2025 Electricity Statement of Opportunities

August 2025

A 10-year outlook of investment requirements to maintain reliability in the National Electricity Market

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

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

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

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

Important notice

Purpose

The purpose of this publication is to provide technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the national electricity market over a 10-year outlook period. This publication incorporates reliability assessments against the reliability standard and interim reliability measure, including AEMO's reliability forecasts, indicative reliability forecasts, and Energy Adequacy Assessment Projection.

AEMO publishes the National Electricity Market Electricity Statement of Opportunities and Energy Adequacy Assessment Projection under clauses 3.13.3A and 3.7C of the National Electricity Rules respectively. This publication is generally based on information available to AEMO as at 1 July 2025 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require and does not amount to a recommendation of any investment.

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Executive summary

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data for the National Electricity Market (NEM) over a forecast period of 10 years from 2025-26 to 2034-35. The ESOO highlights the opportunities for market participants, investors, governments and other jurisdictional bodies to invest in new assets and systems to maintain a reliable supply of electricity in the NEM.

The energy transition is well underway for Australia's NEM. Investments in renewable generation and storage capacity continue to increase, and the pipeline of potential developments continues to expand, providing the means to meet growing demand amidst the steady retirement of coal power stations. Continuing to increase the pace of new infrastructure delivery ahead of closures will be essential to meet both reliability and system security requirements and avoid operability challenges associated with coordinating planned maintenance.

- While updated system security analysis will be published by AEMO in December, this 2025 ESOO contains **power system reliability** analysis of two development outlooks:
  - With delivery of renewable generation and dispatchable resources to target levels and timings in federal and state government programs alongside actionable transmission and coordination of forecast consumer energy resources (CER[1]), AEMO forecasts sufficient generation capacity to meet growing electricity demand within the relevant reliability standards in most regions and years in the next decade.
  - With delivery of only those developments sufficiently progressed to meet AEMO's commitment criteria[2], subject to recently observed project development delays, AEMO forecasts an improved outlook relative to the 2024 ESOO, with some challenges identified in the short term for Queensland and South Australia. Over the longer term, reliability gaps are forecast in all mainland NEM regions, which have the potential to be managed as further projects progress towards meeting AEMO's commitment criteria.
- Both outlooks reflect an increase in the pace of generator commissioning, from 4.4 gigawatts (GW) in 2024-25[3] to between 5.2 GW and 10.1 GW expected to commission per year over the next five years.
  - While the pace of generation and storage investment has increased, delivering identified generation, storage, transmission and CER **on time and in full at even greater pace** will be essential for the ongoing reliability of the NEM.
- This ESOO identifies potential reliability risks arising from shortfalls in both instantaneous energy production (capacity) and energy production over periods of hours, days or weeks. Due to the changing mix of electricity generation and storage in the NEM, energy production over longer periods (days and weeks) is likely to become a more dominant factor in reliability assessments than the availability of instantaneous energy production capacity.

[1] CER are playing a transformative role in the energy transition, and will be a valuable resource in the future energy system. If well-coordinated ('orchestrated'), they help deliver reliable and secure energy, offset the need for grid-scale investment, and reduce costs for consumers as well as energy sector emissions.

[2] AEMO defines five commitment criteria regarding a developer's progress towards land procurement, financial commitment, component contracts, relevant planning approvals and construction. Developers demonstrate the achievement of these criteria through direct surveys. The *Committed and Anticipated Developments* sensitivity includes all developments classified as 'existing', 'in commissioning', 'committed', and 'anticipated'. 'Committed' projects must meet all five criteria; 'anticipated' projects must show progress towards at least three criteria.

[3] In 2024-25, 4.4 GW of new capacity commissioned in the NEM, a record level in one year since the NEM began. See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

- Reliability risks in the next five years are primarily triggered by the retirement of large power stations in some regions. It is imperative that replacement generation and storage to meet the evolving needs of consumers is delivered ahead of these announced closures:
  - An 80 megawatts (MW) reliability gap in **Queensland has emerged for the coming summer 2025-26**, due to reduced generator availability, higher forecasts of maximum demand, and slower advised commissioning of projects than was previously advised. Reliability risks decrease in 2026-27 when numerous dispatchable projects are projected to have completed commