by all stakeholders and provides confidence to AEMO and TNSPs that power system security obligations can be met.

Given close electrical coupling between synchronous condensers, BESS and other IBR within CWO REZ, coordinated voltage control is preferred over individual changes to plant setpoints. The coordinated voltage control design minimises risk of hunting, interactions between assets and losses. It prioritises stable steady state voltage control and improves overall response. It enables a well damped aggregate response and reduces risk of operator error.

CWO REZ Network Operator will manage its network voltage and reactive power reserves while cooperating with AEMO to aid with system voltage control. Reactive power margins are location-dependent, thus the REZ reactive contribution provides limited support to constrained load-centre areas.

Embargoed to 12.01am Tuesday 1 December 20

Central-West Orana Renewable Energy Zone (CWO REZ)

New South Wales

Moderate readiness



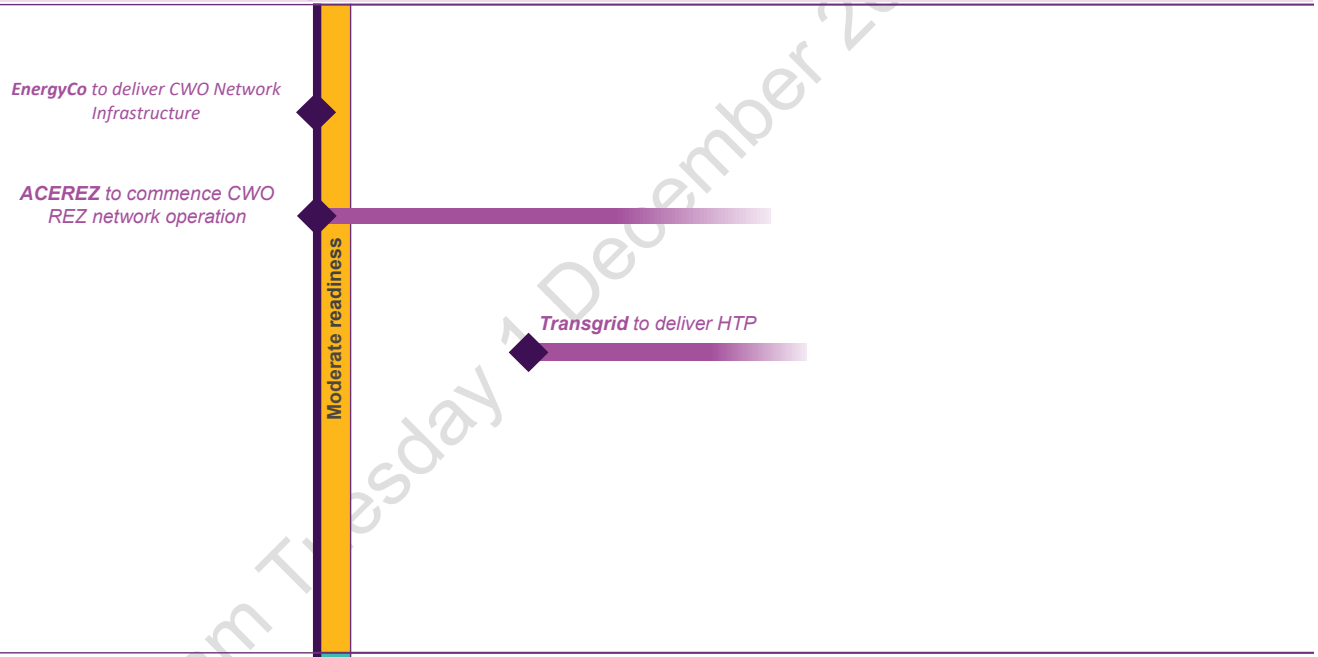
Transient and oscillatory stability

The CWO REZ topology and asset mix risk introducing new dynamic interactions within the New South Wales region, with potential implications for inter-area modes, active power swings, and system damping.

ACEREZ are undertaking significant power system studies to identify dynamic responses that may require further investigation. Synchronous condensers can introduce negative damping to a system, and ACEREZ studies indicate that this effect is observed with CWO REZ synchronous condensers online, although the system remains damped. Power oscillation dampers can be enabled on CWO REZ synchronous condenser controls to enhance damping of power swings. However, as more synchronous condensers are connected across the NEM, a whole of system approach is required to ensure system damping is maintained[A].

The large concentration of IBR in the REZ, particularly BESS, if set with aggressive primary frequency response (PFR)/fast frequency response (FFR) settings, could cause interactions with other NEM plant under major loss of generation or load contingency conditions. Uncertainty remains regarding the impact of the combined active power response from these assets. AEMO is collaborating with NSPs, including ACEREZ, to progress modelling and understanding of these issues.

Consideration will be given to the effects on transient and oscillatory stability of the coincident retirement of Eraring Power Station from the New South Wales power system[B].



System restoration

CWO REZ was not designed and is not under any regulatory obligation to provide system restart capability. However, the concentration of system restoration-enabling capabilities within CWO REZ presents an opportunity to support future restoration strategies. Its asset mix has the potential to support the system restoration processes.

Significant engineering work would be required to provide system restoration capability, including altering the performance standards imposed on generators to enable the use of this REZ during restart. Further assessment of the role of REZ-based resources in future system restoration processes is a body of work identified within the Engineering Roadmap workplan[C].



Embargoed to 12:01am Tuesday 1 December 2026

A. Refer to Section 8.2 for further details.
B. Refer to Eraring exit for further details.
C. Refer to Section 9.2 for further details.

Central-West Orana Renewable Energy Zone (CWO REZ)

New South Wales

Moderate readiness

Operability

The CWO REZ is a purpose-built transmission network designed to accommodate generation projects connecting under the specific access rights framework. Its thermal capability supports power transfers across a broad range of operating conditions. Exports from the CWO REZ may alter regional power flows across New South Wales, and studies have identified export limits under certain operating conditions. Planned Transgrid augmentations and connection projects may alter these limits, requiring the New South Wales limits advice to be updated as these developments progress. ACEREZ and Transgrid are working to share the information required to support development of the updated limits.

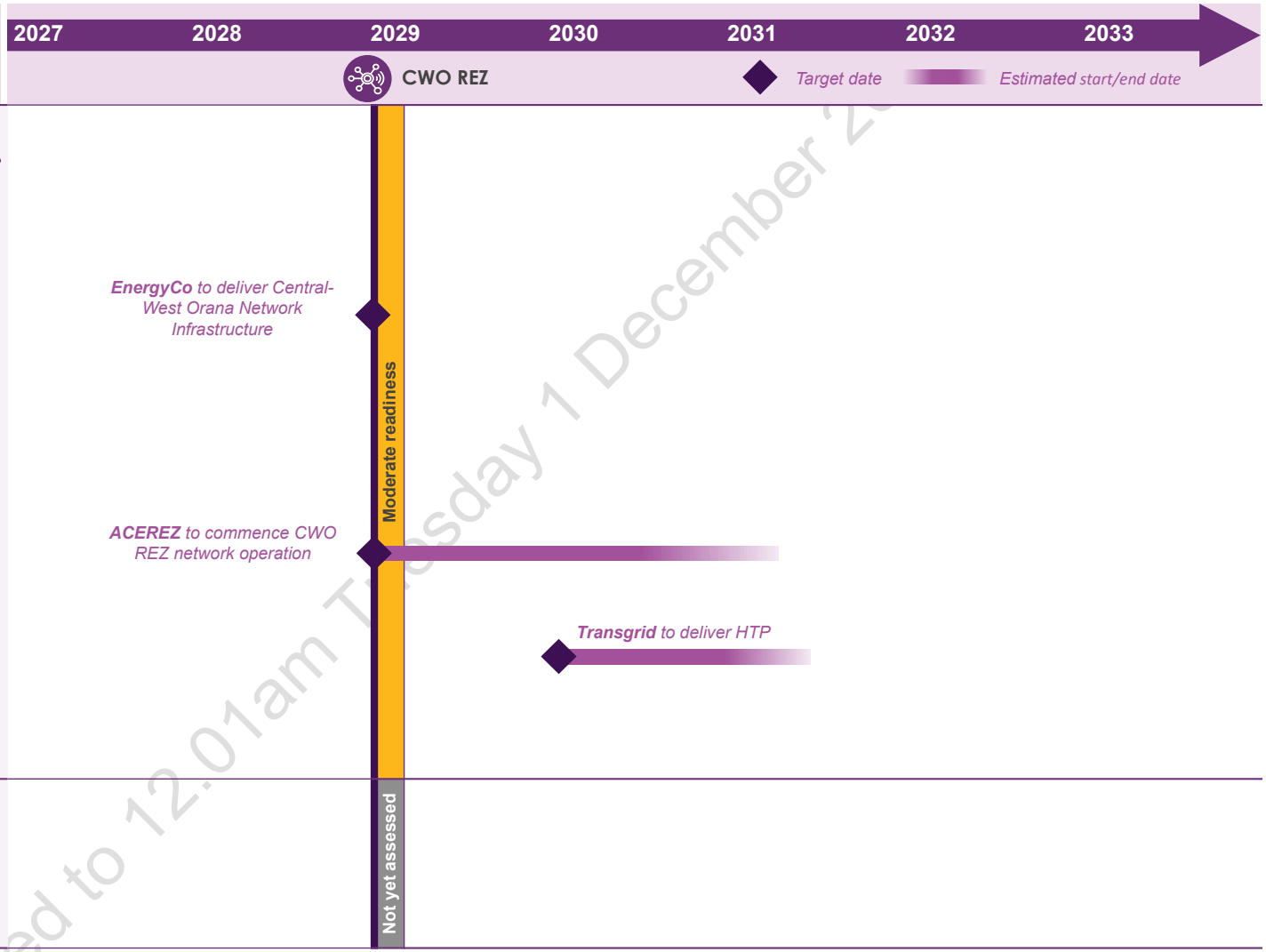
Given the scale and complexity of the REZ, early indicative limits advice would support operational readiness by identifying emerging constraints, informing resecuring requirements, and enabling timely development of operational procedures and mitigation measures.

In planning the network, non-credible contingencies should also be considered consistent with NER S5.1.8, with appropriate mitigation measures developed where material risks are identified. Transgrid has identified that an N-2 risk exists when high power flows occur on the 500 kV network between Barigan Creek and Bayswater after the connection of CWO REZ[A]. Joint planning is underway to consider wider system impacts and interactions, including any changes required for new or existing remedial action schemes. Where material risks cannot be appropriately mitigated through the planning process or managed through emergency controls, further assessment may be required through the GPSRR.

Resecuring arrangements should consider whether run-back and load shedding actions can be implemented within 30 minutes. Jurisdictions may also consider opportunities for flexible data centre loads to support rapid load shedding.

Resource adequacy

Not relevant for this transition point.



Embargoed to 12.01am Tuesday 1 December 2

A. For further information, see https://www.transgrid.com.au/tapr-2026/.

Eraring exit

April 2029

New South Wales

Moderate readiness

Assessed

System strength

Frequency and inertia

Voltage control

Transient and oscillatory stability

System restoration

Operability

Resource adequacy

Context

Since the 2025 TPSS, Eraring Power Station's planned retirement has been deferred from August 2027 to April 2029. The revised timing allows a longer preparation window, during which significant new generation, storage and system security infrastructure is expected to progressively enter service across New South Wales.

From a system security perspective, a key dependency for readiness is the timely delivery of Transgrid's system strength RIT-T Phase 1 synchronous condensers[A]. Latest advice from Transgrid is that delivery is on track prior to Eraring exit. AEMO's December 2026 ESOO Update[B] indicates that the reliability standard is met under the *Government Schemes and Actionable Developments* assessment but not the *Committed and Anticipated Developments* assessment, highlighting the importance of planned projects being delivered on schedule to maintain reliability and security.

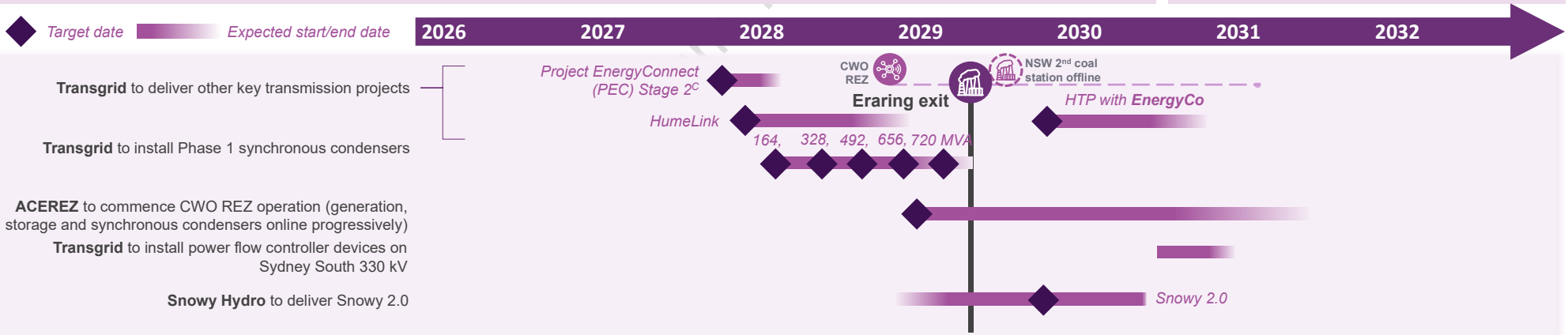
Impact

Eraring's closure will remove a significant amount of synchronous inertia, fault current, dynamic reactive capability and dispatchable generation from a strong part of the New South Wales network in Sydney-Newcastle. While Transgrid's Phase 1 synchronous condensers and network developments address most of the system security risks, targeted contracts and/or operational measures may be required under challenging scenarios to ensure adequate transfer capability, oscillatory behaviour, system resilience and overall operability.

Maintaining sufficient supply to the Sydney-Newcastle load centre is expected to become more dependent on having sufficient transfer capacity for accessing generation from the south and north. The timely delivery of planned network augmentation projects, such as HumeLink and HTP, will be critical to alleviating future transmission constraints. Additional operational measures – including constraints, new procedures and market interventions or instructions – may be required under challenging operational scenarios.

Preparatory actions

- **Transgrid** to continue facilitating timely delivery of Phase 1 synchronous condensers[A].
- **ACEREZ** to complete timely delivery of CWO REZ synchronous condensers and commence CWO REZ operation.
- **Market Participants** to progress timely delivery of committed and anticipated projects.
- **Transgrid** to complete timely delivery of HumeLink.
- **EnergyCo and Transgrid** to complete timely delivery of HTP.
- **Transgrid** to assess future operating limits and dynamic behaviour post-Eraring retirement well in advance of operational timeframes to provide early indication of the evolving technical operating envelope to AEMO.
- **AEMO** to perform due diligence on the limit advice.



A. For further information, see https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf.

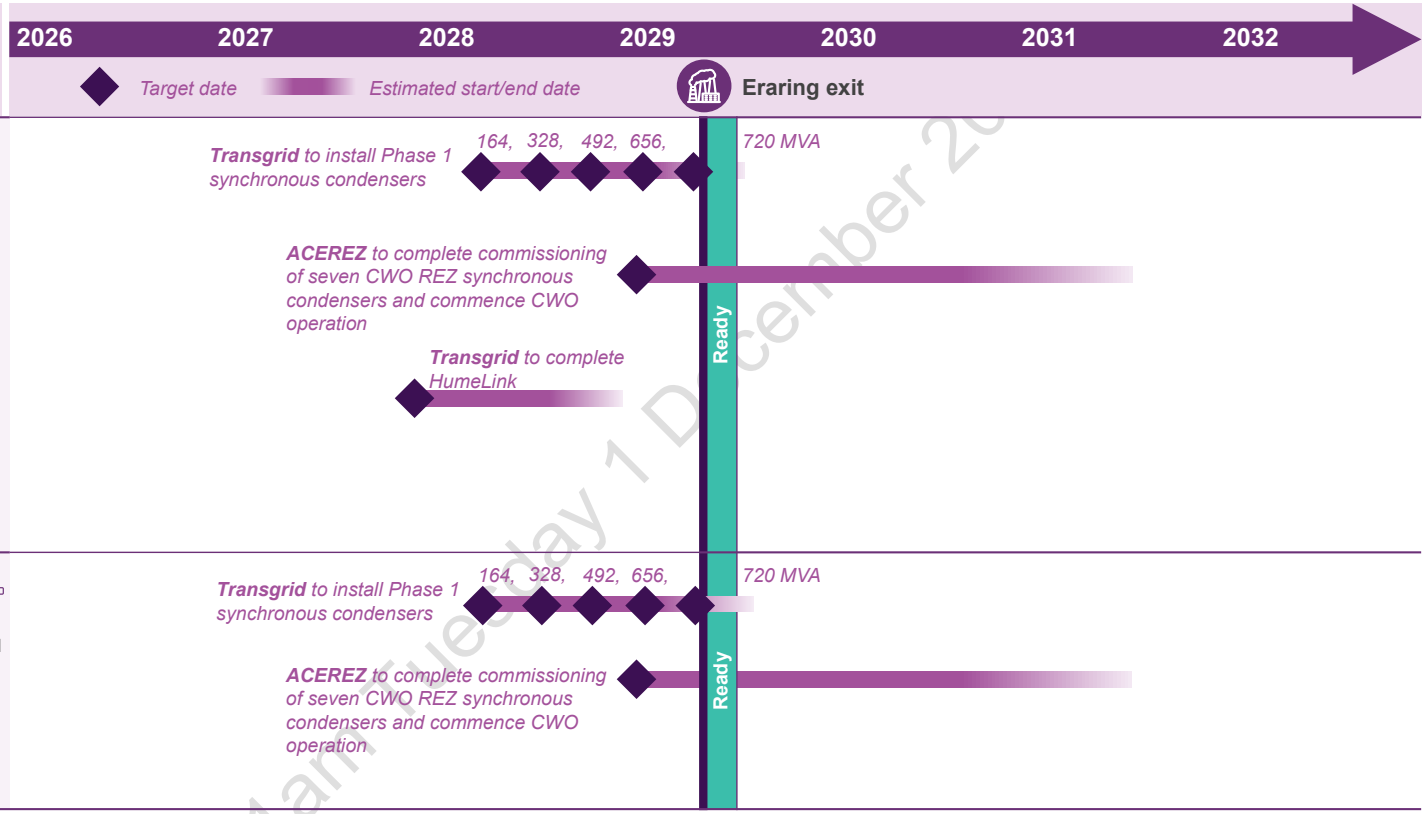
B. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

Embarg

Eraring exit

New South Wales

Moderate readiness



System strength

Since the 2025 TPSS[A], Eraring retirement has been deferred two years, allowing more time for TransGrid to fully commission Phase 1 synchronous condensers ahead of this transition point. System strength readiness will be supported by the progressive delivery of committed and anticipated synchronous condensers across New South Wales through to 2029 as part of Transgrid's System Strength RIT-T[B] and new REZs. These synchronous condensers are expected to significantly support fault current contribution and system strength across the New South Wales network, enabling system strength readiness post Eraring. This assessment is contingent on the timely delivery and commissioning of committed projects, particularly CWO REZ synchronous condensers and HumeLink, as well as the proposed modification of up to 650 megawatts (MW) of generation in New South Wales to enable synchronous condenser mode, as reported in Transgrid's System Strength Project Assessment Conclusions Report (PACR)[B].

Frequency and inertia

With the deferral of Eraring retirement, more committed and anticipated synchronous condensers equipped with flywheels are expected to be online prior to station closure. Therefore, this transition point is not anticipated to result in an inertia shortfall in 2029-30. Frequency control is expected to remain adequate as BESS continue to enter the market and provide increasing levels of FFR services.

Embargoed to 12.01am Tuesday 1 December 20

A. See https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-transition-plan-for-system-security.pdf.

B. For further information, see https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf.

Eraring exit





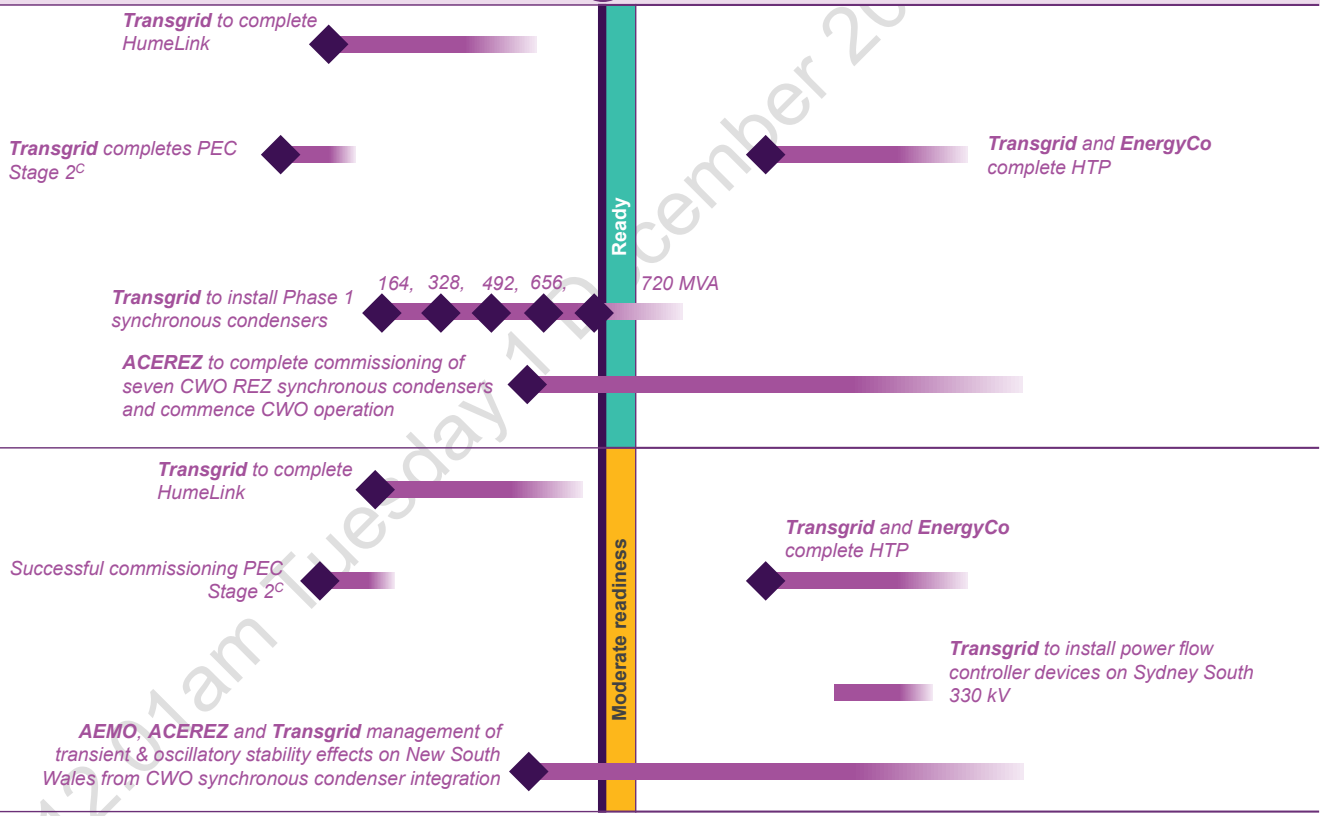
Voltage control

Eraring's retirement will reduce available dynamic reactive power support in a central part of the network and will materially change power flow patterns across the system. As a result, voltage-related transfer constraints may begin to bind during system operation. As maintaining reliability becomes increasingly reliant on power transfers into Sydney and Newcastle load centres from remote generation sources, the management of dynamic reactive power flows and sources is expected to become increasingly important in maintaining adequate reactive power margins.

Additionally, NSCAS results show that material thermal overloads are expected to emerge under high-demand conditions along the 330 kV corridor south of Sydney, for which a gap has been declared[A]. However, the underlying cause of these thermal challenges is the transmission line overloads; mitigation of these thermal overloads are also expected to materially alleviate the associated voltage control challenges in the area.

Transient and oscillatory stability

Available preliminary AEMO assessments indicate that Eraring's retirement is unlikely to reduce existing interconnector transfer limits due to transient or oscillatory stability within the scenarios assessed. Further assessment from Transgrid as soon as practically feasible is required to confirm whether existing transfer limits within New South Wales, particularly in and around Sydney, remain appropriate under post-Eraring operating conditions. AEMO and Transgrid will need to coordinate their respective planning and operational activities sufficiently ahead of retirement, so that any necessary updates to stability limits and operational arrangements can be implemented or mitigated as required. Consideration should be also given to the effects on transient and oscillatory stability of the coincident introduction of CWO REZ to the New South Wales power system[B].



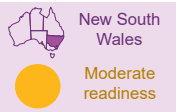
Embargoed to 12:01am Tuesday 15 December 20

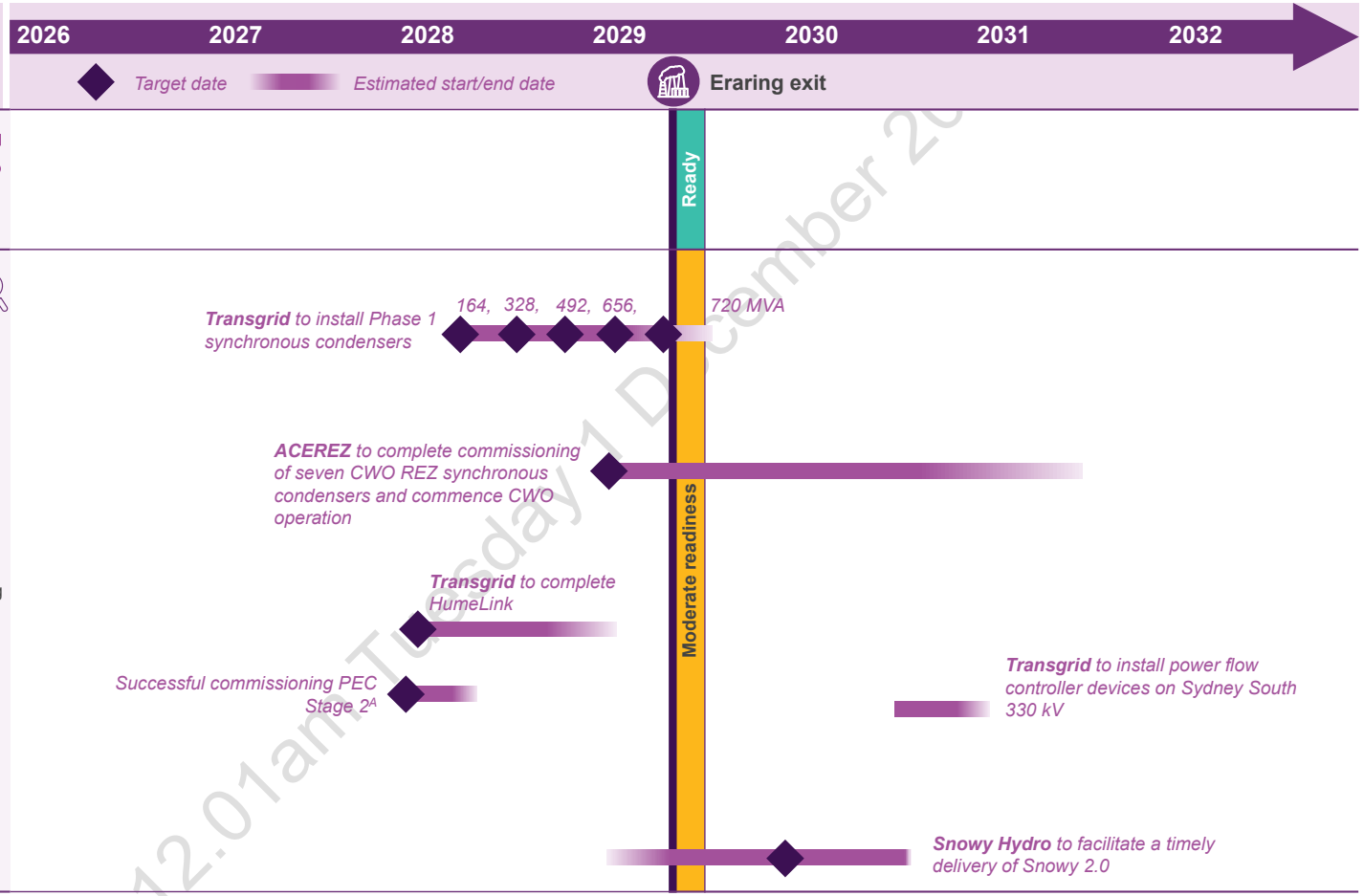
A. For further information, see Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

B. For further information, see Central-West Orana Transient and Oscillatory Stability.

C. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

Eraring exit





System restoration

Existing system restoration strategies, procedures and capabilities are expected to remain sufficient to support restoration requirements following Eraring's retirement.

Operability

The complexity of operating the New South Wales power system is expected to increase materially with the exit of Eraring and delayed commissioning of Snowy 2.0, particularly during any prolonged renewable lulls. Once available, Snowy 2.0's ability to supply energy will help reduce operational complexity during such events, providing a buffer to shift energy across weeks and months during prolonged periods of low renewable generation.

Additionally, as generation is increasingly located further from the Sydney-Newcastle load centre, maintaining system security may become more operationally challenging. Changing power flow patterns may result in voltage and transient stability limits binding more frequently. Under high demand conditions constraints on the 330 kV corridor south of Sydney are expected to manifest more often, reducing operational flexibility and materially increasing the potential need for operational interventions or instructions.

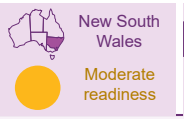
The extent of these challenges remains uncertain, as the post-Eraring operating envelope is yet to be fully defined by Transgrid. While detailed operational limits will be established closer to Eraring's exit, early development of planning limits would provide insight into how operability, resilience and flexibility may evolve, allowing more proactive planning and timely identification and development of necessary mitigation measures.

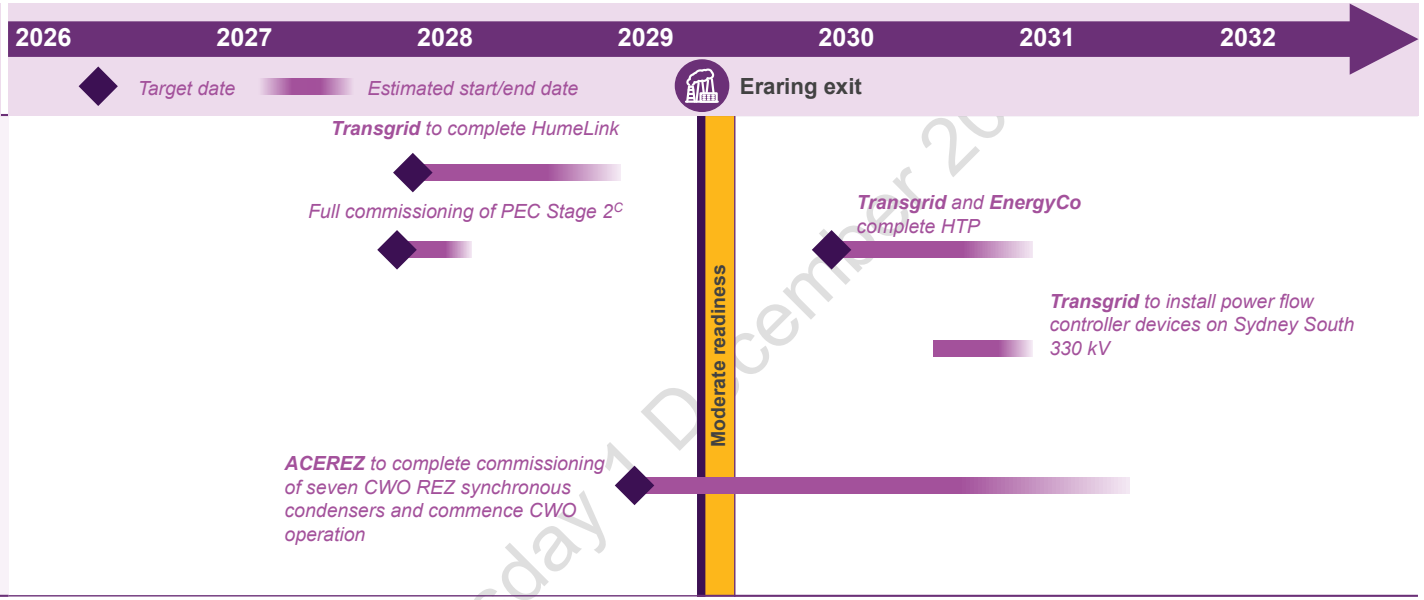
As reliance on storage and demand-side resources increases, resilience during prolonged system stress will depend on their effective coordination, with longer-duration storage, including Snowy 2.0, expected to play an increasingly important role.

Embargoed to 12.01am Tuesday 1 December 20

A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results

Eraring exit





Resource adequacy

Under the *Committed and Anticipated Developments* assessment in the December 2026 ESOO Update[A], the reliability standard is not met from 2029-30 following Eraring's closure. The standard is met under the *Government Schemes and Actionable Developments* assessment, highlighting the importance of planned projects being delivered on schedule to maintain reliability. The 2026 NSCAS[B] assessment also identified a gap from 2029-30 associated with the thermal capacity of the southern 330 kV corridor supplying Sydney, triggered by Eraring's closure. This highlights the need for sufficient transmission capacity to enable replacement generation and storage to supply the Sydney load centre following Eraring's closure.

Resource adequacy risks may emerge across seasons, particularly during periods of low renewable generation during winters as heating loads increasingly electrify and while solar production is lower due to shorter days. Continued investment in a broad suite of energy generators, network investments and coordinated consumer responses will provide the best mechanism to ensure energy availability and resource adequacy as coal generators such as Eraring exit.

Embargoed to 12.01am Tuesday 1 December 20

A. See 2026 ESOO Update, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
B. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.
C. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

NSW 2nd coal station offline

July 2029

New South Wales

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability
- Resource adequacy

Context

In addition to the exit of Eraring, the 2026 ISP[A] *Step Change* scenario projects a reduction of 1,320 MW of New South Wales coal generation capacity in 2029 to support achievement of government policies, contingent on the projected delivery of generation, storage, and network investments. Since publication of the ISP, however, the announced delay to Snowy 2.0 has changed the circumstances affecting the timing of any decommitment. While AEMO has not received a notice of closure, an unexpected decommitment remains possible, particularly following a significant plant failure or unplanned outage, and it remains prudent to prepare for this possibility.

The timing of this transition point compounds major changes to the New South Wales power system, including CWO REZ and Eraring transition points, and uncertainty regarding the revised plan for delivery of proposed Phase 2 synchronous condensers and Snowy 2.0.

Impact

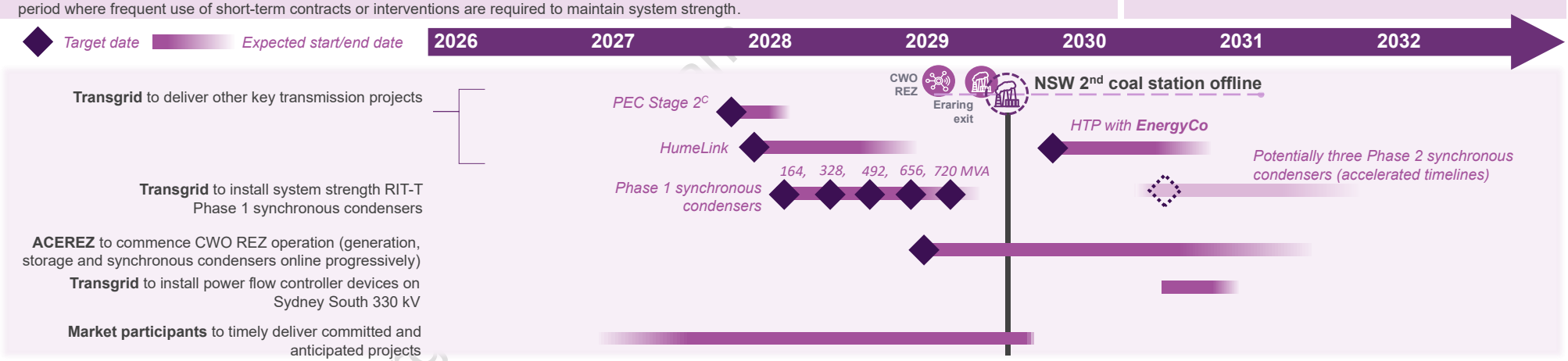
The decommitment would remove a large synchronous source of fault current, inertia, stabilising controls, and dynamic reactive power capability located close to the Sydney and Newcastle load centres. New generation is expected to mostly be IBR located further away from load centres, which may make secure operation more challenging under some operating conditions.

Preliminary AEMO studies indicate that this transition point is unlikely to materially reduce interconnector transfer limits due to transient or oscillatory stability within the scenarios assessed. However, the implications for transfer limits within New South Wales, voltage control requirements, operational security frameworks and system restoration remain subject to further assessment by AEMO and Transgrid. The operating envelope following this transition point is still being defined, and future limits advice will help determine whether new operational constraints or mitigation measures are required.

To be ready for this transition point to occur, preparations for Eraring's exit will need to be completed along with HTP and/or complementary transmission reinforcement. A timing mismatch between further coal generator decommitment and the delivery of Transgrid's planned system strength portfolio[C] may create a period where frequent use of short-term contracts or interventions are required to maintain system strength.

Preparatory actions

- **Transgrid** to progress preparation and delivery of its planned portfolio of system strength solutions.
- **Transgrid** to provide planning limits to AEMO to support operational readiness assessments prior to operational timeframes and enable the identification and implementation of any required mitigation measure.
- **EnergyCo, ACEREZ, AEMO** and **New South Wales Government** to ensure the secure and timely connection of the CWO REZ and its connecting generation.
- **EnergyCo** and **Transgrid** to ensure timely delivery of HTP which will support power supply to load centres.
- **AEMO** to progress system restoration workplan to ensure objectives of system restoration standard can be met under the post-transition point system configuration.



A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

B. For more information, see https://www.transgrid.com.au/media/m5ycbumc/260825_transgrid_system-strength_final-mcc-report-1.pdf.

C. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

Embargo

NSW 2nd coal station offline

New South Wales

Moderate readiness

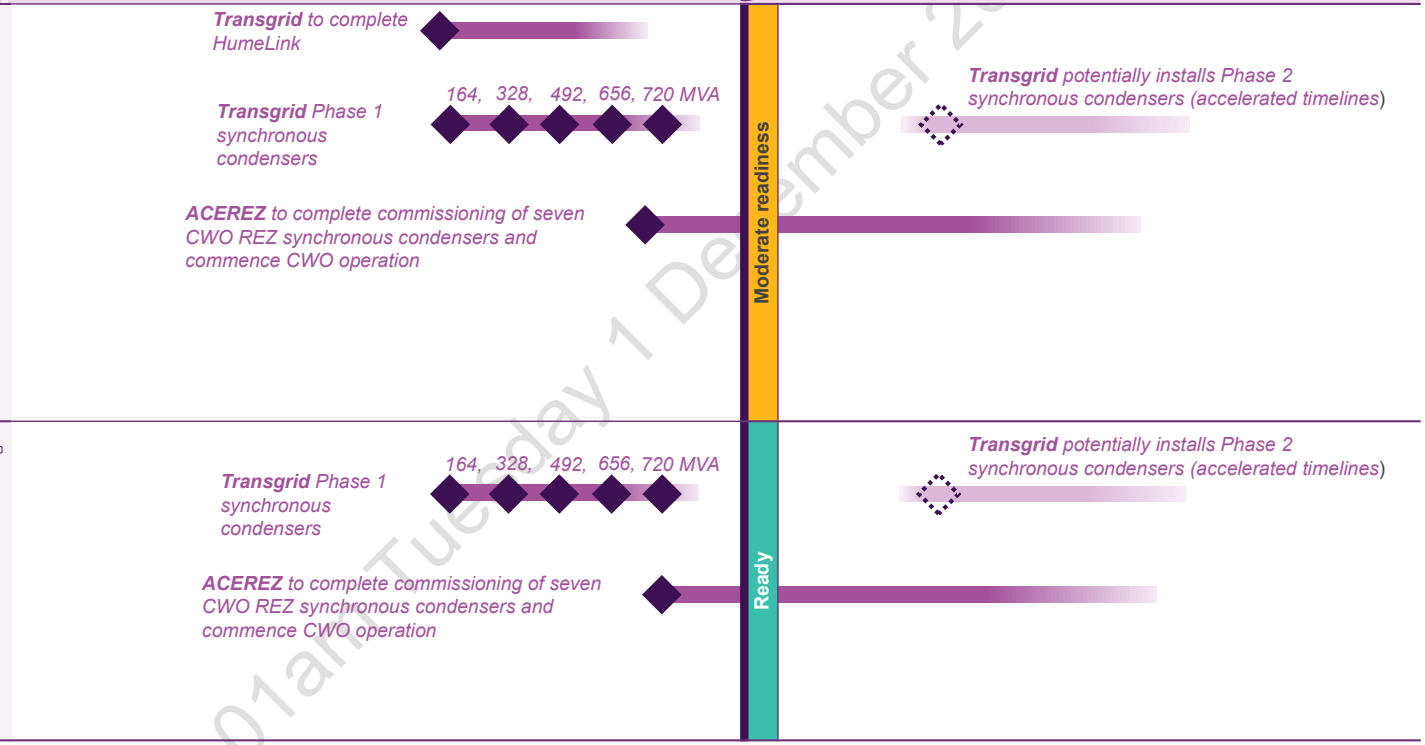


System strength

Maintaining minimum levels of system strength for this transition point depends on timely delivery of system strength related actions required prior to Eraring retirement, as well as supplementary provisions from contracting existing synchronous generators to either operate in synchronous condenser mode or run at minimum power[A]. These additional contracts or market interventions may be needed to cover shortfalls in system strength if synchronous units are unavailable, such as during prior-outage periods, or if market conditions sufficiently incentivise the remaining units to run two-shifting operation. The duration and impact of these market shortfalls depend on the actual coal units' availability in real time. Further resilience will be provided by the subsequent CWO REZ synchronous condensers planned from mid 2029.

Frequency and inertia

The on time delivery of Phase 1 synchronous condensers equipped with flywheels will offset the inertia reduction resulting from the second New South Wales coal generator decommitment as well as Eraring's retirement. As more synchronous condensers are installed, particularly those concentrated within CWO REZ, the distribution of inertia in New South Wales will materially change. The resulting changes to power system dynamic behaviour require further assessment by Transgrid and AEMO. Frequency control is expected to remain adequate, supported by significant growth in BESS and associated frequency response capability.



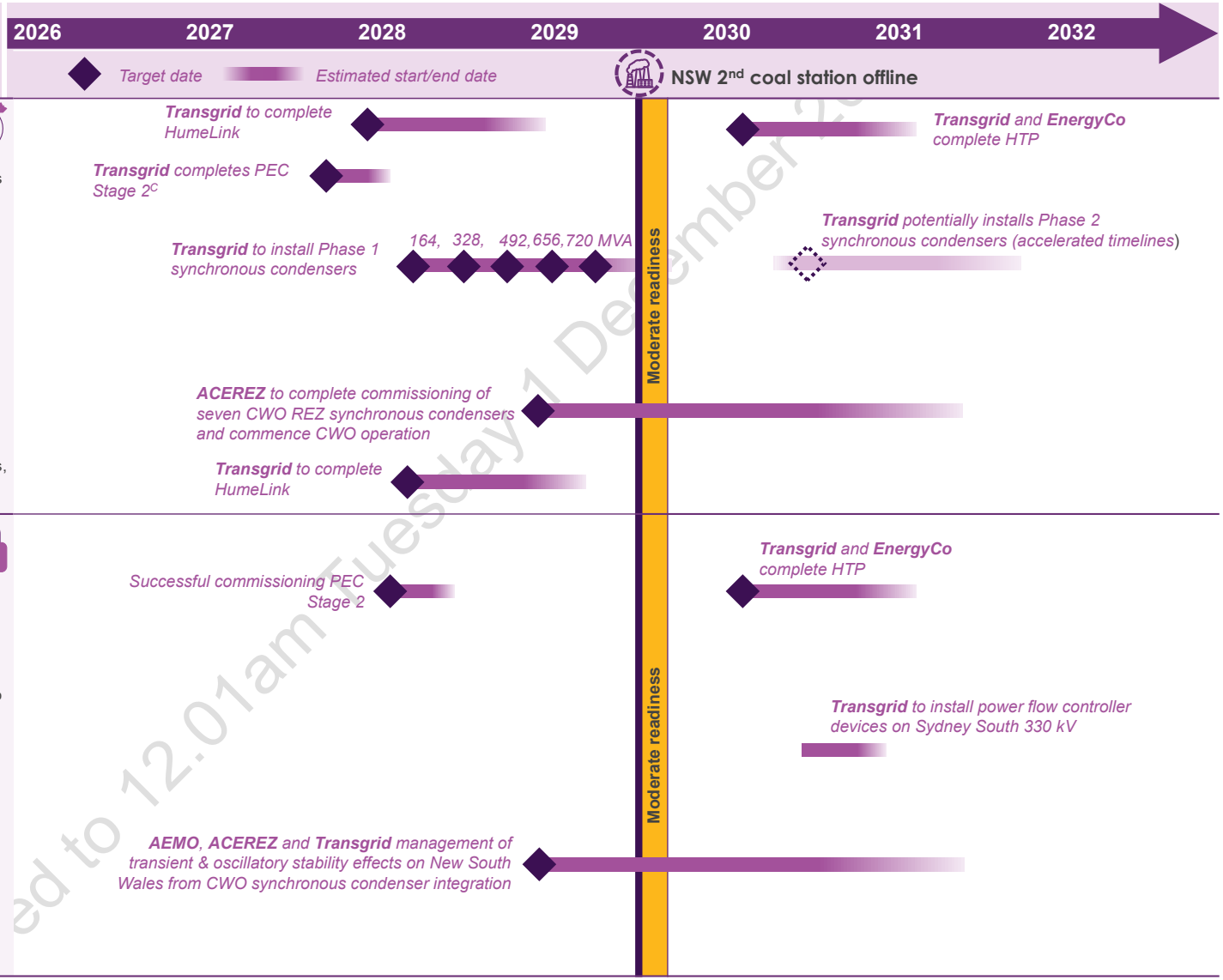
Embargoed to 12.01am Tuesday 1 December 2026

A. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

NSW 2nd coal station offline

New South Wales

Moderate readiness



Voltage control

Further coal generator decommitment around Eraring retirement date is expected to further reduce dynamic reactive power support. Impact would be dependent on the location of the decommitted generator, but would likely exacerbate voltage control challenges and increase voltage-related transfer constraints at a time of increasing reliance on remote generation to supply Sydney and Newcastle. Additionally, NSCAS results show that material thermal overloads are expected to emerge under high-demand conditions along the 330 kV corridor south of Sydney, for which a gap has been declared[A]. However, the underlying cause of these thermal challenges is the transmission line overloads; mitigation of these thermal overloads are also expected to materially alleviate the associated voltage control challenges in the area.

This period also coincides with substantial forecast growth in New South Wales data centre demand[A]. The performance of large Inverter Based Loads (IBL) introduces additional system security considerations, with actions to address these currently underway and planned[B].

Transient and oscillatory stability

Decommitment of a second coal-fired power station in New South Wales could materially change power flow patterns and reduce availability of system strength, inertia and dynamic reactive power capability. It may also remove controls tuned to manage oscillatory stability.

Preliminary AEMO studies indicate that this transition point is unlikely to materially reduce interconnector transfer limits due to transient or oscillatory stability within the scenarios assessed. Impacts on transfer limits within New South Wales have not yet been assessed and will depend on the location of offline coal units. Ahead of this transition point, further assessment of these future limits across a reasonable range of coal generator outage and dispatch combinations would be needed.

Any material stability limit found to be applicable post this transition point could reduce operational flexibility and available reserves, particularly during generation or network outages. AEMO will continue to support Transgrid ahead of decommitment to identify and implement any necessary changes to stability limits, operational arrangements or network assets, as well as identify mitigation options ahead of time as required

Embargoed to 12.01am Tuesday 1 December 2

A. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.
B. See Section 12.
C. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

NSW 2nd coal station offline

New South Wales

Moderate readiness

System restoration

While it will remain feasible to comply with Stage 1 of the system restart standard and form stable restoration islands, without further investment in or testing of alternative restoration pathways, it will be challenging to meet the Stage 2 system restoration MW targets as currently defined.

Detailed investigation and AEMO operational procedure assessment will be required to properly assess system capability. AEMO is developing a system restoration workplan to ensure resource adequacy for restart under anticipated conditions[A].

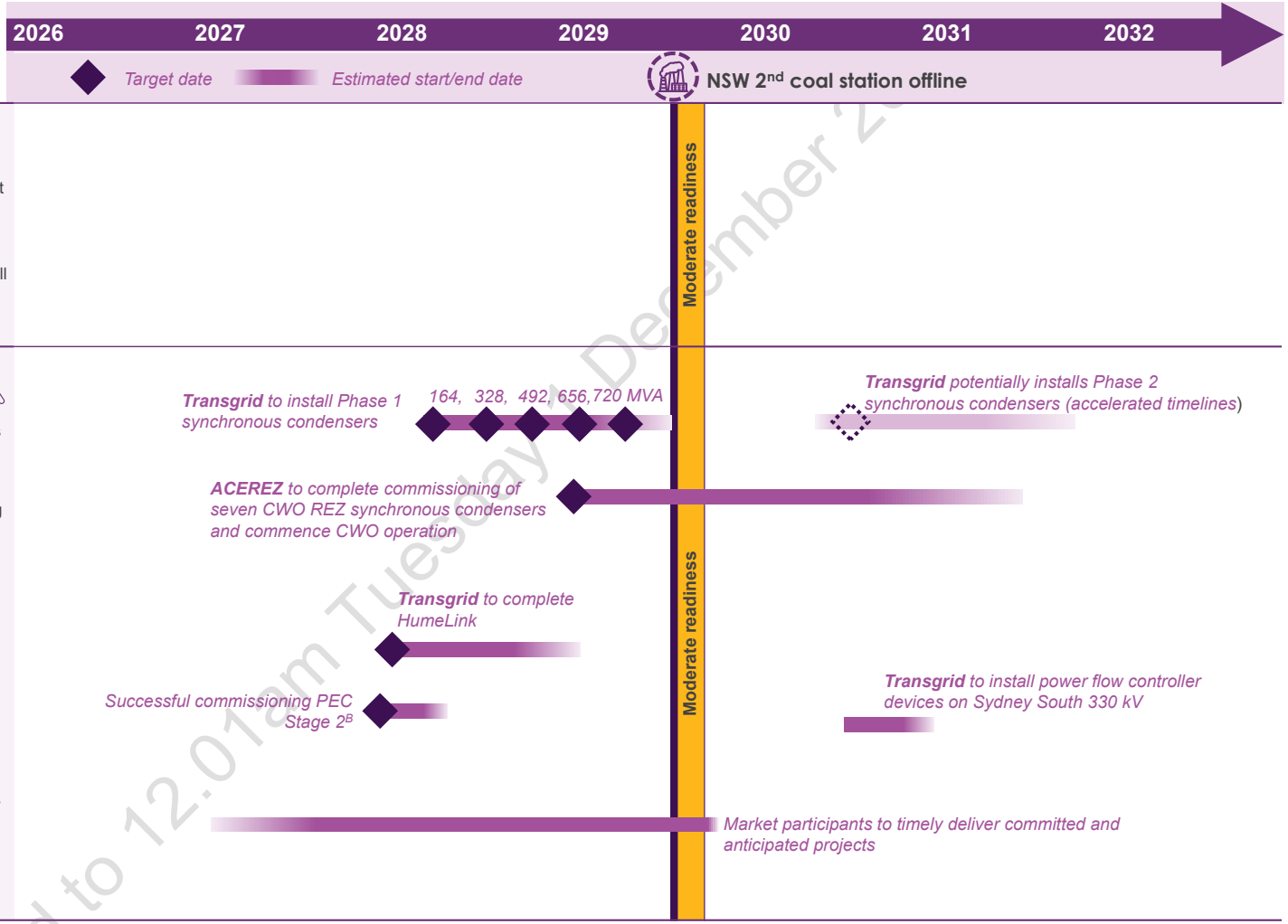
Operability

The decommitment of a second New South Wales coal power station is expected to further tighten the operating conditions identified following Eraring's retirement. Under challenging conditions, particularly prolonged periods of high demand and low renewable generation, the 2026 ISP projects that the system would become heavily reliant on long term storage, peaking gas and diesel generation, and demand-side response to maintain reliability across consecutive days.

Long-duration storage would be particularly important, as limited opportunities to replenish storage may progressively reduce available reserves. Effective coordination of storage state of charge, strategic reservoir management, and load response, together with careful management and timely replenishment of diesel reserves, would therefore be paramount to maintaining operational resilience post this transition point.

In line with the declared NSCAS gap associated with overloads on the 330 kV corridor south of Sydney, in order to reduce operational complexities, sufficient network transfer capability would be required to support the decommitment of a second coal power station and enable available generation and stored energy to be transferred to the Sydney-Newcastle load centres during challenging operating conditions.

Transgrid's early development of planning limits and future operating envelopes would support AEMO's assessment of operability risks, identification of infrastructure bottlenecks and timely development of mitigation measures where required.



Embargoed to 12.01am Tuesday, December 2

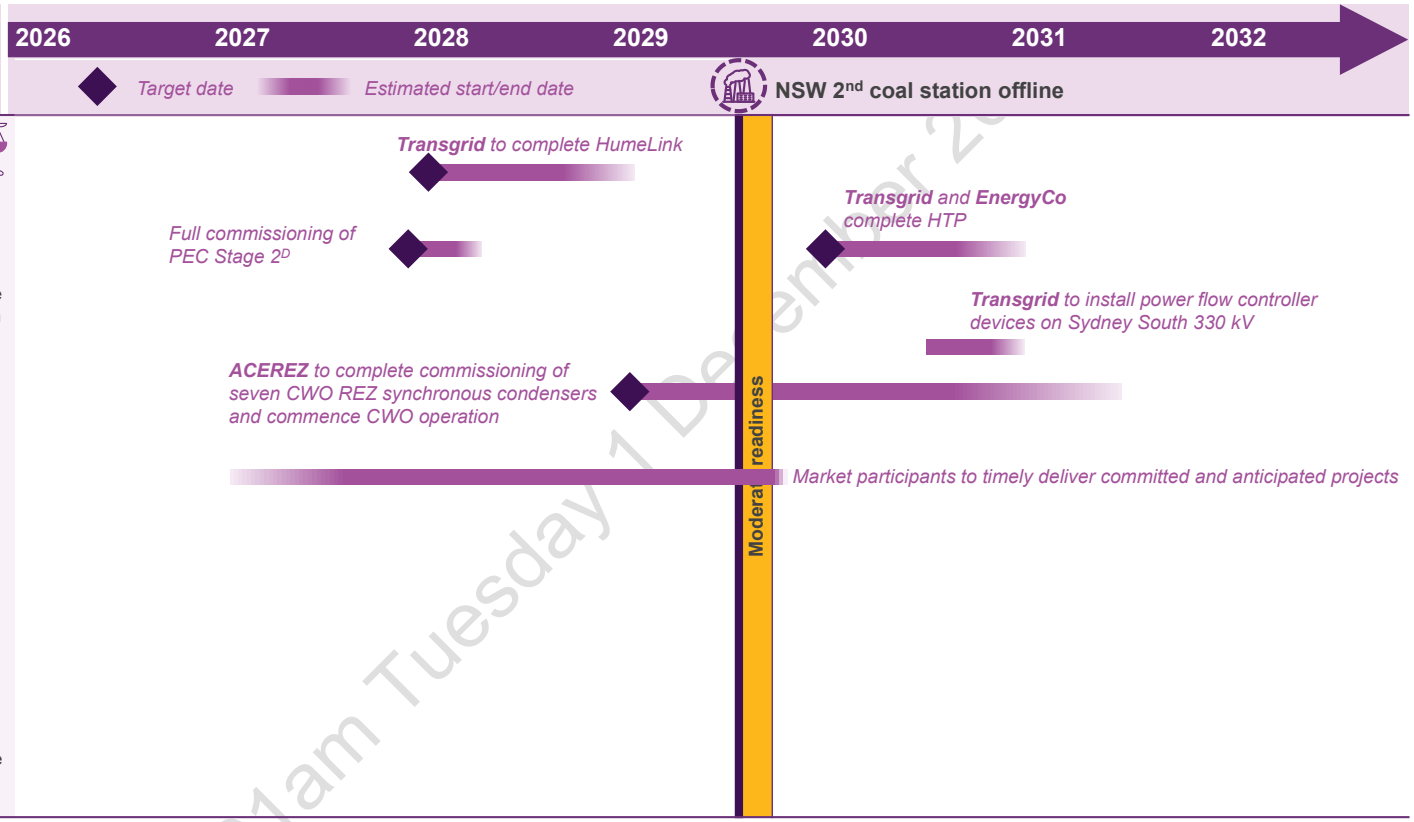
A. See Section 9.

B. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

NSW 2nd coal station offline

New South Wales

Moderate readiness



Resource adequacy

The December 2026 ESOO Update[A] *Committed and Anticipated Developments* assessment forecasts levels of expected unserved energy that exceed the Reliability Standard in New South Wales following the retirement of Eraring. With *Government Schemes and Actionable Developments* included, the standard is met, highlighting the importance of planned projects being delivered on schedule to maintain reliability.

Note that the ESOO Update[A] assumes coal capacity remains online until its announced withdrawal. A second coal station going offline in mid-2029, ahead of its currently announced withdrawal date, would require a substantial increase in new capacity above current developments to meet the generation portfolio projected in ISP *Step Change*. These further development opportunities are outlined in the 2026 ISP.

NSCAS assessment also identified that the decommitment of a second coal station would exacerbate thermal overloads on the southern 330 kV corridor supplying Sydney that emerge following Eraring's retirement.

Readiness for the second coal generator decommitment will depend on the timely delivery of new generation and storage capacity, supported by government schemes, alongside transmission developments identified as actionable in the 2026 ISP, to provide sufficient electricity generation, firming and operational flexibility.

The 2026 GSOO[B] shows that risks of peak day shortfalls in 2029, evolving into seasonal gas supply gaps from 2030, driven largely by the decline in southern gas production capacity, which materially limit operational flexibility of the gas system.

Embargoed to 12.01am Tuesday 1 December 2026

A. See 2026 ESOO Update, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

B. For more information, see https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp

C. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf?rev=58e84053c8d240a487cf274c91ebd284&sc_lang=en.

D. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

NSW 3rd coal station offline

July 2033

New South Wales — Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Resource adequacy

To be assessed

- Transient and oscillatory stability
- System restoration
- Operability

Context

The 2026 ISP *Step Change* scenario projects a further 2.7 GW of coal decommitment in 2033 to support achievement of government policies, contingent on the projected delivery of generation, storage, and network investments. Both Bayswater and Vales Point power stations have announced their intention to retire in 2033. Following this transition point, only two coal generating units would remain, leaving a credible possibility of operating with no coal generation online due to planned and/or unplanned outages. Industry needs to prepare for secure and reliable operation under these conditions.

Transgrid's revised system strength portfolio[A] in 2033-34 includes three Phase 2 synchronous condensers, 900 MW of GFM BESS contributing to minimum three phase fault current requirements. The Phase 2 synchronous condensers remain subject to commercial feasibility. The GFM BESS contributions depend on demonstration of technical feasibility[B] and are considered only to the extent that sufficient fallback hydro and gas re-dispatch is available.

Impact

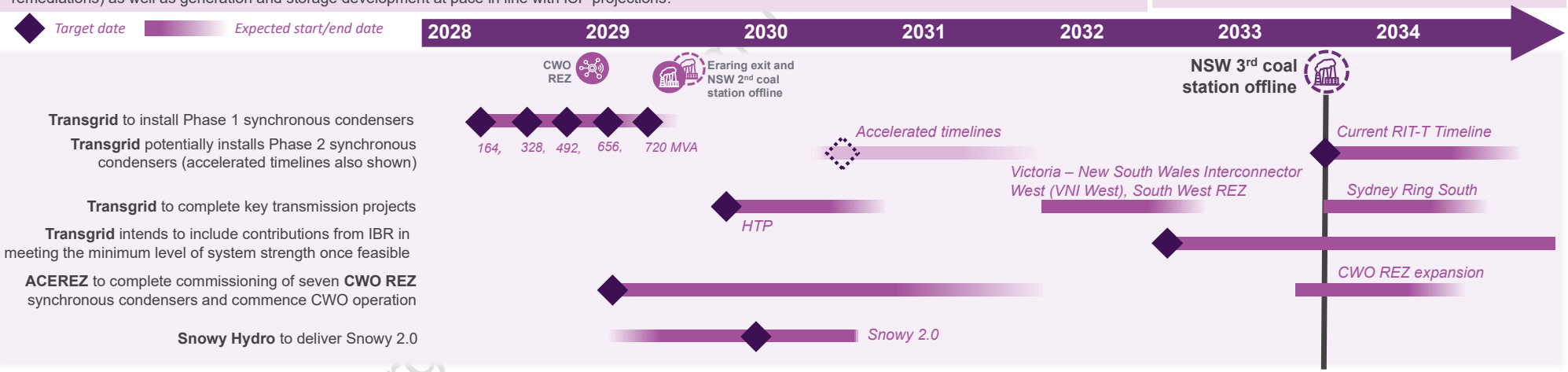
Like Eraring's exit and second coal generator decommitment, this transition point reduces dispatchable generation capacity, synchronous inertia, fault current, and dynamic reactive capability from close to the Sydney-Newcastle load centre. Changes in system security criteria and power flows will shift the technical operating envelope, increasing operational complexity and reliance on advanced support tools to maintain system security.

Uncertainties include delivery of Phase 2 synchronous condensers and the compatibility of GFM BESS with protection systems. In their absence, greater reliance on synchronous generator re-dispatch and market interventions may be required, potentially increasing costs for consumers. Reduced synchronous generation may increase restoration complexity as strategies and operational processes adapt to changing system characteristics. AEMO is progressing work through the Engineering Roadmap system restoration workplan[C] to prepare for restoration of the future power system.

Preparing for this transition point to occur at this time involves timely delivery of network infrastructure (including VNI West, Sydney Ring South and system security remediations) as well as generation and storage development at pace in line with ISP projections.

Preparatory actions

- **Transgrid** to deliver planned system strength portfolio in advance of this transition point.
- **AEMO** and **Transgrid** to continue joint planning to enable timely identification of the future network limits that may materially affect the ability to supply load under operational challenging scenarios and identify timely mitigations.
- **EnergyCo** and **Transgrid** to ensure timely delivery of HTP and development of Sydney South Ring (for **Transgrid** only) which will support power supply to load centres.
- **Market proponents** to consider impactful locations[D] north of 330 kV south corridor when assessing location of new projects - location can influence power flow patterns and either heighten or reduce future system security challenges
- **AEMO** to progress system restoration workplan.



A. See https://www.transgrid.com.au/media/m5ycbumc/260825_transgrid_system-strength_final-mcc-report-1.pdf.
B. See Section 5.
C. See Section 9.2

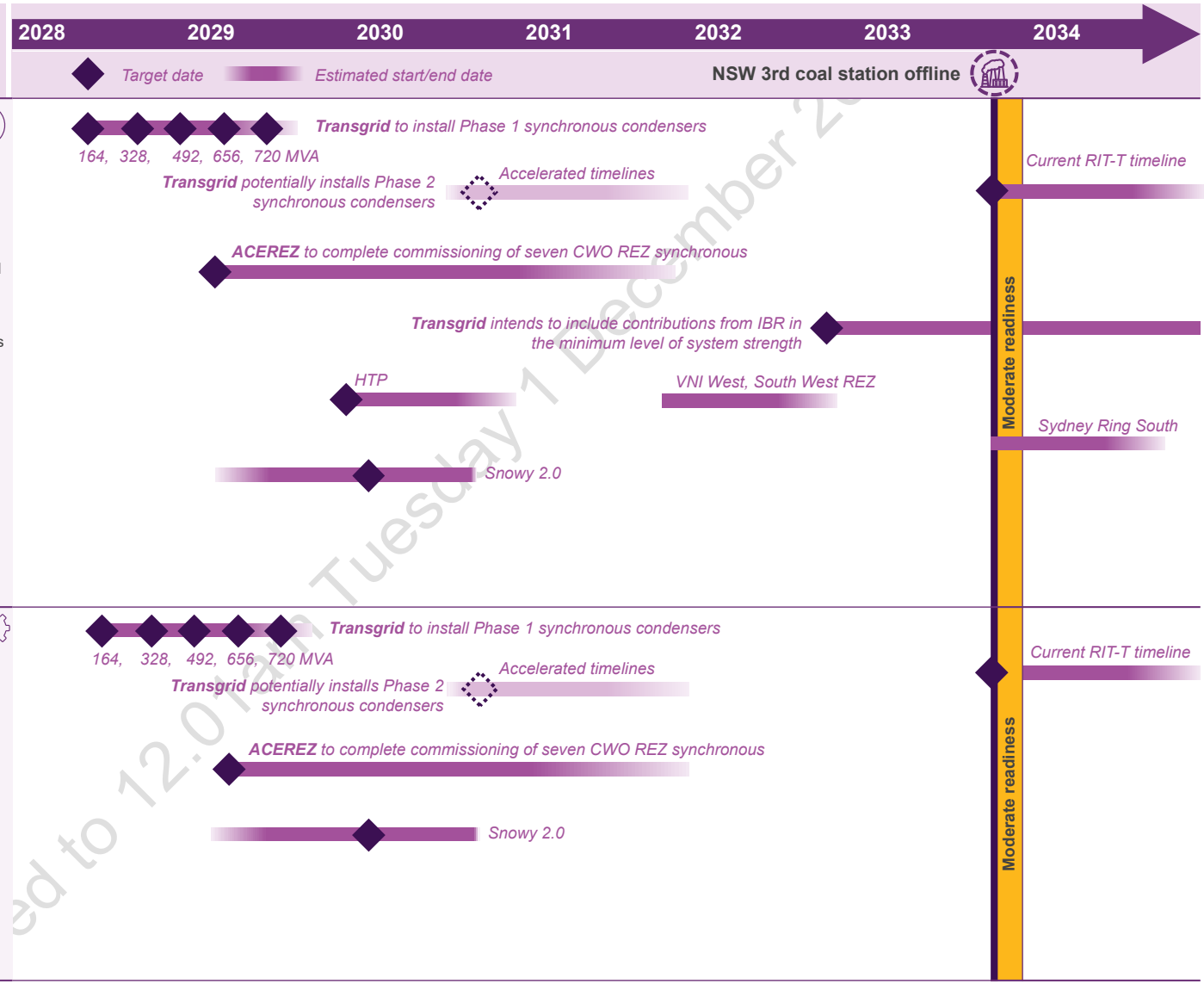
D. For more information see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/enhanced-locational-information and https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

Embargo

NSW 3rd coal station offline

New South Wales

Moderate readiness



System strength

Transgrid has indicated that the development of the preferred Phase 2 synchronous condensers identified in their RIT-T is no longer commercially feasible, as noted in their MCC which was triggered by material cost increases for synchronous condensers. Transgrid now proposes three Phase 2 synchronous condensers instead of five, one of which would support the future South West REZ IBR fleet, with GFM BESS contributing to the minimum three-phase fault level. If three synchronous condensers were not delivered prior to this transition point, according to Transgrid's MCC, the system would be exposed to system strength risk. Transgrid will continue to monitor for future MCCs which could reshape the preferred portfolio of options further.

At present, GFM are not proven to be capable of contributing to minimum three phase fault levels. AEMO, Transgrid and industry are working to progress this through a more detailed understanding of the technical needs underpinning each component of minimum three phase fault level and building the evidence base of the compatibility of GFM fault current with protection needs[A].

Transgrid has advised there is sufficient hydro and gas generation in the system to be re-dispatched as a fallback solution if GFM capability is not proven in time. The three Phase 2 synchronous condensers could be operational in 2033, under an assumed delivery timing which follows the standard NER process. This would alleviate the risks, provided that commercial feasibility is solved.

Frequency and inertia

As coal generators depart from the New South Wales system, additional inertia will be provisioned through synchronous condensers and their flywheels as well as synthetic inertia from GFM BESS. Committed synchronous condensers and their flywheels are expected to provide sufficient inertia under most conditions, with only extreme scenarios potentially not meeting the current sub-regional inertia requirements[B].

Uncertainty remains around inertia availability at this transition point. The CWO REZ Network Operator is not the designated system security service provider for New South Wales and is therefore not required under NER system security frameworks to deliver specific inertia outcomes via the CWO REZ synchronous condensers. The inertia capability of potential Phase 2 synchronous condensers is not yet specified, while the contribution from GFM BESS remains subject to further assessment. In addition, inertia requirements may evolve as the power system changes.

Embargoed to 12.01am Tuesday 1 December 2026

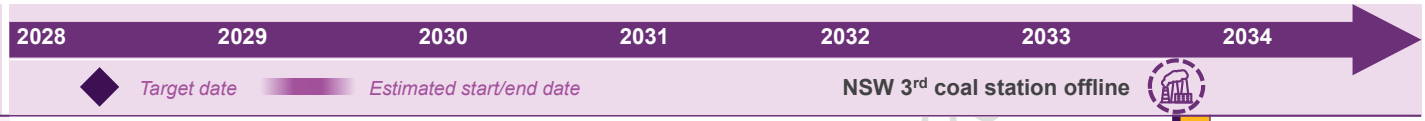
A. See Section 5.

B. For further information, see https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf.

NSW 3rd coal station offline



Moderate readiness



Voltage control

Future voltage control performance remains uncertain due to the evolving nature of future power system configurations, AEMO and TNSPs are expected to identify and assess potential issues through their planning activities well in advance as the transition points approach operational timeframe, allowing sufficient time to develop and implement any necessary mitigations or system enhancements.

When planning new generation and storage connections, market proponents should consider locational factors and target electrically strong parts of the network, such as the Hunter Valley region, where feasible.

Preliminary assessments indicate that timely delivery of Actionable ISP projects, including the HTP and Sydney Ring South, will be essential to maintaining adequate voltage-control margins around the Sydney load centre. Additional access to Queensland generation would provide firming capacity, supporting voltage control in northern New South Wales and the Sydney region, as well as relieving pressure and reliance from the 330 kV south corridor.

Under low variable renewable energy (VRE) conditions, reduced renewable generation availability will increase reliance on dispatchable generation, storage and interconnectors capacity, resulting in power flows channelled through a subset of corridors. Thus, voltage outcomes will increasingly depend on the location and dispatchable generation and storage along with the transmission infrastructure capability to transfer the available capacity to the load centres.

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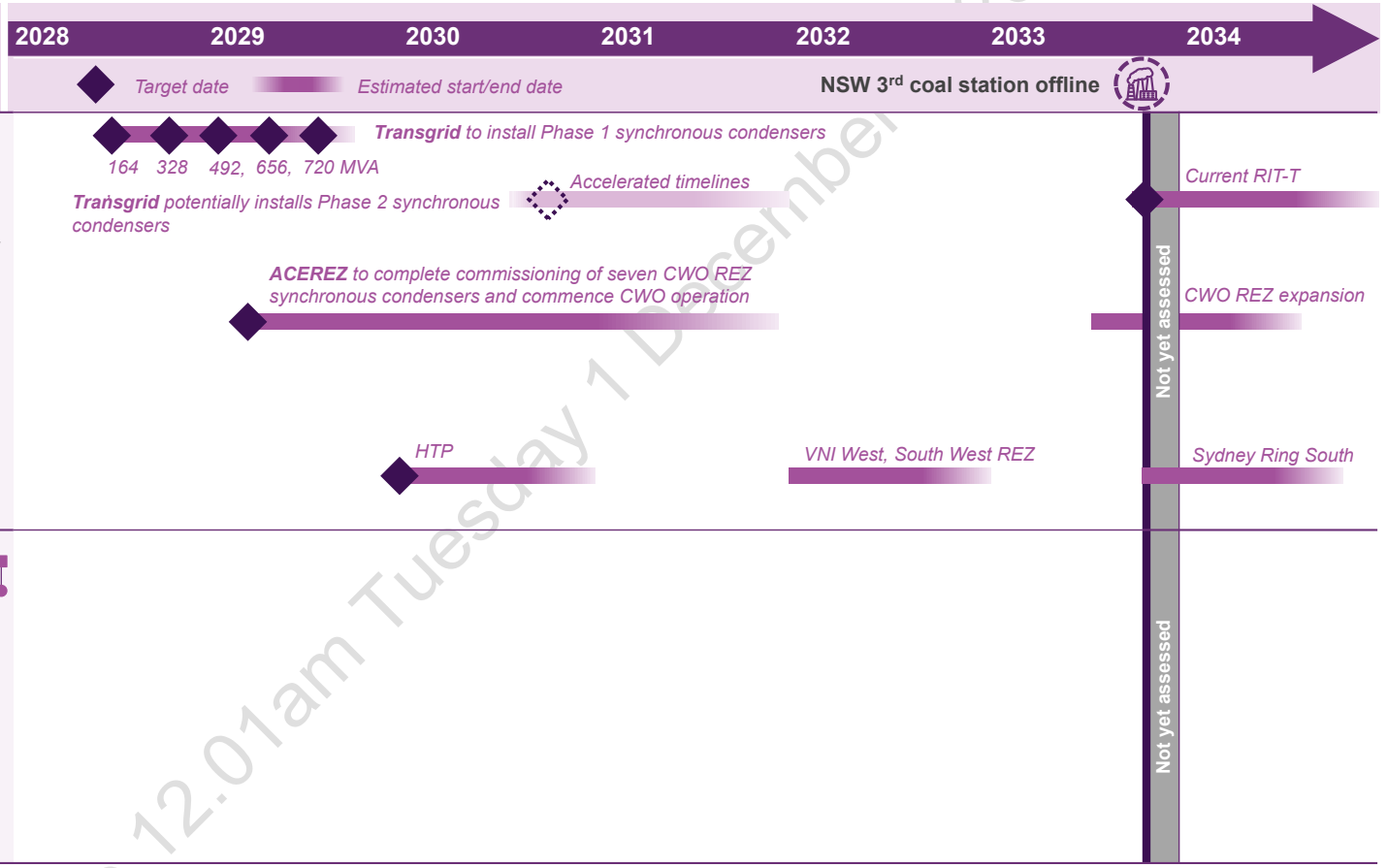
NSW 3rd coal station offline

New South Wales

Moderate readiness



Transient and oscillatory stability

By 2033, the New South Wales power system is expected to have undergone significant changes in generation fleet and network topology which may alter the system's transient and oscillatory stability characteristics. The reduction of coal units will reduce the available traditional stabilising and damping services usually provided through synchronous generators' power system stabiliser.

Given the uncertainty associated with power system and technology development over longer planning horizons, detailed dynamic performance assessments are unlikely to provide meaningful insights at this stage.

AEMO's Engineering Roadmap workplan for transient & oscillatory stability[A] lays out the work required to build understanding of evolving stability characteristics and uplift industry wide capabilities and processes to enable rapid identification and response to future stability characteristics, where required.

System restoration

While it will remain feasible to comply with Stage 1 of the system restart standard and form stable restoration islands, without further investment in or testing of alternative restoration pathways, it will be challenging to meet the stage 2 system restoration MW targets as currently defined[B].

Additional strategically located dispatchable capacity will help support stage 2 restoration process post this transition point[C].

AEMO is developing a system restoration workplan to ensure resource adequacy for restart under anticipated conditions[D] This includes assessing opportunities for REZ-based resources to support future restoration pathways as synchronous generation retires.

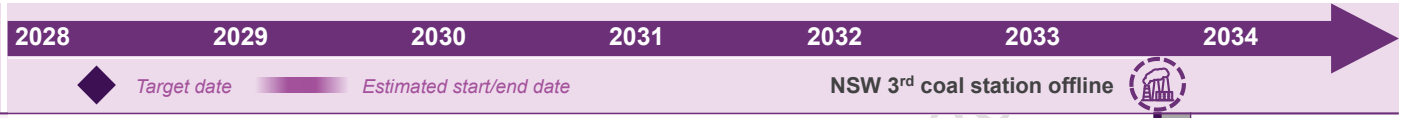
Embargoed to 12.01am Tuesday 1 December 2026

A. See Section 8.2.
B. See Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.
C. For further information, see Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.
D. See Section 9.

NSW 3rd coal station offline

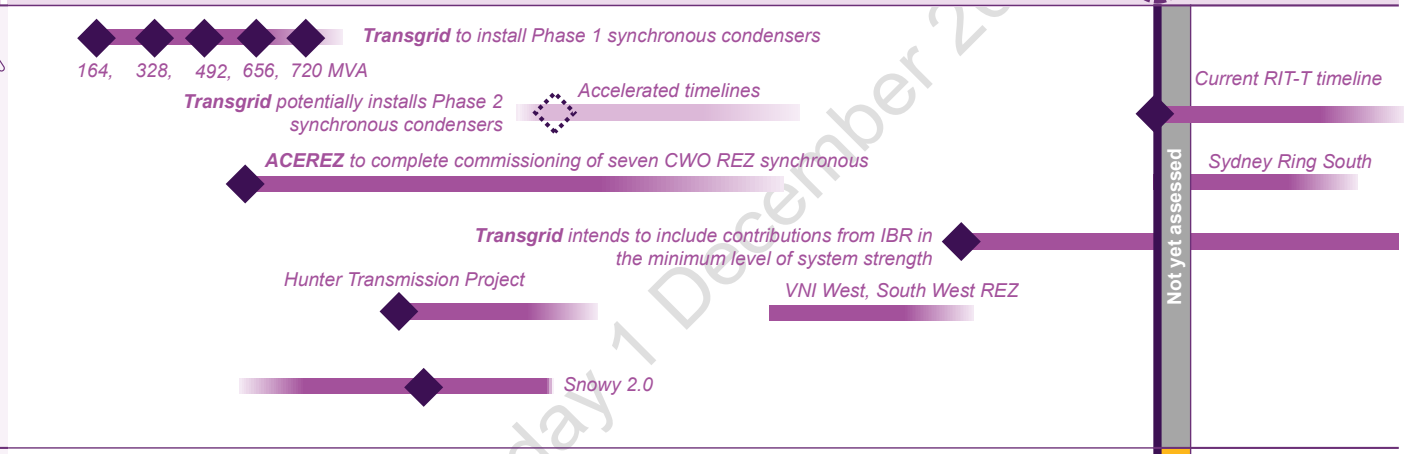
New South Wales

Moderate readiness



Operability

Assessment of operability for distant transition points is challenging due to system configuration uncertainty, along with changing operational tools and processes. Nevertheless, AEMO expects that the operational approach will radically change under scenarios with no coal online. AEMO and TNSPs continue to prioritise projects based on operational risk reduction and capability uplift to ensure operability through upcoming transition points. Operability will be further assessed as this transition point enters closer horizons.

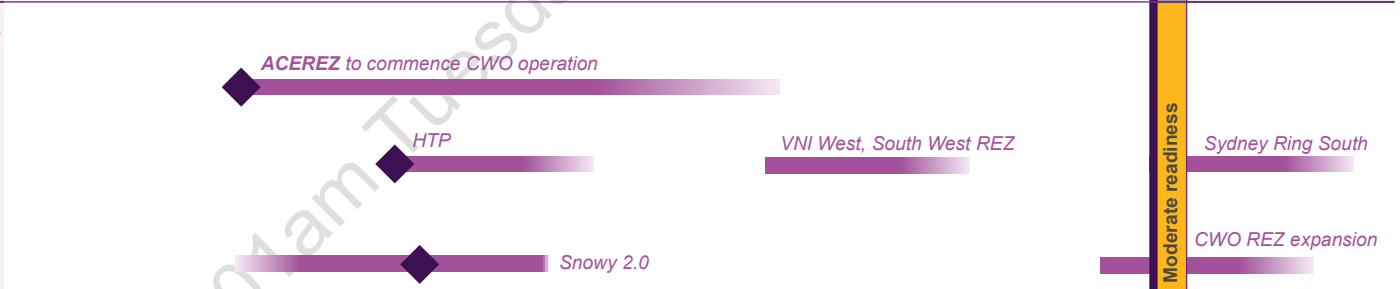


Resource adequacy

To ensure resource adequacy is met post this transition point, and accounting for the significant data centre growth, the 2026 ISP[A] *Step Change* scenario projects that in addition to committed and anticipated developments, a further 10 GW of utility scale solar, 6 GW of utility scale storage and 6 GW of wind is required.

Replacement generation will be enabled by the build out of New South Wales REZ network infrastructure, including Hunter Central-Coast, CWO, New England and South West.

Completion of HTP will enable power transfer from central and northern regions into Newcastle and Sydney load centres. Completion of Sydney Ring South power flow control and 500 kV assets will allow power transfer from southern regions into Sydney, including releasing the full potential of Snowy 2.0.



Embargoed to 12.01am Tuesday 1 December 2026

A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

Queensland

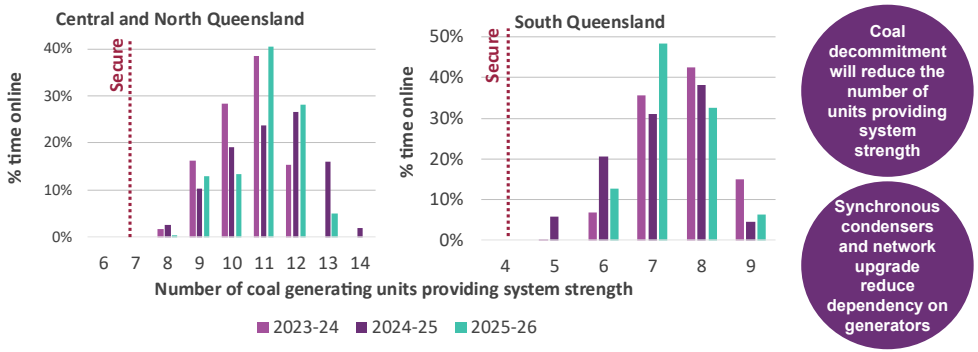
Context

Queensland has the youngest coal fleet in the NEM, with many Queensland coal stations not expected to reach their end of life until the next decade and beyond. The 2025 Queensland Energy Roadmap[A] establishes an Electricity Maintenance Guarantee for state-owned synchronous generation fleet to ensure plant safety, integrity and performance and to support operation of state-owned plants to at least their technical lives.

CS Energy has provided Notice of Closure for the potential exit of Gladstone Power Station by March 2029[B]. The 2026 ISP *Step Change*[C] scenario projects a second Queensland coal generator going offline in 2031, the timing of which is consistent with the Queensland Government's extension of Callide B's operating life to the station's end-of-asset life[A].

***Since the 2025 TPSS**: readiness for Gladstone's exit remains 'on track' due to confirmed delivery schedule of Stage 1 of the Gladstone Priority Transmission Investment (PTI) project[D] and Tranche 1 system strength RIT-T[E] synchronous condensers to address key system security risks. The 2026 ISP[C] revises the date of the 2nd coal station offline transition point to 2031 (from 2027) with readiness reduced to 'moderate readiness' due to dependence on a fifth system strength service currently under MCC assessment[E].*

Available coal units are above system strength limits



Coal decommitment will reduce the number of units providing system strength

Synchronous condensers and network upgrade reduce dependency on generators

Timeline — Now | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036

- Transition Point
- Monitored potential Transition Point
- Planned Transition Point
- Complete/on track
- Moderate readiness
- Unresolved issues

Gladstone exit (2029)

QLD 2nd coal station offline (2031)

Security challenges

Retirement of Gladstone Power Station in 2029 poses localised system strength and thermal risks that are being mitigated by Powerlink's Gladstone PTI project[D] and System Strength RIT-T synchronous condensers[E].

A second coal power station going offline would further reduce operating margins to meet security limits. Powerlink is reassessing the need for further investments, consistent with the system outlook in the Queensland Energy Roadmap[A].

Accurate models, enhanced monitoring and targeted joint AEMO–Powerlink planning are critical to identifying and addressing damping risks ahead of each transition point.

Central Queensland also faces a risk of not achieving system restoration targets within required timeframes, particularly when high-DPV output reduces stabilising load, or outside business hours[F]. Re-energising Queensland in a timely manner depends on voltage control, load, and generation available at early stages of restart, with additional contracting or investment required.

The MSL outlook[G] during typical system-normal conditions has improved. However, Queensland retains a management capability shortfall under rare but plausible onerous conditions, requiring increases in emergency backstop coverage and compliance, along with continued integration of storage and demand-side opportunities.

Preparatory actions

- **Powerlink** to continue to progress timely delivery of the Gladstone PTI project[D] and System Strength RIT-T synchronous condensers[E].
- **Market participants** and **Queensland Government** to progress timely delivery of committed and anticipated generation and storage projects, including projects supported by government schemes such as new generation delivered through the Central Queensland Gas Power Tender. Where possible, new synchronous projects should support black start and synchronous condenser operation.
- **Powerlink** and **AEMO** to complete dynamic assessments and implement measures to maintain transient and oscillatory stability through future transitions. AEMO to progress the transient and oscillatory stability workstream of the Engineering Roadmap to improve understanding of future power system dynamics[H].
- **AEMO** to procure additional SRAS capability and enhance operational processes for increasingly complex system restart strategies.

A. See https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf.
B. See https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station.
C. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
D. See https://engage.powerlink.com.au/pti-gladstone-project.
E. See https://www.powerlink.com.au/news-media/new-synchronous-condensers-strengthening-central-queensland and https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
F. See https://www.aemo.com.au/-/media/files/electricity/nem/data/ancillary_services/2026/nmas-report-2025-26.pdf.
G. Refer to Appendix A3 for further details, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.
H. Refer to workplan for transient and oscillatory stability in Section 8.

Endorsed Tuesday 26

Queensland security assessment

Now	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036

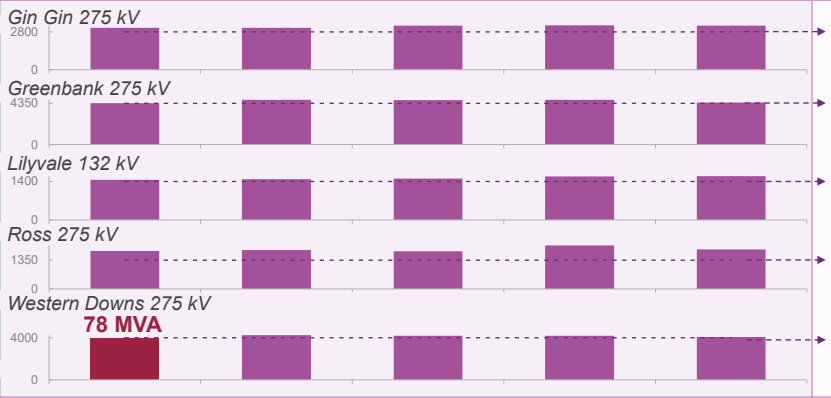
Assessment horizon

NSCAS assessment *(See Appendix 2)*

Long term assessment

System strength – *nodal assessment*
(minimum fault current in MVA)





In October 2026, Powerlink published a draft MCC[A] which reassesses the preferred option of system strength solutions. Powerlink's draft MCC reduces the number of synchronous condensers required from nine to five, with the fifth synchronous condenser being uncommitted to allow opportunity for a non-network solution to provide an equivalent system strength service.

No major system strength deficits were identified with the delivery of the revised portfolio of system strength solutions.

The remaining synchronous condensers are now likely required well outside the 10-year horizon.

Long term, system strength procurement is managed by the RIT-T process.

Inertia (MWs)



Through the delivery of synchronous condensers with significant inertia, there is low risk of inertia deficits

Other system attribute assessments

Voltage control & thermal limits

The successful delivery of the Central Queensland Synchronous Condensers[A] project and Stage 1 of the Gladstone Project transmission augmentation[B] is essential for managing emerging thermal and voltage risks in the Gladstone region following the retirement of Gladstone Power Station.

System restoration

A risk exists of being unable to form a stable restoration island north of Bundaberg within times required to meet the System Restart Standard (SRS) Stage 1 target. These risks increase during sunny daytime conditions when stabilising load is limited, and if a system black event were to occur outside of business hours[C]. To reduce system restoration risk in Central Queensland requires voltage control and generation capacity with short ramp times at early stages of restart, alongside access to stable load. This could be provided by additional trip to house load (TTHL) capability on Central Queensland synchronous fleet, assets with rapid response capability, and targeted network and reactive power support enhancements. While suitable assets exist in the region, these may require further investment to test or upgrade existing plant before restart services can be provided. New synchronous capacity delivered from the Queensland Government's Central Queensland Gas Power Tender could also provide restart services and could be designed with SRAS capacity to avoid more complex future retrofit works.

Transient and oscillatory stability

As greater amounts of fast-acting IBR have been deployed, changes in Queensland's network configuration have been accompanied by changing oscillatory mechanisms that may influence the magnitude and shape of QNI mode oscillation or introduce new modes. Ongoing changes in oscillatory behaviour must be accurately monitored and modelled to assess the adequacy of existing damping solutions or deploy new measures.

Transition points

Gladstone exit

QLD 2nd coal station offline

Requirements | Available level | Deficit

Embargoed

A. See https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
B. See https://engage.powerlink.com.au/pti-gladstone-project.
C. See https://www.aemo.com.au/-/media/files/electricity/nem/data/ancillary_services/2026/nmas-report-2025-26.pdf.

Gladstone exit

March 2029



Queensland

Ready

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability
- Resource adequacy

Context

On 1 October 2025, CS Energy notified AEMO of the potential market exit of Gladstone Power Station in March 2029[A], providing the required 3.5-year notice period for closure of electricity generators. Gladstone Power Station is Queensland's largest coal plant and one of the few that is privately-owned[B]. It supplies several large industrial customers at the Gladstone zone, including Rio Tinto's Boyne Island aluminium smelter.

Impact

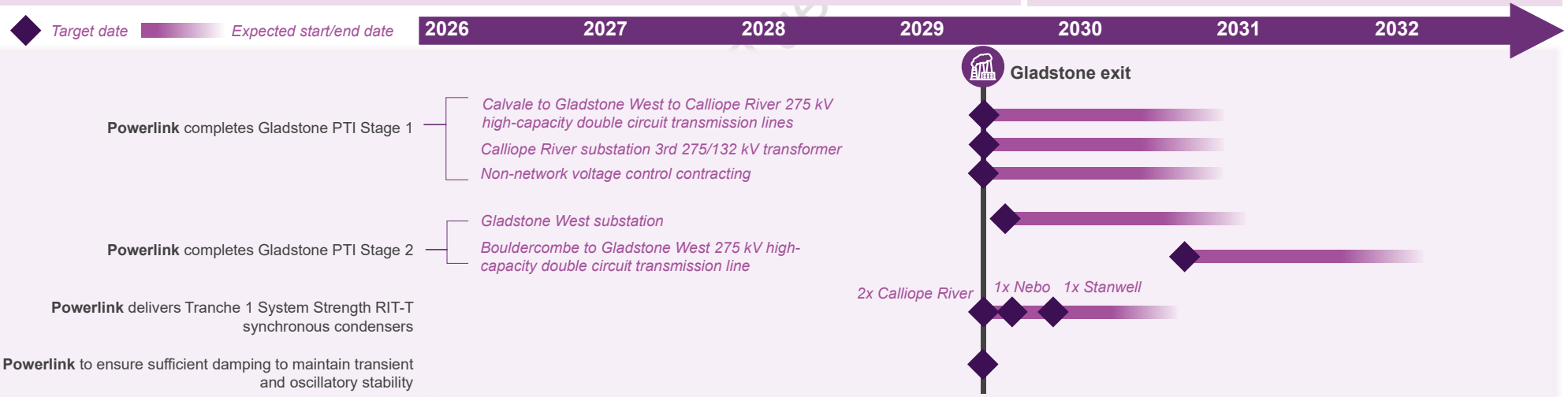
Gladstone Power Station's retirement has localised implications for reliable supply of key load centres and system security in the Gladstone region of Central Queensland. After closure of the 1,680 MW power station, electricity supply to local Gladstone industry will require increased power transfer capacity from wider Central Queensland into the Gladstone area.

Powerlink and AEMO have been actively planning for the eventuation of this transition point for some time, including the inaugural 2018 ISP[C] identification of the Gladstone Grid Reinforcement project.

To address risks to system strength, inertia, thermal limits, and voltage control, Powerlink is progressing new synchronous condensers and the Gladstone PTI project[D]. Powerlink has confirmed that Stage 1 of the PTI project, which involves new transmission between Calvale and Calliope River, and the first two synchronous condensers are on track for delivery just in time for Gladstone's exit. Timely completion of these projects is critical to derisk this transition point. Until Stage 2 of the Gladstone PTI project is delivered, there is expected to be a period of heightened dependency on generation from the Central West area in meeting the Reliability Standard.

Preparatory actions

- **Powerlink** to target delivery of critical Stage 1 components of the Gladstone PTI project[D] ahead of Gladstone station exit, and ongoing delivery of Stage 2 components.
- **Powerlink** to progress delivery of Tranche 1 synchronous condensers at Calliope River, Nebo and Stanwell substations[E].
- **Powerlink** and **AEMO** to complete small-signal stability studies to evaluate adequacy of remaining network assets in managing changes in oscillatory modes associated with Gladstone Power Station exit. Powerlink to ensure stabilising devices continue to effectively dampen oscillatory modes and install new stabilising devices if required.
- **AEMO** to procure additional restart services via the next SRAS procurement round.



A. See https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station.
B. Gladstone Power Station is an unincorporated joint venture, of which Rio Tinto holds the largest stake. Energy trading for Gladstone Power Station is managed by CS Energy.
C. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2018/isp-appendices_final.pdf.
D. See https://engage.powerlink.com.au/pti-gladstone-project.
E. See https://www.powerlink.com.au/news-media/new-synchronous-condensers-strengthening-central-queensland and https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

Embargo

Gladstone exit

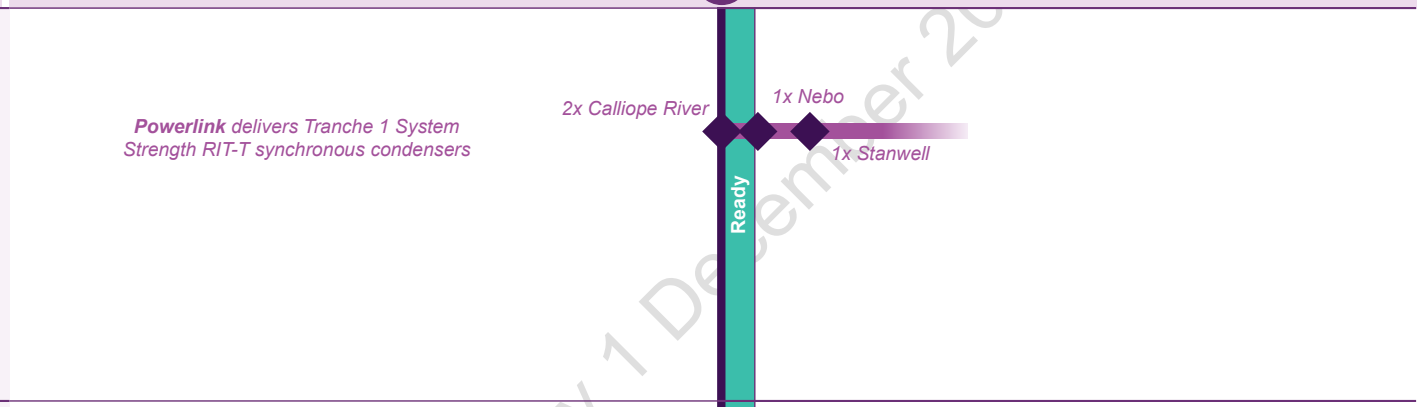




System strength

Powerlink's Tranche 1 synchronous condensers[A] and PTI project network augmentations[B] are critical to address the loss of system strength associated with the closure of Gladstone Power Station. Powerlink advises that two synchronous condensers at Calliope River are on track for delivery ahead of Gladstone Power station closure, while commissioning of the remaining two at Nebo and Stanwell are expected over the following months.

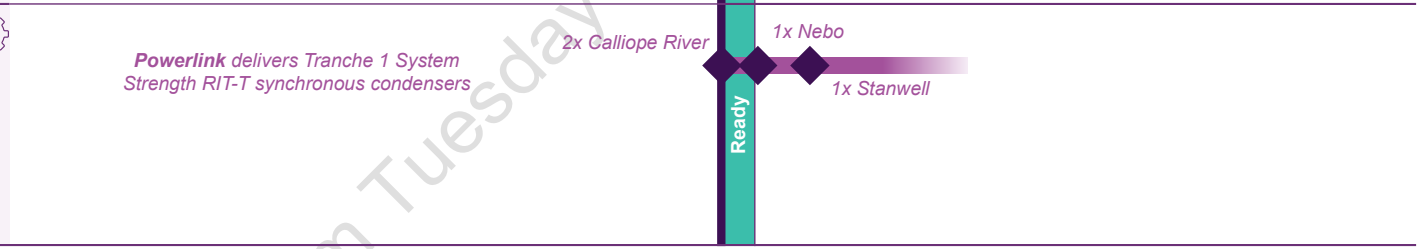
Following delivery of the four Tranche 1 synchronous condensers, AEMO projects that fault levels will be maintained above requirements. Until all Tranche 1 synchronous condensers are installed, AEMO may need to enable system security services or use directions if forced outage or generator decommitment overlaps with conditions involving four or more units on planned outage across Stanwell, Callide B or Callide C.



Frequency and inertia

Powerlink's Tranche 1 synchronous condensers[A] will compensate for loss of inertia from closure of Gladstone Power Station. Joint planning between AEMO and Powerlink will manage inertia risks during closure of Gladstone Power Station, alongside the commissioning of Tranche 1 synchronous condensers.

Sufficient FCAS and PFR providers are expected to remain available for primary and secondary frequency management.



Embargoed to 12.01am Tuesday 1 December 20

A. See https://www.powerlink.com.au/news-media/new-synchronous-condensers-strengthening-central-queensland and https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

B. See https://engage.powerlink.com.au/pti-gladstone-project.

Gladstone exit





Voltage control

Powerlink's Gladstone PTI project[A] is designed to address voltage control deficits through new reactive non-network contracting and Tranche 1 system strength RIT-T[B] synchronous condensers. Delivery of solutions to address voltage control is planned by March 2029.

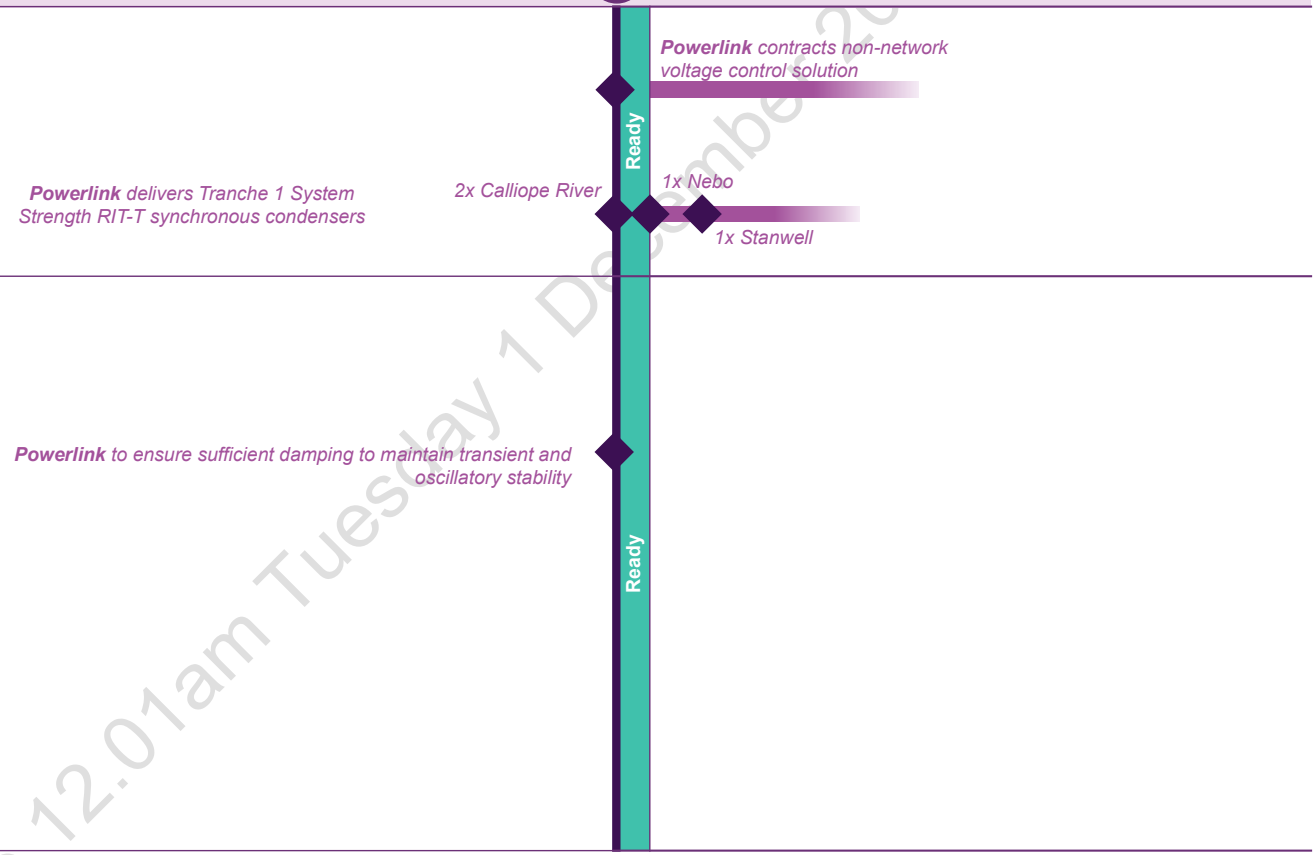
Project delays risk voltage control deficits if Gladstone Power Station exits before voltage control remediation is delivered, including risk of over-voltage on trip of Boyne Island pot line.

Transient and oscillatory stability

Gladstone Power Station was installed with power system stabilisers that were originally tuned to provide oscillation damping for QNI mode but have lower effectiveness in managing dynamic behaviour in today's network that now comprises greater proportions of fast-acting IBR. Their retirement is therefore not expected to materially impact oscillatory stability.

Powerlink has commenced studies to identify remediation measures required to maintain adequate transient and oscillatory stability following Gladstone Power Station exit. With efforts underway, transient and oscillatory stability for this transition point is rated as ready. Continued progress on identified damping solutions is critical to maintaining this assessment.

Queensland has existing transient and oscillatory stability risks related to changing oscillatory behaviour that are described in Queensland's regional security assessment. While remediation technology is available, ensuring accurate models and network monitoring are prerequisites to building understanding of new stability behaviour, before effective damping solutions can be deployed. AEMO is developing a workplan for transient & oscillatory stability[C] to build understanding of evolving stability characteristics and uplift industry wide capabilities and processes to enable rapid identification and response to future stability characteristics, where required.



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A. See https://engage.powerlink.com.au/pti-gladstone-project.
B. See https://www.powerlink.com.au/news-media/new-synchronous-condensers-strengthening-central-queensland and https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
C. Refer to workplan for transient and oscillatory stability, in Section 8 .

Gladstone exit



System restoration

System restoration plans in Central Queensland feature but do not rely on Gladstone Power Station. AEMO is coordinating with Powerlink to investigate options for ensuring restoration services are available to be procured via the next SRAS procurement round. Region-wide energisation beyond Central Queensland is expected to be supported by Powerlink's four new synchronous condensers[A].

Central Queensland has existing system restoration risks that are described in Queensland's regional security assessment.

Operability

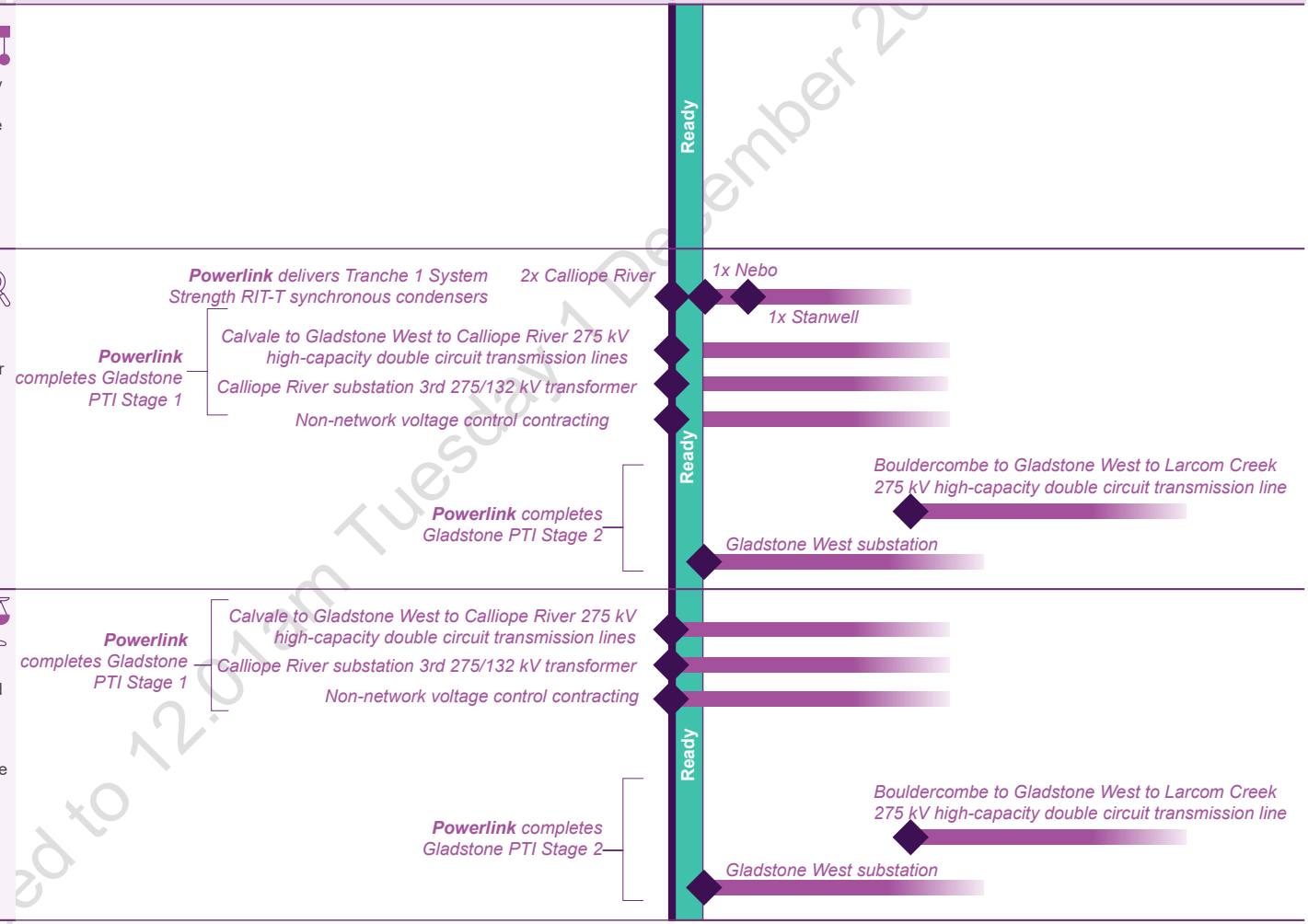
Managing operability and ensuring adequate margins for outages requires Powerlink to coordinate commissioning of Tranche 1 synchronous condensers[A] and PTI project[B], ahead of Gladstone Power Station's planned closure schedule.

Additional operability considerations are related to ensuring models, monitoring and mechanisms for managing QNI oscillation modes remain adequate, and are addressed under the transient and oscillatory stability section.

Resource adequacy

Commissioning Stage 1 of Powerlink's Gladstone PTI Project[B], ahead of Gladstone Power Station exit, is critical to relieving thermal overload and congestion of 275 kV lines connecting the Gladstone area to the broader region and ensuring reliable supply to load in the Gladstone area. Without the PTI project, reliability risks may arise from existing transfer limitations constraining generation to the West and North of the Gladstone area.

In the interim 15-month period between Gladstone Power Station closure and delivery of Stage 2 of the Gladstone PTI project (Bouldercombe to Gladstone West 275 kV lines) scheduled for August 2030, transmission constraints will heighten the importance of Callide area generation for meeting the Reliability Standard.



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B See https://engage.powerlink.com.au/pti-gladstone-project.

QLD 2nd coal station offline

July 2031

Queensland — Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- System restoration
- Resource adequacy

To be assessed

- Transient and oscillatory stability
- Operability

Context

The 2026 ISP[A] projects decommitment of a second Queensland coal station in 2031 to support achievement of government policies, contingent on the projected delivery of generation, storage, and network investments. This aligns with the timing of Callide B's expected closure under the Queensland Energy Roadmap[B] and the Queensland Government's April 2025 announcement to fund upgrades to Callide B1 and B2 coal generating units and extend their expected closure date from 2028 to at least 2031[C] (subject to adequate system and market outcomes).

Powerlink has identified that the revised coal retirement schedule under Queensland Energy Roadmap activates a reopening trigger in relation to its System Strength RIT-T assessment and is progressing a MCC assessment[D] on the need for synchronous condensers or equivalent system strength services beyond the initial four synchronous condensers already procured.

Impact

The impacts of this decommitment are focused on the Central Queensland region:

- Maintaining system strength and inertia above secure requirements becomes more exposed to conditions involving concurrent outages or economic decommitment of the remaining Central Queensland coal units. A fifth synchronous condenser or equivalent system strength service could provide replacement security services and is under MCC assessment[D].
- Achieving the System Restart Standard Stage 2 target becomes challenging and would rely on simultaneous restart by parallel pathways, creating substantial operational complexity for AEMO and Powerlink to implement in practice.
- Without timely delivery of additional dispatchable capacity, this coal decommitment could increase reliability risk.

Synchronous generation projects supported by the Queensland Government may reduce risks if these are appropriately specified.

Preparatory actions

- **Powerlink** to confirm the preferred options of system strength solutions under its System Strength RIT-T MCC assessment[D] and progress delivery on Tranche 2 system strength services in Central Queensland, if the MCC assessment deems appropriate.
- **Powerlink** to complete small-signal stability studies and progress efforts to ensure transient and oscillatory stability post 2031. **AEMO** to progress the Engineering Roadmap workplan for transient and oscillatory stability[E].
- **Market participants** and **Queensland Government** to progress timely delivery of committed and anticipated generation and storage projects, including projects supported by government schemes such as new generation delivered through the Central Queensland Gas Power Tender. Where possible, new synchronous projects should incorporate black start capabilities and synchronous condenser operating modes to support system strength and reinforce restoration pathways and reduce restoration risk.
- **AEMO** and **Powerlink** to enhance operational processes and coordination to implement increasingly complex system restart strategies that involve a larger number of generating units and network elements.



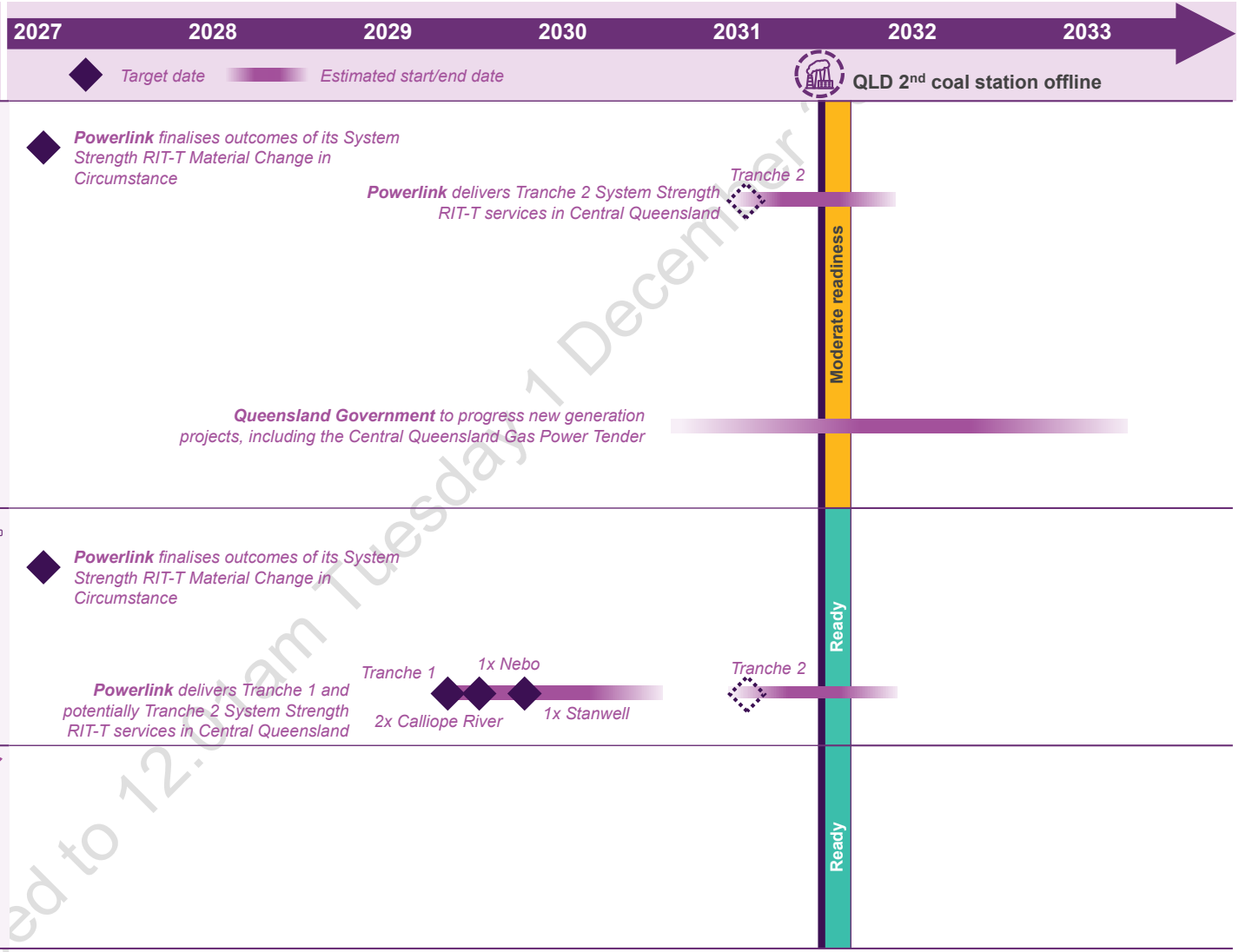
A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
B. See https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf.
C. See https://statements.qld.gov.au/statements/102355 and AEMO's Generation information resource updated April 2025 at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
D. See https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
E. Refer to workplan for transient and oscillatory stability, Section 8.

Embargo

QLD 2nd coal station offline

Queensland

Moderate readiness



System strength

Under Tranche 2 of its System Strength RIT-T[A], Powerlink plans to deliver a fifth Central Queensland synchronous condenser or equivalent system strength services. The solution is currently being evaluated through a MCC assessment.

Without a fifth Central Queensland system strength service in place ahead of this transition point, system strength deficits against minimum requirements could occur following a second Central Queensland coal station going offline. During periods where maintenance, forced outage or decommitments occurs at remaining coal units, AEMO may need to direct on fast start synchronous units to remain secure.

Additional synchronous system strength services could be provided by installation of a new synchronous condenser, or equivalently by clutched gas turbine or pumped hydro solutions. New synchronous generation, including projects delivered through the Queensland Government's Central Queensland Gas Power Tender could provide additional system strength services if designed with synchronous condenser operating capability.

Frequency and inertia

Following delivery of Powerlink's four Tranche 1 synchronous condensers at Calliope River, Nebo and Stanwell substations[B] by late 2029, no inertia risks are expected.

Voltage control

Following delivery of Stage 2 of the Gladstone PTI project[C], no voltage control risks have been identified related to further decommitment of coal units in Central Queensland.

Embargoed to 12.01am Tuesday 1 December

A. Powerlink has commenced an MCC assessment of its System Strength RIT-T which assesses the need for system strength beyond the four synchronous condensers that have already been procured. See https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

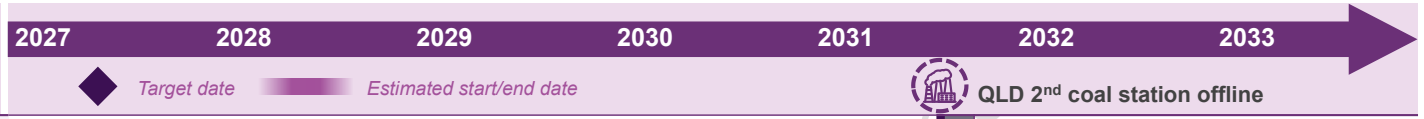
B. See https://www.powerlink.com.au/news-media/new-synchronous-condensers-strengthening-central-queensland.

C. See https://engage.powerlink.com.au/pti-gladstone-project.

QLD 2nd coal station offline

Queensland

Moderate readiness



Transient and oscillatory stability

This transition point will occur alongside changes in network topology, generation mix and load composition. As synchronous coal generation declines and contribution from fast-acting and geographically dispersed IBR increases, new interactions and dynamic responses may emerge that affect transient and oscillatory stability.

Detailed dynamic assessments depend on modelling specific network conditions and equipment. As long-term network development plans become more defined and the relevant information becomes available to AEMO and Powerlink, these assessments will provide clearer insights into the stability implications. Powerlink will conduct studies as the transition point approaches and deploy adequate solutions.

AEMO is also developing a workplan for transient & oscillatory stability[A] to build understanding of evolving stability characteristics and uplift industry wide capabilities and processes to enable rapid identification and response to future stability characteristics, where required.

System restoration

Queensland's system restoration pathways continue to be viable following a second Queensland coal station going offline. However, without further investment and improved restoration strategies, it will be challenging to meet stage 2 system restoration MW target as currently defined (see Appendix 4[B]). Actions to address existing system restoration risks in central Queensland (see Queensland's security assessment) are expected to support meeting the stage 2 target.

Meeting restoration targets may also increasingly rely on parallel restoration pathways. Enabling restart via parallel pathways is expected to require substantial uplift in operational capabilities across AEMO and Powerlink.

Additional new black start capability could reinforce restoration pathways and reduce restoration risk. Accelerated delivery of new synchronous generation, including the Queensland Government's Central Queensland Gas Power Tender, could provide additional black start supply capacity and restoration services. This additional dispatchable and synchronous generation may support the formation of a stable restoration island under the SRS Stage 1 target, as well as contribute to meeting the SRS Stage 2 target. Early consideration of SRAS capability in design of new synchronous generation plant may avoid need for complex and costly future retrofit works.

Embargoed to 12.01am Tuesday 1 December

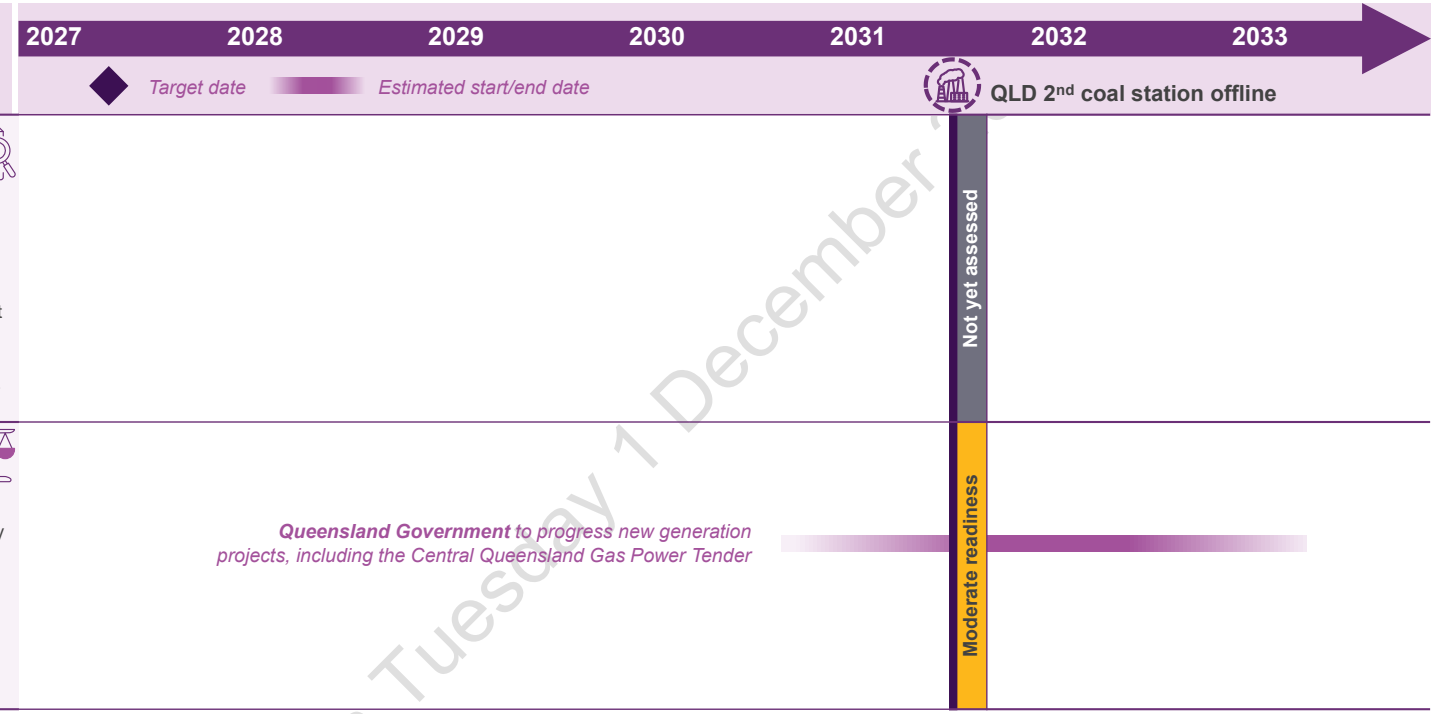
A. Refer to workplan for transient and oscillatory stability in Section 8.

B. Refer to Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.

QLD 2nd coal station offline

Queensland

Moderate readiness



Operability

By 2031, the Queensland network is expected to be augmented by new transmission, synchronous condensers, and fast-acting and sparsely located IBR – alongside the projected decommitment of another coal station. These network changes may lead to different system dynamics that require new operational tools and processes to effectively manage. As the network evolves, sufficient monitoring must also be installed to ensure control room visibility and network predictability.

Operability will be assessed further as this transition point approaches closer horizons.

Resource adequacy

The 2026 ESOO *Committed and Anticipated Developments* reliability assessment[A] forecasts a risk that expected USE exceeds the reliability standard from 2032-33 – the first full year modelled by the ESOO without a second Queensland coal station. Delivery of dispatchable generation and storage projects within Central Queensland, including those supported by the Federal Capacity Investment Scheme (CIS) and by the Queensland Government, is critical to address reliability risks.

Embargoed to 12.01am Tuesday 1 December

A. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2026/2026-electricity-statement-of-opportunities.pdf.

South Australia

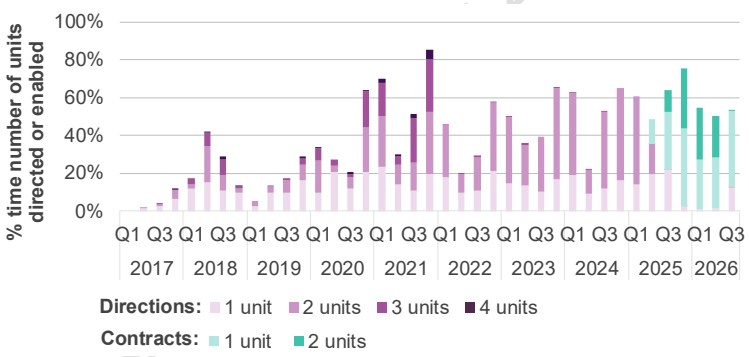
Context

The South Australian power system continues to be world leading in renewable energy generation, including rooftop solar. System security in South Australia is currently supported by synchronous condensers, reactive equipment, neighbouring regions via interconnectors and a small number of synchronous generators.

The reliance on gas and diesel generation for system security, and the risk of South Australia islanding, are expected to decrease with the recent energisation of PEC Stage 2 in Q4 2026. The full capacity release of PEC Stage 2[A] and new reactors installed via ElectraNet's voltage control RIT-T, expected in October 2027, will contribute to enabling the reduction of the minimum synchronous generator requirement, at times, from one to zero synchronous generators. However, voltage oscillations around 6Hz are being observed in South Australia and must be remediated prior to operating at zero synchronous generators.

***Since the 2025 TPSS**: the exit of Torrens Island Power Station B (TIPS BZ) has been assessed as 'moderate readiness' (treated in 2025 as a transition point to monitor, but not fully assessed), and the planned date for Zero minimum synchronous generation operation has been deferred a year to Q4 2028, to provide more time to diagnose and remedy the 6Hz oscillations increasingly being observed.*

The need to direct gas units for security is expected to reduce



Directions have been replaced by contracted system strength services

SA can operate at times with one synchronous generator, with two often required

Timeline

Now | 2027 | 2028 | 2029 | 2030 | 2031

- Transition Point
- Monitored potential Transition Point
- Planned Transition Point
- Complete/on track
- Moderate readiness
- Unresolved issues
- TIPS B exit
- Zero minimum synchronous generator operation

Security challenges

Instances of voltage oscillations have been observed in South Australia under low demand and high DPV conditions[B]. Interim operating limits that constrain on some synchronous generators are currently in place to mitigate these oscillations while testing is underway to identify root causes. As constraining on synchronous generation is currently the only measure available to AEMO to manage these oscillations, alternative medium and long-term solutions are required to de-risk both TIPS B retirement and zero minimum synchronous generator transition points.

Additionally, ElectraNet has raised concerns of incorrect protection operation under periods of high IBR contribution, even with four synchronous condensers online, particularly under zero synchronous generator operation. Until these issues are resolved, interim operating arrangements with multiple synchronous generators online must remain under certain conditions to maintain power system security, contributing to the revised indicative timing for the zero minimum synchronous generator transition point from Q3 2027 indicated in the 2025 TPSS to Q4 2028.

South Australia continues to have risks of MSL events. The outlook for MSL has improved with the integration of PEC Stage 2, and other factors outlined in Appendix 3[C].

Preparatory actions

- **AEMO, ElectraNet**, and **SA Power Networks** to continue close and targeted collaboration to resolve observed voltage oscillation challenges, including testing in 2027.
- **ElectraNet** to complete protection adequacy reviews and provide associated limits advice under zero synchronous generation operation, in collaboration with broader industry action and **AEMO** prior to moving to zero synchronous operation.
- **ElectraNet** to complete closure of the declared 2023 NSCAS voltage gap, through the installation of reactors under its voltage control RIT-T, and provide associated limits advice under zero synchronous generation operation.
- **Transgrid** and **ElectraNet**, with **AEMO** support, to complete delivery of the full capacity release of PEC Stage 2[A]. PEC Stage 2 is critical to support South Australia's reliability and security with few synchronous generators online and to support minimum system load management.
- Continued efforts are needed across **AEMO** and **SA Power Networks** to support readiness for MSL conditions through improved compliance and response, the speed of current mechanisms and investigation of transitional services and other operational measures.

A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.
B. For details on voltage oscillations see Section 1.2.
C. Refer to Appendix A3, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.

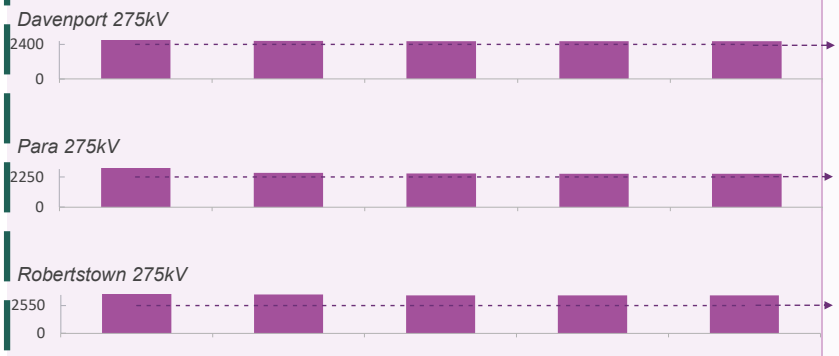
Embargo Tuesday 2026

South Australia security assessment

	Now	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Assessment horizon	***NSCAS assessment** (See Appendix 2)*						***Long-term assessment***				

System strength – *nodal assessment*
(minimum fault current in MVA)



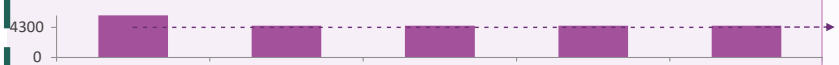


Long term, system strength procurement is managed by the RIT-T process

Electranet have published the Project Assessment Conclusions Report, which focused on the efficient level of system strength and found no action is required, however noted future growth in IBR may change this.

This year AEMO has included DPV in the forecast IBR which sets the 'efficient level' requirements for system strength This reflects evidence that DPV is participating in the sub-synchronous oscillations observed in South Australia, although the root cause of these oscillations remains under investigation. AEMO will continue working with ElectraNet, SAPN and other relevant stakeholders to further our collective understanding of the oscillations, their contributing factors and potential short, medium and long-term mitigation options.

Inertia (MWs)



Low long term risk due to existing synchronous condensers, and grid forming inverters. Additionally, with the completion of Project Energy Connect and associated controls schemes the likelihood of islanding is reduced, so that only the sub regional allocation will need to be met.

Other system attribute assessments

Voltage control

Existing voltage control NSCAS Gap

AEMO has identified improvement in the previously declared voltage control gap; ElectraNet is remediating this gap via installation of new switched reactors in the Adelaide and South East regions. Five of six reactors have been installed with the remaining reactor to be in service by October 2027. This gap will be closed upon installation of the remaining reactor.

Voltage oscillations

Undamped oscillations on the 275 kV network have been observed throughout South Australia during periods of high DER contribution, including during system normal conditions. This is explored further on the next page.

Transition points

TIPS B exit

Zero minimum synchronous generator operation

Requirements | Available level | Deficit

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South Australia voltage oscillations

South Australia transition points

TIPS B exit

Zero minimum synchronous generator operation

Critical action for South Australia and both South Australian transition points

- **AEMO**, **ElectraNet**, and **SA Power Networks** to continue close and targeted collaboration to resolve observed voltage oscillation challenges, including testing in 2027.

Context

Undamped oscillations on the 275 kV network have been observed throughout South Australia during periods of high DER contribution, including during system normal conditions. Oscillation magnitudes have reached as high as 2% peak-peak root mean square (RMS) voltage. Following this observation, temporary operating advice was implemented based on limits advice from **ElectraNet** that oscillations above 0.5% constitute a widespread system security risk. Undamped oscillations present serious risks to system security and can lead to cascading blackouts if left unaddressed.

Oscillation risks could become a key barrier to achieving zero minimum synchronous generator operation in South Australia, resulting in increasing costs to consumers.

Analysis to date

ElectraNet, **SA Power Networks** and **AEMO** are conducting detailed investigation into these oscillations. Field testing and oscillation source location (OSL) analysis of phasor measurement unit (PMU) data has identified multiple contributing sources of oscillations in the South Australian network.

A particular transmission-level plant is one source, when it generates at high output. This plant's contribution to the oscillations is being addressed in accordance with its Generator Performance Standard (GPS). However, oscillations are still occurring when this plant is operating at low generation, with oscillation magnitudes up to 1.9% observed even when constrained off.

Growing evidence suggests DER generation is a major contributor to these oscillations, and **AEMO**, **ElectraNet** and **SA Power Networks** are continuing to investigate.

Furthermore, while operational evidence to date shows that keeping additional synchronous generation online has been able to bring oscillations back under the 0.5% threshold, addressing the underlying root cause remains necessary.

DER observations

Measured behaviour

- Largest magnitude oscillations occur consistently when DER generation is high, demand is low, and less synchronous generation is online. Higher magnitude oscillations are typically observed during low synchronous unit combinations.
- OSL analysis of PMU data indicates that there is no clear single source of oscillations from the transmission network, and that multiple distribution connection points across the region are contributing to the oscillation, with top contributing distribution connection points correlated to locations with the highest installed DER capacity.
- Data from **ElectraNet** and **SA Power Networks** finds flicker (often correlated with and linked to oscillations) shows a clear escalation at the same time that oscillations are observed at transmission level, particularly in locations around Adelaide.

Additional information

- Laboratory bench tests of DPV inverters find persistent oscillatory modes at low short circuit ratio (SCR). Higher magnitude oscillations in South Australia have been observed during high DPV and lower SCR conditions.
- International observations suggest sub-5 MW distribution-connected inverter energy devices contribute to oscillations due to a range of factors. Two public examples are in Hawaii, where DER were observed to contribute to oscillations, and in New York State, where multiple sub-5 MW PV plant were observed to contribute to oscillations in a weak part of the network[A]. Although the latter example involved larger distribution connected plant, the inverters at these sites were connected in parallel, similarly to DER connection in the NEM. In both examples, operators worked with OEMs to implement updated anti-islanding firmware settings on their inverters, which dampened the oscillations magnitude.

Early indications suggest that the South Australian DER contribution to oscillations could be due to a range of factors including inverter volt-var response, active ant-islanding and active power generation levels, although more investigation is required to confirm. As DER levels continue to grow and synchronous generator dispatch continues to reduce in South Australia, without effective remediation solutions in place, oscillation risks are likely to increase.

Action delivery plan

AEMO, **ElectraNet** and **SA Power Networks** will continue to investigate and mitigate oscillation risks through a strategic work plan involving four pillars:

- **Continue assessment and determine root causes** – potential causes include a range of DER oscillation causes, transmission-level generator performance and/or system strength issues. AEMO will continue working with ElectraNet, SA Power Networks and other stakeholders to advance the collective understanding of the oscillations and develop efficient short-, medium- and long-term mitigations.
- **Network-level management –** at present, oscillations are managed by:
  - constraining generation from the contributing transmission-connected plant, noting this does not always dampen oscillations as the plant only contributes when it is generating at high levels, and
  - bringing on additional synchronous generating unit(s).
- **Pursuing inverter-based solutions for DER contributions** – field and bench testing of mechanisms of DER contributions to isolate contributing inverter behaviours, alongside OEM engagement to investigate root causes and develop and validate firmware-based mitigations. Formal engagement to consider enduring mitigations through AS/NZS 4777.2:2020.
- **Long-term pathways –** Uplift in governance arrangements to help DNSPs manage distribution effects on system security, via National CER Roadmap where appropriate.
- From 2026, AEMO's system strength requirements, updated annually, will reflect these emerging issues.

A. Tschang, Y. L. Jiang, W. Ren and T. Key, "Instability Risk of Distributed Energy Resources (DERs) in Weak Distribution Networks: Impact of Anti-Islanding Schemes," 2026 IEEE Power & Energy Society General Meeting (PESGM), Montreal, QC, Canada, 2026, pp. 1-5, doi, at https://ieeexplore.ieee.org/document/11693243.

Embargo

TIPS B exit

June 2028

South Australia

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability
- Resource adequacy

Context

Torrens Island Power Station B (TIPS B) has an announced retirement date of 30 June 2028, with one 200 MW unit mothballed in 2021 and 600 MW remaining until retirement. Port Lincoln, Snuggery and Osborne have all also announced retirements prior to TIPS B, retiring an additional 337 MW from South Australia. TIPS B exit was monitored but was not a formally assessed transition point in the 2025 TPSS. Emerging operational challenges and complex dependencies across critical projects in South Australia mean AEMO believes a detailed transition point planning assessment is now warranted.

TIPS B retirement risks are significantly reduced after PEC Stage 2's full capacity release, scheduled for six months before retirement[A]. However, the recently observed voltage oscillations being seen in South Australia create a complex environment to navigate changing to zero synchronous generator operations.

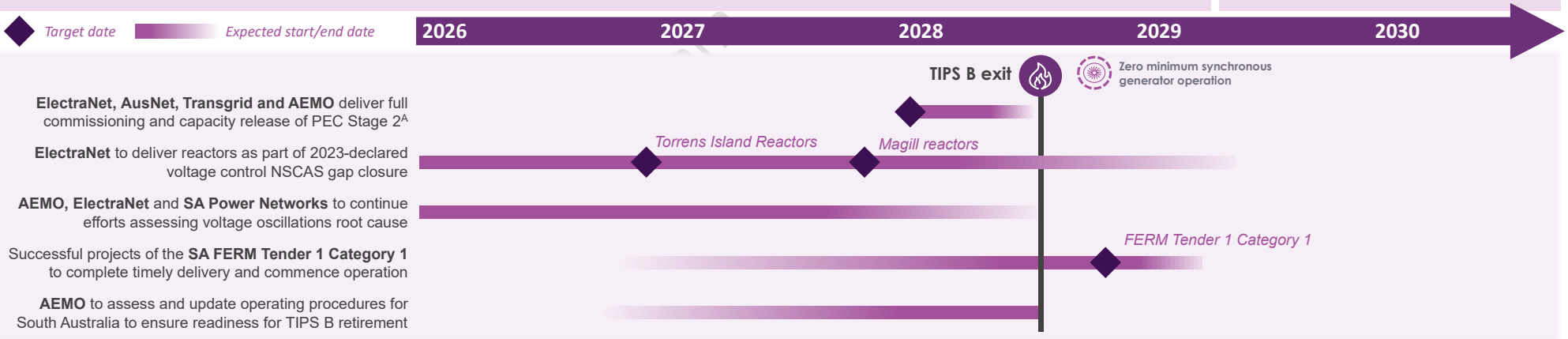
Impact

TIPS B is one of two power stations in South Australia under which single-synchronous generator operation is currently adequate, according to current ElectraNet limit advice[B]. Therefore, without updates to the limit advice with additional unit combinations, operability may be more difficult following retirement. Additionally, temporary operating advice that includes specific viable synchronous unit combinations, some of which include TIPS B, is currently being used to manage and mitigate the observed voltage oscillations in South Australia. In the absence of the root cause of the oscillations being identified and additional solutions being implemented to manage them, the retirement of TIPS B would reduce options to manage these oscillations.

While PEC is now energised, ElectraNet and Transgrid's delivery of the full capacity release of PEC Stage 2 is required to provide additional transfer capacity in South Australia and its timing is critical to reduce reliability risks associated with TIPS B's retirement[A]. Following this, South Australia's electricity demand must be met by renewable generation, firmed by BESS and interconnection, and backed up by remaining gas and diesel generation. This is supported by the South Australian Government's Firm Energy Reliability Mechanism (FERM). Accordingly, effective storage management and dispatch will be critical to maintain energy adequacy through periods of low renewable output.

Preparatory actions

- **AEMO**, **ElectraNet** and **SA Power Networks** to continue collaboration to find root cause of oscillations and develop enduring solutions that do not require TIPS B online.
- **AEMO**, **ElectraNet** and **Transgrid** to continue close collaboration to ensure PEC Stage 2 commissioning is completed on time and in full[A].
- **ASL** and the **South Australian Government** to continue facilitating the delivery of long duration storage, including the FERM Tender 1 Category 1 to support tight supply conditions. Successful projects of the FERM along with other committed and anticipated projects to complete timely delivery and commence operation[C].



A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

B. See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?rev=b42ff9893d2b47788d65404d045124f0&sc_lang=en.

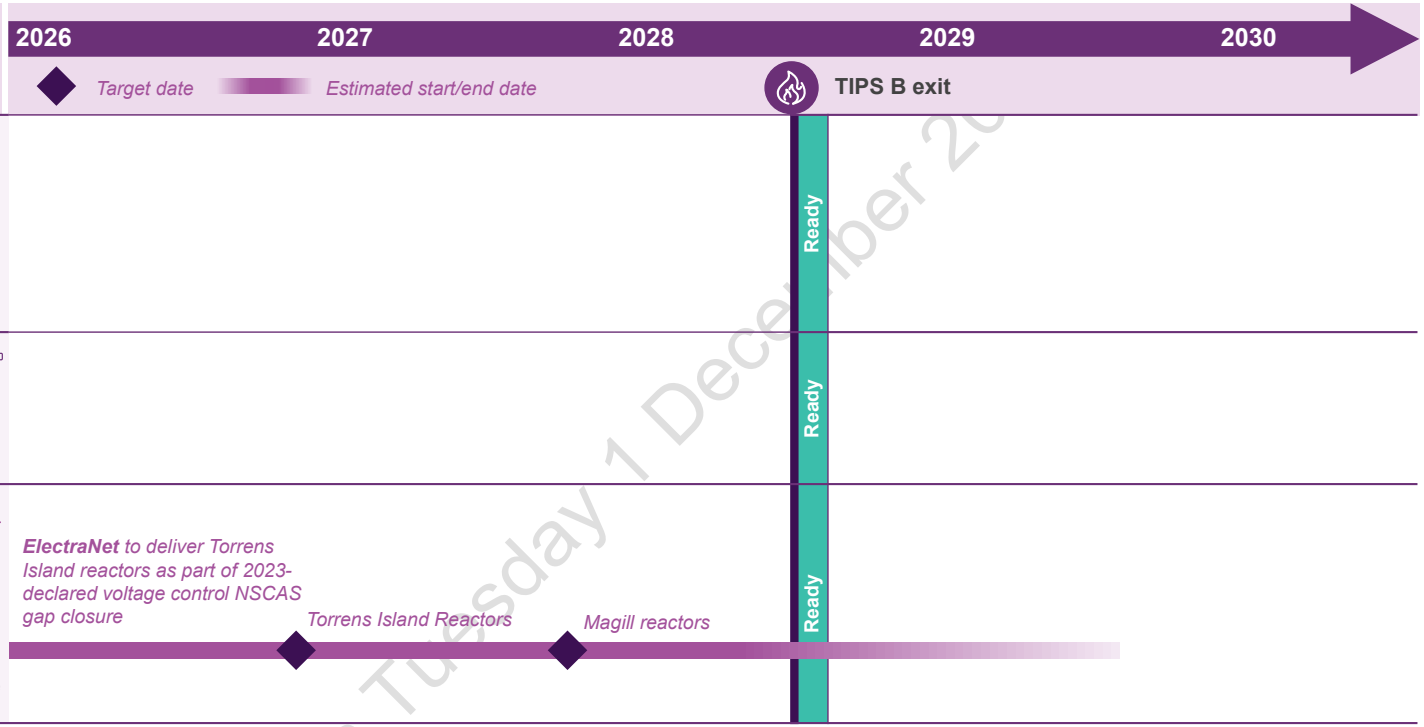
C. See https://asl.org.au/tenders/sa-ferm-tender-round-1.

Embargo

TIPS B exit

South Australia

Moderate readiness



System strength

No system strength gaps have been declared in South Australia and minimum and efficient levels of system strength are expected to be maintained over the forecast horizon. Refer to Appendix A2 for further details[A]. The impact of the observed voltage oscillations, which may be influenced by system strength, is discussed below under Transient and Oscillatory Stability.

Frequency and inertia

South Australia is expected to have sufficient inertia over the next five years, and no inertia gaps have been identified. Existing and new IBR are also expected to provide frequency support.

Voltage control

ElectraNet is installing new reactors in South Australia to close a previously declared voltage control gap in the 2023 NSCAS report[B]. The new reactors are expected to be commissioned by late 2027, prior to TIPS B closure, and would reduce reliance on TIPS B for voltage control. TIPS B is currently under a Type 1 Transitional Service contract for grid reference, which is also providing voltage control in the interim until the gap is closed.

Embargoed to 12.01am Tuesday 1 December 20

A. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

B. See 2023 NSCAS Report, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-nscas-report.pdf.

TIPS B exit

South Australia

Moderate readiness

Transient & oscillatory stability

TIPS B's retirement would also remove its installed Power System Stabiliser (PSS). Intra-area oscillatory stability must be assessed and maintained by ElectraNet following TIPS B retirement, while inter-area oscillatory stability is a shared collaboration between relevant TNSPs and AEMO. If damping issues arise, they may require coordinated retuning of existing plant, as well as potential deployment of additional damping assets, such as power oscillation damping on GFM, synchronous condensers, or Flexible AC Transmission Systems (FACTS)[B].

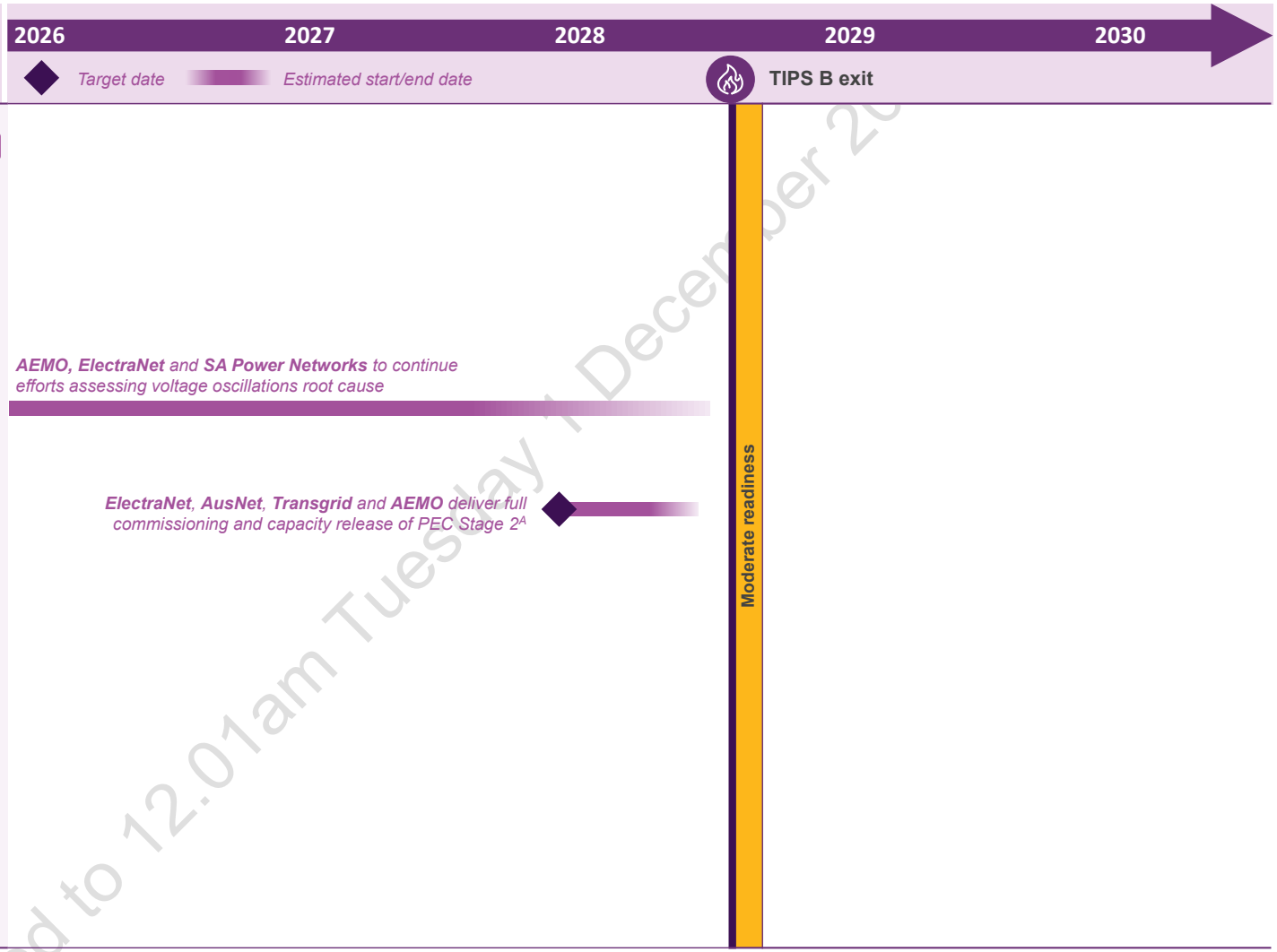
Successful commissioning of PEC Stage 2[A] is necessary for TIPS B retirement, including actions from ElectraNet and Transgrid that are required to ensure no undamped oscillatory modes are introduced.

AEMO continues to observe and coordinate with relevant TNSPs to ensure any necessary actions are planned and taken, and it is expected that constraints can be developed to manage this as an interim measure if required.

Additionally, an oscillation of approximately 2% amplitude has been observed in South Australia during high DPV conditions when operational demand drops below 300 MW. This is included under transient and oscillatory stability, though its mechanism and root cause are still under investigation.

The size of this oscillation is much higher than the current AEMO and ElectraNet agreed limit of 0.5%. Certain synchronous unit combinations show greater susceptibility to the oscillations and are currently being avoided via temporary operating advice developed by ElectraNet, with AEMO support. Collaborative efforts are currently underway between AEMO and TNSPs to review limits advice NEM-wide to ensure TNSPs can continue to provide accurate and least-restrictive limits advice to AEMO, with these activities expected to support enhanced readiness for post-TIPS B retirement operation.

ElectraNet, SA Power Networks and AEMO are progressing targeted collaboration to find root causes and develop long-term solutions to address the oscillations, prior to TIPS B retirement. If long-term solutions cannot be delivered in time, alternative interim solutions, such as additional unit combinations that avoid the oscillations, will also need to be developed.



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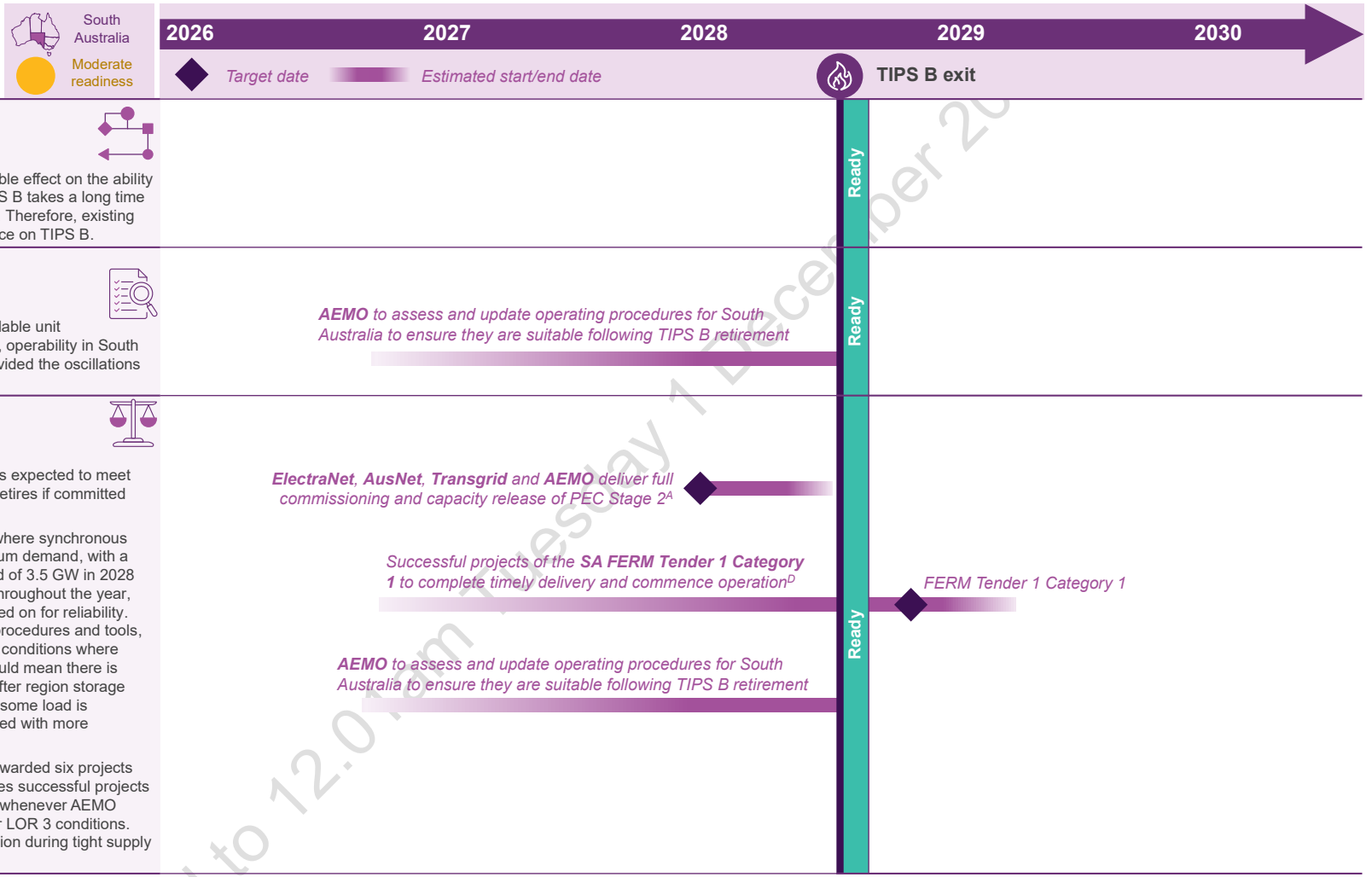
A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

B. See Section 8.

TIPS B exit

South Australia

Moderate readiness



System restoration

TIPS B's retirement is expected to have a negligible effect on the ability to restart South Australia and meet the SRS. TIPS B takes a long time to restart, significantly later than the SRS targets. Therefore, existing procedures restore South Australia without reliance on TIPS B.

Operability

While the withdrawal reduces the number of available unit combinations per current ElectraNet limit adviceB, operability in South Australia is expected to remain manageable, provided the oscillations have been remediated beforehand.

Resource adequacy

The 2026 ESOOC forecasts that South Australia is expected to meet the reliability standard immediately after TIPS B retires if committed and anticipated projects proceed.

However, South Australia will be the first region where synchronous capacity is significantly less than forecast maximum demand, with a 10% POE maximum forecast operational demand of 3.5 GW in 2028 and a region synchronous capacity of 2.0 GW. Throughout the year, VRE, BESS and interconnectors will often be relied on for reliability. AEMO is assessing adequacy of its operational procedures and tools, which may require uplift to respond to edge case conditions where heavy BESS dispatch too early in the evening could mean there is insufficient gas generation capacity to come on after region storage depletes. Situations could otherwise arise where some load is unsupplied that could have otherwise been avoided with more staggered dispatch of storage.

ASL with the South Australian Government has awarded six projects under the first round of the FERMD, which requires successful projects to operate to at least eight-hour storage duration whenever AEMO forecasts or declares Lack of Reserve (LOR) 2 or LOR 3 conditions. Once delivered, this is expected to benefit operation during tight supply conditions, including low VRE periods.

Embargoed to 12.01am Tuesday 1 December 20

A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

B. See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?rev=b42ff9893d2b47788d65404d045124f0&sc_lang=en.

C. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf.

D. See https://asl.org.au/tenders/sa-ferm-tender-round-1.

Zero minimum synchronous generator operation

Q4 2028

South Australia

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability
- Resource adequacy

Context

AEMO and ElectraNet are continuing to work towards further reducing the minimum synchronous generator requirement in South Australia, following the reduction of the minimum number of synchronous generators from two units to one unit in September 2025. AEMO has contracted multiple synchronous generators under Type 1 Transitional Services[A], which are enabled to maintain system security and avoid use of directions.

The 2025 TPSS stated the transition to zero synchronous generators was planned to occur in Q3 2027. Revised ElectraNet voltage control gap RIT-T commissioning timelines, new ElectraNet protection adequacy study findings, and the emerging voltage oscillations challenges led AEMO to revise the anticipated timing to Q4 2028.

Impact

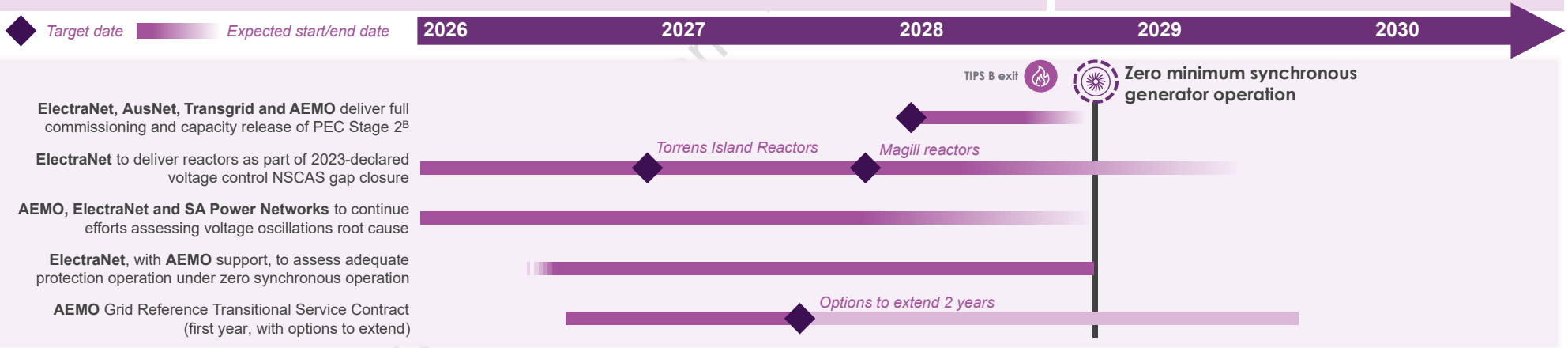
Operating South Australia with zero synchronous generation represents a step change in power system operation. The impacts of this change cannot be fully assessed with modelling alone. To mitigate the risk of the change, AEMO will use available information from international experience, and local trials as required. Successful commissioning of key projects such as PEC Stage 2 and installation of new reactors under ElectraNet's voltage control RIT-T is also required. Following completion of PEC Stage 2[B], the risk of South Australia being islanded becomes non-credible.

The transition to zero synchronous generation will aid MSL management in South Australia by reducing likelihood of MSL occurrences, allowing more CER generation. Reliance on contracted synchronous generation would reduce.

While this transition point is complex and involves multiple interdependent technical solutions, operating South Australia with zero synchronous generation would represent a world-first milestone, as the first interconnected transmission network of its scale to operate under normal operating conditions without synchronous generation outside of trials or testing. Progress is being made through incremental, judicious steps, with close collaboration and across industry and stakeholders.

Preparatory actions

- **ElectraNet** to complete protection adequacy reviews and provide associated limits advice under zero synchronous generation operation, in collaboration with broader industry action and AEMO prior to moving to zero synchronous operation.
- **ElectraNet** to complete assessment of correct protection operation prior to transition point occurrence.
- **AEMO**, **ElectraNet** and **SA Power Networks** to continue collaboration to find root cause of oscillations and develop enduring solutions that allow zero minimum synchronous generator operation. **AEMO** and **ElectraNet** plan to undertake physical test plans on the South Australian network to establish root causes, followed by implementing enduring remediation measures, or medium-term solutions if required.
- **AEMO** plans to support the transition to zero synchronous generators throughout 2027. **ElectraNet, SA Power Networks** and **AEMO** efforts will establish limits advice and subsequent operational procedures for the secure operation of South Australia while at zero synchronous generation.



A. See Section 2.2.1.

B. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

Embargo

Zero minimum synchronous generator operation

South Australia

Moderate readiness

System strength

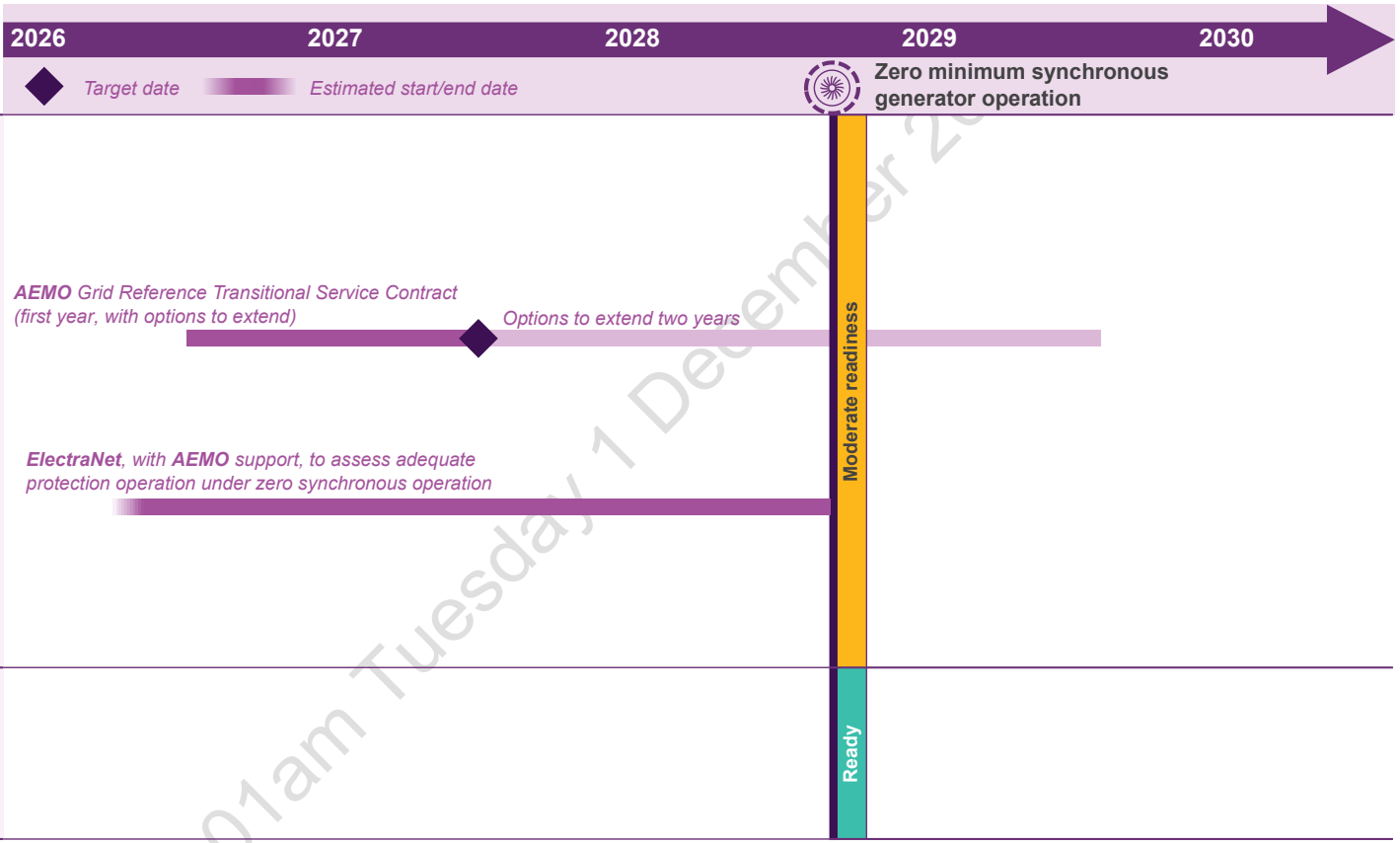
No system strength gaps have been declared in South Australia and minimum and efficient levels of system strength are expected to be maintained over the forecast horizon. Refer to Appendix A2 for further detail[A]. Impact of the observed voltage oscillations, which may be influenced by system strength, is discussed below under Transient and Oscillatory Stability.

However, ElectraNet has raised a potential risk of protection misoperation where IBR contribution is high relative to synchronous sources of fault current. While previous assessments have indicated that fault-current magnitude requirements can be met, ElectraNet has recently identified that the composition of fault current may also affect the performance of some protection functions. This issue therefore warrants further assessment under conditions with high IBR contribution and minimum synchronous fault current levels.

ElectraNet is currently developing effective technical strategies, with AEMO and industry support, to assess correct protection operation under high-IBR conditions to safely transition to zero synchronous generator operation. This is required in advance of navigating this transition point, including AEMO due diligence. This has contributed to moving the indicative transition point timing from Q3 2027 to Q4 2028, subject to demonstrating reliable protection performance.

Frequency and inertia

A combination of both BESS and fast start synchronous units ready to react to contingencies is expected to be available and adequate to achieve sufficient frequency control under zero synchronous generator operation.



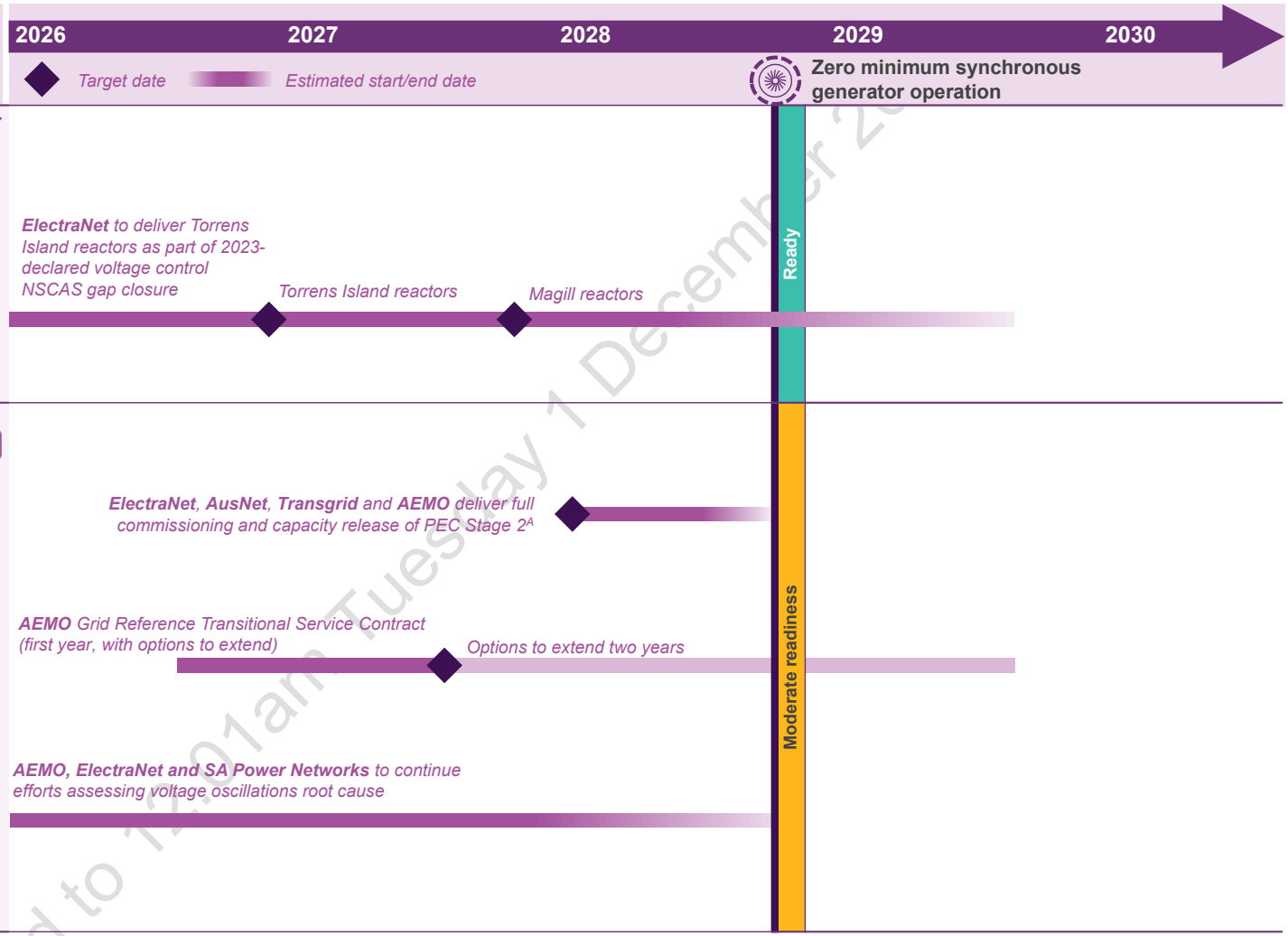
Embargoed to 12.01am Tuesday 1 December 2026

A. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

Zero minimum synchronous generator operation

South Australia

Moderate readiness



Voltage control

Current ElectraNet voltage control advice drives the requirement for two synchronous units at times when demand falls below 600 MW. Analysis indicates synchronous generators will not be required for voltage control installation of all RIT-T reactors, which ElectraNet has confirmed are on track to be in-service October 2027.

AEMO is currently engaging with ElectraNet to assess if the 600 MW operational demand threshold in ElectraNet's current limits advice can be reduced for one synchronous generator operation and zero synchronous generator operation prior to the final installation of the Magill reactor if the voltage oscillations are remediated prior to their installation.

Transient and oscillatory stability

Oscillatory stability within South Australia must be assessed and maintained by ElectraNet, while inter-area oscillatory stability is a shared collaboration between relevant TNSPs and AEMO.

As part of the commissioning of PEC Stage 2[A], it will be critical to address any new oscillatory modes it may introduce during system normal or relevant outage conditions. This is critical for secure operation at zero synchronous generators. Advice from ElectraNet during the commissioning process will be needed to determine any required remediations. This will be addressed via existing PEC Stage 2 collaborative working groups prior to the move to allowing zero synchronous generator operation during system normal without additional condition restrictions.

Additionally, a voltage oscillation of approximately 2% amplitude has been observed in South Australia that occurs during high DPV conditions when operational demand drops below 300 MW, compared to the 0.5% agreed limit with ElectraNet. This is included under transient & oscillatory stability, though its mechanism and root cause are still under investigation.

A solution to these oscillations will need to be in place before the transition to zero units can proceed. A focus group has been established between AEMO, ElectraNet and SA Power Networks to determine root causes and solutions.

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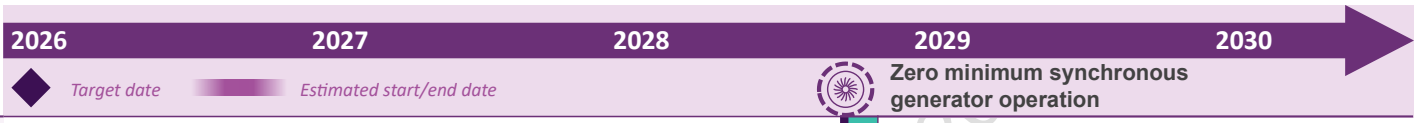
A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

Zero minimum synchronous generator operation

South Australia

Moderate readiness



System restoration

There are negligible risks to system restoration associated with this transition point. South Australia's black start generators have fast start capability even while cold and the region is capable of meeting the SRS, even under zero synchronous generator operating conditions.

Operability

AEMO is currently using Grid Reference Transitional Services to manage power system security during high impact transmission outages. These existing contracts are currently used to improve the operability of one synchronous generator operation in South Australia. They are expected to no longer be required once relevant transition point actions are completed and the zero minimum synchronous generator operation transition point proceeds.

AEMO will monitor the need for any Type 1 Transitional Services as well as resource availability to resecure under non-credible events.

Resource adequacy

The 2026 ESOO[B] forecasts South Australia continues to meet the reliability standard until 2031-2032 under the *Committed and Anticipated Developments* assessment in the 2026 ESOO, with TIPS B, Osborne, Snuggery and Port Lincoln all expected to retire between now and 2028. This reliability outlook has not changed in the December 2026 ESOO Update.

However, timely development of committed and anticipated projects along with those supported by government schemes, such as the CIS and SA FERM, are critical for South Australia's reliability

Embargoed to 12.01pm Tuesday 1 December 2026

A. The capacity release timing for PEC Stage 2 is conditional on availability of suitable market conditions and acceptable test results.

B. See 2026 ESOO Update, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Tasmania

Context

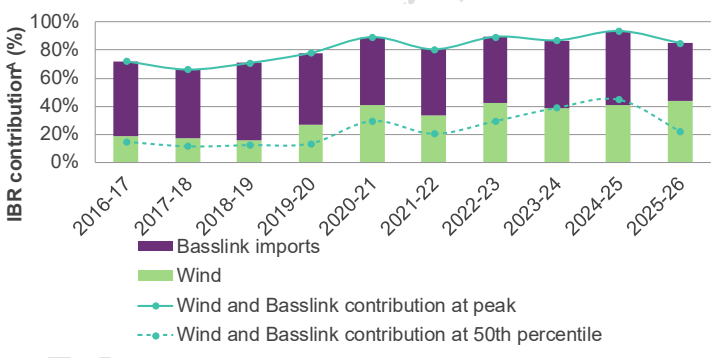
The Tasmanian power system is driven by high proportions of highly flexible hydro-electric generation while benefiting from additional wind generation, allowing the region to already operate at 100% renewables. However, Tasmania is currently unable to operate at 100% IBR because of limited frequency control capability if Basslink is unavailable.

System security is heavily supported by Tasmania's fleet of hydro generators, most with synchronous condenser capability, with back up gas generation to support years with lower dam levels. These are expected to remain into the future.

AEMO is still monitoring the need for Project Marinus to be classified as a transition point, as this may have a significant impact on Tasmanian power system security under certain market outcomes with the potential to provide additional system security support and impact frequency control requirements with effective integration.

***Since the 2025 TPSS**: Project Marinus Stage 1 has become anticipated, and Stage 2 has remained actionable.*

Wind and Basslink imports are making greater IBR contributions



Tasmania's record highest IBR contribution is 94%

System security is supported by Tasmanian hydro units

Timeline	Now	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036

Transition Point
Monitored potential Transition Point
Planned Transition Point
Complete/on track
Moderate readiness
Unresolved issues

Project Marinus Stage 1

Project Marinus Stage 2

Security challenges

Marinus Link Stage 1 is currently anticipated, and Stage 2 is actionable, each specified at 750 MW capacity. Tasmania's largest possible contingency is expected to increase to 500 MW with Stage 1 capacity release. Many of the potential risks associated with designing, constructing and commissioning Project Marinus are expected to be addressed and managed through its delivery by Marinus Link Pty Ltd, TasNetworks and AEMO.

Stage 1 alone represents a significant change for the Tasmanian power system. With Marinus Link 1 and 2 in service, there will be enough IBR and converter-based interconnector capacity to supply all of Tasmania's load without synchronous generation while some hydro units are run in synchronous condenser mode[A].

AEMO believes these factors mean each stage of Project Marinus could benefit from detailed assessment as a Transition Point in future and will continue to monitor Project Marinus and efforts required to successfully integrate it into the Victorian and Tasmanian power systems.

Preparatory actions

- **TasNetworks** to continue progression of system strength RIT-T to meet short term obligations. Long-term minimum and efficient system strength requirements will be monitored and set by AEMO and managed by TasNetworks through the RIT-T framework.
- If required, long-term inertia remediation may be possible alongside system strength remediation measures.
- **AEMO** to continue to monitor the stages of Project Marinus as transition points and assess if additional transition planning efforts or transition point classification are needed over the coming TPSS publications.

A. TasNetworks uses the System Non-Synchronous Penetration (SNSP) ratio to measure IBR contribution. SNSP is the ratio of generation from wind and Basslink H C imports to operational demand. A full equation is also available in AEMO's 100% Inverter Based Resource Generation Study – Tasmanian Region report, at https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/tasmania-100-percent-ibr-generation-study.pdf.

Tasmania security assessment

Now	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036

Assessment horizon	*NSCAS assessment* (See Appendix 2)	*Long-term assessment*
System strength – *nodal assessment* (minimum fault current in MVA)	 *Burnie 110kV* 750 MVA 750 MVA (750 / 0) *George Town 220kV* 1450 MVA 1450 MVA (1450 / 0) *Risdon 110kV* 1330 MVA 1330 MVA (1330 / 0) *Waddamana 220kV* 1400 MVA 1400 MVA (1400 / 0)	AEMO has identified system strength and inertia deficits across Tasmania from 2029-30, but TasNetworks is anticipated to procure contracting arrangements which will address these future deficits. Long Term, system strength procurement is expected to be managed by the RIT-T process and future RIT-Ts.
Inertia (MWs)	3200 MWs 3200 MWs (3200 / 0)	Low long-term risk due to high proportions of synchronous machines within Tasmania and anticipated contracting arrangements alongside system strength.
Other system attribute assessments	**AEMO has not identified any thermal or voltage gaps in Tasmania over the five-year period.**	
Transition points	Project Marinus Stage 1	Project Marinus Stage 2

Requirements Available level Deficit

Embargoed to 12.01am Tue

Victoria

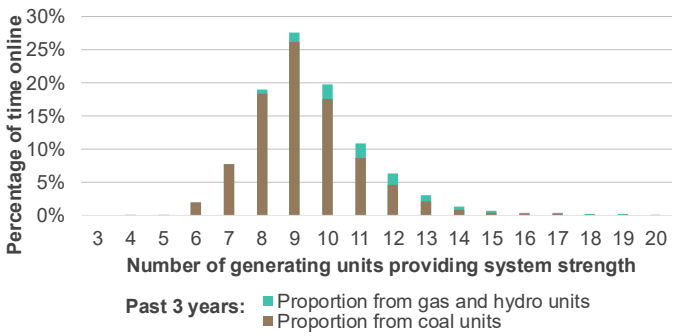
Context

Victoria currently relies on coal-fired generation for much of its system strength and inertia. Yallourn Power Station is expected to retire in July 2028, while the Victorian Government has a Structured Transition Agreement (STA)[A,B] for the orderly closure of Loy Yang A by June 2035. The 2026 ISP[C] *Step Change* scenario also projects further coal capacity reductions from 2031, to support achievement of government policies, contingent on the projected delivery of generation, storage, and network investments. AEMO considers it prudent to prepare for both coal retirements and conditions involving decommitment or unplanned outages and has accordingly selected these as transition points.

These changes align with significant development of Victoria's power system, including network augmentations, REZs and offshore wind. These developments will increase the resources and network capabilities available to maintain power system security as coal-fired generation retires.

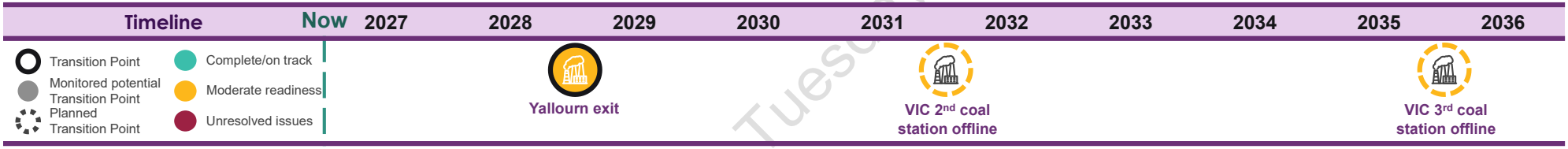
***Since the 2025 TPSS**: The 2026 ISP revised the date of the third coal station offline transition point to 2035 (from 2033). Operational impacts of Yallourn's exit are clearer and understanding of required solutions for second coal station offline have developed, while timelines have reduced by one year. The December 2026 ESOO Update[D] forecasts reliability gaps in Victoria from 2029-30 under the Committed and Anticipated Assessment which may be resolved if all committed, anticipated and government-supported projects are delivered on time and in full.*

Increasing reliance on gas and hydro as coal unit availability reduces



Yallourn Power Station exit removes four synchronous generation units

Synchronous condensers and network upgrade reduce dependency on generators



Security challenges

Delivery of VicGrid's planned synchronous condensers is critical to manage system strength following the exit of Yallourn Power Station and to prepare for later coal station decommitments. Proactive steps are underway to maintain system security at required operational levels following Yallourn Power Station's scheduled retirement. However, some of the required investment in system security services has not progressed sufficiently to meet AEMO's commitment criteria[E]. Without these assets in place, there would be periods of heightened risk in which operational intervention may be necessary to maintain system strength.

Managing that risk will require interim system strength arrangements with existing assets, measures to minimise overlapping unavailability of critical units, and operating measures to manage severe contingencies until enduring solutions are in place. AEMO is reviewing operational procedures and working with VicGrid to prepare for these conditions ahead of Yallourn's exit.

The MSL outlook has marginally worsened since last year, due to forecast synchronous unit dispatch increasing and updated interconnector transfer limits which have reduced expected export capacity during MSL conditions. However, forecast MSL3 events are expected to clear following control room actions outlined in the MSL operational management framework[F].

Preparatory actions

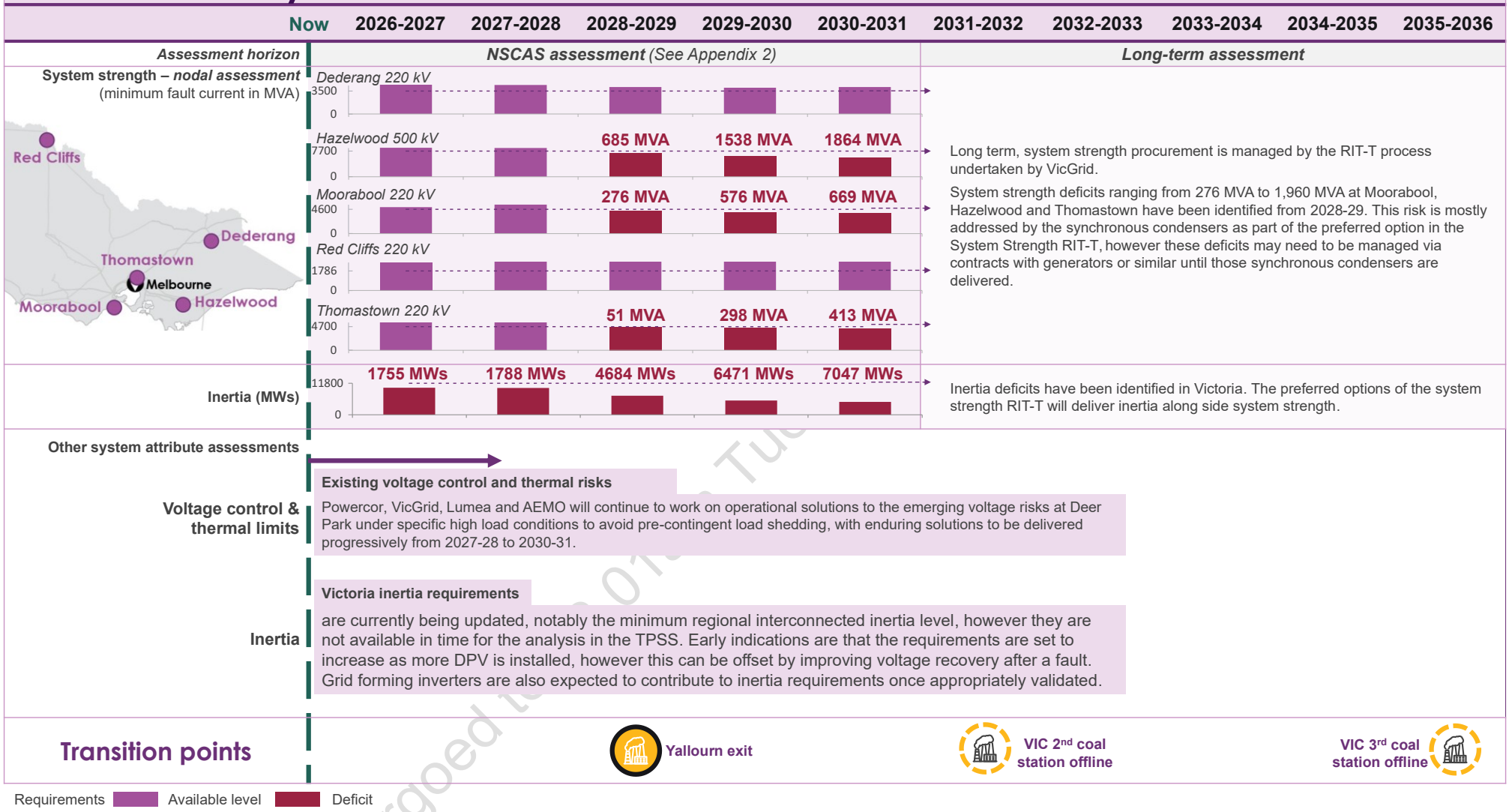
With synchronous condensers not yet committed, VicGrid is actively negotiating contracting arrangements to manage operating scenarios that result in insufficient system strength, inertia, and resecure actions, while continuing to expediate procurement of enduring solutions. Recommended actions include:

- **VicGrid** to consider targeted measures to minimise overlapping unavailability of critical system strength units following Yallourn's exit, until synchronous condensers are installed.
- **VicGrid** to deliver synchronous condensers as quickly as possible to minimise duration of higher risk period following Yallourn retirement and better prepare for potential decommitments of remaining plant.
- **VicGrid** to explore options to broaden the range of minimum unit combinations in limits advice when four or fewer Loy Yang units are online.
- **VicGrid** to make available sufficient inertia services in Victoria to meet current and future local and NEM-wide requirements, including any identified changes to these requirements.
- **AEMO** to assess and update contingency procedures in Victoria to prepare for potentially challenging operation between Yallourn retirement and System Strength RIT-T[G] delivery.

A. See https://www.agl.com.au/about-agl/news-centre/2023/august/loy-yang-structured-transition-agreement.
B. See https://www.premier.vic.gov.au/agreement-secures-transition-loy-yang.
C. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
D. See AEMO December 2026 ESOO Update, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.
E. Refer to Section 2.2.2 for definitions of committed, anticipated, and actionable infrastructure projects in the ISP.
F. See Appendix A3, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.
G. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

Tuesday Emerg 2026

Victoria security assessment



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Yallourn exit

July 2028

Victoria

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Transient and oscillatory stability
- System restoration
- Operability
- Resource adequacy

Context

Yallourn Power Station is approaching the end of its asset life and is scheduled to close on 1 July 2028. EnergyAustralia first announced this closure in 2021 and has an STA with the Victorian Government to manage Yallourn's scheduled closure by this date[A,B]. In preparation for Yallourn's closure, EnergyAustralia has now ceased activities to remove overburden from parts of the mine[C], limiting availability of coal supply to the power station beyond 2028. Practical steps are underway to maintain reliability and system security following station closure.

While system readiness for this transition point is unchanged at 'moderate' since the 2025 TPSS, the time remaining to deliver the required solutions has reduced by one year.

Impact

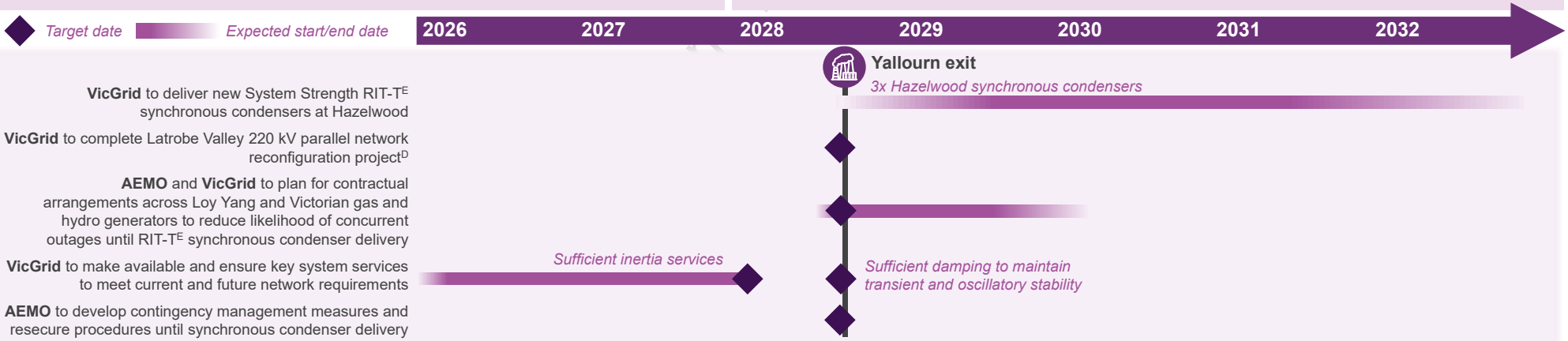
Yallourn's exit will reduce synchronous capacity supplying Melbourne from the Latrobe Valley, decreasing available system strength and inertia, increasing reliance on the remaining coal units at Loy Yang A and B for these services, and limiting resecure options during Loy Yang outages.

Proactive steps are underway to maintain system security at required operational levels following Yallourn Power Station's scheduled retirement, but some system security assets are not yet 'committed' or 'anticipated'. Without these assets, concurrent outage of Loy Yang units could result in AEMO needing to direct some of Victoria's fleet of fast-start synchronous units online to provide sufficient system strength and inertia, possibly for multiple days. If insufficient units are available for direction, AEMO may need to resort to high impact interventions leading to disconnection of generation and load.

Preparatory actions

Enduring system security solutions must be urgently progressed. Until assets are in place, interim solutions are required ahead of Yallourn exit. With urgency, AEMO is reviewing operational procedures and working with VicGrid to be as prepared as possible before Yallourn's exit. If VicGrid's actions do not proceed as planned, this transition point would shift from **Moderate Readiness** to **Unresolved Issues**. Critical actions include:

- **VicGrid** to continue progressing options to minimise overlapping unavailability of critical system strength units until at least the first tranche of synchronous condensers is commissioned. Concurrent unavailability of Loy Yang units and some Victorian synchronous fleet must be avoided wherever possible post-Yallourn until delivery.
- **VicGrid** to deliver new synchronous condensers as soon as possible. Delays to delivery would lengthen Victoria's risk exposure to severe market intervention and could affect readiness for next Victorian transition points.
- **VicGrid** to continue exploring development of new min unit combinations with four or fewer Loy Yang units online, in case it is possible to operate the power system securely without as many directions needed.
- **VicGrid** to deliver the Latrobe Valley 220 kV network reconfiguration project[D] prior to Yallourn exit.
- **VicGrid** to complete studies and progress efforts to ensure transient and oscillatory stability remains adequate following Yallourn closure.
- **AEMO** with **VicGrid** to develop resecure procedures and contingency management.
- **VicGrid** to make sufficient inertia services available in Victoria to meet minimum network requirements, including any changes to these requirements identified through coordination with AEMO, and progress NEM-wide solutions

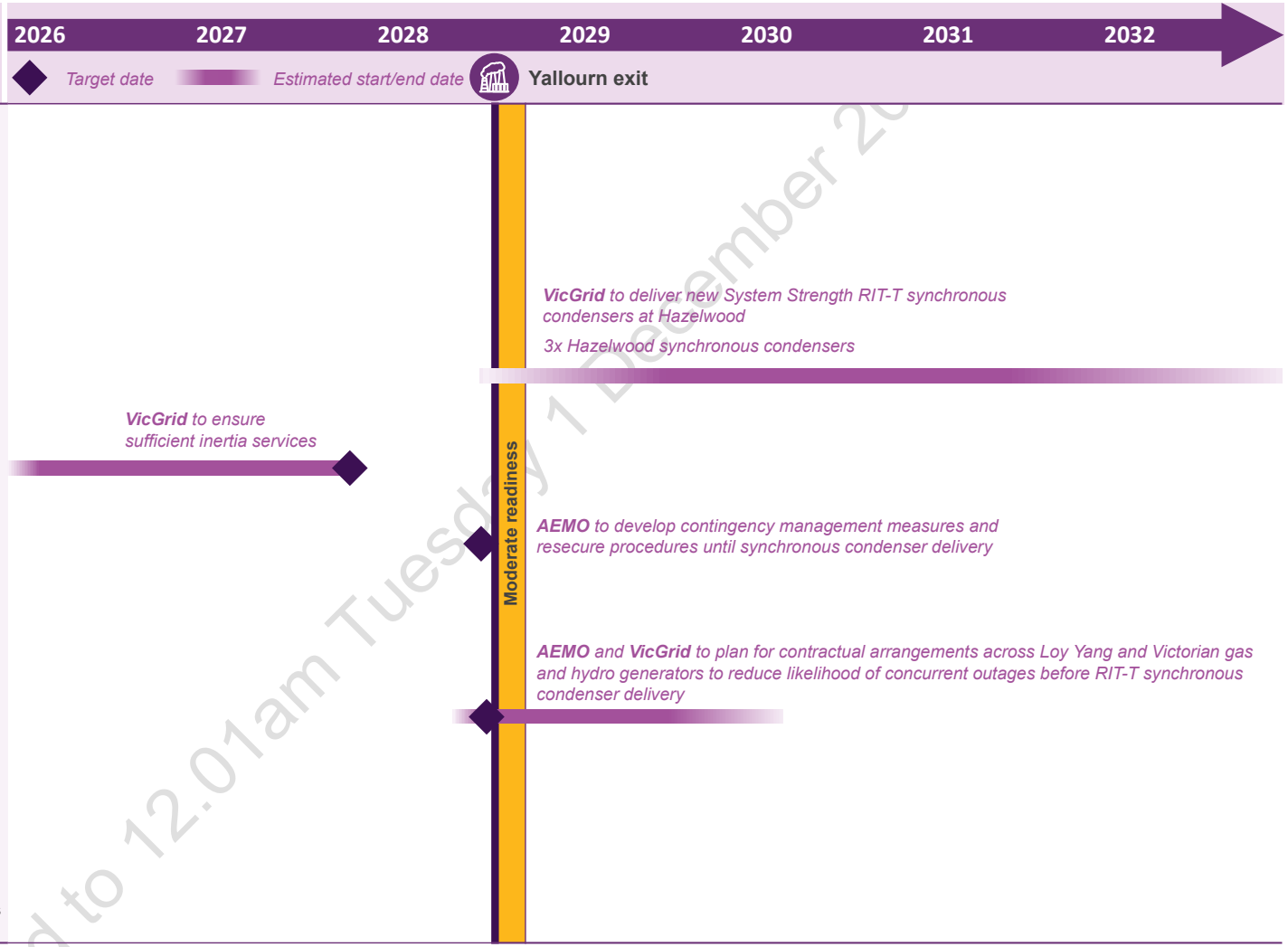


A. See https://www.agl.com.au/about-agl/news-centre/2023/august/loy-yang-structured-transition-agreement.
B. See https://www.premier.vic.gov.au/agreement-secures-transition-loy-yang.
C. See https://www.martincameron.com.au/media-releases/forty-jobs-to-go-at-yallourn-as-closure-looms/.
D. See https://www.vicgrid.com.au/transmission-planning/victorian-annual-planning-report.
E. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

Yallourn exit

Victoria

Moderate readiness



System strength

New synchronous condensers to replace system strength from Yallourn are planned under VicGrid's System Strength RIT-T[A] but are insufficiently progressed to satisfy AEMO's commitment criteria[B]. Construction and supply contracts, financing, and firm commencement date are all yet to be finalised.

Without new assets or appropriate contracts with existing assets, system strength would depend on availability at Loy Yang A/B and other synchronous generating plants, likely to be lower over spring and autumn months when maintenance outages are typically scheduled, operational demand is lower, and other synchronous units are less likely to be online.

Historically, simultaneous outages of two Loy Yang units have occurred 5% of the time and up to 30% in spring. If specific combinations of critical gas and hydro generators and synchronous condensers experienced coincident unplanned outages while two Loy Yang units were offline, the system could not be resecured within NER-required timeframes after a credible contingency (e.g., a further Loy Yang unit trip). To manage this risk, AEMO could need to cancel transmission outages or pre-emptively direct on slow-start units over the duration of the concurrent two Loy Yang unit outage.

Simultaneous outages involving three or more Loy Yang units could not be resecured within 30 minutes of a similar credible contingency. Since 2021 there have been no concurrent planned outages of three Loy Yang units, but three units have been concurrently offline on five occasions after contingencies or unplanned outages, for durations up to a week. Avoiding these conditions is critical for resecure capability.

A non-credible contingency leaving even fewer Loy Yang units online could leave the system susceptible to severe voltage oscillations, as shown by 2026 GPSRR studies[C].

Until delivery of synchronous condensers, concurrent planned unit outages across multiple Loy Yang A and B units and other generators or synchronous condensers should be avoided wherever possible. AEMO is supporting VicGrid in collaborative efforts to manage operability risks in the interim period. AEMO and VicGrid will also develop operational procedures for response to credible and non-credible outages of Loy Yang units, outlining preferred resecure options to reduce operational complexity.

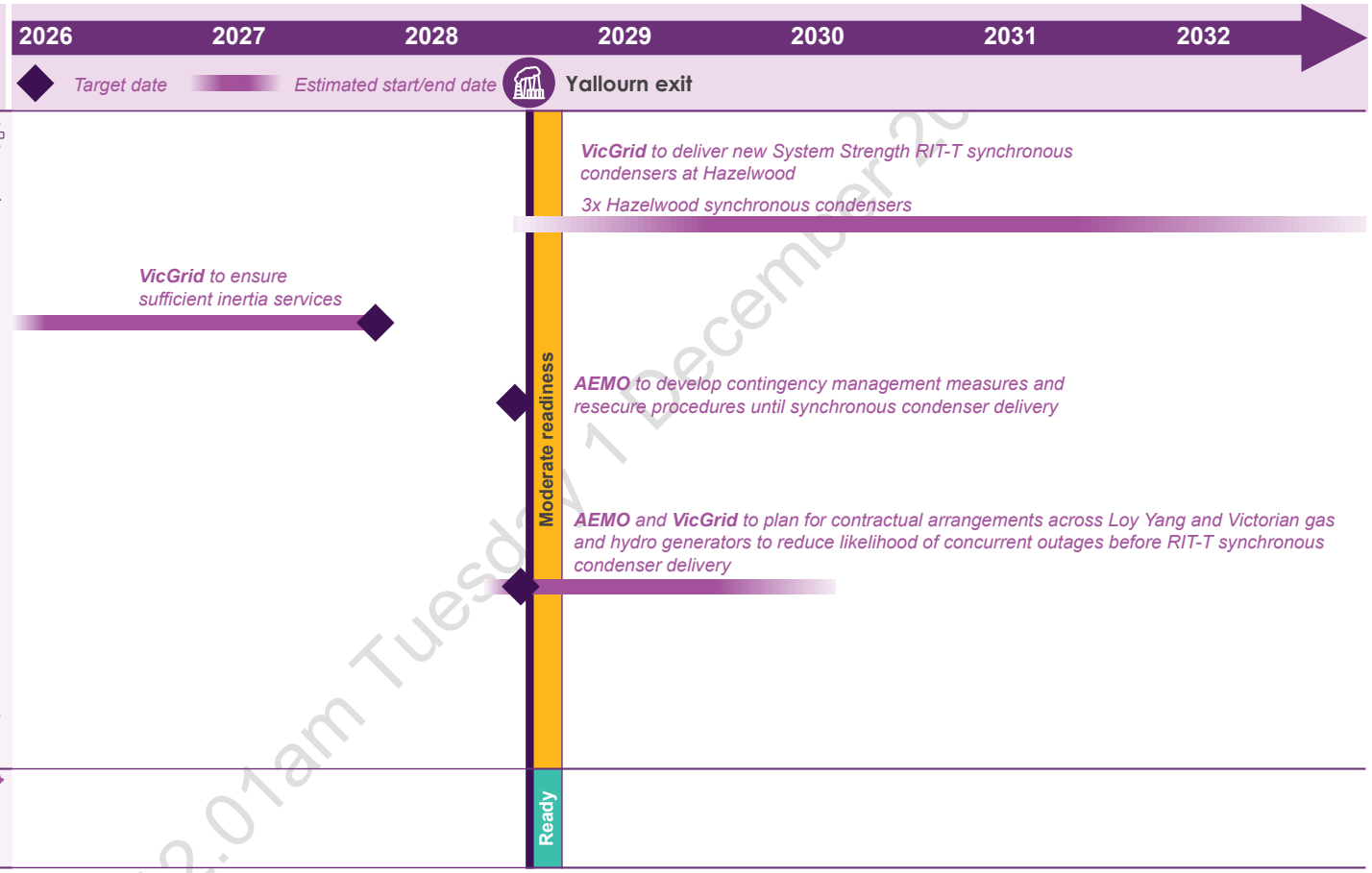
Embargoed to 12.01am Tuesday 1 December 20

A. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.
B. Refer to Section 2.2.2 for definitions of committed, anticipated, and actionable infrastructure projects in the ISP.
C. See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/draft-2026-gpsrr-report-consultation/final-2026-gpsrr-report.pdf.

Yallourn exit

Victoria

Moderate readiness



Frequency and inertia

Yallourn closure will remove up to 5,092 MWs of typically online inertia. If three or more Loy Yang units are on simultaneous outage, Victorian inertia may not meet its minimum regional interconnected inertia requirement. This limit is also expected to increase (refer to Appendix 2[A] for further details).

VicGrid's synchronous condensers[B] could mitigate this risk if they provide material inertia (for example, via flywheels), but they are insufficiently progressed to satisfy AEMO's commitment criteria[C] . Alternatively, existing synchronous units could provide inertia support, or GFM BESS could contribute synthetic inertia, subject to performance testing and validation. Until new assets are in place, VicGrid intends to procure sufficient inertia services to meet the minimum level identified in the 2025 TPSS Appendix 2[A], alongside actions to address system strength.

Without additional assets or contracts, inertia deficits are expected against Victoria's sub-regional network inertia allocation of 11,800 MWs, which VicGrid has planning obligations to meet[D]. However, across the NEM, it is expected sufficient inertia would be available to maintain system security for at least the next three years despite this sub-regional shortfall, meaning further investment at this stage may add additional cost to consumers unnecessarily. As the network incorporates higher levels of IBR, Victoria's inertia requirements will continue to evolve. AEMO will continue to assess future inertia needs and coordinate with VicGrid to reflect any changes to requirements in planning frameworks, including adequate lead times for any new asset procurement, either through RIT-T or NSCAS frameworks.

Voltage control

No identified voltage control risks related to Yallourn exit.

Embargoed to 12.01am Tuesday 1 December 20

A. See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.
B. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.
C. Refer to Section 2.2.2 for definitions of committed, anticipated, and actionable infrastructure projects in the ISP.
D. From 2 December 2027, new inertia planning framework applies under the Improving security frameworks for the energy transition (2024) (ISF) rule; see https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

Yallourn exit





Transient and oscillatory stability

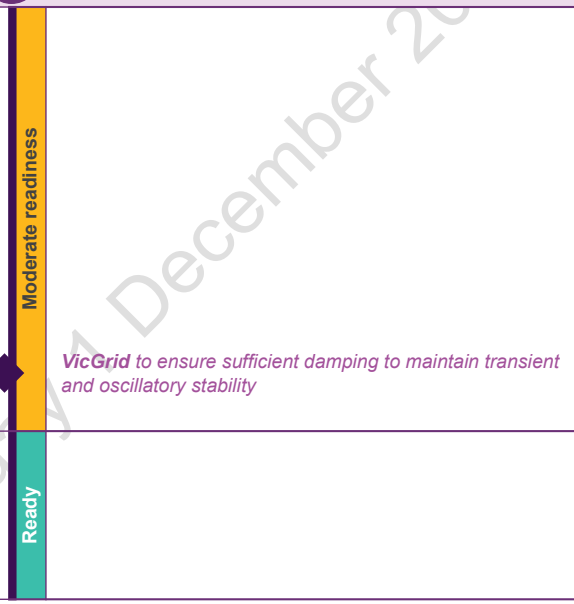
AEMO expects Loy Yang A and B can provide sufficient damping for inter-area oscillation risks without Yallourn.

While very low probability, system conditions that could lead to only one Loy Yang A/B unit online during low demand and high IBR generation conditions may result in severe voltage oscillations, as shown by 2026 GPSRR studies[A]. Such conditions could arise if extreme weather events trigger multi-unit trip or non-credible contingency occurs coincident with multiple maintenance outages. Reducing this risk involves maintaining adequate system strength support, measures to minimise overlapping unavailability of critical units, and AEMO preparing suitable operating measures or relying on the indistinct event framework.

Across the broader range of expected operating conditions, VicGrid is undertaking studies to assess transient and oscillatory stability following Yallourn's closure and identify any necessary measures.

System restoration

System restoration plans in Victoria incorporate, but do not rely on, Yallourn. AEMO will procure sufficient SRAS and RSS via the 2027-28 SRAS procurement round to ensure adequacy of restart pathways in Victoria.



Embargoed to 12.01am Tuesday 1 December 20

A. See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/draft-2026-gpsrr-report-consultation/final-2026-gpsrr-report.pdf.

Yallourn exit



Victoria

Moderate readiness



Operability

Operational complexity is expected to increase materially following Yallourn closure, requiring greater coordination across outage management, market and system operations.

Prior to commissioning of new synchronous condensers[A], current VicGrid limits advice[B] indicates that remaining system strength combinations require three or more coal units online for secure operation with more onerous requirements during some transmission outages.

Challenges with outage planning and resecure actions are associated with maintaining sufficient system strength, and are discussed in the previous section.

Resource adequacy

To ensure transfer capacity from Latrobe Valley remains sufficient to supply metropolitan Melbourne demand, VicGrid plans to undertake network switching as part of the Latrobe Valley 220 kV network reconfiguration project[C]. Delivery is on track.

Immediately following Yallourn's exit, the 2026 ESOO forecasts[D] there is sufficient generation capacity from committed and anticipated developments to maintain Victoria's expected USE within the applicable reliability standard until 2029-30, when a reliability gap is now forecast due to delay of Snowy 2.0. This indicates that Yallourn's exit does not, by itself, result in a reliability gap. However, timely delivery of committed and anticipated developments is critical, and ongoing investment in generation and storage projects and progression towards CIS generation targets are required to maintain reliability beyond the immediate transition point, as indicated by the December 2026 ESOO Update's *Government Schemes and Actionable Developments* reliability assessment.

Adequacy of the gas network to support gas-powered generation and system gas demand was assessed by the 2026 GSOO[E], which forecasts peak day gas shortfall risks could emerge from 2029 onwards under certain conditions in winter during renewable lulls when peak gas and electricity demand coincide. The announced delay of Snowy 2.0 could exacerbate this risk. The GSOO further identifies investment opportunities in East Coast Gas Market infrastructure critical to address gas adequacy concerns from 2030 onwards, and the 2027 GSOO will reassess implications of Snowy 2.0 delay on gas supply adequacy.

VicGrid *to deliver new System Strength RIT-T synchronous condensers at Hazelwood*

3x Hazelwood synchronous condensers

Moderate readiness

AEMO *and* ***VicGrid*** *to plan for contractual arrangements across Loy Yang and Victorian gas and hydro generators to reduce likelihood of concurrent outages before RIT-T synchronous condenser delivery*

AEMO to develop contingency management measures and resecure procedures until synchronous condenser delivery

Moderate readiness

VicGrid to complete Latrobe Valley 220 kV parallel network reconfiguration project

Embargoed to 12.01am Tuesday 1 December 20

[A] See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

[B] See https://www.vicgrid.com.au/__data/assets/pdf_file/0027/766152/victorian-transfer-limit-advice-system-normal.pdf.

[C] See https://www.vicgrid.com.au/transmission-planning/victorian-annual-planning-report.

D See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

E See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf.

VIC 2nd coal station offline

Q2 2031

Victoria

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- System restoration
- Resource adequacy

To be assessed

- Transient and oscillatory stability
- Operability

Context

The 2026 ISP *Step Change* scenario projects that Victoria will see a reduction of 1,160 MW of coal generation capacity in 2031, approximately two units across Loy Yang A and B to support achievement of government policies, contingent on projected delivery of generation, storage, and network investments[A]. While AEMO has not received notice of closure, AEMO considers it prudent to prepare for such decommitment, including possibilities of coal units being displaced by other generation in the market or becoming operationally unavailable ahead of planned retirement dates.

Impact

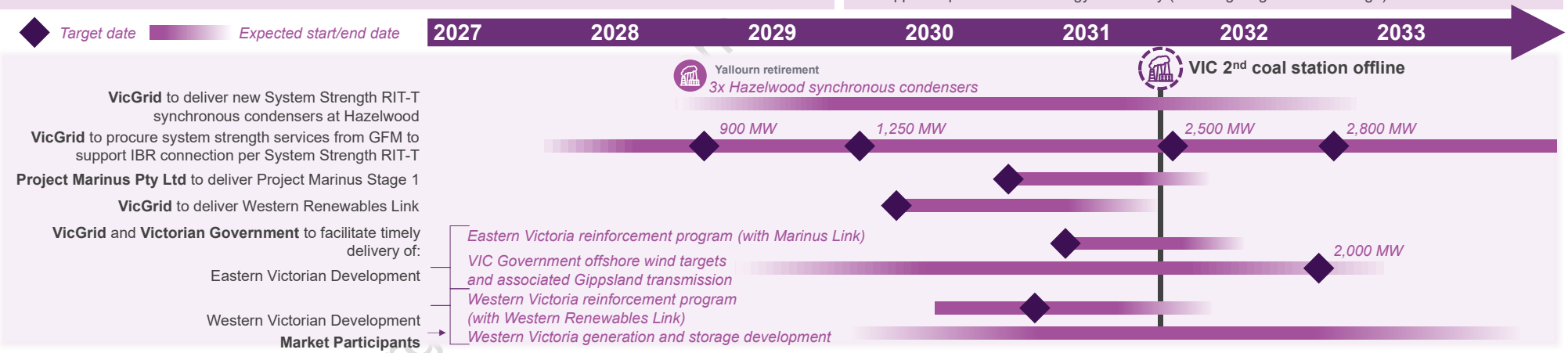
As coal decommits, the Victorian power system must increase flexibility to supply Melbourne from the west, as well as from the east. Reinforcement on both sides is critical to ensure resource diversity to supply peak demand. Supply from the west will involve Heywood, REZs, Western gas generators, Western Renewables Link (WRL) and Victoria – New South Wales Interconnector West (VNI West). Supply from the east will involve remaining coal, Basslink and Project Marinus, Latrobe Valley gas and offshore wind, with opportunities to offset thermal loading risks by connecting generation into the stronger parts of the existing network.

Maintaining system strength and inertia after the decommitment of two Loy Yang units requires full delivery of VicGrid's system strength RIT-T[B], including three synchronous condensers and any necessary contracting with existing units for system strength. Transition point readiness may deteriorate if VicGrid's system strength RIT-T[B] solutions are not delivered in full prior to this transition point. It further requires the completion of other transmission project combinations currently progressing through RIT-T and Victoria Transmission Plan (VTP)[D] processes, alongside timely delivery of new generation and storage projects.

Preparatory actions

Readiness for this transition point is dependent on the full, timely delivery of enduring system strength solutions identified through VicGrid's System Strength RIT-T[B].

- **VicGrid** to deliver system strength solutions, including the first three synchronous condensers or equivalent services, ahead of coal decommitments.
- **VicGrid** to continue facilitating timely delivery of the following project combinations:
  - Western Victorian augmentation pathway, including the Western Victoria reinforcement program, Western Renewables Link, VNI West and associated generation development. This project combination will help manage voltage and thermal loading risks in Victoria and partially support maintaining synchronous fault levels by reducing network impedances to the Ararat and Murra Warra synchronous condensers.
  - Eastern Victorian augmentation pathway, including the Eastern Victoria reinforcement program to increase bi-directional transfer into Eastern Melbourne to address thermal overloads and enable additional imports from Tasmania, through Marinus Link, and offshore wind development to increase reserves for reliability in the absence of the two additional coal units.
- **Market participants** to progress timely delivery of generation and storage projects targeting electrically strong parts of the network[E] and consider projects that combine system security support capabilities with energy availability (including long duration storage).



A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
B. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.
C. Refer to Section 2.2.2 for definitions of committed, anticipated, and actionable infrastructure projects in the ISP.
D. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan/2025-victorian-transmission-plan.
E. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/enhanced-locational-information.

Embargo

VIC 2nd coal station offline

Victoria

Moderate readiness

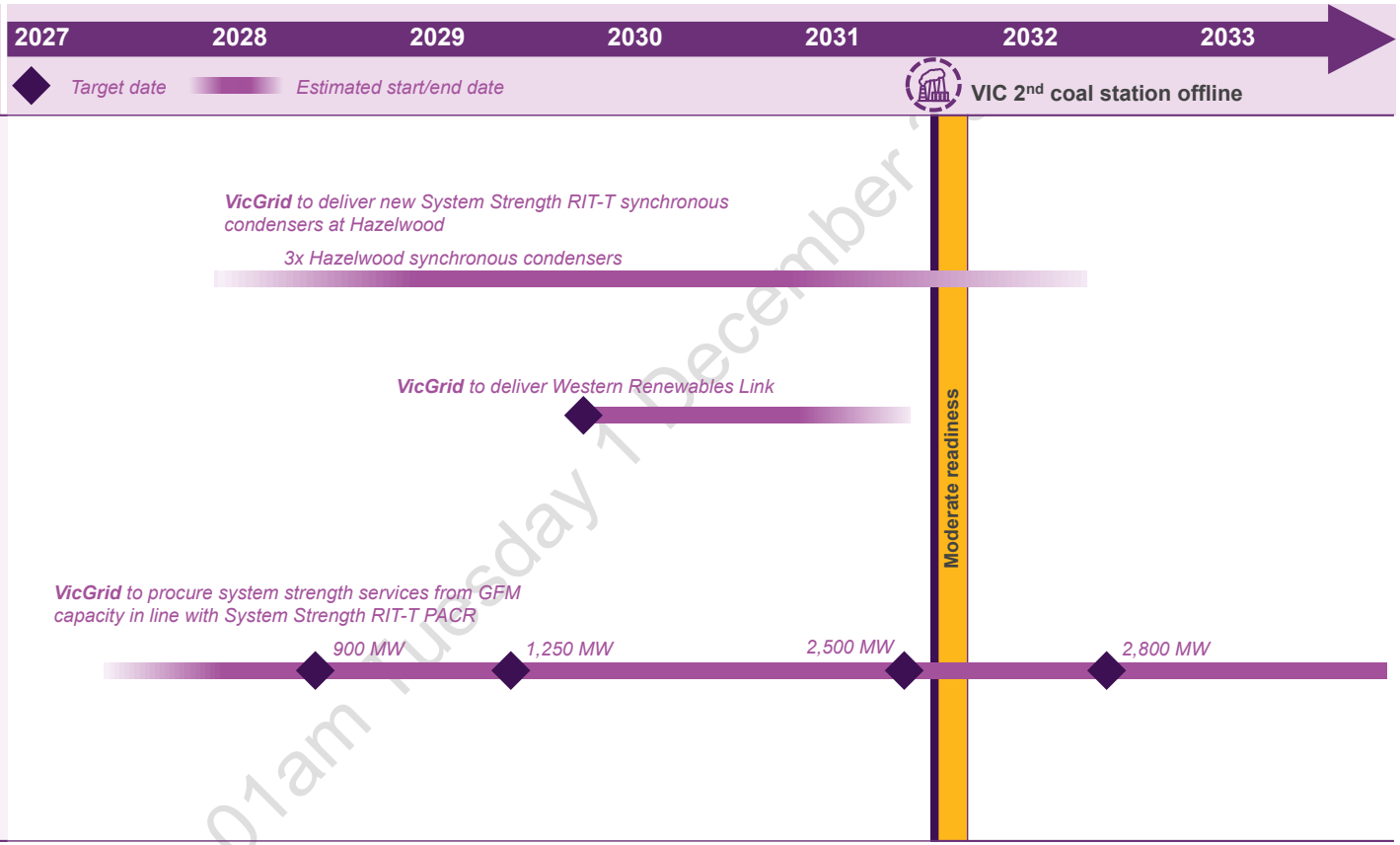
System strength

Three phase fault levels would reduce with Loy Yang decommitment. VicGrid is actively procuring three new synchronous condensers to support minimum three phase fault level requirements. Under the system strength RIT-T[A], these first three synchronous condensers are expected to de-risk this decommitment, however they are not yet committed or anticipated.

Western Renewables Link completion scheduled for late 2029 will improve the ability for metropolitan Melbourne to access synchronous resources in western Victoria. If investments in system strength assets and transmission are not delivered on time and in full, assumptions underpinning the projected timing of this coal decommitment would no longer be valid. Victorian operation after two-unit decommitment in 2031 would be challenging. Minimising overlapping outages of remaining coal units would remain critical and dispatch of additional existing synchronous machines, including gas and hydro units may be required at times, whether through directions or contracts.

VicGrid's system strength RIT-T[A] also plans to procure new GFM BESS to support the efficient level of system strength, needed to support stability of existing and new IBR connections. System strength requirements may change depending on entry of new plant and transmission. AEMO will continue to assess future system strength needs, with input from VicGrid and appropriate Victorian NSPs as required, and reflect any changes to requirements in planning frameworks.

As the first three synchronous condensers and system strength RIT-T GFM IBR capacities are not yet committed, system strength is considered moderate readiness until further developments occur. Transition point readiness may deteriorate if VicGrid's system strength RIT-T solutions are not delivered in full prior to this transition point.



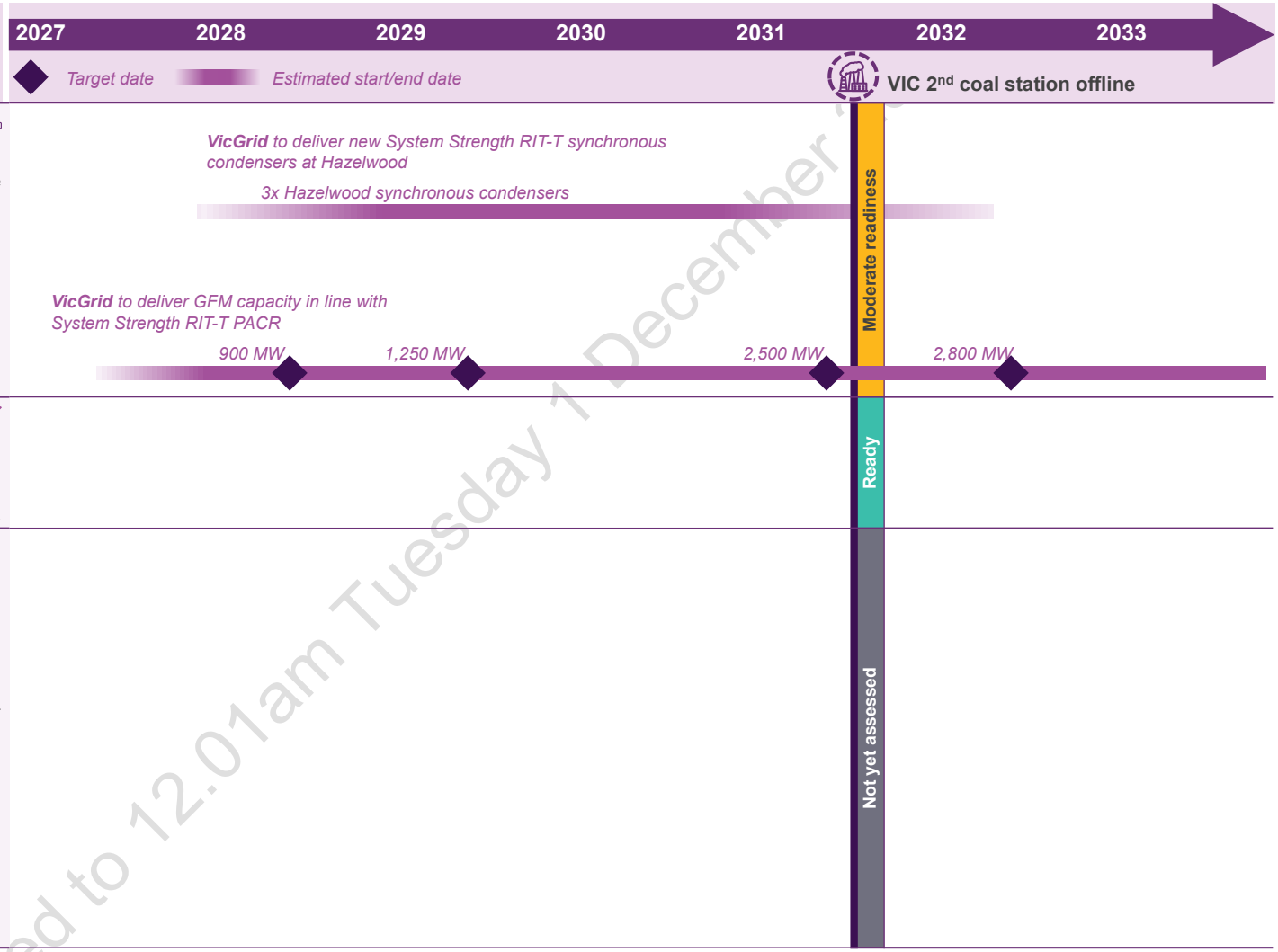
Embargoed to 12.01am Tuesday 1 December

A. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

VIC 2nd coal station offline

Victoria

Moderate readiness



Frequency and inertia

VicGrid has determined that, while Loy Yang decommitment will reduce inertia levels, sufficient inertia services may be provided through synchronous condensers procured through the system strength RIT-T[A], if these are appropriately specified (that is, with flywheels).

However, as the synchronous condensers are not yet committed, sufficient inertia options may not be available to avoid intervention. To meet required inertia levels ahead of this transition point, alternative options for inertia provision would be required, including synchronous generator contracting or expedited GFM procurement to ensure sufficient available inertia prior to 2031-32.

Voltage control

No voltage control risks have been identified for this transition point. Incoming IBR and synchronous condensers are expected to be installed with voltage control capability to manage demand fluctuations.

Transient and oscillatory stability

The decommitment of two additional coal units in Victoria could lead to material changes in power flow patterns, particularly between the east and west of Victoria. Available analysis indicates this is unlikely to reduce existing interconnector transfer limits due to transient or oscillatory stability within currently assessed scenarios.

Further assessment is required by VicGrid to confirm if existing transfer limits within Victoria remain appropriate under these operating conditions.

If decommitment of two additional coal units brings system operation closer to stability limits, this may reduce the ability of the power system to serve load under challenging operating conditions, impacting operational flexibility and lowering available reserves. Generation or network outages may materially exacerbate these impacts. AEMO and VicGrid will need to coordinate their respective planning and operational activities sufficiently ahead of coal decommitment, so that any necessary updates to stability limits, operational arrangements, and/or new assets can be implemented as required.

Embargoed to 12.01am Tuesday 1 December

A. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

VIC 2nd coal station offline

Victoria

Moderate readiness

System restoration

Not expected to be materially impacted by this transition point.

Operability

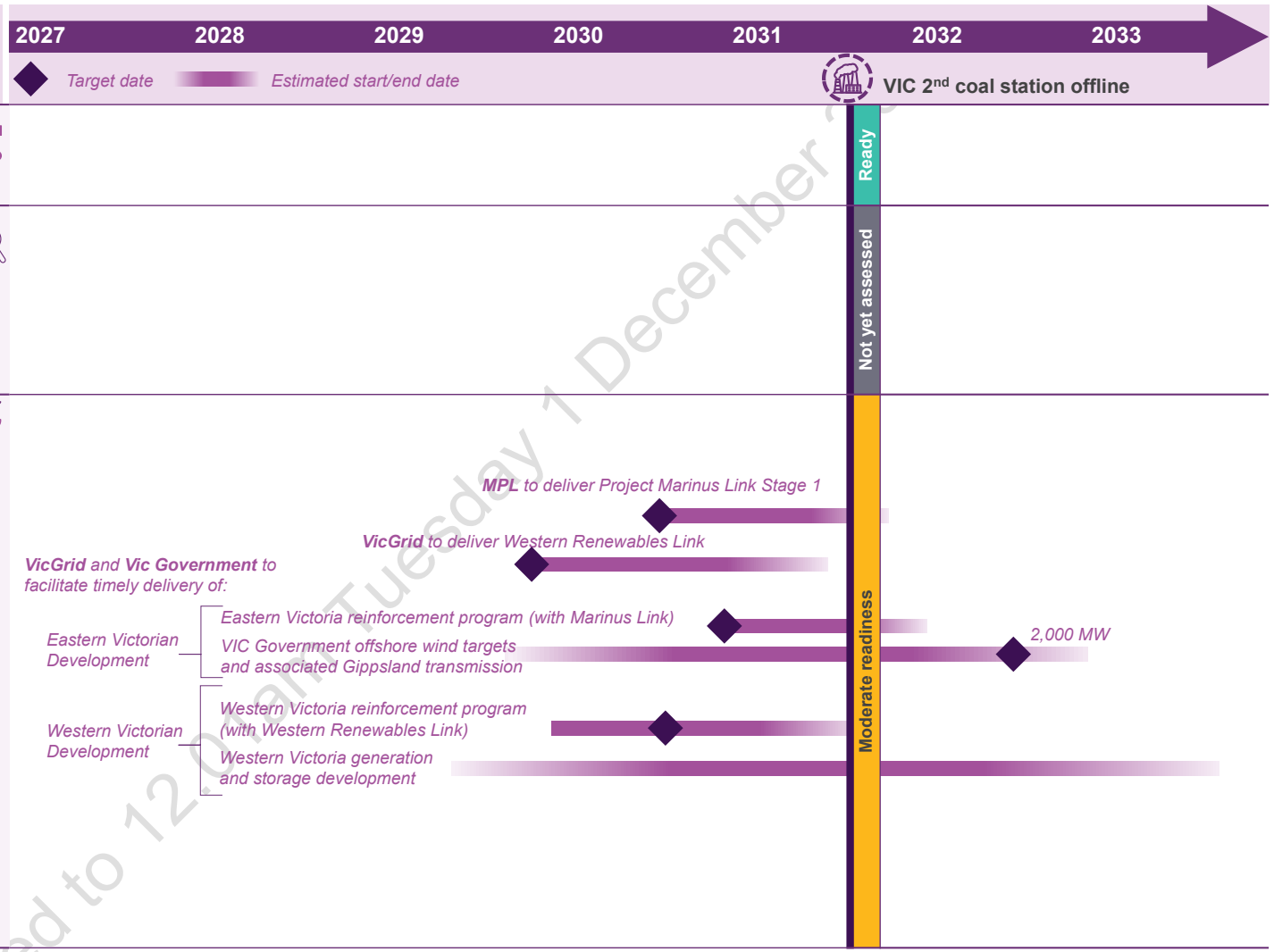
While not yet assessed in detail, operability impacts may include more challenging outage planning to ensure sufficient sources of system strength and inertia. These would be mitigated by the delivery of VicGrid's new system strength RIT-T[A] synchronous condensers, and supported by developments in the use of synthetic inertia from GFM BESS.

Resource adequacy

With reduced supply from Latrobe Valley, Victoria would rely more heavily on wind generation in the west, BESS and gas generation in metropolitan Melbourne, and imports from New South Wales to meet peak demand. WRL unlocks some wind capacity from western REZs but is insufficient alone.

Greater reliance on wind resources from REZs could increase the identified need to address thermal overloading in VicGrid's VTP framework projects[A]. This includes VicGrid's Eastern Victoria reinforcement program to increase eastern metropolitan network capacity, and Western Victoria reinforcement program to address thermal limitations.

With potential for greater reliance on gas generation for system strength combinations or reliability, a risk remains that declining gas supply availability may limit the ability of gas-powered generation to support the system, as peak day reliance on these generators increases in winter months. The 2026 GSOO forecasts[B] that under certain conditions in winter during renewable lulls when peak gas and electricity demand coincide, Victorian gas-powered generation may not be able to access sufficient gas supplies from as early as winter 2029. The announced delay of Snowy 2.0 could exacerbate this risk. The GSOO further identifies investment opportunities in East Coast Gas Market infrastructure critical to address urgent gas adequacy concerns, and the 2027 GSOO will reassess implications of Snowy 2.0 delay on gas supply adequacy.



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A. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan/2025-victorian-transmission-plan.

B. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf.

VIC 3rd coal station offline

July 2035

Victoria

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Resource adequacy

To be assessed

- Transient and oscillatory stability
- System restoration
- Operability

Context

The 2026 ISP *Step Change scenario* projects decommitment of the last Loy Yang unit – and thereby the last coal unit in Victoria – in July 2035 to support achievement of government policies, contingent on the projected delivery of generation, storage, and network investments[A]. This aligns with Loy Yang A's publicly announced retirement date and the Victorian Government's STA with Loy Yang A to manage its orderly closure by June 2035[B,C].

Noting the uncertainties of commercial decisions far in the future, AEMO considers it prudent to prepare for no-coal operating conditions due to possibilities of coal units being displaced in the market or becoming operationally unavailable ahead of planned retirement dates.

Impact

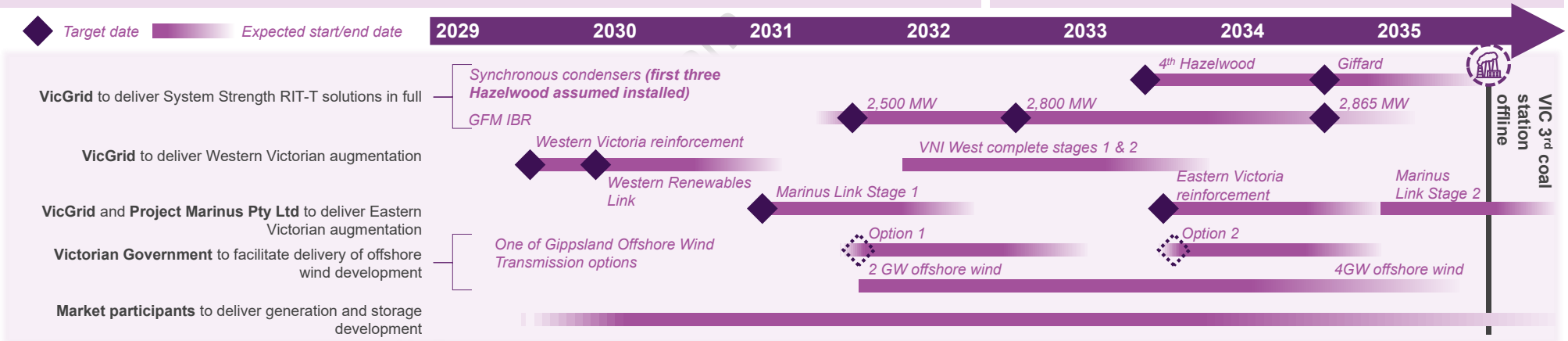
The decommitment of Victoria's last coal unit will be a major milestone and the culmination of a gradual process of reducing synchronous generating units as sources of dispatchable power, inertia, fault current and reactive capability.

Preparation will build on the generation, storage, network and system security assets delivered over the intervening years, including in preparation for previous transition points. These changes will alter network impedance, power flows, power system dynamic behaviour, and may impact requirements for system security.

Readiness for no coal operation in Victoria will require operational uplift to manage a more complex system with increased reliance on coordination across battery storage, hydro resources and gas generation to manage energy across different weather patterns, over days, weeks and months. System restoration will also need to be redesigned.

Preparatory actions

- **AEMO** to review system strength requirements with input from VicGrid and appropriate Victorian NSPs as required, as the network around Latrobe Valley changes with the entry of new plant and transmission.
- **VicGrid** to deliver system strength and inertia solutions ahead of this transition point. This includes synchronous condensers and GFM BESS planned under the current system strength RIT-T[D].
- **VicGrid** to deliver transmission augmentation and associated generation development across the state's east and west[E].
- **Market participants** to progress timely delivery of new generation and storage consistent with 2026 ISP *Step Change* projections[A], including deployment of technologies that could maximise system security services support.
- **AEMO** and **VicGrid** to design new strategies for secure system restart pathways with no coal.



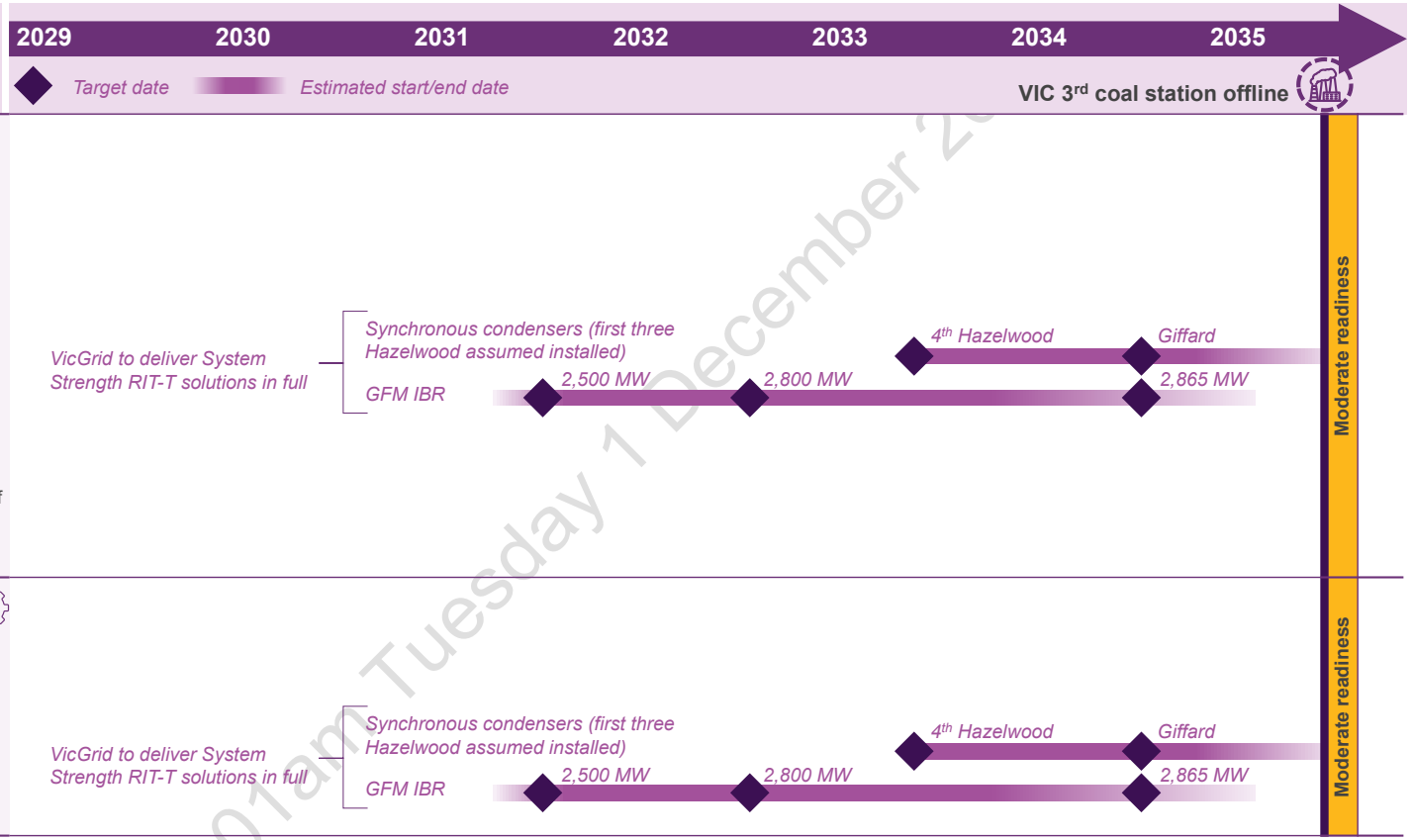
A. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
B. See https://www.agl.com.au/about-agl/news-centre/2023/august/loy-yang-structured-transition-agreement.
C. See https://www.premier.vic.gov.au/agreement-secures-transition-loy-yang.
D. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.
E. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan/2025-victorian-transmission-plan.

Embargo

VIC 3rd coal station offline

Victoria

Moderate readiness



System strength

Replacement system strength solutions are needed to support potential zero coal operation as more coal units go offline.

Under VicGrid's System Strength RIT-T[A], a total of four additional synchronous condensers are currently planned to be installed at Hazelwood before this transition point, as well as a fifth synchronous condenser expected at Giffard by 2034-35 to support connection of offshore wind. VicGrid also plans to procure capability from new GFM BESS to support stability of existing and new IBR connections.

The suitability of planned replacement solutions needs to be continually assessed. Progression to zero coal operation in Victoria will occur alongside significant network augmentation that may result in both impedance changes and altered system strength requirements, subject to the entry of new plant and transmission. As network developments continue, AEMO will review and monitor the adequacy of system strength requirements, with input from VicGrid and relevant Victorian NSPs as required. This may influence specification of new assets.

Frequency and inertia

Decline in synchronous inertia associated with coal units going offline will need to be offset by replacement inertia services. VicGrid plans to deliver these by contracting synthetic inertia support from GFM BESS, contracting with existing synchronous machines, and procuring new synchronous condensers via the System Strength RIT-T[A], which may be specified with flywheels to increase the amount of inertia provided.

AEMO expects to continue monitoring contributions from synthetic inertia to ensure its widespread suitability.

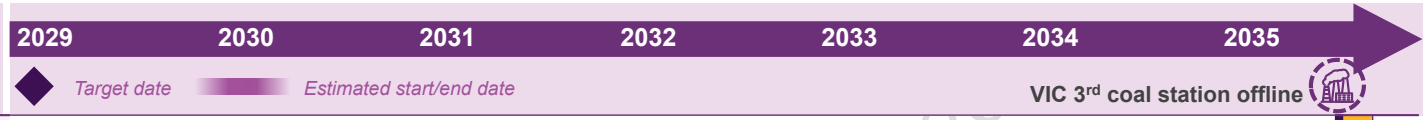
Embargoed to 12.01am Tuesday 1 December 2

A. See https://www.vicgrid.com.au/transmission-planning/regulatory-investment-tests-for-transmission/victorian-system-strength-requirement.

VIC 3rd coal station offline

Victoria

Moderate readiness



Voltage control

Preliminary assessments indicate that development of REZs, generation, storage and transmission infrastructure across eastern and western Victoria may result in altered network flow patterns, that could increase the complexity of maintaining acceptable voltages. While incoming IBR and synchronous condensers are also expected to provide voltage control capability, targeted planning must ensure reactive power support remains adequate to accommodate changing temporal and geographic profiles of demand and supply.

AEMO and VicGrid are expected to identify and assess potential issues through forward planning well before transition points reach operational timeframes. AEMO's annual NSCAS assessment of future voltage control requirements will identify additional investment requirements and give VicGrid a five-year window to action.

Transient and oscillatory stability

This transition point is expected to be accompanied by major changes in network topology, generation mix, and load composition, including the installation of synchronous condensers alongside fast-acting and locationally dispersed IBR and IBL. These changes may alter power system dynamic behaviour and give rise to new interactions that affect transient and oscillatory stability.

However, uncertainty associated with long-term network development means that detailed dynamic assessments that rely on modelling of specific network conditions and equipment are unlikely to provide meaningful insights until closer to the transition point. VicGrid will conduct studies as the transition point approaches and deploy adequate controls. AEMO is also developing a workplan for transient & oscillatory stability[A] to build understanding of evolving stability characteristics and uplift capability to address future stability risks.

System restoration

Victoria will need new and re-designed system restart strategies for stable energisation. Future restart scenarios could involve black start or restoration services being provided by new technologies and along new restart pathways, particularly as the Victorian network evolves over the next 10 years. There remains significant engineering investigation required to validate technical capabilities to support system security during restart, which is a key focus under AEMO's system restoration workplan[B].

Embargoed to 12.01am Tuesday 1 December 2026

A. Refer to workplan for transient and oscillatory stability in Section 8.

B. Refer to restoration workplan in Section 9.

VIC 3rd coal station offline

Victoria

Moderate readiness

Operability

Substantial uplift in operational systems across people, tools, and digital systems will be required to securely operate without any Victorian coal units. Dispatch behaviour and energy management of large-scale batteries must be adequately coordinated with sufficient foresight to balance rapid changes in weather, manage peak demand, respond to contingency events, and cover extended periods of VRE lulls together with gas-powered generation capacity and interconnector support. The role of future control room to facilitate coordinated energy management will be subject to future market settings[A].

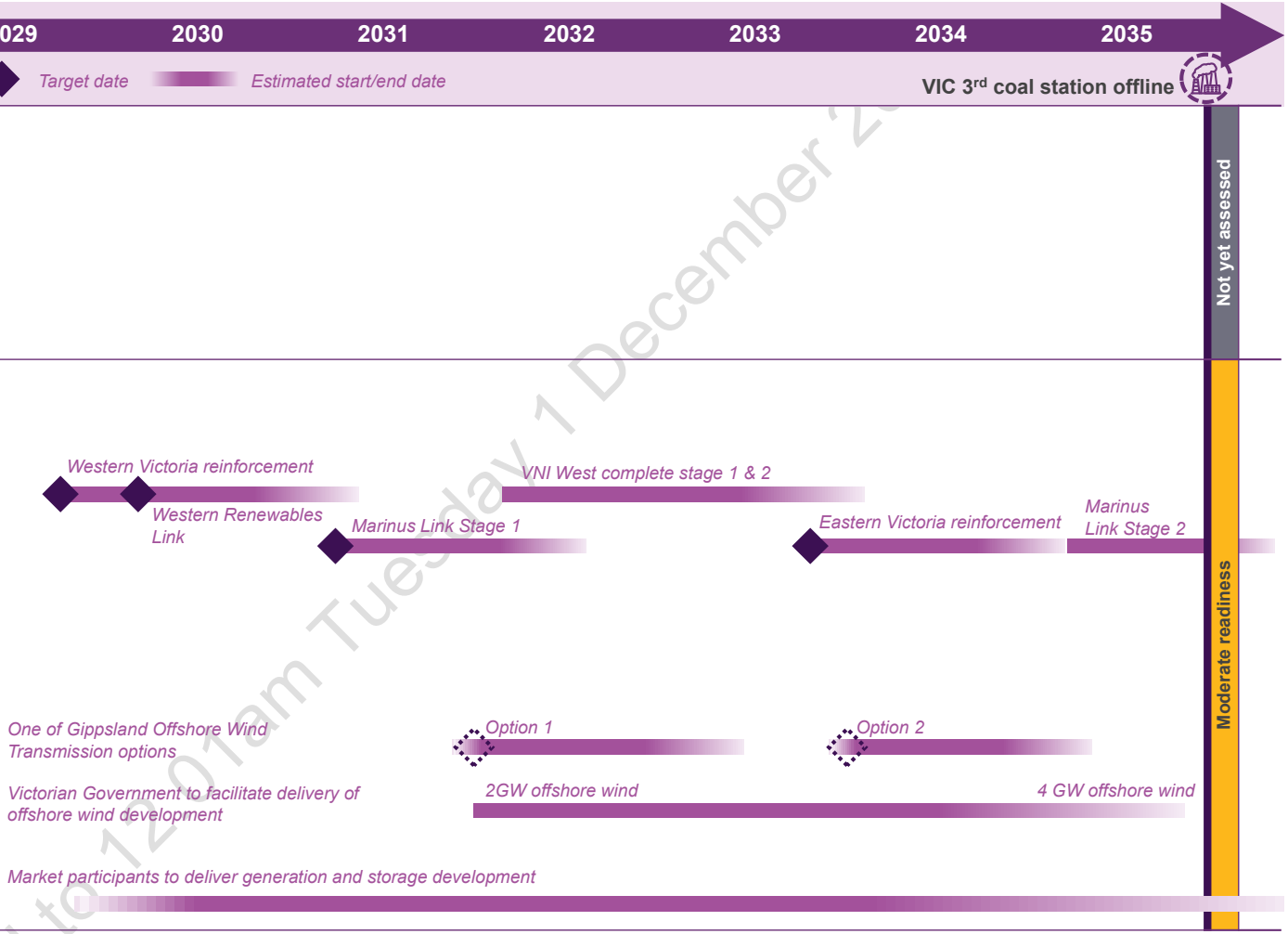
Resource adequacy

Maintaining reliability will require generation capacity beyond the 2026 ESOO's pipeline of committed and anticipated projects[B], as well as completion of new transmission including VNI West and both stages of Project Marinus to support increased transfers from hydro generation in New South Wales and Tasmania. Meeting demand will increasingly rely on weather-dependent variable resources, and energy-shifting storage to manage risks of renewable lulls across weeks and seasons.

Accessing this supply will require network augmentation to increase transfer capacity into metropolitan Melbourne from west and east[D]. The Western Victorian reinforcement program and Western Renewables Link would connect Melbourne to onshore wind resources in western Victoria REZs. Transmission along the Gippsland Shoreline would support build-out of offshore wind, while the Eastern Victorian reinforcement program will increase thermal capacity of the eastern transmission corridor and enable higher Tasmanian exports and Gippsland offshore wind generation.

Delivery of these resources ahead of this transition point will be enabled by coordinated planning across VicGrid and AEMO.

Availability of gas-fired generation for firming during renewable lulls will be subject to gas adequacy, with infrastructure expansion options for the East Coast Gas Market detailed in the 2026 GSOO[E].



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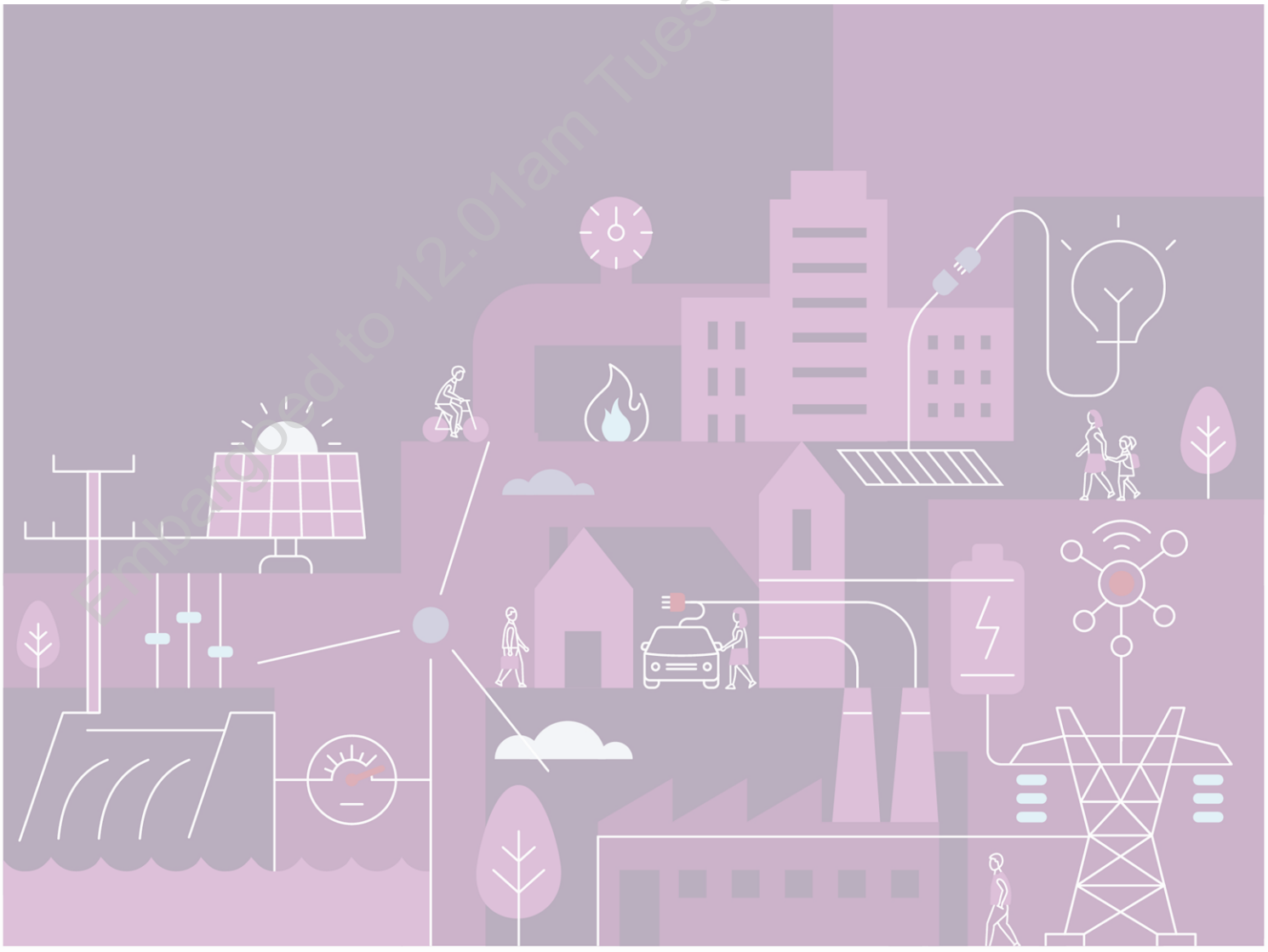
A. Refer to operability workplan in Section 10.
B. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2026/2026-electricity-statement-of-opportunities.pdf.
C. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.
D. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan/2025-victorian-transmission-plan.
E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf.

Part C. System-wide developments and plans

Embargoed to 12.01am Tuesday 1 December 2026



Part C: System-wide developments and plans

Error! Reference source not found.summarised how the transition is affecting power system security, emphasising that the fundamental technical requirements and shared responsibilities of system security are enduring, while the way they are maintained is evolving.

Part B. Regional transition plans focused on detailed assessments of industry readiness for maintaining system security at specific events, transition points, in each NEM region. These assessments foregrounded how some power system criteria, particularly system strength and transient and oscillatory stability, have persistently lower readiness than others. This suggests they will benefit particularly from engineering efforts to address existing limits in understanding and capabilities.

In contrast to **Part B**. Regional transition plans, **Part C**. System-wide developments and plans takes a system-wide approach to the transition, analysing changes, challenges, and opportunities for improving the technical understanding of what is needed to achieve power system security in a low- or zero-emissions power system, including the range of services that may be required.

In this 2026 TPSS, **Part C**. System-wide developments and plans integrates reporting on AEMO's Engineering Roadmap program. This evolution from the 2025 TPSS delivers a structure organised by the power system criteria used consistently throughout the TPSS. Technology developments, such as GFM inverters, that were grouped together in the 2025 TPSS, are now discussed as they relate to specific power system criteria.

While the Engineering Roadmap program continues to be guided by the 2022 *Engineering Roadmap to 100% Renewables* report[49], AEMO is currently prioritising work on system strength, transient and oscillatory stability, system restoration, operability, DER, and large loads including data centres. **Part C**. System-wide developments and plans presents detailed workplans for each of these over a rolling three-year horizon. Compared with AEMO's previous reporting of Engineering Roadmap Priority Actions, these workplans provide stakeholders with longer-term visibility of identified priorities, planned activities, and how the two inter-relate.

Part C. System-wide developments and plans presents brief updates and forward plans on frequency and inertia, and voltage control, which are power system criteria that are, at present, well managed by standard processes. It also provides an update on AEMO's approach to research collaboration and highlights selected areas where further research may have value for future power system security, building on the 2025 TPSS[50].

Objectives and key results

The Engineering Roadmap workplans are structured around the objectives that AEMO considers to be the top priorities to pursue over the coming three years and the key results that define the obtainment of the objectives.

[49] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

[50] See https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-transition-plan-for-system-security.pdf.

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The objectives define the longer-term targets that need to be achieved for operating a low-emissions power system. Even where these cannot or do not need to be fully achieved within three years, they serve to focus AEMO and industry priorities.

Governance, funding and prioritisation

The TPSS is funded through a combination of National Transmission Planner fees and market participant fees, with budgets set each year in advance. They are supported by AEMO's internal governance and assurance arrangements, complemented by engagement with the Reliability Panel and its formal role under the NER to provide independent commentary on the TPSS.

Engineering Roadmap activities are prioritised according to the current and emerging power system risks they address, their expected benefits to consumers, dependencies with other capabilities and reforms, and their cost and deliverability. AEMO will periodically review priorities as system needs, risks and available evidence evolve, and will engage with industry, governments, networks and consumer representatives on the workplans to test priorities and identify opportunities for collaboration. This ongoing engagement will help inform future prioritisation and investment decisions.

Delivery of the workplans will necessarily be subject to available funding, specialist capability and broader organisational delivery capacity. Where these constraints require activities to be re-sequenced, re-scoped or deferred, AEMO will consider the resulting system security and operational risks and, where possible, alternative delivery, funding, reform or industry pathways.

Engineering Roadmap activities will be delivered on an ongoing basis, often in collaboration with industry and government stakeholders, and sequenced around key capability dependencies. Trusted data and models, foundational tools and agreed industry responsibilities must reach sufficient maturity to support implementation of dependent capabilities. Where possible, outputs will be published as they become available, noting the uncertainties and confidentiality associated with some activities. Future TPSS reports will provide concise updates on progress over the preceding year and updated workplans for the following three years.

The TPSS and Engineering Roadmap can help signal areas where further research may provide industry value, drawing on identified system risks and knowledge gaps as well as emerging issues further over the horizon. This can help researchers, academia and industry identify areas of mutual interest and strengthen pathways from research to practical power system applications. AEMO may collaborate where research aligns with emerging system needs and has potential for industry application.

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5 System strength

Summary

- System strength comprises several distinct components. At the highest level, it involves meeting both the minimum three phase fault level and efficient system strength requirements, which serve different power system security objectives and can be delivered by different technologies
- A key driver of the minimum fault level requirement is the secure and dependable operation of network protection systems. These systems have historically been designed around the well understood fault current behaviours of synchronous machines, which differ from the fault response characteristics of IBR.
- As synchronous generation retires and IBR grows, meeting the requirements of network protection systems is expected to become challenging. GFM BESS may provide a means of supporting minimum fault level requirements, but their suitability will depend on demonstrating appropriate compatibility with existing protection needs.
- Over the past year, AEMO has advanced understanding of the compatibility of GFM and protection with studies and testing indicating that compatibility depends on more than fault current magnitude alone, with further work needed to establish where GFM capability can be reliably applied. AEMO is continuing to advance the understanding through offline simulations, laboratory testing, and potentially Type 2 Transitional Services field trials, and is a planning a review of short circuit (SC) modelling methods for high-IBR operating conditions.
- NSPs remain primarily responsible for the security and dependability of network protection systems, including for determining whether identified solutions are technically and economically suitable for their networks. AEMO may work with select NSPs to investigate if any areas might be more exposed to protection-related risks in the future.
- The planned work does not alter existing minimum three phase fault level requirements[51] or SSSP obligations to deliver solutions that meet them. AEMO expects that near-term procurement will continue to rely on established synchronous-machine solutions to meet minimum fault level requirements while industry-wide efforts build the evidence base to clarify the suitability of GFM BESS for supporting existing network protection systems.

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5.1 System strength and the transition

5.1.1 Definition

System strength refers to the inherent robustness of the electrical network and its ability to support the stable operation of power system equipment under changing operating conditions. Where system strength is high, the network is generally less sensitive to variability in power flows (both real and reactive) and better able to withstand and recover from disturbances, such as faults or the unexpected loss of generation or transmission equipment. Importantly, 'system strength' is an umbrella term that encompass several distinct components, each with their own implications for power system security.

[51] Assessed in Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

AEMO's *System Strength Requirements Methodology* (SSRM)[52] describes the individual technical criteria that are actively managed through the system strength framework. NER S5.1a.9 specifies two categories of system strength requirements:

a) Maintaining **minimum *three phase fault levels*** sufficient to:

   i. Ensure correct operation of network protection systems.

   ii. Support the stable operation of voltage control systems.

   iii. Enable the power system to remain stable following any *credible contingency event* or *protected event*.

b) Providing an **efficient level of system strength** to ensure that stable voltage waveforms are maintained at all *connection points* such that:

   i. In steady state conditions, *plant* does not create, amplify, or reflect instabilities.

   ii. Voltage waveform stability is maintained following any *credible contingency event* or *protected event* and is not dependent on *plant* disconnecting or varying its active or reactive power transfers, other than in accordance with agreed performance standards.

The constituent components of system strength must be considered individually to ensure that underlying power system security risks are appropriately managed.

Protection compatible fault current

AEMO has previously used the term "protection quality fault current" to describe fault current of appropriate magnitude, duration, sequence composition and waveform characteristics to enable existing protection systems to operate in a secure and dependable manner.

Consistent with stakeholder feedback, AEMO now uses the term "protection compatible fault current" to describe fault current characteristics that support the reliable operation of relevant protection systems. This avoids an implied measure of "quality" and focuses on functional compatibility between fault current source characteristics and network protection requirements.

5.1.2 Status

The delivery of system strength is changing

Synchronous generators and synchronous condensers are the traditional providers of system strength. Their dynamic behaviour is understood and predictable with a high degree of confidence using well established and validated modelling techniques. This has shaped the design of protection systems and contributed to the development of simplified metrics, such as 'short circuit ratio (SCR)', that are often used to quantify system strength.

The decommitment and retirement of synchronous generators reduces the availability of their well-defined fault current contributions to support network protection during system fault events. This reduction is evident in the system strength readiness ratings for multiple transition points associated with coal decommitments in **Part B**. Regional transition plans, including:

[52] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

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- New South Wales third coal station offline – assigned a 'Moderate Readiness' rating, on the basis that Transgrid is exploring alternatives to some of the synchronous condensers previously nominated in Phase 2 of its regulatory investment test for transmission (RIT-T), and
- Victoria second coal station offline – assessed as 'Moderate Readiness', as the approach for maintaining minimum three phase fault levels are expected to rely heavily on the timely procurement and installation of network based synchronous condensers, some of which are not yet committed or anticipated.

These examples highlight present challenges in procurement costs and/or timing constraints and the potential benefit of SSSPs being able to consider a broader range of solutions. GFM converters, which act as controllable voltage sources, are a technology that can make contributions to the different aspects of system strength. As detailed in **Table 15**, these include the capability of maintaining appropriate voltage source behaviour during and immediately after network disturbances and proven capabilities to support the operation of grid-following (GFL) devices when connected within suitable proximity. Transgrid intends to contract with 5 GW of GFM BESS by 2032-33[53] as part of meeting efficient system strength requirements in New South Wales.

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Table 15 Technical considerations for planning system strength solutions.

Category	Component	Technical considerations for GFM solutions
Minimum three phase fault level	Correct operation of network protection systems.	• At present, synchronous machines are the only recognised contributors to the corresponding minimum fault level requirement. • It has generally been assumed that any fault current provided by IBRs, whether GFL or GFM, would act to further support, rather than hinder, the performance of network protection systems. • The potential utilisation of GFM BESS going forward is to be assessed.
	Stable operation of voltage control systems.	• In addition to synchronous machines, it is reasonable to assume that other technologies could support stable operation of voltage control systems where sufficient reactive power capability is available and dynamically controllable. • For example, GFM-controlled Flexible AC Transmission System (FACTS) devices may provide a credible future solution, particularly under very weak-grid conditions where the stable operation of conventional GFL-based FACTS devices can become increasingly challenging. • Credible solutions will be dependent on the nature of the voltage control issue to be managed but conceptually, need not be synchronous machine based.
	Stability following any credible contingency event or protected event.	• The current-limited nature of GFM converters requires different and more complex considerations compared to synchronous machine solutions. • As an example, GFM BESS can provide a range of system security services including dynamic voltage control, inertial response, and increased voltage waveform stability to support the operation of GFL IBR. • Credible GFM solutions will be dependent on the type of instability that is to be mitigated.
Efficient level of system strength to ensure that stable voltage waveforms are maintained.		• In addition to synchronous machines, GFM BESS can increase voltage waveform stability to support the operation of GFL IBR. • Other GFM technologies are likely to be proven going forward once more operational experience becomes available, such as GFM static synchronous compensators (STATCOMs).

A key remaining uncertainty is the ability of GFM converters to adequately support the secure and dependable operation of existing network protection systems, including unbalanced faults in their various forms. Unlike synchronous machines, hardware and software designs implemented by different OEMs can result in material differences in GFM converter fault

[53] See Section 10 of Project Assessment Conclusion Report (PACR), at https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf.

responses, further complicating short circuit modelling and protection analysis. Given current uncertainties with the technology, the protection component of the minimum three phase fault level requirement presently requires exclusive use of synchronous machines. This includes synchronous condensers being procured by several SSSPs to replace the contributions currently being provided by retiring coal generation.

Challenges and opportunities

Synchronous condensers are an established option for managing fault levels, but supply chain constraints and global demand are driving up costs and lead times. While near-term synchronous condenser procurement remains critical in the absence of proven alternatives, efforts are needed to identify alternative future sources of 'protection compatible' fault current that can reliably contribute to satisfying minimum fault level requirements. This presents an opportunity to reduce long-term costs for consumers by broadening future technology and contracting options available to SSSPs. GFM BESS is a key technology being investigated for suitability, in part because of its existing[54] and expanding capacity in the NEM[55].

At present, evidence from modelling, laboratory testing and field observations, both within the NEM and internationally, has demonstrated that the fault current characteristics of IBR, including GFM devices, can affect the performance of existing protection systems and, in some circumstances, contribute to protection misoperation. Uniform standards for the interconnection and interoperability of GFM devices are not yet fully established and remain the subject of ongoing industry development both in Australia and internationally[56].

Protection systems detect faults and initiate the rapid, selective disconnection of affected equipment, helping to protect people and assets, while limiting disruption to the wider power system. Failure to clear a fault promptly, or unintended disconnection of equipment, can result in potential plant damage, supply interruptions and, in some circumstances, wider power system impacts. Protection design involves coordinating detection methods, settings and operating times across a range of network conditions to balance dependable fault clearance against unintended operation. As the generation mix changes, maintaining this balance requires careful assessment of how different fault current characteristics interact with existing protection schemes, together with validation of IBR performance against evolving technical requirements.

While it is reasonable to expect advances towards network protection designs that are less sensitive to differences between synchronous machines and IBR[57], there are practical and economic limitations that prevent rapid deployment of new solutions across a network the size of the NEM. It will therefore remain important to ensure the security and dependability of protection equipment already in service.

If a pathway to utilise GFM BESS contributions to minimum fault level requirements can be identified, this is likely to add complexity to short circuit modelling and system strength analysis. If not adequately addressed, this complexity could introduce uncertainty into the planning and assessment of system strength solutions, potentially delaying their implementation or limiting the extent to which GFM BESS contributions can be relied upon operationally.

AEMO sees opportunities to explore and evaluate the role of GFM converters to contribute to minimum fault level requirements. This is a key technical priority to support the timely and cost-effective procurement of future system strength

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[54] As of September 2026, the nameplate capacity of in-service transmission connected GFM BESS is ≈ 4.1 GW.

[55] As of September 2026, the nameplate capacity of identified transmission-connected GFM BESS projects in the development pipeline is ≈ 37 GW.

[56] For example, IEEE Standard 2800.1, at https://development.standards.ieee.org/myproject-web/public/view.html#pardetail/13109 .

[57] See discussion in NLR report "A Comprehensive Study of the Impact of Inverter-Based Resource (IBR) Modelling and Control on Protection Relay Elements", at https://docs.nlr.gov/docs/fy26osti/94430.pdf.

solutions across the NEM, complementing ongoing regulatory reform[58]. This needs to be balanced against the possibility that GFM BESS may not be sufficiently proven to support some or all existing protection system designs, necessitating continued reliance on synchronous machines for the foreseeable future.

5.1.3 Building the knowledge base

AEMO recently published four Engineering Roadmap technical reports that contribute to an evolving evidence-base of IBR fault response characteristics, observed compatibility challenges with common protection designs, and options for assessing the fault current contributions from GFM equipment. The purpose and objectives of each report are outlined in **Table 16**. The reports collectively move from defining the problem and reviewing international experiences, through identifying practical protection and modelling requirements, to testing physical relays using detailed GFM models.

Table 16 The focus of each technical publication.

Report	Primary objective and contribution
Etik Energy[A] Grid-Forming and Grid-Following Inverter Fault Current Contribution	Establishes the technical problem by comparing synchronous machine, GFL and GFM fault current characteristics, reviews international protection incidents, identifies the attributes of fault current that influence relay performance, and proposes preliminary criteria for "protection quality" fault current and future modelling studies.
Amplitude Consultants[B] Grid Forming BESS – Fault Current Contribution Study Scope	Develops a structured investigation framework for determining whether GFM BESS can provide fault current suitable for protection operation and potentially contribute to minimum fault level requirements. It proposes staged electromagnetic transient (EMT) simulation, waveform playback, HIL testing, increased OEM engagement and wide-area NEM studies.
DEL Engineering[C] Impact of IBRs on Power System Protection	Examines contemporary protection engineering practices, available short circuit models, impacted relay functions and the GFM parameters most relevant to protection engineers. It also identifies testing priorities and considers the separate protection challenges that arise during system restart.
AEMO summary of EPRI analysis[D] An analysis of fault current performance from grid-forming (GFM) inverters.	Extends the work into detailed verification using OEM-specific GFM models, EMT simulation, and open loop playback of simulated fault events into commercial protection relays. It investigates response magnitude, negative-sequence behaviour, phase-angle dynamics, and charging versus discharging operation of GFM-BESS, while also assessing the feasibility of larger-scale closed-loop HIL testing.

A. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/grid-forming-and-grid-following-inverter-fault-current-contribution.pdf.
B. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/grid-forming-bess-fault-current-contribution-study-scope.pdf.
C. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/impact-of-ibrs-on-power-system-protection.pdf.
D. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/analyse-fault-current-performance-from-grid-forming-inverters.pdf.

The overall focus of AEMO's investigations to date has been to build an understanding of the fault current characteristics the future power system is likely to need; determine whether GFM and other IBR technologies can provide it consistently, considering typical OEM design approaches and the inherent technical limitations of power converters; and better define the modelling and testing regimes needed to demonstrate the required capabilities with confidence.

Key outcomes

The reports highlight several common observations and concerns (summarised in **Table 17**), which provide the building blocks for the next stages of the system strength work program described in Section 5.2. One of the most practical observations is that existing protection systems have been designed around the fault current characteristics of synchronous machines. As a result, the specific characteristics of fault current delivery materially affects their in-service performance. While some protection functions are less susceptible to misoperation because of their basic operating principles, other

[58] Including the Security Frameworks Enhancement rule change process; see https://www.aemc.gov.au/rule-changes/security-framework-enhancements.

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functions are reliant on the presence of, and assumed fixed relationship between, particular electrical quantities. For these reasons, it is important to understand in depth how IBR, including GFM-based technologies, respond to fault conditions.

Table 17 Notable issues identified for consideration and action as part of future activities

Identified issue	Explanation
Synchronous-machine and inverter fault responses differ.	Synchronous machines provide comparatively high, physically determined and predictable fault currents. IBR fault current is generally lower, current-limited and strongly influenced by converter controls, fault ride-through design and initial operating conditions. Relevant differences include current magnitude and duration, positive- and negative-sequence content, phase angle response, frequency tracking abilities, harmonic content and apparent impedance behaviour.
Whether fault current is "protection compatible" is not simply a matter of magnitude.	Reliable relay operation depends on the characteristics of the fault current waveform including speed of response under fault conditions, phase-angle qualities, stability, and duration of the current contribution. A nominally adequate current magnitude may still be unsuitable if it develops too slowly, contains limited or inconsistent negative-sequence current, exhibits unpredictable angle behaviour, becomes distorted, or decays before backup protection can operate.
Compatibility with existing protection schemes.	Investigations have considered how IBR characteristics affect typical protection elements including distance, directional, overcurrent, and differential protection, as well as fault-identification, power-swing and auxiliary supervision functions. Identified concerns include failure to detect certain types of faults, incorrect determination of fault direction, overreach or underreach across protection zones, wrong faulted-phase detection, and unintended tripping.
Performance during unbalanced faults.	Negative-sequence current is a major focus because its magnitude, phase relationship and response time are used by many directional, supervision and fault-identification functions. Unlike synchronous machines, IBR negative-sequence behaviour is determined by control design and may vary across different equipment.
Variability across OEM designs.	OEM specific current-limiting strategies, fault ride-through controls, and prioritisation of active, reactive and sequence currents can produce materially different outcomes. A key question is therefore what performance should be specified at the plant terminals, rather than assuming every implementation of GFM automatically guarantees suitable behaviour.
Adequacy of modelling and study tools.	Traditional short circuit assessment methods were developed around the relatively predictable fault response of synchronous machines and may not adequately represent the control-dependent and non-linear fault current characteristics of IBRs. Further work is necessary to investigate the limitations of conventional phasor-domain short circuit calculations and the extent to which EMT simulations, supported by validated OEM-specific models, are required to accurately calculate network fault levels in systems with high IBR penetration.

Advancing simulation techniques to operationalise any new capabilities identified

As the capabilities of GFM converters become better understood, a key challenge is accurately representing demonstrated equipment capability within power-system planning, operational assessments and protection studies. The four technical reports consistently identify improved modelling and simulation techniques as an important enabler, particularly where GFM behaviour differs from the assumptions embedded in conventional analysis methods.

Traditional short circuit and phasor-domain methods were developed primarily around the predictable physical response of synchronous machines. GFM fault response, by comparison, can depend strongly on control design, fault ride-through logic, current limiting, inverter operating point and OEM-specific implementation. The reports highlight a need to improve IBR representations within conventional short circuit tools and to use higher-fidelity electromagnetic transient (EMT) simulations where the relevant behaviour cannot be adequately represented in the phasor domain. The potential need to use EMT simulations within routine short circuit analysis has practical implications given the time and computational resources involved.

Utilising GFM capability requires more than demonstrating that the technology can provide a desired response. It requires modelling and simulation methods that can represent that response with sufficient accuracy and consistency to determine where it can be relied upon, under what operating conditions, and with what limitations. Developing validated and scalable simulation frameworks is therefore an important foundation for translating emerging GFM capabilities into practical planning methodologies, protection assessments and, where supported by evidence, future system security requirements.

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5.2 Strategy

With the capability of GFM to support efficient level of system strength well established and anticipated to be procured at scale, AEMO's activities are focused on potential GFM contributions to the components of minimum three phase fault level, particularly regarding uncertainties in protection compatible fault current.

As the installation, management and assessment of network protection is the responsibility of NSPs[59], AEMO is focusing on facilitating industry alignment on technical understanding, modelling techniques, and technology options, including contributing to the evidence base of GFM fault current interactions with protection systems.

5.2.1 Objectives

Informed by the challenges, opportunities and risks identified in Section 5.1.2, the learnings accumulated to date as described in Section 5.1.3, and AEMO's ongoing international collaboration through ISON[60], IEEE, CIGRE, and the Energy Systems Integration Group (ESIG), AEMO is pursuing the following objectives over the coming three years:

- **Objective 1:** Technical understanding and technology options for minimum three phase fault levels are aligned.
- **Objective 2**: Efficient and accurate modelling techniques are available to represent IBR in fault level analysis.
- **Objective 3:** An evidence base for the compatibility of GFM BESS and network protection systems is developed to inform NSP considerations and selection of technologies to address identified future system needs.

Through joint planning, Objective 1 will strengthen the shared understanding of the technical needs underpinning NER S5.1a.9, and, where needed, consider whether minimum fault levels need to be updated. Where practicable and beneficial, this may include examining the allocation of minimum fault levels across the three technical criteria: network protection, voltage control and post-contingent stability. This will support evidence-based assessment of available and emerging technology options, including GFM BESS.

Objective 2 is a priority item regardless of the outcomes of Objective 3. As the contribution from transmission connected IBR continues to expand, there is an increasing need to better understand how this type of plant should be represented in short circuit studies undertaken by AEMO and NSPs. This is particularly relevant for GFM devices, given their shorter history of application in power systems, whereas the analysis methods for GFL solutions have been progressively refined over time.

Objective 3 is time critical to enable GFM solutions to be considered in future system strength procurement decisions. Given present uncertainties regarding GFM fault current capability, near-term decisions will continue to rely on proven synchronous machine solutions, while accelerated industry learning can progressively broaden the range of technically viable options available for future procurement decisions[61].

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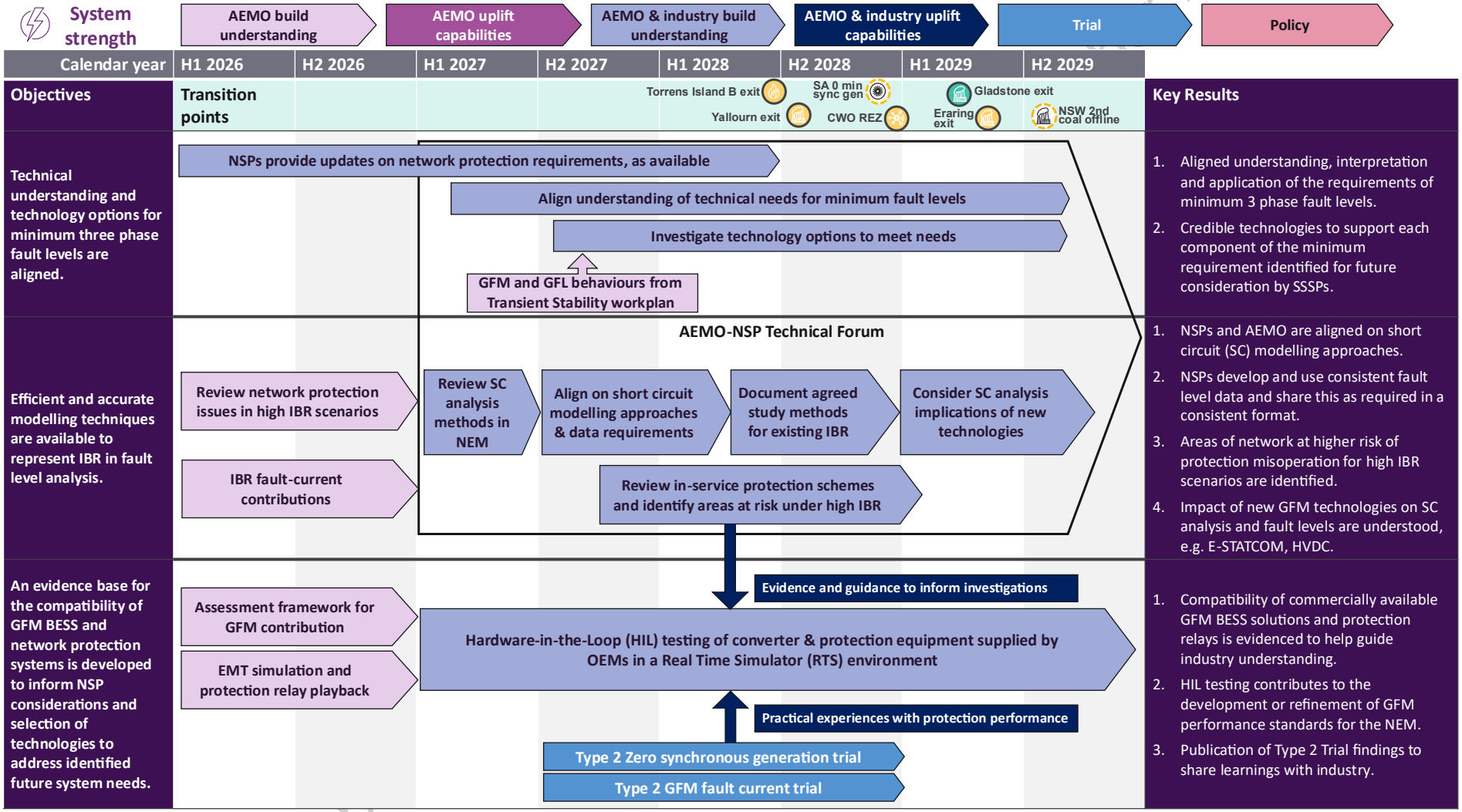
[59] Refer NER Schedule 5.1.9(c) and Chapter 4.3.4(g).

[60] See https://www.isonetwork.org/.

[61] See Transgrid RIT-T Material Change in Circumstances Report, at www.transgrid.com.au/projects-innovation/meeting-system-strength-requirements-in-nsw/.

Figure 16 Workplan for system strength



5.3 Workplan delivery

5.3.1 Objective 1: Technical understanding and technology options for minimum three phase fault levels are aligned

In collaboration with SSSPs, AEMO will seek to strengthen the shared understanding of the requirements of NER S5.1a.9 and its components, including the underlying technical needs and intended power system outcomes. This will include ongoing joint planning activities, where needed, including consideration of whether minimum fault levels at System Strength Nodes (SSNs) need to be updated to reflect evolving understanding of network requirements (including protection-related considerations), and findings from recent system strength RIT-Ts.

Where practicable and beneficial, the allocation of minimum three-phase fault level across the three technical criteria (network protection, voltage control and post-contingent stability) may also be examined to help identify opportunities for alternative technologies to address the underlying requirements. AEMO will collaborate with SSSPs to develop a common, evidence-based understanding of the capabilities of different technologies to address these requirements, notably GFM BESS.

This work will not alter existing system strength delivery obligations but will provide a stronger basis for assessing available and emerging technologies that may be capable of addressing some or all of these needs in the future. The resulting evidence base may support future SSSP decisions on the selection of technologies capable of meeting their obligations under the NER.

It is intended that this activity will be progressed through re-establishment of the System Strength Service Provider Working Group (SSSPWG), which is a technical sub-committee of the Joint Planning Committee comprising AEMO and JPBs.

5.3.2 Objective 2: Efficient and accurate modelling techniques are available to represent IBR in fault level analysis

In synchronous machine-dominated power systems, network fault behaviour can be represented with sufficient accuracy by well-established calculation methods based on phasor-domain sequence networks. The largely linear short circuit models of synchronous machines and network elements enable efficient calculation of fault currents without the need for more computationally intensive time domain analysis[62].

In assessing whether GFM BESS may, in the future, support minimum fault level requirements, it is important to consider the most appropriate methods of simulating GFM BESS fault current contributions. Traditional short circuit analysis techniques may not be suitable, given the IBR's non-linear response due to current limiting controls and more complex dynamics associated with the delivery of negative sequence current during unbalanced faults.

The same questions apply to the assessment of network fault levels considering all IBR contributions, including GFL. Identifying computationally efficient short circuit modelling techniques that can support both system planning and real-time operational requirements is an important parallel activity that complements Objectives 1 and 3.

As the methods and tools used to evaluate IBR within short circuit analysis impact all NEM participants, but are particularly relevant to NSPs, AEMO proposes to progress this initiative through a technical forum of system planning and protection

[62] Either root mean square (RMS) or EMT simulations.

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specialists from each NEM region, expected to be the SSSPWG outlined in Objective 1 or the Power System Modelling Reference Group (PSMRG). AEMO will play a coordinating role to promote awareness of identified issues, coordinate investigations and analysis, and encourage consistency of preferred modelling approaches. AEMO is proposing the technical forum to include the following activities:

1. Review existing representations of IBR in short circuit analysis and network protection design studies by NSPs (and their consultants) and what software is used.
2. Evaluate short circuit analysis methods, associated software and available modelling data to determine if existing tools will remain fit for purpose as installed IBR capacities increase. Developing a clear understanding of the role of EMT simulations.
3. Review how fault level data, including network equivalents defined at regional or asset boundaries, are calculated and shared between network users, recognising that simple Thevenin equivalents may have limitations where the 'aggregated source' is comprised of both IBR and synchronous machines.

To specifically support Objective 3, two additional activities may be progressed to draw on the knowledge base of the forum:

1. Review the types of network protection schemes currently installed in each region and identify where risks of misoperation may be elevated, and how such risks might be mitigated. This would ideally include a review of any confirmed or suspected protection misoperations identified by NSPs.
2. Consider the role of emerging GFM technologies that use multi-level converters, such as E-STATCOMS and HVDC, (in addition to wind, solar, and BESS) and their potential contributions to network fault levels, resulting protection impacts, and provision of system strength services more generally.

Desired outcomes from these activities would be improved understanding and direction on:

1. The short circuit analysis methods and tools that are most appropriate to support both system planning and operational requirements when considering high contributions from IBR across the NEM in future years. This includes understanding the potential contributions from GFM BESS to minimum three phase fault level requirements.
2. The locations in the network where protection related risks might be elevated when IBR contributions are high (which may also coincide with synchronous generator contributions being low as transition points are reached). This will enable targeted assessment of future operating scenarios.

Both outcomes provide guidance and direction to the activities associated with Objective 3.

5.3.3 Objective 3: An evidence base for the compatibility of GFM BESS and network protection

AEMO is planning the following activities to contribute to the development of an evidence-based position on whether GFM BESS are technically capable of supporting the secure and dependable operation of network protection systems.

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HIL testing of converter controllers and protection relays connected to a real-time-simulator (RTS)

The Protection & Relay Operation for Inverter-based Low-inertia Electrical Systems (PROFILES) Project, led by the University of New South Wales (UNSW) and funded by ARENA[63], commenced on 20 July 2026.

The project will apply modelling, simulation, and hardware-in-the-loop (HIL) testing to develop a stronger evidence-based understanding of how IBR, including GFM BESS, interact with existing network protection systems during power system faults and other disturbances. The fault response of IBR is strongly influenced by converter control design, including current limiting, sequence-current allocation, control-mode transitions and post-fault recovery. Protection performance depends not only on the characteristics of the individual converters or protection relays, but on the interaction between network conditions, converter control behaviours, and protection system design. PROFILES adopts a system level approach to assess these interactions and examine their implications for protection performance.

A central component of the project is the development of a structured testing and validation program combining detailed simulation with control and protection HIL testing. OEM-specific testbeds will allow converter controllers and protection relays to be assessed under controlled disturbances, while wider-area testbeds will enable multiple converter controllers and protection schemes to be examined together under representative network conditions. This approach allows investigation of a broad range of fault types, system-strength conditions, converter responses, protection functions and OEM implementations, including interactions that may not be apparent from assessing individual devices in isolation. The project will progressively move from model development and single-unit validation to integrated, wide-area system testing, with findings aligned with real-world data and operational experience where these are available.

The intended outcome is a credible and transferable evidence base for assessing the compatibility of GFM BESS and network protection systems across different technologies, network conditions and protection configurations. Rather than seeking to demonstrate that all GFM BESS are inherently compatible with existing protection systems, PROFILES will help identify the converter behaviours, protection characteristics and coordination considerations that influence compatibility, including particular configurations that may be robust or sensitive. This evidence is intended to increase industry confidence, reduce reliance on assumptions and bespoke studies, and provide practical guidance to NSPs, developers, OEMs, and AEMO on protection-relevant GFM behaviour, control-protection coordination and future system design. The findings may help identify where further design, testing or mitigation could be needed to meet protection requirements.

AEMO, together with the NSP and OEM project partners, is contributing technical guidance to the project. The project's objectives include:

- develop evidence-based understanding of protection relay performance in power systems with significant IBR capacity installed,
- reduce uncertainty about the responses of commercially available power electronics converters to disturbances and protection systems' interpretation of these responses,
- inform guidance on mandatory versus discretionary control behaviours from IBR, and
- identify future pathways for protection system design and operation in IBR dominated power systems.

[63] This Project received funding from ARENA as part of ARENA's Advancing Renewables Program. Project details are available at https://arena.gov.au/projects/unsw-protection-relay-operation-for-inverter-based-low-inertia-electricity-systems-profiles-project.

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The PROFILES Project is expected to be completed in Q4 2029.

Progressing Type 2 Transitional Service Trials

As discussed in **Error! Reference source not found.** Section 2.4, AEMO has published SONs for a GFM Inverter Protection Quality Fault Current Trial and a Zero Synchronous Generation Trial, undertaken market engagement, and held workshops with TNSPs to explore potential trial locations and implementation arrangements. This work has advanced AEMO's understanding of the practical requirements for undertaking such trials, and clarified the challenges associated with coordinating multiple parties and managing the risks arising from unusual or less familiar operating conditions. AEMO continues to work through these challenges in considering opportunities to progress the trials.

If undertaken, the trials would provide valuable real-world experience and an opportunity to compare observed power system, GFM BESS, and protection behaviour against those predictions from offline modelling and HIL-based simulations. This could provide important insights into the performance of GFM plant and network protection systems under real world power system conditions, support validation of models and simulation approaches, and help build confidence in conclusions drawn from the broader PROFILES work program. However, individual live trials are necessarily limited in scope and can only practically examine a relatively small subset of network operating conditions, protection schemes and in-service equipment.

The trials therefore represent an important complement to, not a substitute for, establishing the wider evidence base sought through the PROFILES Project. Knowledge gained from the reports described in Section 5.1.3 has reinforced the value of an extensive HIL testing programs, which provides greater flexibility to systematically assess a broader range of protection configurations and OEM equipment against different GFM control systems and network operating conditions. Used alongside offline simulation and targeted live trials, HIL testing can substantially broaden the range of technology combinations and system conditions that can be assessed. Live trials meanwhile provide an important opportunity to test and validate aspects of this understanding when applied in a real-world power system.

While the relevance of the GFM Type 2 trial is clear, it has also become apparent that the Zero Synchronous Generation trial may provide useful learnings on protection related issues as the security and dependability of protection in a test sub-section of network will need to be carefully assessed. Since potential sites include GFM BESS unit(s), their ability to support protection operation will form part of the assessment process. Any learnings from the Zero Synchronous Generation Trial will be used to support activities within the PROFILES Project.

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6 Frequency and inertia

Summary

- Frequency control is expected to remain satisfactory over the TPSS timeframe due to the available suite of operational tools and increasing amounts of BESS contributing frequency responses.
- Inertia is declining as synchronous generation is substituted with IBR and synchronous condensers. While sufficient sources of inertia are currently available, inertia requirements are becoming increasingly dependent on the characteristics and operating conditions of the wider power system, rather than inertia levels alone. AEMO's ongoing Victorian inertia assessment highlights the importance of factors including DPV, post-fault voltage recovery, system strength, BESS and the location of inertia across the network when setting inertia requirements.
- AEMO has specified the functional requirements for synthetic inertia response from IBR, which is expected to become an increasingly material part of the inertia solution set. To date, no such services have been procured. AEMO intends to progress work to support the operational delivery of synthetic inertia.

6.1 Frequency and the transition

AEMO completed an in-depth *Technical Review of the NEM Frequency Control Landscape* in 2025[64], which found that current performance is satisfactory and suitable arrangements exist to handle emerging and approaching issues. Frequency control is not considered an area of significant concern over the TPSS timeframe. AEMO will therefore maintain its existing frequency control strategies and make incremental adaptations in response to emerging or approaching issues, including:

- managing increasing semi-scheduled dispatch deviation by reducing unit issues and increasing regulation frequency control ancillary services (FCAS) efficacy,
- completing the implementation of mandatory primary frequency response (PFR),
- assessing the relationship between very fast contingency FCAS and inertia, which are closely linked with lower inertia generally increasing the fast frequency response required to securely manage a given contingency, and
- maintaining adequate under frequency load shedding (UFLS) and over frequency generation shedding (OFGS) systems in each NEM region.

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6.2 Inertia and the transition

The most pressing frequency-related consideration is how to maintain sufficient inertia in the NEM during periods of low synchronous unit commitment. AEMO's 2026 inertia assessments (in Appendix A2[65]) confirm that, for at least the next three

[64] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2025/technical-review-of-the-nem-frequency-control-landscape.pdf.

[65] See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2.

years, the installation of synchronous condensers (many with flywheels) is reducing potential inertia shortfalls and that the remaining gap can be bridged by out-of-merit-order synchronous redispatch via inertia network services.

The assessments also highlight how DPV and BESS are increasingly important factors in setting inertia requirements. The increase in the amount of installed DPV increases minimum regional interconnected inertia requirements, particularly when the network exhibits slow voltage recovery after a fault[66]. This is because DPV, at present, needs voltage to recover to a certain level before it returns to generating power. Increases in installed large-scale BESS, particularly GFM BESS (studied without a synthetic inertial response), can decrease the requirements by providing voltage support that improves voltage recovery. Further details about this specific phenomenon can be found in the *Inertia Requirements Methodology*[67].

These interdependencies are making assessment of minimum regional interconnected inertia requirements more complex, particularly in regions like Victoria where DPV levels are a dominant factor in setting the inertia requirement.

Comprehensive studies are underway to update the minimum regional interconnected inertia level for Victoria, however these are not yet complete, and these studies will likely have implications for the inertia *sub-network allocations* as well as the secure and satisfactory inertia requirements. Preliminary results have found that voltage recovery after a fault is a critical factor in the frequency behaviour, and hence the inertia requirements, and that sources of inertia which are electrically distant from Victoria's load centres have diminishing benefits. Conversely, plant that improves the voltage recovery are highly effective, even if the inertial contribution is low.

If regional inertia falls below the minimum regional interconnected inertia threshold, supporting inertia from neighbouring regions may be insufficient to maintain compliance with the FOS following a credible contingency, due to high network impedances between regions[68].

Synthetic inertia response

In addition to the voltage support GFM BESS can provide through faults, they may support inertia more directly through a programmed synthetic inertia response. The functional requirements and testing specifications to quantify a synthetic inertia response are now included in AEMO's *Inertia Requirements Methodology*, and TNSPs are able to procure synthetic inertia services to meet the inertia requirements. To date, no such services have been procured. AEMO intends to undertake work in 2027 to confirm the operational delivery of synthetic inertia to AEMO and TNSP technical requirements under an appropriate range of operational conditions in the NEM.

Similar work will be occurring in 2027 to operationalise synthetic internal response in the South-West Interconnected System (SWIS) in Western Australia, where AEMO interventions currently commit additional system inertia (procured through the co-optimised ROCOF Control Service) during low demand periods. AEMO intends to consult and initiate an expression of interest process, seeking participation from GFM BESS in a "pre-operational deployment" for live testing of synthetic inertia in the SWIS.

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[66] Times of low system strength typically have slower voltage recovery, however plant that provides fast dynamic voltage control, such as SVCs can also improve voltage recovery.

[67] See Appendix A2, Section A.3 and Sections 4.2 of the *Inertia Requirements Methodology*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.

[68] See Appendix A2, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a2, and Section 6.1 for calculation and operational application of these minimum regional interconnected inertial levels.

7 Voltage control

Summary

- Voltage control needs will evolve and become more dynamic as synchronous generation exits, generation and storage become more dispersed and variable, load characteristics change, and power flows across the NEM shift more frequently. These changes will require reactive power resources with sufficient static and dynamic capability and headroom to be available in the right locations and across a wider range of operating conditions. They also create opportunities for greater use of reactive support from VRE, and deeper consideration of the location and voltage control capability of new supply, storage and large loads.
- Processes and technologies for managing voltage are generally well established, with the focus now on identifying and addressing changing needs as the power system evolves. Voltage control has therefore not been prioritised for a dedicated workplan in this TPSS. Operability aspects are covered in Section 10.
- AEMO will continue to identify emerging needs through NSCAS and transition planning, while evolving its operational tools and coordination with TNSPs to manage an increasingly variable and dynamic voltage control environment in real time.

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7.1 Voltage control and the transition

Voltage is controlled by supply and absorption of reactive power[69] (measured in Volt-Amperes reactive [Var]), which is inherently more localised than production, transmission and consumption of active power (measured in W). As the types and locations of generation and load in the NEM, and system topology evolve through the transition, planning for and real time management of reactive power capability, location, and dispatch must evolve as well.

The retirement of large generators close to load centres, replaced by more geographically diverse VRE, DER and storage, changes power flow patterns across the network and removes local reactive capability. New storage, VRE, synchronous condensers and network reactive equipment can replace retiring MVAr capability, but not always at the most appropriate locations: maintaining total reactive capability does not by itself ensure that local voltage support remains adequate.

Demand composition is also changing, with widespread use of power electronic equipment changing the type and amount of local reactive support required. Together with growing CER output and declining daytime grid demand, this increases the need to manage high-voltage conditions, particularly during minimum demand and overnight periods. Large IBL, such as data centres (see Section 12), introduce different voltage sensitivities and dynamic behaviours around existing load centres, which may materially affect reactive requirements and voltage management strategies, depending on load locations.

The range of system operating conditions is also becoming more variable. VRE or storage plant can rapidly alter their output and power transfers across the network, changing reactive capability and requirements. The key focus of voltage control management therefore shifts from simply having sufficient installed reactive capability towards ensuring the right mix of

[69] See **Table 5**, Section 1.2.

static and dynamic capability is available, with adequate headroom, at strategically important locations and across the increasingly diverse range of operating conditions. Joint planning processes between AEMO and JPBs provide a platform to manage these needs, with evolving focus on analysing a broad range of possible operating conditions well ahead of operational timeframes, allowing emerging gaps to be identified with sufficient lead time for remediation or mitigation.

VRE and storage also present new voltage control opportunities, with the ability to provide reactive support when operating at zero active power. The 2026 NSCAS methodology recognises this by modelling BESS reactive capability at zero MW and, where supported by generator performance standards, reactive capability from wind and solar at zero active-power output. Making effective use of this capability could become increasingly important as synchronous generation withdraws.

7.2 Strategy

While TNSPs are responsible for ensuring sufficient voltage control in their network (see **Table 5**, Section 1.2), AEMO assesses emerging voltage control requirements through the NSCAS framework, including assessment of normal and post-contingent voltages, reactive margins and voltage-step changes. These assessments are AEMO's principal mechanism for identifying locational voltage control gaps and informing the need for additional reactive capability. Transition point planning provides a complementary longer-term view of material changes associated with generator decommitments, network augmentations and changing generation and load patterns beyond the 5-year NSCAS horizon.

The 2026 GPSRR[70] identifies voltage control as an emerging operational challenge, highlighting the need to maintain sufficient dynamic reactive capability at critical locations and ensure effective coordination and tuning of voltage control resources.

Operationally, AEMO primarily coordinates reactive resources through the Var Dispatch Scheduler (VDS), which optimises the use of generator and network equipment capabilities. As the system transitions, voltage control strategies, control settings, VAr requirements and control room tools may need to evolve to manage real-time system security. Cooperation between TNSPs and AEMO under the established joint planning frameworks, including the Joint Planning Committee and NEM Operations Committee, is paramount for the successful design and implementation of any required voltage management change.

The increasing variability of system operating conditions will place greater demands on real-time voltage management. Operating procedures based on a limited set of predictable generation and load patterns will become outdated as power flows, reactive capability and voltage control needs vary more frequently. Operations will increasingly rely on improved real-time visibility, projection, assessment and coordination of available reactive capability and voltage control actions. The Operability workplan (Section 10) identifies work towards enhanced NEM-wide coordination of voltage control across planning, scheduling and real-time operations, including improvements to tools, procedures and monitoring.

AEMO's forward strategy is a progressive evolution of established NSCAS planning and VDS-based operational arrangements so that emerging locational requirements are identified early, adequate static and dynamic capability is delivered where required, and operators have the information and tools needed to coordinate an increasingly diverse and variable portfolio of reactive resources.

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[70] See Section 4, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/draft-2026-gpsrr-report-consultation/final-2026-gpsrr-report.pdf.

8 Transient and oscillatory stability

Summary

- Changing power system characteristics are creating challenges for assessing and managing transient and oscillatory stability. Recent examples include ongoing difficulties identifying the root causes of voltage oscillations in South Australia (see Part B. Regional transition plans) and the blackout of the Iberian Peninsula in 2025.
- The specific evolution of stability characteristics is difficult to predict far in advance due to high sensitivities on yet-to-be-detailed network and plant configurations. Monitoring and responding to changes requires close collaboration and ongoing engineering across TNSPs, DNSPs, and AEMO. Where issues arise, responses may include operational measures or control system changes, and potentially the deployment of new stabilising plant.
- Available analysis suggests early consideration of damping capability in new synchronous plant, such as power oscillation damper (PODs), could provide low-regret options for managing future oscillatory stability needs. While detailed control design and tuning require sufficiently defined network and plant configurations and substantial engineering assessment, opportunities to preserve future capability can be considered before these studies are complete.
- AEMO and NSPs are uplifting modelling, plant models, and monitoring capabilities to improve timely identification and management of emerging stability issues. AEMO's Power System Modelling Strategy[71], currently out for consultation, will guide further development of modelling capability across AEMO and industry to better understand increasingly complex system behaviour and support timely planning, connections and operational decisions.

8.1 Stability through the transition

8.1.1 Definition

Power system stability is defined as "the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact"[72]. The 2026 TPSS focuses on stability through large transients (rapid electrical changes), which may occur during contingency events, and stability against oscillations, which can arise from natural modes[73], control interactions, and forced oscillations[74].

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[71] See https://www.aemo.com.au/consultations/current-and-closed-consultations/power-system-modelling-strategy-consultation.

[72] See *Power System Dynamic Modelling and Analysis in Evolving Networks*, https://www.cigre.org/GB/publications/green-books.

[73] See Voltage Oscillation box in **Error! Reference source not found.**, Section 1.3.

[74] See AEMO, *Power System Stability Guidelines*, 2022, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf.

8.1.2 Status

Changing stability characteristics

The transition affects power system stability in many ways. Network augmentations change the topology of the network and the impedances between plants, which affect how disturbances (transitory and oscillatory) propagate and plants respond and interact. Generator changes – including the retirement of large synchronous generators and their PSSs, and the addition of high inertia synchronous condensers, REZs, and dispersed inverter-based generation and loads – alter the distribution of inertia. Operating conditions – such as lower minimum demand, higher interconnector transfers, changing system strength characteristics and voltage control strategies, and increasingly dynamic patterns of generation and demand – also influence plant responses and interactions. The stretched-out nature of the NEM, with long transmission lines linking remote load and generation centres, heightens the susceptibility to transient and inter-area oscillatory stability issues.

These changes influence traditional electromechanical modes and increase exposure to converter-driven, forced or previously unobserved oscillations, particularly during periods of high power transfer, low system strength, or reduced synchronous generation. The influence of oscillations can be localised, such as control interactions between nearby generators, as well as NEM-wide, such as inter-area oscillations. Some aspects require new analytic tools and models, which are undergoing significant development internationally.

The system changes also affect transient stability limits. In some parts of the network, existing limits may increasingly bind affecting transfer capability in ways that differ from current practice. For TNSP development of limits, assessments need to allow sufficient time for AEMO due diligence and implementation of the resulting constraints before the relevant system change or outage.

AEMO recently published a preliminary assessment[75] of damping behaviour and emerging inter-area oscillation stability risks in future high-IBR conditions where the dominant rotating masses in the NEM are synchronous condensers[76] rather than large coal units. This work, completed using existing time-domain modelling tools, found that damping performance requires closer attention as the system evolves. The study identified scenarios with insufficient damping of Queensland – New South Wales Interconnector (QNI) type oscillations, with GFM BESS and synchronous condensers both participating in the oscillations.

The preliminary study also demonstrated the potential for appropriately tuned GFM BESS controls and supplementary POD controls on synchronous condensers to improve damping in the assessed scenarios. Detailed engineering studies are needed to identify damping-support needs, and design, tune and validate suitable controls across relevant operating conditions. For example, more detailed studies are needed for AEMO to assess emerging damping risks at future transition points and for TNSPs, supported by equipment manufacturers, to develop supplementary POD controls for new synchronous condensers. Starting these assessments early can inform plant specifications and preserve future damping capability before key design decisions are locked in, with detailed control design and tuning progressing as network and plant configurations become sufficiently defined. Regular reassessment is then needed as the system evolves.

While the oscillatory stability characteristics of the NEM and analysis tools are evolving, the practical methods for managing stability are enduring. Maintaining system stability will require accurate dynamic models, regular reviews of the

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[75] Performed as part of the FY2026 Engineering Roadmap Priority Actions. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/report-on-future-power-system-damping.pdf.

[76] Many fitted with flywheels.

performance of existing control systems and damping devices, such as generators' PSSs and PODs, and coordination of these devices. It also requires the stability controls for the newly entering plants – including IBR, synchronous condensers and reactive compensation devices – to be designed in a coordinated manner. These tuning activities typically require detailed studies, appropriate modelling capability, and coordination among NSPs, OEMs, and AEMO. Where new damping devices are required, these are currently available at modest cost and without foreseeable supply-chain constraints. Maintaining stability during the transition therefore depends more on responding adaptively to change than on delivering major infrastructure, provided damping control flexibility has been preserved at the project design stage.

Challenges

While it is known that each of these changes to the power system will alter the system's stability characteristics, it is difficult to predict their precise impact due to the unprecedented complexity of the number of plant interacting with one another and the novelty and commercial confidentiality of IBR control systems.

The central challenge is to develop and implement fit-for-purpose modelling capabilities for such power systems. This capability is foundational to tuning relevant control systems in planning and operational contexts, including interconnector commissioning, as well as identifying and mitigating oscillations in the live system. A related challenge is processing the high-speed monitoring data (such as from Phasor Measurement Units [PMUs]) required for model validation, instability identification and real time interventions. Methods and tools for addressing these challenges are under development globally, with industry coordinating and implementing modelling tools and plant models in the NEM, including through AEMO's Power System Modelling Strategy[77].

These technical capabilities must be complemented by processes for efficiently evaluating stability limits and tuning stabilising equipment, including processes for coordinating and implementing retuning or re-design of controllers.

Failure to address these challenges could leave the system vulnerable to significant risks, including:

- Operational risks of running the system without complete confidence in simulations or management of oscillations. This was a contributing factor to the blackout of the Iberian Peninsula in 2025. In the 2027 GPSRR, AEMO is proposing to assess oscillatory stability risks that, left unmanaged, could lead to cascading failures or major supply disruptions, and identify mitigation actions[78].
- Market impacts of using overly conservative constraints due to inadequate modelling capability, observability or controllability. Alternatively, security or resilience could be impacted if constraints are unknowingly not conservative enough. These risks become exacerbated if new equipment were to be connected without adequate modelling, which could prevent confidence in the expected dynamic behaviour of the system.
- The need to potentially request remedial action of a growing fleet of legacy plant. Identifying and implementing requests for plant, control or network changes can have long lead times, add cost, and create operational complexities.
- Increased risk of disturbances leading to cascading failure due to complex interactions between IBR and IBL fault ride-through behaviour, and automated protection and control actions. This has been considered recently through the 2025

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[77] See https://www.aemo.com.au/consultations/current-and-closed-consultations/power-system-modelling-strategy-consultation.

[78] See the Draft 2027 GPSRR Approach Paper, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/draft-2027-gpsrr/draft-2027-gpsrr-approach-paper.pdf.

GPSRR[79], which assessed aggressive IBR frequency droop response and the unexpected operation or interaction of protection and control systems, and the 2026 GPSRR[80], which covered risks related to increasing IBL connections.

As described in the section of Part B. Regional transition plans, NSPs and AEMO have recently observed voltage oscillations in South Australia that are yet to be resolved. These demonstrate the inherent complexity of identifying the root causes and mitigations of oscillations and how existing modelling capabilities and asset models exacerbate the challenge.

8.2 Workplan strategy

While uncertainty in future network configurations and plant characteristics limits the precision of long-term stability assessments, scenario-based studies can provide early insights into potential risks and mitigation options. AEMO and TNSPs, in collaboration with industry, are uplifting capabilities to enable rapid identification and response to the future evolution of local and wide area stability characteristics.

8.2.1 Objectives

As part of this strategy, AEMO is collaborating with TNSPs towards the following objectives over the coming three-years:

- **Objective 1:** Small signal stability models are accurate for high IBR, low synchronous generation conditions.
- **Objective 2:** Local & inter area oscillations are adequately damped within appropriate operating limits.
- **Objective 3:** Transient stability is managed in high IBR, low synchronous generation conditions.

Objective 1 is the top priority because accurate models are foundational for assessment of connections, stability limits, and system security generally. AEMO and industry modelling capability requires an uplift to reduce risk of the market being overly constrained or the power system being overly exposed to operational impacts.

Objective 2 is a priority because effective damping settings and stability limits are the practical ways to prevent oscillations causing major impacts – that is, this is the objective of maintaining a secure system (to NER specifications). This requires practical solutions to modelling, monitoring and processes challenges.

Objective 3 is also a priority because transient stability is critical for system security and resilience to unexpected events. Among other aspects, it is known to have been affected significantly by the connection of new inverter-based equipment that currently exhibit variable behaviour during faults.

Delivery of these objectives draws on the complementary roles of AEMO and TNSPs. TNSPs retain planning and operational responsibilities for stability on their networks and provide stability limit advice, which AEMO reviews through due diligence. Intra-area oscillatory stability is principally a TNSP responsibility, while inter-area issues may require AEMO coordination.

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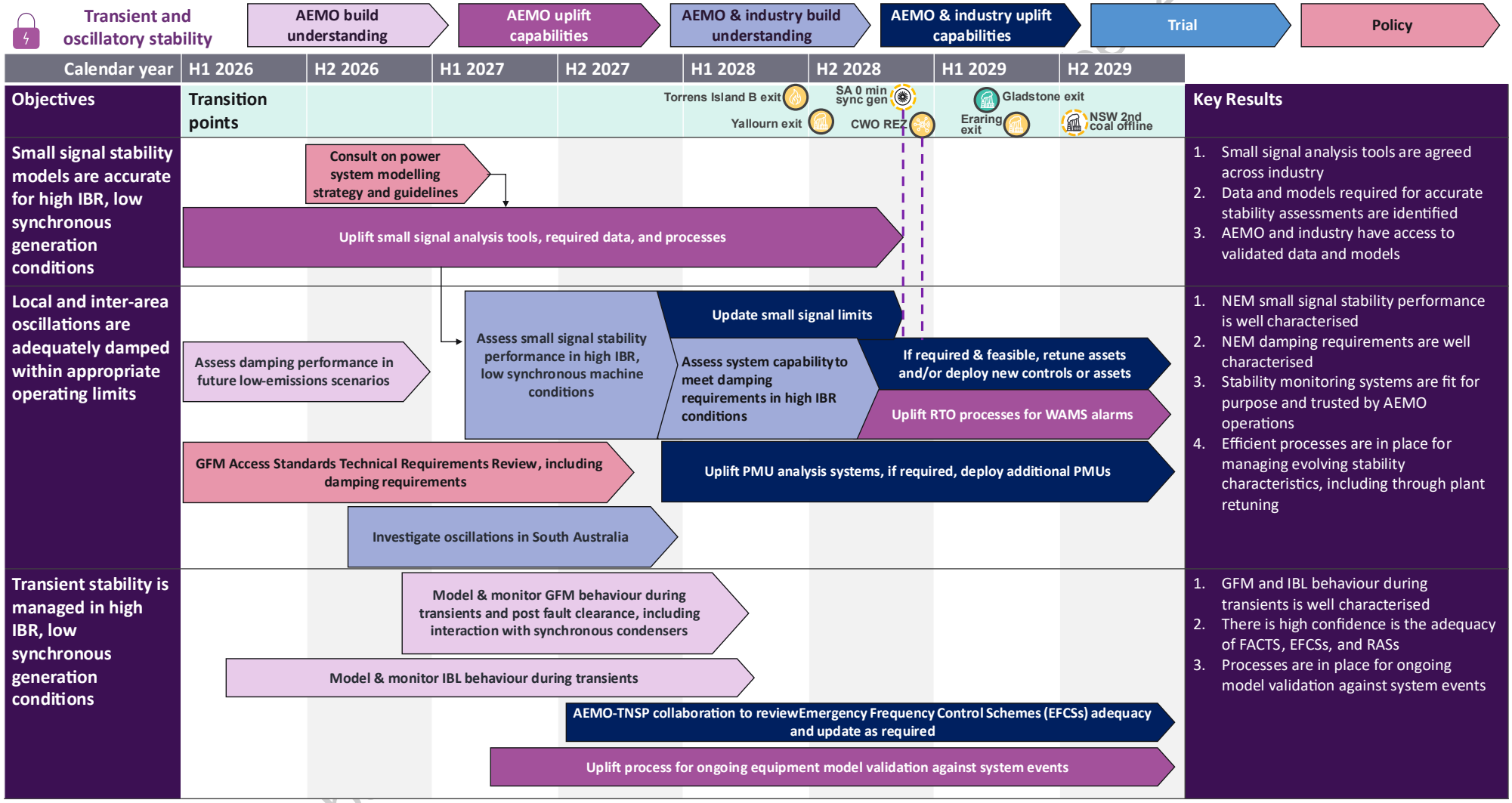
[79] See Section 2 and 4 of the 2025 GPSRR, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

[80] See Section 1 of the 2026 GPSRR, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2026/draft-2026-gpsrr-report-consultation/final-2026-gpsrr-report.pdf.

Figure 17 Workplan for transient and oscillatory stability



8.3 Workplan delivery

8.3.1 Objective 1: Small signal stability models are accurate for high IBR, low synchronous generation conditions

A substantial uplift of small signal analysis tools and required data, including IBR models as required, is a foundational requirement to progressing the understanding and capabilities for managing stability. Internationally, these tools and models are undergoing significant development, with the capabilities and applicability of various methods and tools yet to be resolved. AEMO is consulting on its Power System Modelling Strategy[81] and will soon consult on the *Power System Modelling Guidelines* to ensure the costs of uplifting modelling capabilities are balanced with security benefits.

In addition to modelling tools, it remains to be determined which plants must be included in small signal analysis, and with which accuracy, to get adequately accurate results for specific applications. In light of these uncertainties, AEMO and NSPs are taking an agile approach. An AEMO-NSP collaboration, the Small Signal Analysis and Modelling Working Group, is coordinating development of small signal models for large synchronous machines and static Var compensators (SVCs) in Small Signal Analysis Tool (SSAT), as well as some examples of IBR plant. These data will enable investigations to determine the factors influencing stability characteristics – such as plant capacity, location and technology type – which will inform the development of modelling tools and plant model requirements. The data and modelling capabilities also serve immediate operational needs, such as analysing the impacts of energising PEC, and preparation for transition points, including zero minimum synchronous generating units in South Australia, energising CWO REZ, and the exit of Gladstone Power Station.

In parallel, AEMO is exploring alternative approaches to modelling the stability impacts of IBR, including through the transfer function feature in SSAT, and uplifting and benchmarking operational stability monitoring tools to measurements.

8.3.2 Objective 2: Local & inter-area oscillations are adequately damped within appropriate operating limits

The establishment of fit-for-purpose models and modelling tools in Objective 1 is critical for AEMO and NSPs to accurately assess small signal stability performance, damping requirements, and small signal limits[82] in conditions with high IBR contributions and low availability of synchronous generation and their PSSs[83].

Available analysis[84] suggests early consideration of damping capability in new synchronous plant, such as PODs, could provide low-regret options for managing future oscillatory stability needs. While detailed control design and tuning require sufficiently defined network and plant configurations and substantial engineering assessment, opportunities to preserve future capability can be considered before these studies are complete. Uplifted modelling capability will enable quantitative assessment of the technical benefits and limitations of these options, informing and complementing economic assessments. Detailed design, tuning and validation, coordinated among NSP, AEMO, market participants and OEMs, can follow.

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[81] See https://www.aemo.com.au/consultations/current-and-closed-consultations/power-system-modelling-strategy-consultation.

[82] See core capability 1.1 in the Transmission System Operational Capability Framework, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.

[83] Set out in NER S5.1.8 and in the *Power System Stability Guidelines*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf.

[84] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/report-on-future-power-system-damping.pdf.

In addition to modelling capabilities, AEMO and NSPs will review the data quality and analysis tools of existing PMUs to enhance system observability and assist the assessment of damping needs and implementation of asset retuning and/or commissioning[85]. It may be necessary to uplift PMU analysis systems and deploy additional PMUs at selected locations. Relatedly, AEMO also plans to uplift Real Time Operations (RTO) processes for Wide Area Monitoring System (WAMS) alarms. This is a high priority because this system currently gives many spurious alarms (see **Figure 14**).

The voltage oscillations recently observed in South Australia demonstrate the challenge of appropriately damping oscillations in high IBR operating conditions. As described in Part B. Regional transition plans, ElectraNet, SA Power Networks and AEMO are collaborating to investigate the root causes of the oscillations and progress a management plan that translates improved understanding into oscillation management procedures, validated inverter-based mitigation options, and incorporation of oscillation risks into future system security planning, including through the CER Taskforce process. Collectively, these activities aim to support secure system operation at higher levels of IBR.

8.3.3 Objective 3: Transient stability is managed in high IBR, low synchronous generation conditions

In parallel to activities focused on small signal stability, it is critical to ensure the system remains secure to transient events. While oscillatory stability assessment focuses on whether oscillations are adequately damped, transient stability assessment focuses on whether the power system and connected plant maintain stable operation following large disturbances, such as faults. Both can involve local and wide-area interactions. As such, AEMO's activities are more focused on building the understanding of how specific technologies respond to specific types of disturbances.

Specifically, in the short term, AEMO is modelling and monitoring GFM transient behaviour during disturbances and following fault clearance, including interactions with synchronous condensers, alongside IBL responses to disturbance events. This also involves gathering field data from contingency events and comparing these to EMT simulations to validate models and dynamic behaviour of GFM and IBL. This will support earlier identification of stability limitations, inform operating limits and identify where control interactions or other instability phenomena warrant further assessment. This work is increasingly important as GFM deployment expands and connection interest in large inverter-based loads grows.

As models are validated and future configurations become clearer, AEMO and NSPs can use existing insights to progressively refine analysis to inform transition planning and operating limits, and provide lead time to investigate and develop any required mitigation. Where assessments identify a need, potential responses may also include adjustments to existing plant controls, such as Flexible AC Transmission Systems (FACTS), control settings, or other mitigation measures. Any review or adjustment of NSP-owned equipment would be undertaken by the relevant NSP, in coordination with AEMO where required.

One of the last lines of defence for major contingencies is emergency frequency control schemes (EFCSs). For non-credible contingency events that present an increased risk related to the consequence or likelihood of occurrence, targeted RASs may be implemented as a mitigation measure. The GPSRR reviews the performance of existing EFCSs annually to identify any needed modifications. The GPSRR has made a number of recommendations related to the uplift of RASs and EFCSs[86].

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[85] See core capability 2.3 in the Transmission System Operational Capability Framework, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.

[86] See Section 2 of the 2025 GPSRR, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

9 System restoration

Summary

- Synchronous generator retirements necessitate investment and redesign of restoration pathways. With long lead times on new black start capable plant, proactive action is required now.
- AEMO is procuring services to meet the new System Restart Standard (SRS) from July 2027, which now includes improved restoration guidance and procurement flexibility. However, increasing operational complexity, the changing generation mix, and evolving network topologies are creating emerging concerns for operability and security of restoration under expected scenarios.
- The Engineering Roadmap System Restoration workplan seeks to deliver the technical insights to ensure adequate future restoration investment and capability. The workplan targets engineering analysis and operational uplift for current and future restart scenarios, requirements to support appropriate network augmentation and interconnector-led restoration capability, and trials of DPV, IBR and BESS interaction with future restoration, in concert with current reform.

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9.1 System restoration and the transition

Black system events are rare, but when they do occur, consequences can be severe. The 2016 South Australian black system event (where two contracted restart units were unable to commence energisation[87]) and the 2025 Iberian Peninsula black event (50 million people impacted, with restoration times of up to 16 hours[88]) highlight the importance of effective system restoration capability. This capability has historically been supported by, and continues to rely on, synchronous generators. System restoration capability will need to be managed and invested in as many progressively retire.

9.1.1 Definition

System restoration refers to the operational processes to restore load and generation following a black system event. In advance of any event, system restoration planning includes power system modelling to inform the creation of system restart procedures, and the setting of system restart ancillary services (SRAS) requirements. These requirements are determined by the Reliability Panel in accordance with the SRAS Objective. System restoration capability is considered critical infrastructure under the 2018 *Security of Critical Infrastructure Act*, with responsibilities to assess vulnerabilities and identify pathways for remediation.

In practice, system restoration requires the sustained, sequential execution of many interacting system and operational capabilities at a time of significant complexity and pressure. Following initial black start and energisation of a second generator, system restoration involves an alternating sequence of growing the size and technical headroom of the

[87] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/integrated-final-report-sa-black-system-28-september-2016.pdf.

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

restoration island, then energising additional generation and load within these bounds. This is sequentially repeated until a region is fully restored.

The creation and extension of the island during restoration is highly sensitive and the island must be operated within its technical limits to avoid re-collapse. This relies on asset characteristics, available SRAS Restoration Support Services (RSS), and operational capability.

During restoration, it is possible for an island to encounter a bottleneck where further stable restoration is not possible without risking re-collapse of the island. Examples include energisation of large transformers with inrush currents greater than the capability of the island to withstand, or excessive voltages when energising long lines. Such potential bottlenecks may often be remediated ahead of time through simple network augmentations, such as point-on-wave switches on transformers or bus reactors.

Restoration capability also depends on interactions between generation, network, load, protection and control systems as electrical islands are progressively established and expanded. Particularly, restoration creates unusually challenging protection conditions, where fault levels may be low, voltage conditions abnormal, and transformer energisation or cold-load pickup can challenge protection security. As the role of IBR in system restoration evolves, these interdependencies will need to be increasingly considered in system restart planning, including the implications of IBR fault-current characteristics for protection performance[89].

While the approach to restoration is changing as the system evolves, **Table 18** describes the enduring, fundamental capabilities required during any restoration, during real time operation and for advanced planning.

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Table 18 System restoration requirements

Requirement	Operation (in real time)	Planning (in advance)
Establishing and growing a restoration island	• At least one black start generator is available to initiate restoration. • Black start generators are capable of energising at least one additional generator, keeping voltage and frequency within bounds and supporting the correct operation of protection schemes. • Operational staff are available and supported throughout any restoration. • Islands can sequentially energise the next network elements. • Sufficient stable load is available to maintain generators above minimum stable operating levels.	• Black start and restoration support capability is installed in advance, noting location is critical. • Network capability is sufficient to enable island formation and to avoid bottlenecks in regional restoration. This includes appropriate locational installation of reactors, point-on-wave switches, low-gain modes on SVCs, and access to stable load blocks as required. • Control rooms for all restart participants have sufficient tools to execute a restoration strategy, including AEMO, TNSPs, DNSPs and participating generators. • Procedures for controllers are developed and available, and regular training and testing of tools and procedures is conducted. • Black start capability and other critical components of restart procedures are frequently tested, including deep network restart tests beyond the SRAS facilities. • Operators are well trained to be ready to make critical decisions on the day with engineering judgement and experience, should advance plans fail.
Building supply to restore the region to reliable operation	• Generators have sufficient supply availability early enough to restore time-sensitive loads and subsequent generator auxiliaries. • Load can be restored based on available supply within restoration islands' technical limits.	• Plans support restoration to reliable operation for each region. • There is confidence that critical loads, including sensitive loads, will receive restored supply in time.

[89] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2026/impact-of-ibrs-on-power-system-protection.pdf.

9.1.2 Status

A revised SRS takes effect on 1 July 2027. This outlines procurement targets to contract generator capabilities to facilitate formation of one or more restoration islands within two hours after a black system (Stage 1), and support restoration of generation to meet at least 50% of forecast average annual underlying demand within eight hours (Stage 2).

AEMO's analysis indicates that the requirements of the 2027 Standard can be met in procurement when it takes effect, subject to successful procurement of RSS. However, significant operational, technical and planning challenges remain regarding the delivery of secure, resilient and timely restoration outcomes under current and future scenarios, particularly after coal retirements anticipated over the coming decade.

The restoration environment is changing

Synchronous generation retirements necessitate restoration redesign and new investment. Synchronous generators have underpinned system restoration since the first power systems were built. As coal generators in the NEM retire, restoration pathways will require redesign, incorporating new generators, transmission, REZs, high DPV generation, and large-scale storage capacity. Future system restoration capability will depend not only on replacement services but also on forward planning to identify capability gaps, test future pathways and support timely, cost-effective investment. With long lead times on new black start capable plant (in some cases, up to five years or more), proactive action is required now to prepare for anticipated retirements of assets that are currently critical for restoration.

The required size of black start generators will depend on location and proximity to neighbouring generators requiring energisation. Prior to demonstration with confidence of alternative technologies (such as through Type 2 Transitional Services), it is likely that black start sources will need to be synchronous generating units – either new hydro or gas generation. AEMO encourages any party considering the deployment of a large (100 MVA+) synchronous generating unit to contact AEMO (nmas@aemo.com.au) and explore the opportunities to provide black start services.

Additionally, national security obligations for power system planning and emergency management arrangements are being considered. In 2026, Energy Ministers agreed in principle to recommendation 12 of the AEMO Governance Review that energy laws should be amended to include a national security objective for AEMO. Ministers tasked energy officials with further work to clarify the scope and design of the proposed changes[90].

Challenges

The restoration operational environment is becoming increasingly complex for both AEMO and NSPs. Restoration is transitioning away from an environment characterised by a small number of high-power, mostly transmission-connected synchronous black start generators with inherent system strength and inertia. The future environment may involve a larger number of smaller black start SRAS and RSS providers, a different distribution of system strength and inertia, less stable load blocks, and increased data requirements.

In 2026, AEMO undertook a restoration operability review to support readiness activity for the revised SRS, benchmarking AEMO and NSP practices against leading international system operators, including NESO, EirGrid and CAISO, as well as EPRI, ENTSO-E and 14 NSPs. The review confirmed that the NEM's system restoration planning framework remains a strong, but

[90] See https://www.energy.gov.au/sites/default/files/2026-07/aemo-governance-review-final-report.pdf.

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identified capability gaps in the operational functions required to execute restoration plans, including communications resilience, situational awareness, control room coordination, multi-party training, load forecasting, DER controllability and DNSP restoration capability.

Restoration within the current framework enables concentrated dependencies on critical assets. While the updates to the procurement standard assist with planning for future system restoration, there may be a need for additional focus on risk minimisation and resiliency to prepare for possible complex restoration scenarios. Traditional approaches to restoration can exhibit concentration risks or dependencies on critical assets where alternative restoration options are limited. In some regions, the unexpected unavailability of a single SRAS provider could result in a long restoration delay to significant parts of the network. Similarly, the unavailability of one pathway may delay re-energisation of parts of a region.

Further investigation is required to identify and address any vulnerabilities in future restoration arrangements, consistent with AEMO's security obligation. This work would strengthen confidence in the ability to re-energise the network and inform any relevant change to regulatory frameworks and processes. AEMO engaged with the recent ISON review of international best practice for system restart[91] which also outlined alternative approaches for nested resilience in restart (for example, NESO in the United Kingdom).

The existing system restart investment framework supports the procurement of services from existing legacy restoration infrastructure (annual SRAS expenditure of $44.3 million in FY26) but is currently limited in its ability to attract new entrants to build dedicated SRAS infrastructure. As part of this 2026 TPSS, AEMO has, for the first time, provided high level information on technical capabilities required to facilitate viable restoration pathways, or for market participants to invest in plant capability in advance of participating in AEMO's SRAS tenders in Appendix A4[92]. Synchronous generators currently provide important capabilities supporting system restoration, and replacement capability will be required as these generators progressively retire.

There is limited field experience of IBR meeting the technical requirements to provide support to restoration, whether as a black start unit, an RSS, or a non-contracted part of restoration. Significant technical investigation is required to validate their performance and strengthen confidence in their ability to support system restoration. This is particularly important as large synchronous power stations retire, since smaller black-start generators may not be able to restore whole regions on their own.

Increasing DPV contributions are significantly reducing the amount of stable, controllable load available during daylight hours. Stabilising load is critical to support voltage control, absorb reactive power, and maintain generator stability during system restoration and is therefore becoming increasingly scarce. This trend presents growing challenges for traditional restart strategies and highlights the need to reassess restoration plans under future high DPV conditions.

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[91] See https://www.isonetwork.org/-/media/ison/files/international-system-restoration-review.pdf.

[92] See Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.

9.2 Workplan strategy

Opportunities to support restoration through the transition

The 2026 ISP projects significant gas, pumped hydro, and BESS capacity to be installed in the NEM in the coming 10 years. Incremental uplift in investment for a small fraction of these units (for example restoration capability for a new gas turbine, or resilient communications capability for a new BESS in a restoration pathway) could significantly increase confidence and resilience in NEM restoration capability. There may be opportunities for governments to explore requirements for black start capability for new plant as part of existing schemes to support cost-effective investment that enables the energy transition, similar to recent announcements in New South Wales requiring gas turbines to be fitted with clutches to enable provision of system strength, inertia and voltage control, independently of power generation[93].

There are emerging technical needs to support restart across all mainland regions as synchronous generators retire, including in locations where market, network and system security signals may align. New assets could either replace retiring black start capability or support existing black start capability in the absence of larger "second generators". Opportunities for lower-cost solutions are particularly available during initial design phases, compared to subsequent plant retrofits which may result in major change or an expanded plant footprint.

Similarly, minor network augmentations may support resilience in existing pathways, re-energisation of sensitive and high-priority loads, and maintain bidirectional interconnector restoration. These solutions are not clearly facilitated by the current restart framework. Further consideration is required as to how the need for, and efficient delivery of, these investments are identified and supported through existing planning and regulatory arrangements. AEMO will continue to assess these issues and inform relevant reform processes[94] as the evidence base develops.

A key challenge remains the long lead times for procurement decision and delivery of restoration supporting or black start capable assets. Even if procurement decisions were made today, solutions may not be available before the retirement of several synchronous generators currently providing critical capabilities during restoration.

Targeted strategic outcomes

AEMO's Engineering Roadmap actions target strategic outcomes over three different time horizons, as shown in **0**.

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[93] See https://www.energy.nsw.gov.au/sites/default/files/2026-10/nsw-gas-statement.pdf.

[94] See https://www.aemc.gov.au/rule-changes/enhancing-system-restart-frameworks.

Table 19 Engineering Roadmap near-, medium- and long-term workplan outcomes

Near-term workplan outcomes	Medium-term workplan outcomes	Long-term workplan outcomes
• Actions implemented to meet 2027 standard, including progressing RSS procurement and conducting additional deep network tests. • Provision of locational information to support investment in restoration capability. • Operational uplift across AEMO, NSPs and participants (communications, situational awareness, training capabilities, load forecasting and DER controllability). • Proving the different roles BESS can play to support restoration. • Strategic approach established, reform supported, and accelerated engineering analysis completed to design restoration in 2030+ following synchronous retirements. • Adequacy assessment of the current procurement framework to drive required future investment.	• 2030 SRAS Procurement and investment supports long-term future restoration approach. • Engineering analysis supports low-regrets investments in future restoration. • Type 2 System Restart under High DPV Conditions trial(s) delivers operational technology and approaches for managing risk. • Type 2 Black Start from IBR trial, if required, informs AEMO's understanding of equipment capability and system restoration planning. • Continued engineering analysis enables preparation for future transition points. • Ongoing network and restart testing. • Development of future restoration technical strategy informs investment and technology needs in advance of critical retirements.	• Investigations into the feasibility of IBR-only restoration pathways within the technical envelope of the power system. • Investigation of distribution capability to support restoration, where secure and efficient to do so. • System restart frameworks deliver abundant, resilient, and efficient system restoration capability.

9.2.1 Objectives

The system restoration workplan outlines actions over the coming three years to support these outcomes over all time-horizons, through enduring strategic objectives targeting capabilities to energise the grid, investment and operability:

- **Objective 1:** Restoration of generation and load is assured within technical limits under anticipated conditions.
- **Objective 2:** Planning, policy, and investment frameworks enable future restoration.
- **Objective 3:** Required operational tools, capabilities and assets are progressively delivered to ensure system restoration from any anticipated fleet and network.

Locational investment information for restart and indicative restoration capacity gaps

This year's TPSS includes forward-looking information on the relative locational suitability for future black start capable SRAS sources across the NEM[95]. It also provides further forward-looking analysis to help inform future restoration investment, including how the withdrawal of firm synchronous generation could affect the capacity available to support restoration. The assessment considers a 2032 NEM scenario, including committed projects and the ISP *Step Change* retirement schedule, and applied a set of criteria reflecting characteristics relevant to efficient system restoration.

The assessment provides an early indication that future black start sources may make a relatively greater contribution to restoration objectives if located close to major generation, load centres and practical restoration pathways. Higher-suitability areas include Sydney–Newcastle and the Snowy area in New South Wales; southern and central Queensland; metropolitan Adelaide; metropolitan Melbourne, north-east Victoria and the Latrobe Valley; and much of Tasmania's 220 kV network. Moderate-suitability locations commonly follow transmission corridors connecting these areas, but may require more capable restart sources or tailored restoration arrangements. Detailed capacity analysis focuses this year on

[95] See Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.

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New South Wales and Queensland, reflecting their materially larger potential requirements identified in the 2025 TPSS, with other regions to be revisited as generation retirement schedules, developments and restoration requirements evolve.

There may be opportunities to co-optimise investment in restoration capability with other power system needs, including resource adequacy and stability, particularly for plant offering multiple forms of flexibility, such as gas turbines with clutches and black start capability, and storage with GFM capability. As coal generation retires, maintaining sufficient firm generation in suitable locations will also become increasingly important to support the expansion of restoration islands. The assessment identifies particular value from additional, suitably located, firm generation in the Sydney–Newcastle–Wollongong area and Central Queensland.

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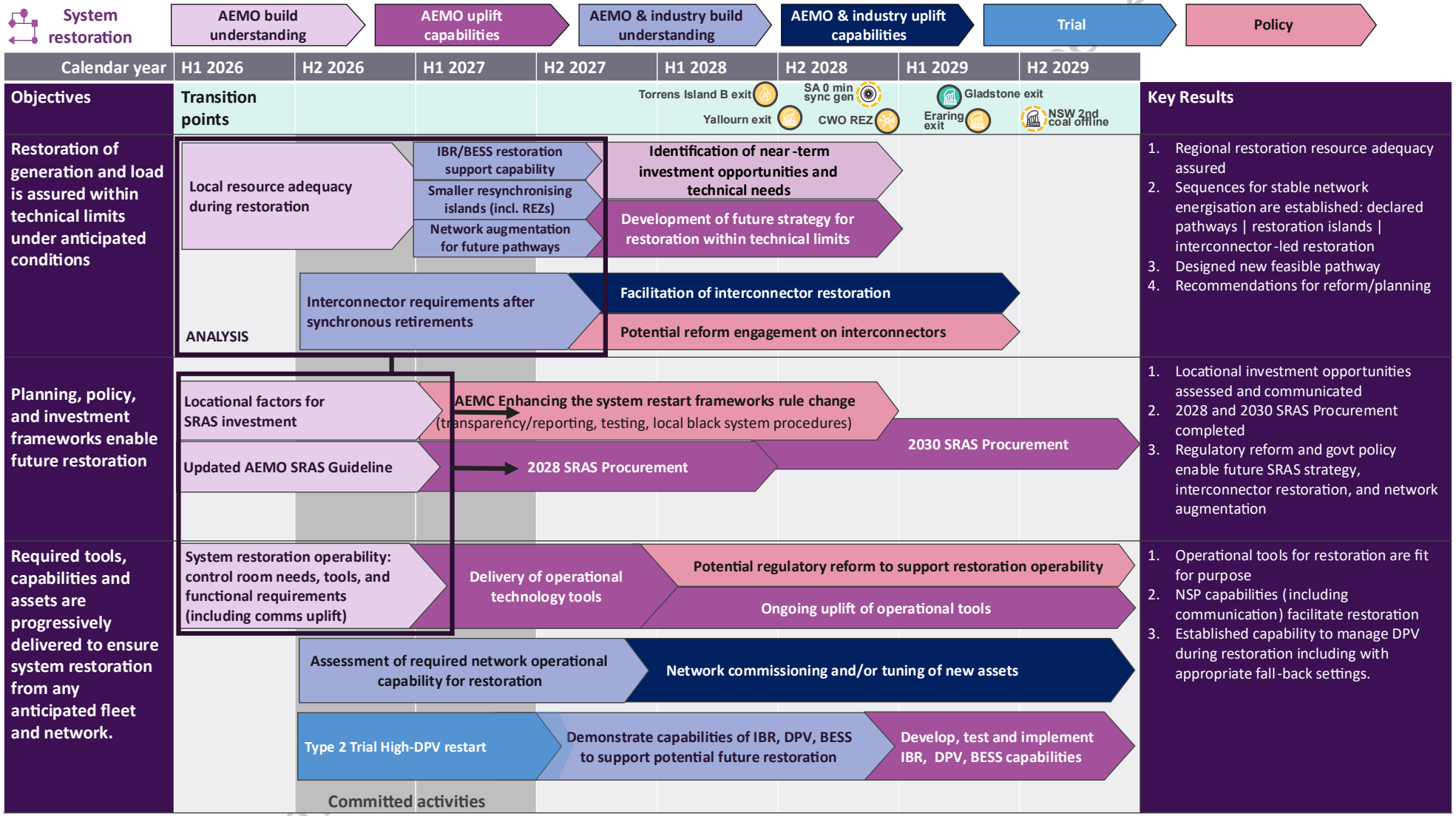
Figure 18 Restoration workplan



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9.3 Workplan delivery

9.3.1 Objective 1: Restoration of generation and load is assured within technical limits under anticipated conditions

As synchronous generators retire over the next 10 years, action is required to ensure system restoration capability under projected future conditions. Actions for this objective aim to identify near-term investment opportunities and technical needs to support upcoming transition points, particularly given the long lead times for new black start assets.

Workplan efforts are underpinned by analysis of the technical requirements of restoration without reliance on coal generation. This includes analysis of local resource adequacy during restoration relative to the technical envelope, smaller resynchronising islands (including REZs), network augmentation for future pathways, and IBR/BESS restoration support capability. The objective also progresses analysis of interconnector restart requirements after synchronous retirements.

Efforts will underpin the development of future strategy for restoration within technical limits, reform development through 2027-28, and renewed strategies to procure SRAS.

9.3.2 Objective 2: Policy, planning and investment frameworks enable future restart

Planning, policy and investment frameworks need to proactively deliver restoration assets in the locations where required. The workplan progresses the provision of locational information for near-term investment opportunities for system restoration[96] and includes the updating of AEMO's SRAS Guidelines. The 2028 and early 2030s SRAS Procurement rounds, held under the current framework and revised July 2027 Standard, are included within this objective.

It also considers current regulatory reform processes underway, with analysis supporting AEMO's engagement with the AEMC's Enhancing System Restart Frameworks rule change. AEMO will continue to work with market bodies, the Reliability Panel and governments to ensure the framework continues to be fit for purpose through the energy transition with the evolution of asset mix and increase in operational complexity. Examples include the consideration of technical limits throughout restoration in the framework, clarity on provisions for network augmentation (including interconnector and intra-connector capability) to support greater resilience in the restoration process (NER 3.11.7.b), and supporting the procurement framework to enable co-investment in restoration capability where efficient (for example any new gas, pumped hydro, or BESS plant in future restoration pathways) and new capital infrastructure and capabilities and services where required.

9.3.3 Objective 3: Required tools, capabilities and assets are progressively delivered to ensure system restart from any anticipated fleet and network

Operational tools for restoration, including clear procedures and resilient communications, must be fit for purpose. Ensuring this requires detailed analysis to understand control room needs, tools, and functional requirements (including communications uplift) for operable future restoration.

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[96] See Appendix A4, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a4.

These future control room capabilities will require coordination across TNSPs, DNSPs, SRAS, RSS providers, supported by appropriate communications capability and the ability to forecast and control DER, load, and IBR, and manage their stability, particularly during the daytime high-solar restoration scenarios.

Initial operational priorities include:

- communications resiliency including resilient SCADA links,
- Restoration Situational Awareness tools for AEMO control room and potentially for all restoration actors,
- DNSP load forecasting capability and network controllability, providing real-time data for load/DER forecasts in collaboration with DNSPs, and
- multi-party restoration training drills for multiple restoration scenario types.

Type 2 trials are included within this workstream – to help identify capabilities of IBR, DPV, BESS and management approaches to support potential future restoration strategies and pathways and outline the scope to develop, test, and implement these capabilities for future pathways.

AEMO has contracted two trials for System Restart under High DPV Conditions through a Direct Request for Offer process (see **Table 9**), which are expected to be completed by June 2028.

AEMO has completed initial market engagement for the Black Start from IBR trial, which highlighted that further locational, technical and commercial analysis is required before AEMO can determine whether, where and how a trial should progress (discussed in further detail in **Error! Reference source not found.** Section 2.4). The analysis outlined in Section 9.3.1 is scoped to deliver some of this.

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10 Operability

Summary

- Operational capability must keep pace with the growing complexity of a more dynamic, decentralised and inverter-dominated power system. The combined effect of interacting system changes places growing demands on operators and support teams, making coordinated capability development across AEMO and NSPs essential to maintaining secure and efficient operation.
- AEMO will evolve its existing operations planning and investment processes through the Operability Program, giving greater emphasis to the capabilities needed to keep pace with the transition. The associated workplan provides a coordinated pathway to strengthen operational foundations and security assessment, support effective control room decisions, and build future-system readiness.
- To successfully manage the scale and complexity of change, those initiatives that most effectively mitigate operational risk and support operability will be prioritised. This may mean that other initiatives, which have a lower impact on operability, will be deferred or progressed by utilising alternative funding methods.

10.1 Operability and the transition

10.1.1 Definition

Operability is the ability to actually operate the system efficiently and securely in practice, with the capabilities available to operators and industry. It depends on the operational capabilities and coordination between AEMO, NSPs, participants and emerging actors. This includes the people, processes, tools, digital systems, information required and operating arrangements to manage increasingly dynamic conditions and respond to operational risk.

10.1.2 Status

Changing operating environment

Australia's power system is changing rapidly as renewable generation, battery storage, IBR, DER, electrification, network development and new forms of variable demand become more prevalent. While the NEM remains secure and operable today, these changes are making operating conditions more weather-dependent, interconnected and data-intensive, and the system is increasingly being operated closer to more complex and dynamic technical limits.

System security services that were historically provided as an inherent feature of synchronous generation must increasingly be forecast, monitored and actively managed. Effective operation therefore depends more heavily on timely and trusted information, advanced assessment and decision-support tools, and coordination across a broader range of technologies, participants and operational timeframes.

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Challenges

The principal challenge for operability is not any individual technology, market reform or operational issue, but the combined effect of many simultaneous and interacting changes across the power system. In combination, these changes create more complex and dynamic technical limits, shorten decision-making timeframes, and place growing demands on the capabilities required to operate the system securely, reliably and efficiently. These operational pressures are already evident in practice, as illustrated by high control room alarm volumes and increased directions to maintain system strength in New South Wales and Victoria (see Section 3.3).

Maintaining secure and reliable outcomes increasingly depends on operational capability evolving at the same pace as the power system itself. Coordinated capability development across AEMO and NSPs is essential, supported by initiatives such as the Transmission System Operational Capability Framework (TSOCF)[97] and transmission–distribution coordination (see Section 11). Capability development takes time, requiring proactive, risk-based investment before emerging needs become operational constraints or adversely affect consumers. Key challenges include:

- **Operational capability development** – the pace of change may exceed the rate at which governance, workforce capability, tools, data, processes and decision support systems can be prioritised, funded, developed and embedded in operational practice. Competing investment and delivery demands may require capability development to be sequenced. Even after prioritisation, available funding and delivery capacity may be insufficient to deliver all required capabilities within the necessary timeframe, leaving capability gaps and residual risk that must be managed.
- **Operational visibility and situational awareness** – as inverter-based, consumer and other distribution-connected resources become more prevalent, system behaviour is becoming more dynamic and weather-dependent, and harder to forecast and observe. Existing measurements, models, support processes and operational tools may not provide sufficient visibility across the changing operating envelope, while operators and planners must manage a growing number of constraints, outages, response schemes and contingencies. Supporting teams must also assess more complex outage interactions, develop and operationalise limits advice, and implement more frequent changes to constraints and models. This can make emerging and interacting risks more difficult to identify and assess.
- **Growing control room demands** – increasing volumes of data, alarms and operational information do not automatically translate into actionable situational awareness. Operators must assess more complex interactions and select from a broader range of potential interventions within shorter timeframes. Without clear information on priorities and effective decision support tools, operators face greater cognitive load and reduced decision-making confidence.
- **Changing conditions and unexpected events** – more rapid transitions in demand, generation and system conditions, together with commissioning activity and unfamiliar resource behaviour, require more frequent non-routine assessment and coordination. Unexpected events may also have greater consequences where operating margins are narrower, or system behaviour is not fully represented in existing models or procedures.
- **Future-system readiness** – new technologies, system services, infrastructure and market changes must be assessed and prepared for before they become operationally material. Incomplete readiness may leave gaps in models, tools, procedures, training, resilience or operating arrangements.

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[97] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.

- **Industry coordination** – misalignment of responsibilities, decision rights, information flows or operational processes across AEMO, market participants, NSPs, OEMs, aggregators, and resource owners may increase operational risk and delay or reduce the effectiveness of operational responses.

If not addressed, these challenges could reduce operational flexibility, increase reliance on conservative operating limits and interventions, and weaken system resilience. Slower or less coordinated incident responses could require more emergency actions and increase the risk, extent or duration of outages. More conservative operation may also increase renewable curtailment, reduce utilisation of low-cost energy resources, and contribute to higher operating costs and wholesale prices, delaying the economic, consumer, and emission-reduction benefits of the transition.

Complexity in practice: June 2026, South Australia

A three-day wind lull reduced South Australian wind generation to approximately 50 MW, while cold weather pushed Adelaide demand above 2,000 MW. A derated 220 kV transmission line constrained imports from Victoria, reducing available operational flexibility. As conditions tightened, the battery fleet discharged to around 10% state of charge during the evening peak and was unable to fully recharge overnight due to prevailing market and system conditions. Forecast reserve shortfalls emerged, and operational actions were required to maintain secure supply.

No single issue created the challenge. Combined low renewable output, high demand, network limitations, energy-constrained storage and tightening reserve conditions required operators to continuously reassess system limits, risks and available response options. While security and supply were maintained, the event highlights a key operability challenge – individually manageable conditions can interact to significantly increase the complexity of real-time security assessment and contingency management, while reducing available response options.

10.2 Workplan strategy

AEMO is building on established operations risk assessment, investment and delivery processes to give operability a more explicit focus in capability planning and prioritisation. From an operability perspective, individual elements across the other workplans need to come together into a coherent operating regime that can be effectively applied in day-to-day operations. AEMO's Operability Program provides a framework for coordinating priority activities across information, models, tools, processes and operating arrangements used for monitoring, assessment, and operational response. The Operability workplan is a three-year view of activities to address operability risks.

10.2.1 Objectives

Over the coming three-year period, AEMO is prioritising four interconnected objectives:

- **Objective 1: Operational foundations** – foundations are focused on prioritising, coordinating, and sustaining operational capability development to keep pace with the transition.
- **Objective 2: System security and operating envelope** – strengthened capability to understand system behaviour, assess system risks, identify emerging exposures, and define and manage secure operating conditions.
- **Objective 3: Control room decision capability** – strengthened operator capability to make effective decisions through operational visibility, decision support and preparedness in an increasingly dynamic power system.

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- **Objective 4: Future system readiness and market alignment** – readiness for future system and market changes is supported by operational capability, strengthened forecasting, industry coordination and aligned reforms.

The four objectives are mutually supportive of each other. Improvements in individual capabilities depend on complementary changes in others to deliver operational benefit. For example, improved assessments only translate into better operational responses when their findings are integrated into tools and procedures that operators are equipped to use. Prioritisation and sequencing must therefore consider these dependencies, rather than treating each objective as a separate delivery stream.

AEMO will lead its operational and analytical capability development, but operability is a shared whole-of-system capability. Delivery will require coordinated action by NSPs, market participants, OEMs, aggregators and resource owners, supported by clear responsibilities, common information standards and effective operating interfaces. AEMO has worked with TNSPs to develop the TSOCF[98], which sets out the operational capabilities TNSPs need to operate their networks and support secure system operation. The TSOCF highlights capability needs aligned with those identified in this workplan, including real-time monitoring and visibility, decision support and operational risk assessment capabilities.

10.2.2 Workplan

The Operability workplan, shown in **Figure 19**, brings together priority activities for coordination through the Operability Program, including existing initiatives, planned projects, trials and industry capability development. Delivering these activities requires alignment with broader capability development and operational coordination across AEMO and NSPs. The TSOCF will support this alignment through shared assessment of capability needs, clearer priorities, and coordinated capability improvement across AEMO and TNSPs. Evolving operational roles, information exchange and coordination across AEMO, TNSPs and DNSPs are also being progressed through the Transmission–Distribution Coordination Program and related National CER Roadmap initiatives, as described below in Section 11.

The Operability Program and workplan delivery depend on available funding, specialist capability and broader organisational delivery capacity. AEMO will prioritise activities by the operational risks they address, their delivery readiness, their role in enabling other capabilities or reforms, and their expected benefits to consumers. Prioritisation will direct resources towards the most material needs but may not enable all required capabilities or priorities to be delivered within planned timeframes.

Building on existing review processes, AEMO will periodically review capability priorities and the workplan against emerging operability needs and consider project staging, consolidation, rescoping or deferral as system conditions, risks, costs, dependencies and delivery capacity evolve. For remaining capability gaps, AEMO will assess residual operational risk and consider alternative delivery, funding, reform or industry pathways.

The workplan is sequenced around key capability dependencies. Trusted data and models, foundational operational tools and agreed industry responsibilities must reach the maturity needed to support implementation of dependent capabilities. The timing shown represents the progressive establishment and application of capability, rather than the full duration of contributing initiatives.

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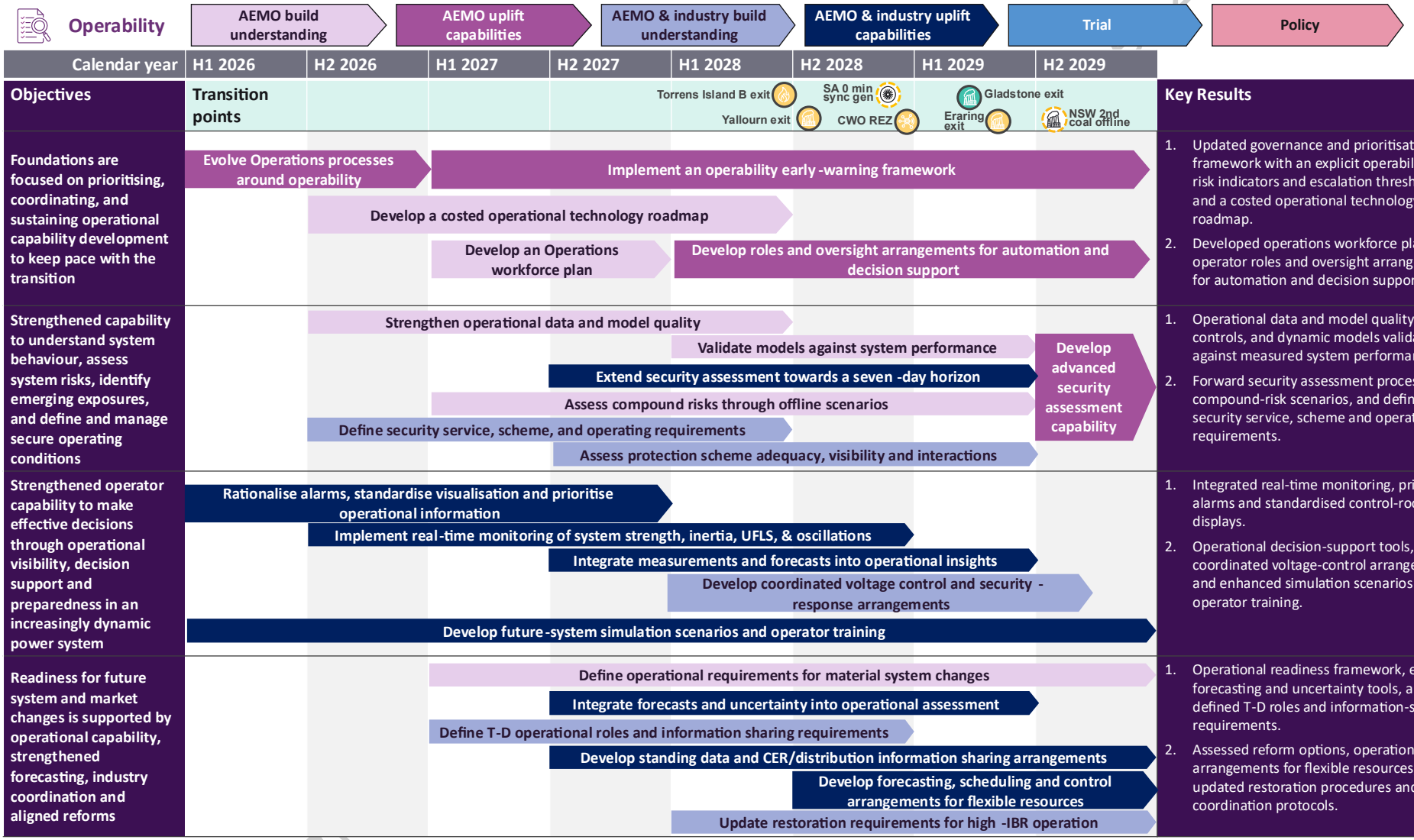
[98] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/transmission-system-operational-capability-framework.

Figure 19 Operability workplan



10.3 Workplan delivery

Through the Operability Program, AEMO will build on established Operations processes to coordinate interdependent activities across the four objectives. These activities connect capability development with the practical needs of operators and support teams, addressing the challenges identified in Section 10.1. This coordinated approach supports secure and efficient operation, operational flexibility and resilience, and readiness for future system and market changes.

10.3.1 Objective 1: Operational Foundations

This objective builds on existing governance, investment and workforce capabilities to prioritise and sustain operational capability development in response to emerging operability needs, within available funding and delivery capacity. Several foundational elements are identified across other workplans in this document and will require formalisation of new operational roles for other parties. These will need to be carefully considered, sequenced and designed to enable the uplift in operational capability and effective operational coordination across parities over time.

AEMO uses established risk-assessment and project-prioritisation processes to guide operational investment and delivery. The Operability Program will build on these processes, placing greater emphasis on the combined effects of system change and the capabilities needed to maintain operability through the transition. The Operability Program will coordinate priorities and dependencies across existing and planned initiatives, linking capability needs with investment and delivery decisions. Key operability indicators and escalation thresholds will complement existing risk assessments, support earlier identification of emerging operability pressures and help show whether capability development is keeping pace with changing system conditions. These arrangements will inform investment priorities and make the operational consequences of unresolved capability gaps visible to decision-makers and relevant stakeholders.

Building on existing operational technology planning, a costed operational technology roadmap will identify priority technologies, data, automation and decision-support capabilities, together with their dependencies, benefits, accountabilities and potential funding pathways. It will inform investment priorities through the Operability Program, focusing on capabilities that provide the greatest operational risk reduction and whole-of-system benefit, while enabling other actions and prioritised reforms. The roadmap will also consider the resilience, integrity and recovery of critical operational technology, data and control systems.

AEMO workforce planning will define the capacity, skills and organisational capabilities required for future system and market operation. This will include critical-role dependencies, recruitment, succession and capability development, as well as the implications of automation and decision support for operator responsibilities and human oversight.

10.3.2 Objective 2: System security and operating envelope

This objective strengthens AEMO's ability to anticipate system exposures and define and manage secure operating conditions, providing an improved basis for control room decisions under changing conditions, compound risks and unexpected events.

AEMO will develop capability for a more comprehensive and increasingly automated security assessment process across a seven-day forward horizon, integrating outage coordination, forecasts and uncertainty information. Representative compound and non-standard scenarios will be used to assess combinations of outages, forecast uncertainty, resource

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limitations and unfamiliar system interactions. Governance and escalation arrangements will support consistent responses where material exposures are identified.

Model governance, management, processes and quality controls will provide authoritative system representations for operational studies. Models will be progressively validated against measured system performance as modelling and monitoring capabilities develop, as described in Section 8. Advanced and online analytical methods will be progressively adopted in line with the modelling strategy and guidelines, as confidence is established in their accuracy and value for operational decisions.

AEMO will also work with NSPs to investigate opportunities to strengthen frameworks for adjusting and applying system strength limits and minimum operating requirements. Protection and response schemes will be assessed at a system level to identify interactions, future adequacy and potential unintended consequences as IBR and distributed resources become more prevalent and synchronous generation declines.

10.3.3 Objective 3: Control room decision capability

This objective improves the information, tools and operating arrangements used to support real-time monitoring, situational awareness and operational decision-making. These capabilities will help operators interpret increasing volumes of information, assess complex interactions and coordinate responses to changing and unexpected conditions within tighter timeframes.

Control room visibility of system strength, frequency, inertia, load-shedding exposure, oscillations and other material security conditions will be improved through enhanced monitoring, operational analytics and integration with security-assessment tools. Integrated wide-area monitoring will support detection and analysis of oscillations, disturbances and system separation, building on the monitoring capability development described in Section 8. Operational indicators, dashboards and risk-based scenario analysis will help operators interpret current conditions, identify emerging exposures and assess potential responses.

AEMO will rationalise alarms, standardise visualisation and prioritise operationally material information. Greater integration of control room applications and workflows will reduce the need for operators to assemble an operational picture across separate tools and interfaces. Measurements, forecasts, security assessments and operating procedures will be progressively consolidated into actionable operator insights. This will help operators recognise significant changes, understand their potential consequences, and assess available responses, without adding unnecessary information or cognitive load.

Targeted automation will reduce repetitive manual analysis and help operators identify material changes more quickly, including through automated oscillation detection, disturbance analysis and improved contingency analysis. Artificial intelligence (AI) enabled tools may further support operators by organising information and recommending potential responses, with human oversight and clear operator accountability retained.

AEMO and NSPs will also strengthen coordination of voltage control across planning, scheduling, network operations and real-time operation in coordination with the voltage control workplan strategy (see Section 7.2). Security assessments will be translated consistently into operating limits, control room information, scheduling inputs and operational actions.

Simulation and training will represent high-IBR, low-inertia and compound operating conditions. Operators will use these environments to rehearse unfamiliar conditions, refine procedures and assess how new tools and system changes affect real-time decision-making.

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10.3.4 Objective 4: Future system readiness and market alignment

This objective is focussed on the progressive AEMO and industry capability uplift required to implement and embed into day-to-day operations committed reforms, coordination across parties to keep pace with new operating conditions as they emerge in the transition.

A consistent readiness framework will identify operational requirements, accountabilities and dependencies for developments such as REZs, major new loads and significant network or market changes. It will provide a structured basis for assessing whether the required models, information, tools, procedures, workforce capabilities and industry arrangements are sufficiently mature to support implementation and ongoing operation.

Operational forecasting will be strengthened through improved data, tools, models and methodologies for representing weather, demand, outages, commissioning, renewable generation, storage, CER and large loads. These capabilities will help maintain forecast performance as the system becomes more complex and weather-dependent, and provide improved uncertainty information to support risk-based decisions on readiness for material system changes, outage coordination, reserve assessment, forward security assessment and control room decisions.

AEMO will work with NSPs and other industry participants to clarify transmission–distribution responsibilities, operating zones, decision rights and information-sharing requirements, consistent with relevant reform outcomes. Trusted standing data and common resource definitions will support the integration of DER, including CER, and other flexible resources into forecasting, scheduling, control and emergency arrangements. These DER integration initiatives are led through the DER workplan in Section 11, with operational requirements and implementation supported through the Operability workplan.

AEMO will also assess whether market, regulatory and procedural arrangements remain appropriate for emerging operability needs. Reforms will need to account for the tools, information, responsibilities and implementation lead times required for effective operation, so the necessary operational capabilities are available when new arrangements take effect.

System restoration capabilities will be assessed and developed for high-IBR and high-DPV conditions, in coordination with Objective 3 of the system restoration workplan (Section 9.3.3) and the DER workplan (Sections 11.3.3 and 11.3.4). Restoration assumptions, decision support, procedures, communications arrangements and responsibilities will be developed through coordinated activities across these workplans. Simulation and coordinated industry exercises will support testing and refinement of these arrangements before operational use.

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11 Distributed energy resources

Summary

- DER continue to shape power system operation as consumers participate in the transition through ongoing uptake of rooftop solar, storage and EVs, and increasing demand side flexibility.
- The DER workplan supports sector-wide collaboration through the National CER roadmap as well as AEMO's Operability Program (see Section 10), focusing on technical enablers for DER integration across five priorities: visibility and predictability; transmission-distribution coordination; management of high-DER system conditions; cyber-physical resilience; and technical requirements and compliance.

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11.1 DER and the transition

11.1.1 Definition

DER are generation, storage, and flexible loads connected within the distribution network. They include CER in the low voltage distribution network behind the customer meter, such as rooftop solar (DPV) systems, battery storage, EVs and other flexible loads (consumers and local management response to prices and control signals), as well as larger resources, typically connected at higher voltages, such as embedded generation, or community and network batteries.

Large loads such as data centres are not considered DER for the purposes of this section and are discussed separately in Section 12. They do however share many power system requirements with DER, particularly regarding predictability, planning, and operational coordination. Through delivery of both workplans, common needs will be considered and addressed together where possible.

11.1.2 Status

Context

Australia is already at world-leading levels of CER, primarily driven by the growth in rooftop solar since 2010. There are now over 3.2 million DPV systems in the NEM, with DPV reaching a record high 54.8% share of NEM generation in the half-hour ending 12.00 pm on 11 October 2026. This consumer-led investment, supported by government incentives, has reduced energy costs for households and businesses and played a major role in lowering emissions from the energy system.

Other forms of CER are also growing, supported by evolving tariffs, government incentives and retail offers. Distributed storage uptake has accelerated rapidly, with NEM installations tripling to more than 770,000 since commencement of the Cheaper Home Batteries Program in July 2025, representing about 16.5 gigawatt hours (GWh) of storage capacity. This has started to impact the NEM system load profile, increasing daytime demand and reducing evening peak demand[99].

[99] See AEMO, *Quarterly Energy Dynamics* Q3 2026, at https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q3-2026.pdf.

Changes

AEMO projects continued growth in CER, with growth over the next five years summarised in **Table 20**. This will amplify its already significant impact on the system load profile and the technical envelope of the power system.

Historically most CER has been predominantly passive, operating in response to local conditions and consumer decisions. Technology is now making it increasingly possible for CER to be managed and coordinated in different ways, including local management and aggregation, with limits and signals from DNSPs, retailers, aggregators and other parties[100].

If effectively integrated, the future CER fleet and emerging demand sources such as data centres can enable a more two-sided system, playing a more active role in balancing supply and demand, and supporting system security.

Table 20 Actual and forecast uptake of key consumer energy resources and emerging demand, FY2026 to FY2032

Component		Actuals 2025-26	Forecast 2026-27	Forecast 2029-30	Forecast 2031-32
Distributed PV	Installed capacity (GW)	26.9	29.3	37.6	43.1
Embedded energy storage (small-scale batteries)	Installed capacity (GW)	5.6	7.2	13.5	16.7
	Coordinated battery (virtual power plant [VPP]) capacity (GW)	0.78	1.3	2.6	3.5
	Non-coordinated (passive) battery capacity (GW)	4.82	5.9	10.9	13.2
Electric vehicles	Vehicles (million)	0.52	0.79	2.1	3.2
	Annual consumption (terawatt hours [TWh])	0.25	1.3	4.7	8.6

* Distributed PV in this table includes rooftop PV and PV non-scheduled- generation (PVNSG) components.
Note: all projections are based on the ISP *Step Change* scenario in the 2026 NEM ESOO.

Challenges and opportunities

The 2026 ISP[101] identifies CER as an important part of the least-cost transition, with $5.2 billion in system costs avoidable via CER coordination[102]. Realising these benefits requires integration capabilities to keep pace as the CER fleet grows and diversifies.

Flexible export offerings, evolving retail offers and equipment capabilities are creating more ways for all consumers to benefit from CER responding to network and market conditions. AEMO's CER Data Exchange[103] project has explored how more efficient and secure information sharing across operational actors could support visibility, new services and greater consumer participation. Benefits are not limited to consumers who participate actively: passive home batteries and simpler tariff-based responses are materially influencing the system load profile by shifting demand towards daytime solar production and reducing evening peaks[104].

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[100] For further discussion see the 2025 TPSS, Section 9.2.1, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-transition-plan-for-system-security.pdf.

[101] AEMO, 2026 ISP, at https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-integrated-system-plan-isp.pdf.

[102] AEMO, Appendix A9. Demand Side Factors Statement, at https://www.aemo.com.au/-/media/files/major-publications/isp/2026/appendices/a9-demand-side-factors-statement.pdf.

[103] AEMO, Consumer Energy Resources (CER) Data Exchange, at https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/consumer-energy-resources-data-exchange.

[104] AEMO, Quarterly Energy Dynamics (QED) - Q3 2026, at https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q3-2026.pdf.

The visibility, coordination and performance assurance needed for a high-DER system were not initially established alongside their early growth. Addressing emerging operational challenges has therefore required coordinated action across governments, networks, manufacturers, installers and other parties, often under urgent timeframes.

This collaboration has delivered important foundations. Analysis of CER behaviour during disturbances informed stronger ride-through requirements in the AS/NZS 4777.2:2020 standard for low-voltage-grid-connected inverters, while subsequent industry efforts have progressively improved compliance to this standard[105]. Emergency backstop mechanisms, alongside operational procedures leveraging storage, Transitional Services and directions, have increased confidence in managing MSL during typical system-normal conditions with minimal consumer impact. More challenging conditions may still require higher-impact measures, including enhanced voltage management and reverse-feeder shedding. Queensland retains a management capability shortfall under rare, but plausible, onerous conditions[106], requiring increases in emergency backstop coverage and compliance. The detailed MSL outlook is in Appendix A3[107].

Further effort and industry collaboration on near-term management and enduring technical and governance arrangements is required to effectively integrate the projected scale of DER and demand side flexibility projected over the next 5-10 years. Part B. Regional transition plans of the TPSS highlights areas where enhanced data and models are needed to better understand impacts of dynamic DER behaviour, namely voltage oscillations in South Australia, and response to voltage disturbances under low inertia conditions in Victoria.

To realise the opportunities and manage the challenges described above, clear transmission–distribution coordination arrangements are needed, with defined roles, capabilities, and information exchanges. Coordination with longer-term planning is also important so that distribution network developments, DER capabilities and demand-side opportunities can be appropriately reflected in relevant planning processes. Growing reliance on communications and software introduces cyber-physical risks. Technical requirements, cyber protections, monitoring and response capabilities, and conformance and compliance arrangements must also evolve as technologies advance and use cases change.

The DER workplan addresses these interdependent needs to support secure and reliable operation in a high-DER future, while enabling greater use of demand-side flexibility across the ways consumers choose to use their resources. The National CER Roadmap[108] provides a reform pathway to help address many of these priorities, leveraging operational experience to date and proactive near-term industry effort to establish enduring arrangements, consistent across jurisdictions where possible, for operational roles, data sharing, technical requirements and governance. Given the materiality of DER across system and market operations it is important these reforms are progressed expediently.

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[105] AEMO, *Compliance of Distributed Energy Resources with Technical Settings: 2025 Update*, at https://www.aemo.com.au/-/media/files/initiatives/der/2025/2025-08-19-as4777-compliance-status-update.pdf.

[106] 'Onerous conditions' is indicative of the worst case that AEMO considers it prudent to plan for. The incidence of onerous conditions is hard to predict as they typically arise following an unplanned outage or unexpected system condition when there may be insufficient time to undertake AEMO MSL2 actions (such as recalling network outages or decommitting generators). In Queensland, this is modelled as operating as an island, with typical large synchronous units operating and minimum levels, only one major pumping load available, and one significant contingency FCAS (lower) provider unavailable.

[107] See Appendix A3, at https://www.aemo.com.au/-/media/files/major-publications/tpss/2026-tpss-appendix-a3.

[108] At National CER Roadmap, Australian Government Department of Climate Change, Energy, the Environment and Water, at https://www.energy.gov.au/sites/default/files/2025-08/National%20Consumer%20Energy%20Resources%20%28CER%29%20Roadmap%20Implementation%20Plan%20Update%20August%202025.pdf.

11.2 Workplan strategy

AEMO will continue to work closely with NSPs, industry, and consumer representatives on existing and emerging high-DER operating conditions, and the operational capabilities required to manage these conditions reliably and securely. This will inform actions to address near-term challenges and build technical foundations.

AEMO will contribute to enduring arrangements and system architecture through the National CER Roadmap and related initiatives, including collaborations with governments, NSPS, industry, consumer representatives and market bodies that establish roles, coordinated data exchange and technical requirements for a high DER future.

11.2.1 Objectives

The objectives of the DER workplan aim to address both existing and emerging challenges, helping to realise the opportunities of DER through the transition. They translate preconditions identified in the 2022 Engineering Roadmap into priority areas for the next three years. The objectives and their importance are summarised in **Table 21**.

Table 21 DER workplan objectives, purpose, and importance

Objective	Purpose	Importance
Objective 1: DER visibility and predictability	Establish the data and analytical capabilities needed to understand and forecast the aggregate behaviour, capabilities and operational state of a growing and increasingly diverse DER fleet.	Enables estimation and modelling of DER for planning, forecasting, system and market operation, disturbance analysis and managing system security.
Objective 2: Transmission-distribution coordination for planning and operations	Establish the roles, coordination and information exchanges needed across the transmission and distribution systems.	Enables distribution developments and demand-side opportunities to inform whole-of-system planning and the operational coordination required under normal, abnormal and emergency conditions.
Objective 3: System-level management of increasing DER	Build the capabilities needed to identify, assess and manage the aggregate impacts of DER on supply-demand balance and power system security.	Required to maintain security and reliability during high DER operating conditions, manage operationally, assess and implement mitigation measures.
Objective 4: Cyber-physical resilience	Strengthen the resilience of the physical assets, information technology systems and communications networks used to monitor, coordinate and manage DER by different parties.	Growing reliance on interconnected third-party systems creates new dependencies that must remain manageable during communications failures, software faults and cyber incidents.
Objective 5: Effective technical requirements and compliance arrangements for DER	Establish fit-for-purpose technical, interoperability, conformance and compliance arrangements for DER and associated management systems.	To provide confidence that required capabilities are implemented, maintained and perform as intended.

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Figure 20 Distributed energy resources workplan (1/2)

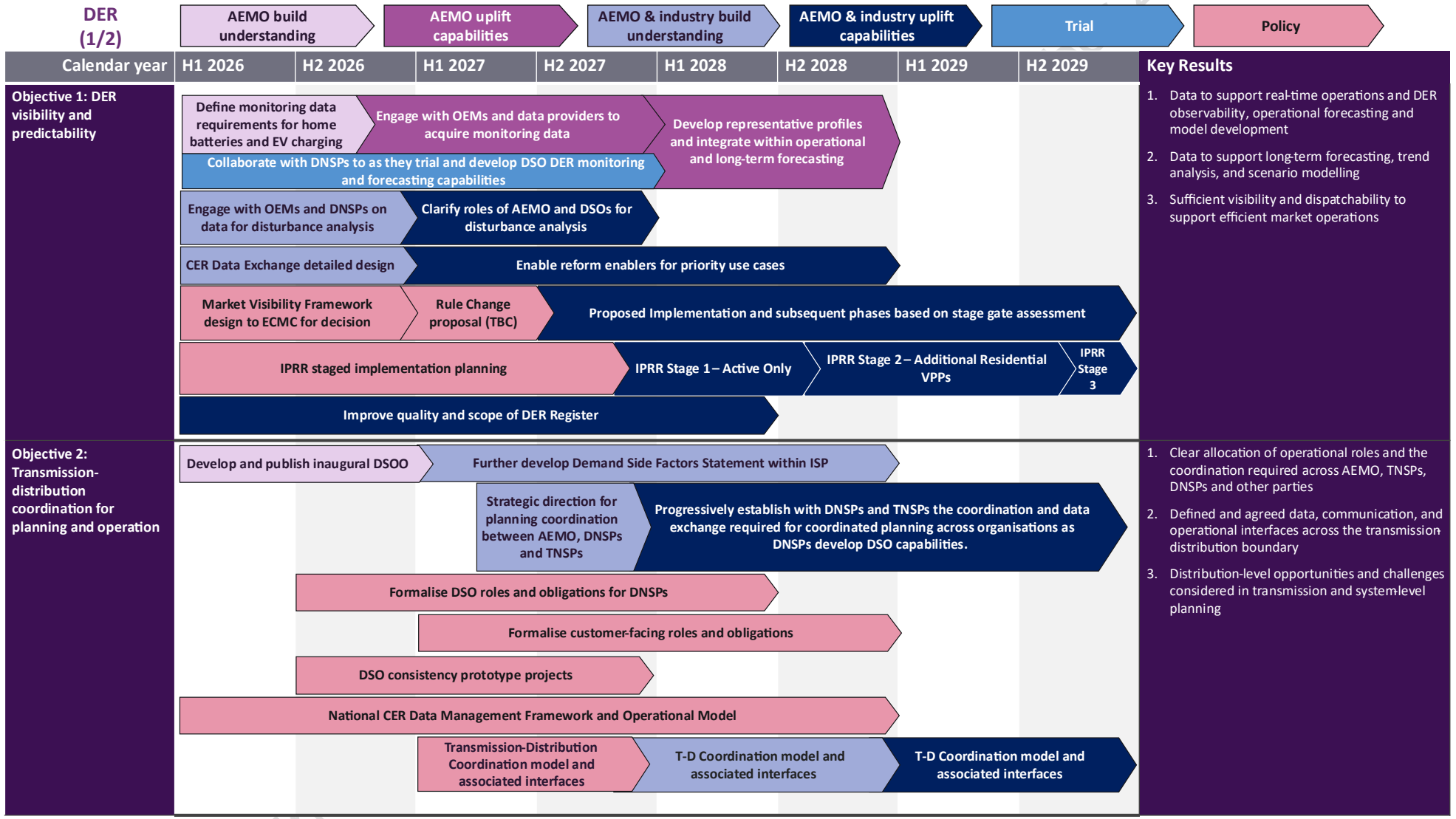
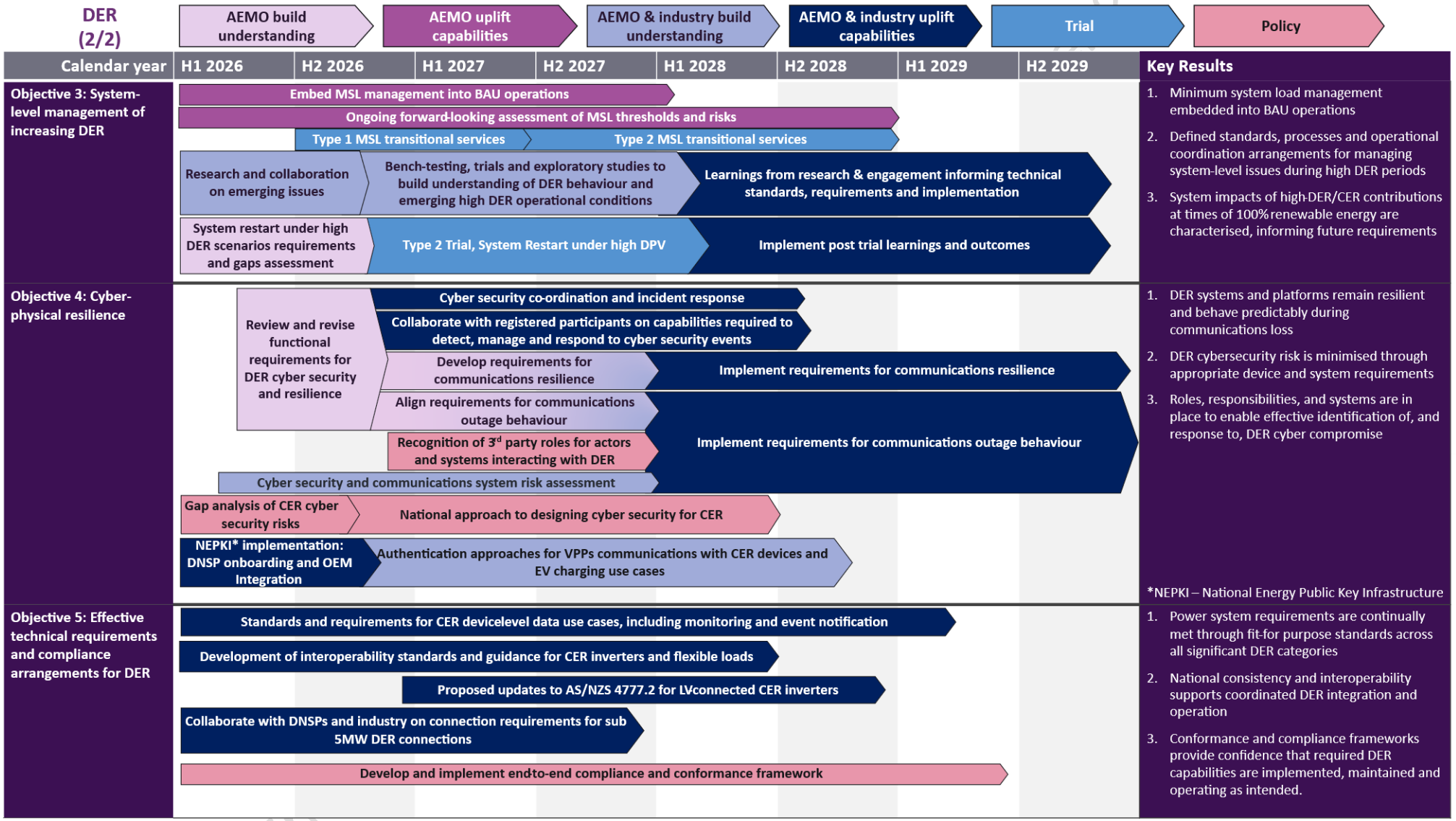


Figure 21 Distributed energy resources workplan (2/2)



11.3 Workplan delivery

This section describes the work AEMO and industry are progressing in the near-term to build towards the objectives outlined above. Key results and activities for each objective are shown in **Figure 21** and **Figure 21** above.

11.3.1 Objective 1: DER visibility and predictability

System operators require trusted standing data on the installed DER fleet – including location, technology, capacity and operational characteristics. AEMO is working with DNSPs to improve coverage and accuracy of the DER Register and is using other available data sources to validate data, address standing data gaps[109], and better track replacements, upgrades and retirements.

Measured operational data from representative samples of monitored DER systems are critical for estimating and forecasting DER contributions and modelling DER behaviour during disturbances. Monitoring data for DPV is not currently representative of the broader fleet, and will need to be expanded to include consumer batteries, EVs, and flexible demand. AEMO is developing data specifications and engaging with OEMs, DNSPs and data providers on practical acquisition arrangements to support development of representative profiles for forecasting and disturbance analysis.

AEMO currently has limited operational visibility of price-responsive resources, coordinated DER, and flexible demand, including larger sites and fleets managed by retailers and other actors. Staged implementation of the *Integrating Price Responsive Resources into the NEM* rule change will provide a pathway for eligible DER aggregations to participate in the wholesale market, making them visible and dispatchable for the market[110]. In parallel, AEMO is co-designing with industry and consumer representatives the *Market Visibility Framework* to manage and integrate unscheduled price responsive resources into the NEM[111].

11.3.2 Objective 2: Transmission-distribution coordination for planning and operation

Following the National CER Roadmap recommendations, AEMO will support the anticipated AEMC rule change process to formalise DNSP Distribution System Operator (DSO) roles and clarify how DNSPs interact with AEMO, TNSPs and customer-facing parties[112]. This includes operational roles and accountabilities for manufacturers, communications providers and customer agents in enduring DER governance and conformance arrangements[113]. Consistency prototype projects will

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[109] Including Clean Energy Regulator data collected as part of the SRES and the Cheaper Home Batteries Scheme, and investigation of other available data sources to address standing data gaps.

[110] Includes structured dispatch modes and operational data requirements. Implementation will be staged to progressively broaden participation, from selected residential VPPs (2027) to broader VPP participation (2028) and ultimately all eligible VSRs. Further information is at AEMO's Integrating Price Responsive Resources into the NEM (IPRR) implementation page, at https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/integrating-price-responsive-resources-into-the-nem.

[111] Through graduated visibility modes and obligations tailored to individual resource types, capability and market impact. See AEMO's Market Visibility Framework (MVF) consultation page, at https://www.aemo.com.au/consultations/current-and-closed-consultations/market-visibility-framework-consultation. The final report provided to energy ministers will be published on this page once available, alongside other consultation materials, submissions and Stakeholder Advisory Group meeting materials.

[112] National CER Roadmap workstream "Redefining roles and responsibilities for power system and market operations in a high CER future", Recommendation 1, Formalise the DNSP as DSO, at https://www.energy.gov.au/sites/default/files/2025-12/Redefining%20roles%20and%20responsibilites%20for%20power%20system%20and%20market%20operations%20in%20a%20high%20CER%20future%20-%20final%20report.pdf.

[113] National CER Roadmap workstream "Redefining roles and responsibilities for power system and market operations in a high CER future", Recommendation 4, Recognise customer-facing actors in energy frameworks.

support more consistent development of DSO capabilities across the NEM, initially focusing on dynamic operating envelopes, emergency backstop mechanisms and flexibility services[114].

AEMO is establishing a collaborative work program with TNSPs, DNSPs, industry and consumer representatives to co-design the architecture and operating model for Transmission–Distribution (T-D) Coordination in a high-DER future[115]. This will progress in parallel with the DSO rule change to align and enable the required DNSP capabilities. The work will also consider design standards for the T-D interface and areas where transmission and distribution system operation influence each other, as well as planning criteria consistent with these design standards to support DNSP actions and potential solutions to assist with system-level needs.

AEMO is leading the development of the National CER Data Management Framework and associated Data Coordination Function[116] to establish an enduring national approach to CER data governance and exchange, including common standards, governance arrangements and responsibilities across industry participants for how data is collected, accessed and shared.

While these initiatives, prioritised through the National CER Roadmap, represent the opportunity to create enduring arrangements to better meet the operational needs of a high-DER system, continued action is required to address near-term challenges through the transition to these arrangements. Much of that action is included in the other objectives. Where interim T-D coordination and data management arrangements can be agreed, these will also be pursued.

AEMO will continue to work with DNSPs and TNSPs and other stakeholders to consider distribution network developments, DER capabilities and demand-side opportunities in long-term system planning. Near-term activities include the inaugural 2027 *Demand-side Statement of Opportunities* (DSOO) and 2028 ISP Demand Side Factors Statement, alongside implementation of new distribution planning and data-publication requirements[117].

The AEMC's ISP Review[118] will assess the coordination required between DNSPs, TNSPs and AEMO to effectively consider and identify the opportunities of an increasingly active distribution system in transmission and system-level planning. The DER workplan complements the review by focussing on the capabilities required to enable this direction, including roles and associated functions, data definitions and standards for effective and scalable data exchange across parties.

11.3.3 Objective 3: System-level management of increasing DER

AEMO has largely embedded MSL management into BAU operations and continues to work with DNSPs on the operational capabilities required for more onerous conditions, as outlined in Appendix A3. Forward-looking assessment will track how MSL risks evolve with changes in synchronous generation, battery storage, network development, increasing demand flexibility, and alternative sources of system security services. MSL Transitional Services will expand operational flexibility

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[114] National CER Roadmap workstream M3/P5 Redefining roles, Recommendation R3, "Redefining roles and responsibilities for power system and market operations in a high CER future", Recommendation 3, Drive consistent delivery of DSO activities across the NEM.

[115] National CER Roadmap workstream "Data sharing arrangements to inform planning and enable future markets", Recommendation 3, Design the Transmission-Distribution (T-D) Coordination model and associated Interfaces, at https://www.energy.gov.au/sites/default/files/2025-12/Data%20sharing%20arrangements%20to%20inform%20planning%20and%20enable%20futre%20markets%20-%20final%20report.pdf.

[116] National CER Roadmap workstream M2 Data Sharing Arrangements, Recommendation R1, Data management framework and coordination function, at https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/electricity-working-group/consumer-energy-resources-sub-working-group/data-sharing-arrangements

[117] Including obligations to prepare a 20-year Distribution Network Development Plan and standardised publication of distribution network data to support identification of DER-related investment and opportunities, coming into effect progressively with DNSP regulatory determinations commencing in 2028. See AEMC, Enhancing distribution network planning & reporting, Final Determination (July 2026), at https://www.aemc.gov.au/rule-changes/enhancing-distribution-network-planning-reporting.

[118] See https://www.aemc.gov.au/market-reviews-advice/review-integrated-system-plan.

during low demand conditions and trial emerging approaches, such as coordinated storage and flexible demand[119]. These may inform consideration of any further mechanisms to efficiently coordinate these resources for system security[120].

AEMO will investigate emerging high-DER system security risks that could materially impact system security during high-DER operating conditions projected over the next 5-10 years, working with TNSPs and DNSPs to identify, monitor and assess risks and develop mitigation strategies. This will be supported by bench testing, exploratory studies and trials to improve understanding of DPV, BESS and EV Supply Equipment (EVSE) behaviour and the impact on AEMO's ability to manage the technical envelope of the power system during high DER operating condition – including managing frequency and inertia (Section 6), transient stability (Section 8.3.3) and oscillations (Section 8.3.2). The near-term focus is on weak grid performance, oscillations and system strength interactions, disturbance ride-through, and momentary cessation. Learnings will inform development of modelling and assessment methods, operating limits, the T-D coordination and capabilities (Objective 2), and updates to DER performance requirements and standards (Objective 5).

Increasing DPV and consumer battery uptake is making system restart during high-DER conditions more complex, as DER reconnection can rapidly reduce or destabilise the load available to form stable restoration islands while communications-based controls may be degraded during a black system event. AEMO is assessing communications, control and fallback requirements for predictable DER behaviour and stable load formation during restoration (see Section 9).

11.3.4 Objective 4: Cyber-physical resilience

AEMO is reviewing functional requirements for DER communications resilience – including parties and systems managing DER devices as well as operational data exchange and coordination between AEMO, TNSPs, DNSPs, DER aggregator and operational actors – across communications loss, MSL, lack of reserve (LOR) and system restart scenarios. The work will define the level of communications resilience needed for critical DER functions, including availability, redundancy, and recovery arrangements. It will further define consistent fallback settings, ramp rates and device behaviours during communication outages. Learnings from the Type 2 Transitional Service for system restart under high DPV conditions[121] are expected to inform development of requirements (Objective 3). These requirements will inform DSO capability development (Objective 2) and standards engagement (Objective 5), and development of testing capabilities under scenarios where communications are degraded or unavailable.

AEMO is supporting industry on security requirements to manage the risk of cyber compromise of CER devices, communications and management systems. This includes participating in activities to assess gaps across interoperability, communications and data-sharing arrangements to inform national requirements, standards and responsibilities[122], and

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[119] For further information, see AEMO information pages for MSL - Type 1 Transitional Service, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/minimum-system-load---type-1-transitional-service, and MSL - Type 2 transitional services, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/msl-transitional-services.

[120] The AEMC is assessing two rule change requests relating to the management of MSL in the NEM and supplementary market arrangements: Minimum System Load framework and floor price proposal rule change request at https://www.aemc.gov.au/rule-changes/minimum-system-load-framework-and-floor-price-proposal, and the Minimum System Load reserve service rule change request at https://www.aemc.gov.au/rule-changes/minimum-system-load-reserve-service.

[121] See Type 2 Transitional Service for System Restart under High DPV Conditions Service, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.

[122] Through the T.5 workstream, "CER cyber security for consumers and the grid", added to the National CER Roadmap in the August 2025 Implementation Plan Update, at https://www.energy.gov.au/sites/default/files/2025-08/National%20Consumer%20Energy%20Resources%20%28CER%29%20Roadmap%20Implementation%20Plan%20Update%20August%202025.pdf.

embedding security requirements into the roles of OEMs, customer agents and other parties involved in DER coordination (Objective 2). Near-term, implementation of National Energy Public Key Infrastructure (NEPKI)[123] continues through DNSP onboarding and OEM integration currently ongoing. Authentication approaches for VPP communication with CER devices and EV charging to be developed as identified in the National CER Roadmap[124].

AEMO is working with the Australian Government and industry on the coordination required across actors for cyber threat detection, regular and risk-based assessment of emerging threats, including increasing AI capabilities and reliance on the public internet. AEMO will collaborate to clarify cyber incident-coordination with NSPs, aggregators, manufacturers and other relevant actors to establish clear responsibilities, information-sharing and response capabilities in the event of DER cyber compromise events impacting system security.

11.3.5 Objective 5: Effective technical requirements and compliance arrangements for DER

AEMO will continue to work with industry on fit-for-purpose technical requirements, anticipating the system security and reliability impacts of large DER fleets as they scale. This includes progressing performance requirements for sub-5 MW DER connections with DNSPs[125] and supporting development of a national standard through Standards Australia committee EL-064. AEMO will also work with stakeholders and Standards Australia EL-042 committee members to consider updates to the AS/NZS 4777.2 standard for low voltage (LV)-connected CER inverters, informed by operational experience and the understanding of emerging risks gained in pursuing Objectives 3 and 4 of the DER workplan.

Interoperability across the CER ecosystem allows devices and systems to operate effectively together and support consumer, market and power system needs. As well as involvement in the National CER Roadmap's technical standards workstream on nationally consistent interoperability arrangements[126], AEMO is working with industry on interoperability for inverters, flexible loads and EVs, site level management and aggregation, including device-level monitoring and event data use cases. AEMO will also collaborate with DNSPs on interoperability needs for key DSO functions, using learnings from CSIP-AUS emergency backstop and flexible export implementations to inform testing and identification of issues in the design phase.

To provide assurance that DER and associated systems will perform as intended once installed and operating, AEMO will support development of a compliance and conformance[127] framework through the National CER Roadmap, focused on linking technical and operational requirements with arrangements to assess, monitor, rectify non-conformance and, where appropriate, enforce conformance. This will enhance confidence that CER capabilities are correctly implemented, maintained and continue to perform as intended over the lifecycle of installations[128].

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[123] NEPKI is a platform intended to act as a trusted security layer for issuing digital certificates to secure real-time communications for DNSP active management of DER including emergency backstop and dynamic operating envelopes.

[124] T.3 workstream "Establish secure communication systems for CER devices". See National CER Roadmap Implementation Plan Update August 2025.

[125] Covering larger DER connections in the distribution network not covered by AS/NZS4777.2, building AEMO's work with DNSPs and industry in 2025. See AEMO, Technical Requirements for sub 5 MW DER Connections - DNSP Guideline and Consultation Report (November 2025), at https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/technical-requirements-for-sub-5-mw-der-connections.

[126] See Standards Australia, New flexible loads guide offers a framework for Australia's energy future, at https://www.standards.org.au/news/new-flexible-loads-guide-offers-a-framework-for-australias-energy-future.

[127] Compliance defines a device/system meeting technical requirements at the time of installation/commissioning. Conformance is defined as the device/system's ability to meet all technical and functional requirements during its functional duration.

[128] National CER Roadmap workstream "Redefining roles and responsibilities for power system and market operations in a high CER future", Recommendation 5, at https://www.energy.gov.au/sites/default/files/2025-12/Redefining%20roles%20and%20responsibilites%20for%20power%20system%20and%20market%20operations%20in%20a%20high%20CER%20future%20-%20final%20report.pdf.

12 Large loads, including data centres

Summary

- New large inverter-based loads (LIBLs), particularly data centres, have technical characteristics and potential system security impacts that are materially different from existing industrial facilities and are predicted to grow rapidly over the next decade.
- Significant progress is being made on technical assessment and policy development to support this growth, including the Improving the NEM Access Standards Package 2 and Operational Integration and Visibility (OIV) of Large Inverter Based Loads rule change processes.
- AEMO's focus continues to be on enabling efficient integration of these loads while maintaining power system security and reliability. This will be achieved by continuing to work with NSPs, regulatory bodies, governments, OEMs and project owners to identify, codify and implement appropriate technical, operational and system integration requirements, while developing new methods for assessing the technical impacts of large IBL during the connections process.

12.1 Large loads and the transition

12.1.1 Definition

Large loads are facilities with a maximum demand of 30 MW or more. While large loads have been part of the NEM for decades, emerging changes in their number, scale, characteristics and growth rates are creating new challenges for power system planning and operation.

LIBLs[129] arising from electrification of industrial activities and growth in digital services, including AI, are key drivers of these changes. Data centres are a particular focus because of their rapid growth and potential for concentration in specific locations within both distribution and transmission networks.

12.1.2 Status

Existing capacity and observed growth rates

Data centre loads are material and growing rapidly. In Q3 2026, average data centre demand in New South Wales was 484 MW, up 40% year-on-year, while Victorian demand grew from 136 MW to 225 MW over the same period[130]. AEMO's 2026 ESOO estimated data centre consumption of around 5 terawatt hours (TWh) in 2025-26, or 2.8% of NEM operational

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[129] For consistency with industry nomenclature, the term large inverter-based load (LIBL) is used. However, many load facilities draw power from the network through actively controlled rectifiers. Large converter-based load (LCBL) is therefore a more technically precise description, with the broader term "converter" also accommodating future developments in network interface designs.

[130] See pg. 10, *Quarterly Energy Dynamics* Q3 2026, at https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q3-2026.pdf.

consumption, growing to around 15 TWh, or 7.8%, by 2029-30 and around 34 TWh, or 13%, by 2035-36 under the ISP *Step Change* scenario.

Reflecting strong development interest, AEMO is currently supporting connection of 22 transmission-connected data centre projects totalling 10.1 GW of connection capacity, predominantly in New South Wales and Victoria. Actual realised demand will depend on project delivery, timing and facility utilisation. The 2026 ESOO found that operating data centres were using around 27% of their maximum connection capacity in early 2026, while a mature fleet is expected to average around 45-51% utilisation, reflecting planned capacity redundancy and diversified compute profiles.

Managing potential technical challenges

Traditional large industrial loads typically behave as 'consumers of power', with relatively limited interaction with the surrounding network. In contrast, many new loads incorporate power-electronic interfaces and control systems that dynamically interact with changing network conditions and whose operating characteristics and transient responses impact on system stability, voltage management, frequency control, and power quality.

Table 22 summarises the leading technical challenges of integrating modern data centres into the power system that were considered in the 2026 GPSRR[131], noting the relevance of some issues depends on facility designs and workload types. Much work has been done, and is in progress, to proactively manage these potential challenges, as outlined in **Table 23** and **0** in the section below.

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Table 22 Typical performance attributes of data centres which have the potential to impact system security

Attribute	Description
Disturbance ride-through	Data centre controls may reduce or interrupt grid demand during voltage or frequency disturbances, even where ride-through is technically feasible. Appropriate fault-ride-through capability, including for multiple successive disturbances, is important to avoid unnecessarily increasing the severity of external network events.
Simultaneous loss of multiple facilities	A single network disturbance may affect multiple data centres with similar control settings, resulting in a large aggregate reduction in demand. This can increase load contingency sizes, resulting frequency excursions and changes in network power transfers, requiring assessment of both individual and collective responses.
Post-disturbance demand recovery	The timing and rate at which demand returns following a disturbance can influence power system recovery, even where the initial interruption is brief. Uninterrupted Power Supply (UPS) transfer logic, restoration of computing and cooling loads, and battery recharging need to be considered when assessing the facility's overall recovery behaviour.
Rapid demand changes and ramping	Changes in computing activity can produce rapid variations in electricity demand unless sufficiently buffered by a facility's power supply systems. Ramp-rate limits and visibility of significant demand changes are expected to become more important to assist manage effects on frequency, voltage and the orderly dispatch of generation.
Forced oscillations from cyclic workloads	Repetitive computing workloads can introduce cyclic variations in active power demand that may excite power system oscillatory modes.
Converter control interactions and system strength	Actively controlled converters and other power-electronic equipment can interact with the network and neighbouring equipment, potentially introducing poorly damped or unstable responses. Performance needs to be assessed across relevant network configurations and system strength conditions, rather than inferred from facility demand alone.
Voltage response and reactive power demand	Changes in active and reactive power demand during and after faults can affect network voltage recovery. Assessments need to capture the combined response of all converter interfaces, as well as auxiliary plant.
Concentration of connection points and network capability	Large data centres can be concentrated in parts of the network, increasing local capacity requirements and the significance of nearby network disturbances. Connection assessments therefore need to consider cumulative impacts and interactions between developments, rather than assessing each proposal in isolation.

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

Activities completed or currently in progress

Australia is learning from international experience, creating an opportunity to develop standards, processes, and tools to support system security in parallel with helping facilitate the connection of shovel-ready projects. Relevant AEMO activities focussed on power system security and operability are summarised in **Table 23** and **0**.

Table 23 Technical assessments and guidance

Activity	Description
Large-load connection framework and technical guidance	AEMO has published a draft Interim Guideline for Connection of Inverter Based Loads (IBLs)[A] to support the connection of new large loads as the regulatory frameworks continue to evolve. This guideline provides information on the modelling, model validation, access standards assessment, and commissioning activities required to connect IBL. Further guidance from AEMO is intended to include: • Schedule 5.3 Participant Modelling Guideline – to clarify modelling requirements and expectations for large loads under the connection process. • LIBL DMAT Guideline – to establish the approach for applying Dynamic Model Acceptance Testing to large inverter-based loads. • Hardware Model Validation Guideline – to provide a consistent approach for validating hardware and associated simulation models used in connection assessments. • Schedule 5.3 Access Standards Assessment Guideline – to support consistent assessment and negotiation of applicable access standards for large loads. • LIBL Commissioning Guideline – to establish commissioning and hold-point expectations to demonstrate that connected plant performs consistently with agreed models and performance standards. • NER 5.3.12 Alterations Guideline – to provide guidance on assessing modifications or alterations to existing connected facilities under clause 5.3.12. • LIBL Early Assessment Framework (EAF) – to enable earlier technical assessment of large inverter-based load projects, including early identification of modelling, performance and system-impact issues. • System Strength Impact Assessment Guidelines (SSIAG) – to update system strength impact assessment arrangements for large inverter-based loads, aligned with the new Package 2 framework.
2026 GPSRR: increasing large load connections	Assessed large load integration as a priority risk, including disturbance ride-through, active power recovery, rapid ramping and oscillatory behaviour. Findings supported the development of load access standards and continued monitoring of emerging risks. Final report published in July 2026[B].
2027 GPSRR: residual voltage control and inverter-based load risks	Proposed assessment of residual risks as data centre connections increase, including dynamic voltage control challenges and the adequacy of mitigation measures following access standard reforms. Scope and methodology development is currently in progress, with a draft approach paper published for consultation by AEMO on 13 October 2026[C]. The final approach paper is expected in December 2026.
International collaborations through International System Operator Network (ISON)	ISON[D] provides an ongoing forum to shares practical experience on large-load behaviour, integration challenges and grid requirements with other system operators, informing AEMO's understanding and approaches.

A. At https://www.aemo.com.au/consultations/current-and-closed-consultations/interim-guideline-for-connection-of-inverter-based-loads.
B. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.
C. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.
D. ISON page, https://www.isonetwork.org/.

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Table 24 Reforms and policy development to support power system security and operational readiness

Activity	Description
Improving the NEM Access Standards Package 2 Rule Change	AEMO has supported the development and implementation of technical requirements for large inverter-based loads, including assessment requirements for LIBL over 30MW, disturbance performance, stability and clearer treatment of UPS configurations. The final Rule change determination was published by the Australian Energy Market Commission (AEMC) on 12 November 2026[A].
Operational Integration and Visibility (OIV) of Large Inverter Based Loads Rule Change	Proposes consistent monitoring, communications and information-sharing requirements for large inverter-based loads, including advance notice of significant demand changes, appropriate ramp-rate limits and operational coordination with AEMO. These measures aim to improve forecasting and management of power system events while supporting efficient investment, as well as secure and reliable network operation. AEMO submitted the rule change request on 21 July 2026. On 12 November 2026 the AEMC published a consultation paper seeking stakeholder feedback[B].
Data centre contracting obligation for firmed energy	The rule change proposal aims to support power system security and reliability by requiring qualifying data centres to back their electricity demand with eligible firming arrangements, including new generation, storage and dependable demand flexibility, matched to the scale and profile of their consumption. The broad objectives are to reduce the risk of supply shortfalls during peak demand, low renewable generation and periods of system stress, while recognising credible demand flexibility as an alternative to additional supply-side capacity. Its effectiveness would depend on the final design of the firming, new-investment and compliance requirements. The Honourable Chris Bowen MP, Minister for Climate Change and Energy, submitted the rule change request on 20 October 2026, which at the time of writing, is yet to be initiated by the AEMC[C].

A. Details on the rule change are at https://www.aemc.gov.au/rule-changes/improving-nem-access-standards-package-2.
B. Details on the proposed Rule change are at https://www.aemc.gov.au/rule-changes/operational-integration-and-visibility-large-inverter-based-loads.
C. Details on the proposed Rule change are at https://www.aemc.gov.au/rule-changes/data-centre-contracting-obligation-firmed-energy.

The significant work completed or progressing provides a strong foundation for managing the known system security risks outlined in **Table 22**, and provides a platform for dealing with any future challenges as they emerge. Section 12.2 outlines how AEMO will continue to support the effective integration of data centres as experience and the evidence base develop.

Several other initiatives[132] related to data centres are in progress and cover issues including network augmentation cost recovery mechanisms, network connection processes, and commercial frameworks for demand flexibility and market participation. These are beyond the scope of the TPSS and are not considered in detail within this document.

12.2 Strategy

AEMO's workplan builds on existing activities and reforms to cover the development and implementation of appropriate technical, operational, and regulatory arrangements to support secure and reliable integration of these facilities in the NEM. In parallel, AEMO will actively monitor emerging issues in this domain, drawing on international experience, technological developments and advances in modelling and simulation to identify and assess evolving reliability and system security risks and opportunities.

12.2.1 Objectives

Recognising the significant amount of activity already inflight, AEMO is pursuing the following objectives over the coming three years:

[132] Summarised at https://www.aemc.gov.au/sites/default/files/2026-11/Energy%20market%20body%20coordination%20on%20data%20centre%20reforms%20-%20Fact%20sheet.pdf.

- **Objective 1:** Appropriate technical performance requirements for the connection of data centres are identified and implemented.
- **Objective 2:** Operational visibility and communication arrangements are in place to manage system security as data centre load increases.
- **Objective 3:** Registration and system integration requirements are defined.

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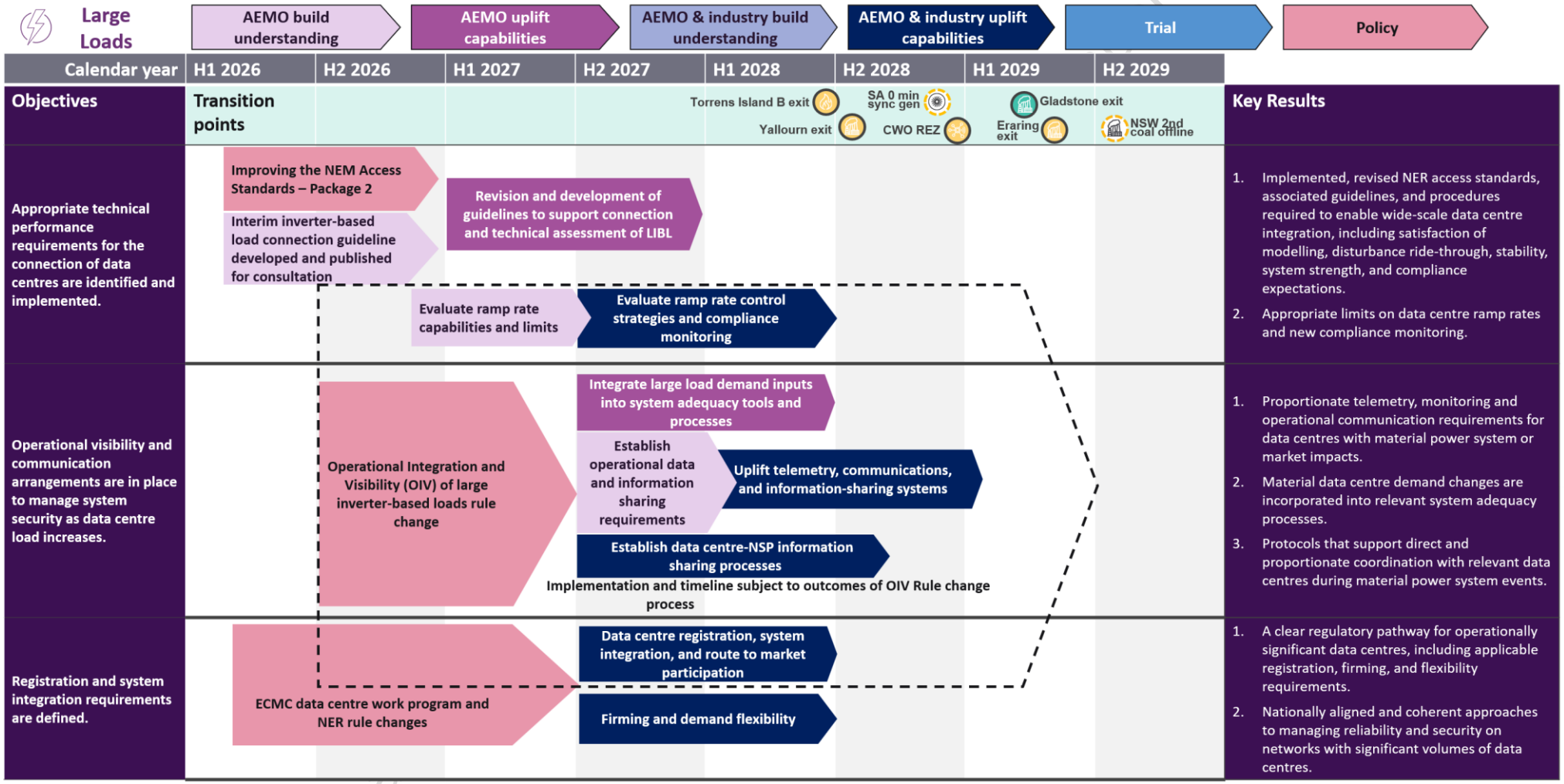
Figure 22 Large loads workplan



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12.3 Workplan delivery

This section describes the near-term work of AEMO and industry building towards the objectives outlined above.

12.3.1 Objective 1: Appropriate technical performance requirements for the connection of data centres are identified and implemented

Delivery of this objective will focus on establishing clear, practical and consistently applied connection performance requirements for data centres and other LIBL which address power system security. A key component will be implementing new and updated access standards introduced in the "Improving the NEM Access Standards – Package 2" rule change and embedding them in AEMO's connection assessment processes. Supporting activities will include updating relevant AEMO guidelines, procedures and internal assessment methods.

Specific external-facing documentation to be revised or developed includes:

- Power System Modelling Guideline (PSMG),
- Power System Stability Guideline (PSSG),
- Schedule 5.3 Participant Modelling Guidelines,
- LIBL DMAT Guideline,
- Hardware Model Validation Guideline,
- Schedule 5.3 Access Standards Assessment Guideline,
- LIBL Commissioning Guideline,
- NER 5.3.12 Alterations Guideline,
- LIBL Early Assessment Framework (EAF), and
- System Strength Impact Assessment Guidelines (SSIAG).

AEMO will undertake industry consultation on relevant documentation changes following applicable NER requirements. Collectively, these activities will support a consistent approach to the modelling, assessment and demonstration of compliance for data centres and other LIBL seeking connection to the NEM.

In parallel, AEMO will support consideration of appropriate ramp-rate requirements for large loads through the AEMC's Operational Integration and Visibility (OIV) rule change process. Ramp-rate limitations were proposed by AEMO in its July 2026 rule change submission to the AEMC[133], and AEMO will prioritise the provision of technical advice to support the AEMC's consideration of industry submissions and potential implementation arrangements, should this be requested. Should ramp-rate requirements form part of the final rule determination, further work may be required to establish compliance arrangements, including evaluation of proposed control strategies and monitoring capabilities for assessing ongoing compliance.

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[133] For details, see the AEMC website, at https://www.aemc.gov.au/rule-changes/operational-integration-and-visibility-large-inverter-based-loads.

These activities are helping establish a clearer and more consistent framework for defining, assessing and monitoring the technical performance expected of data centres and other LIBLs. In supporting these reforms, AEMO's driving principle is to ensure that connection requirements remain proportionate to potential power system impacts while providing greater clarity for project proponents, NSPs and other stakeholders involved in the connection process.

12.3.2 Objective 2: Operational visibility and communication arrangements are in place to manage system security as data centre load increases

This workstream focuses on implementing the operational arrangements arising from the OIV rule change to provide AEMO and NSPs with the ability to manage the impacts of operationally significant data centres and other LIBLs. This is expected to include establishing proportionate monitoring, telemetry and information-sharing requirements, incorporating significant anticipated changes in LIBL demand into forecasting and market processes, and developing operational communication and coordination arrangements.

Implementation will need to be coordinated with NSPs and other affected stakeholders and aligned with related reforms to connection, market visibility and transmission-distribution coordination arrangements, including those described in Section 11.3.2 above. Operating protocols will be needed to manage multiple loads with demand flexibility in their connection agreements.

12.3.3 Objective 3: Registration and system integration requirements are defined

Delivery of this objective will focus on establishing clear, consistent and proportionate arrangements for market and system integration of data centres. AEMO will support the development and implementation of relevant requirements arising from the OIV rule change, such as potential requirements relating to any new load registration categories and streamlined treatment of back-up generation.

In parallel, AEMO will support the development of practical arrangements for implementing any changes that may arise from the data centre contracting obligation rule change request[134].

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[134] At https://www.aemc.gov.au/rule-changes/data-centre-contracting-obligation-firmed-energy.

13 Research opportunities

Summary

- Research can help industry anticipate future power system challenges, build evidence ahead of critical decisions, and explore new options for maintaining power system security through the transition.
- The TPSS highlights selected areas of power system security research where AEMO is already engaged or where further research may have industry value, informed by identified system risks and knowledge gaps, Engineering Roadmap activities and emerging issues further over the horizon. These areas are illustrative rather than exhaustive, recognising that researchers and industry will identify many other important opportunities as technologies and power system needs evolve.

13.1 How research supports system security through the transition

Research can complement industry engineering and operational activities by exploring questions where the nature of the problem, future system conditions or potential solutions remain uncertain. It can help identify emerging challenges and opportunities early, build evidence ahead of critical decisions, and expand the range of options available to support power system security through the transition.

Research areas can emerge from several sources. The TPSS identifies system security risks and areas where technical understanding remains incomplete. Engineering Roadmap workplans identify more specific knowledge and capability gaps where further evidence could support practical engineering outcomes. Research can also look further ahead, exploring emerging technologies, behaviours and system interactions before they become material operational or planning risks.

Figure 23 illustrates the relationship between AEMO's transition planning and engineering activities, its current major research collaborations and the Zema Energy Studies Scholarship program[135]. AEMO-led activities generally focus on issues with more immediate relevance to operational and planning decision-making, where the problem and required capability are sufficiently defined to support engineering, demonstration or implementation. Researcher-led activities can complement this by exploring questions with greater uncertainty, testing alternative approaches and developing new knowledge that may influence how future challenges are understood and addressed.

AEMO engages with researchers to share operational and planning insights, emerging system needs and relevant international experience gained through knowledge exchange in the ISON, and to identify areas of mutual interest. This can help create pathways for research to inform practical engineering and operational outcomes, and inform AEMO's understanding of future system needs. Some research collaborations have a direct relationship with Engineering Roadmap activities, including where research explores a knowledge gap or extends investigation of an identified engineering challenge. Where there is overlap, research can explore a wider range of possibilities and experimental approaches than may be appropriate for engineering work directed towards a specific operational outcome.

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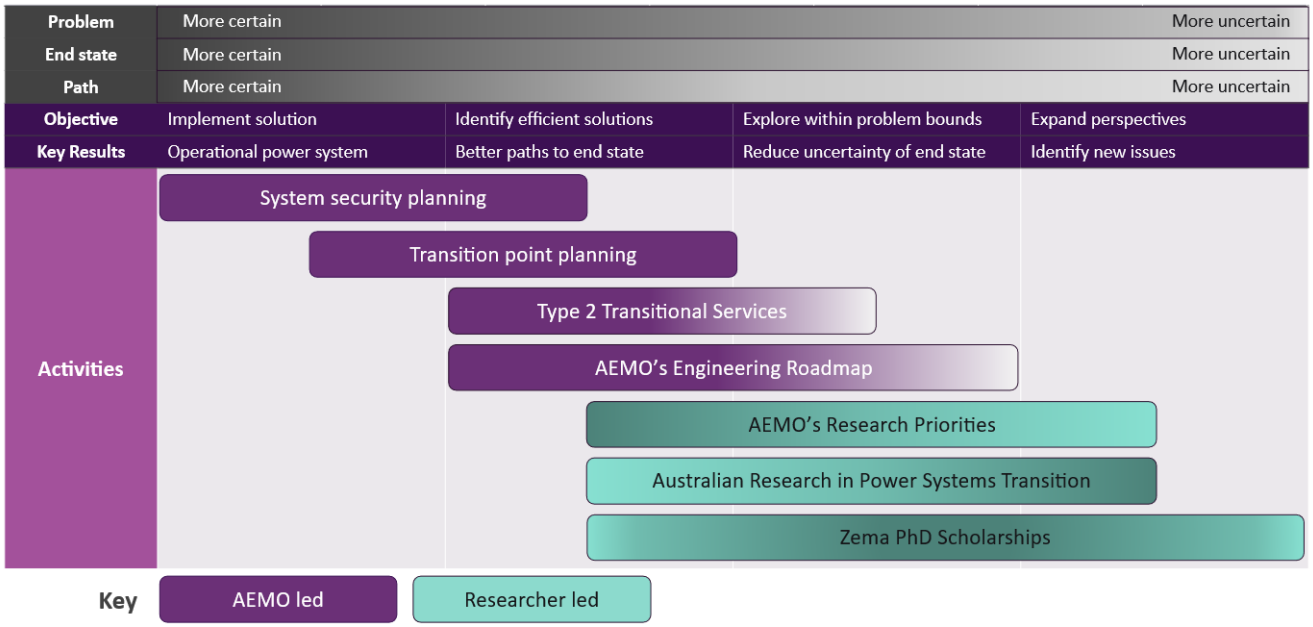
[135] See https://www.aemo.com.au/about/zema-energy-studies-scholarship.

Figure 23 Complementarity of AEMO and researcher activities



Major research collaborations

AEMO proactively engages with universities, research organisations, system operators, network service providers, OEMs and other partners. AEMO's current major research collaborations are summarised in **Table 25**.

Table 25 Major current research collaborations

Initiative	Description	Linkages to Engineering Roadmap
ARENA-funded research projects	Tools to enhance energy grid resilience led by Monash University[A]. Through this project AEMO benefits through the development of a tool that assists with investigations of power system oscillations due to IBR interactions, by providing frequency scans of individual IBR plants and wide area models.	Transient and Oscillatory Stability Objective 1: Small signal stability models are accurate for high IBR, low synchronous generation conditions
	Project PROFILES led by UNSW[B] . This project assists AEMO and the wider industry to understand how GFM inverters can provide fault current of sufficient magnitude, duration, and composition for protection relays to operate correctly under diverse system operation and fault conditions.	System Strength Objective 3: An evidence base assessing the compatibility of GFM BESS and network protection systems.
	Hardware testing to improve the design, commissioning, and operations of Hybrid Renewable Power Plants led by the University of Queensland[C]. This project provides AEMO with practical evidence from hardware-based testing to improve AEMO's understanding and assessment of hybrid renewable plant controls, supporting more robust plant design, commissioning and integration into the power system.	Transient and Oscillatory Stability Objective 3: Transient stability is managed in high IBR, low synchronous generation conditions
CSIRO's Australian Research in Power Systems Transition (AR-PST) Initiative	Originating from the Global Power System Transformation Research Roadmap which details the research required to support Australia's transition to a stable, secure and affordable power system AEMO partners with CSIRO in this multi-year program. AEMO's subject matter experts are the industry leads for nine AR-PST Topics including Control Room of the Future, Power System Planning, Data Centres and Stability in collaboration with energy research teams from Australian Universities[D].	Various across the Transient and Oscillatory Stability, Operability, and Large Loads, including Data Centres workplans.

A. See https://arena.gov.au/projects/rezonance-impedance-based-stability-assessment/.
B. See https://arena.gov.au/projects/unsw-protection-relay-operation-for-inverter-based-low-inertia-electricity-systems-profiles-project/.
C. See https://arena.gov.au/projects/uq-control-design-for-hybrid-renewables-study/.
D. See https://www.csiro.au/en/research/technology-space/energy/electricity-transition/ar-pst.

13.2 Areas of potential research interest

The areas in **Table 26** illustrate research questions that could help address current knowledge gaps or anticipate emerging challenges identified through the TPSS, Engineering Roadmap and broader horizon scanning. They are intended to signal areas where further research could have practical industry application, rather than prescribe research priorities or limit the scope of potential collaboration. The areas will evolve as technical understanding, system conditions and industry priorities change. AEMO also welcomes engagement on research questions outside these areas where they have potential relevance to future power system security, reliability or operability.

Table 26 Potential research areas of industry interest

Research Priority topic	Description
Future behaviour and modelling of large inverter-based loads	Develop fit-for-purpose IBL models that represent IBL flexibility and vulnerabilities. • Identifying leading modelling practices and key instability risks • Developing risk- and technology-specific modelling approaches • Defining appropriate model scope, including controls and protection • Developing aggregation methods for complex IBL and non-IBL facility loads
Efficient modelling of increasingly inverter-dominated power systems	Integrate EMT and impedance-scan analysis to support efficient and reliable planning, connections and operational studies. • Identifying screening methods (potentially leveraging automation and AI) to reduce simulation effort while maintaining confidence in study outcomes
Future coordination and system impacts of CER	Develop and refine forecasts of coordinated CER. • Developing consistent categories for comparing coordinated CER forecasts • Forecasting growth across different types of coordinated CER • Tracking new customer offerings, participation and technology developments • Incorporating regulatory change, technology costs and market opportunities • Assessing how financial drivers and consumer preferences influence uptake
Resource adequacy and energy management in storage-rich systems	Review reliability assumptions for power systems with high levels of variable generation and storage. • Developing reliability metrics for high-renewables and storage systems • Improving dispatch optimisation during high variability and system stress • Exploring market incentives for effective storage response during energy shortfalls
Next-generation power system modelling and simulation	Develop enhanced modelling capabilities aligned with AEMO's modelling strategy*. • Developing tools and methods to automate model and data checking, conversion and validation • Developing techniques to improve simulation performance including through automation, AI and application of high performance computing hardware

* See https://www.aemo.com.au/consultations/current-and-closed-consultations/power-system-modelling-strategy-consultation.

These areas are intended to support engagement between researchers, industry and AEMO on questions of potential mutual interest and practical industry value. AEMO may contribute to research question development, technical and operational context, or subject matter expertise where there is alignment with system needs and capacity to participate.

The areas identified in this TPSS are not exhaustive. For example, a set of research questions on system operation in high-renewable power systems has been compiled by ISON and may also be valuable as a guide[136]. AEMO welcomes engagement on other emerging research questions, particularly where these could help anticipate future power system challenges or expand the options available to manage them. To discuss research opportunities, contact research@aemo.com.au.

[136] See https://www.isonetwork.org/system-operator-priorities.

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Abbreviations

Term or acronym	Term in full	Term or acronym	Term in full
AC	Alternating current	**MVAr**	Megavolt ampere reactive
ACEREZ	Acciona, Cobra, Endeavour Energy Renewable Energy Zone	**MVF**	Market Visibility Framework
AEC	Australian Energy Council	**MW**	Megawatt
AEMC	Australian Energy Market Commission	**MWs**	Megawatt-seconds
AEMO	Australian Energy Market Operator	**NEPKI**	National Energy Public Key Infrastructure
AER	Australian Energy Regulator	**NEM**	National Electricity Market
AI	Artificial intelligence	**NEMOC**	National Electricity Market Operations Committee
ARENA	Australian Renewable Energy Agency	**NER**	National Electricity Rules
AR-PST	Australian Research in Power Systems Transition	**NMAS**	Non-market ancillary services
AS/NZS 4777.2	Australian/New Zealand Standard 4777.2	**NSCAS**	Network support and control ancillary services
BESS	Battery energy storage system	**NSP**	Network service provider
CAISO	California Independent System Operator	**OCGT**	Open-cycle gas turbine
CEC	Clean Energy Council	**ODP**	Optimal development path
CER	Consumer energy resources	**OEM**	Original equipment manufacturer
CIGRE	International Council on Large Electric Systems	**OFGS**	Over-frequency generation shedding
CIS	Capacity Investment Scheme	**PACR**	Project Assessment Conclusions Report
CRI	Connections Reform Initiative	**PADR**	Project Assessment Draft Report
CSIP-AUS	Common Smart Inverter Profile – Australia	**PASA**	Projected Assessment of System Adequacy
CWO	Central-West Orana	**PEC**	Project Energy Connect
DER	Distributed energy resources	**PFR**	Primary frequency response
DNSP	Distribution network service provider	**PMU**	Phasor Measurement Unit
DOE	Dynamic operating envelope	**POD**	Power oscillation damper
DPV	Distributed photovoltaic	**POE**	Probability of exceedance
DSO	Distribution System Operator	**PROFILES**	Protection & Relay Operation for Inverter-based Low-inertia Electrical Systems
DSOO	Demand-side Statement of Opportunities	**PSMRG**	Power System Modelling Reference Group
DSP	Demand-side participation	**PSS**	Power System Stabiliser
EFCS	Emergency frequency control scheme	**PV**	Photovoltaic
EMT	Electromagnetic transient	**PVNSG**	Photovoltaic non-scheduled generation
EMS	Energy Management System	**QNI**	Queensland – New South Wales Interconnector
ENTSO-E	European Network of Transmission System Operators for Electricity	**RAP**	Reconciliation Action Plan
EOI	Expression of Interest	**RAS**	Remedial action scheme
EPRI	Electric Power Research Institute	**REZ**	Renewable Energy Zone
ESOO	Electricity Statement of Opportunities	**RIT-T**	Regulatory Investment Test for Transmission
ESIG	Energy Systems Integration Group	**RoCoF**	Rate of change of frequency

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Term or acronym	Term in full	Term or acronym	Term in full
EV	Electric vehicle	**RRO**	Retailer Reliability Obligation
EVM	Enhanced Voltage Management	**RSS**	Restoration support service
EVSE	Electric vehicle supply equipment	**RTS**	Real-time simulator
FACTS	Flexible AC Transmission System	**SC**	Short circuit
FCAS	Frequency control ancillary services	**SCADA**	Supervisory Control and Data Acquisition
FFR	Fast frequency response	**SCR**	Short circuit ratio
FOS	Frequency Operating Standard	**SOCI Act**	Security of Critical Infrastructure Act 2018
FY	Financial year	**SON**	Statement of Need
GFL	Grid-following	**SRAS**	System restart ancillary services
GFM	Grid-forming	**SRES**	Small-scale Renewable Energy Scheme
GPS	Generator Performance Standards	**SRS**	System Restart Standard
GPSRR	General Power System Risk Review	**SSAT**	Small Signal Analysis Tool
GRTS	Grid Reference Transitional Service	**SSN**	System Strength Node
GSOO	Gas Statement of Opportunities	**SSSP**	System Strength Service Provider
GW	Gigawatt	**SSSPWG**	System Strength Service Provider Working Group
GWh	Gigawatt hour	**SVC**	Static Var compensator
HIL	Hardware-in-the-loop	**SWIS**	South-West Interconnected System
HVDC	High-voltage direct current	**T-D**	Transmission–distribution
IASR	Inputs, Assumptions and Scenarios Report	**TAPR**	Transmission Annual Planning Report
IBL	Inverter-based load	**TIPS B**	Torrens Island Power Station B
IBR	Inverter-based resource	**TNSP**	Transmission network service provider
IEEE	Institute of Electrical and Electronics Engineers	**TPSS**	Transition Plan for System Security
IPRR	Integrating Price Responsive Resources into the NEM	**TSOCF**	Transmission System Operational Capability Framework
IRM	Interim Reliability Measure	**TWh**	Terawatt hour
ISON	International System Operator Network	**UFLS**	Under-frequency load shedding
ISP	Integrated System Plan	**UNSW**	University of New South Wales
JPB	Jurisdictional Planning Body	**USE**	Unserved energy
kV	Kilovolt	**VDS**	VAr Dispatch Scheduler
LOR	Lack of reserve	**VPP**	Virtual power plant
LV	Low voltage	**VRE**	Variable renewable energy
MSL	Minimum system load	**VSR**	Voluntary Scheduled Resource
MSOL	Minimum stable operating level	**WAMS**	Wide Area Monitoring System
MVA	Megavolt ampere	**WEM**	Wholesale Electricity Market

Discharged to 12.01am Sunday 1 December 2026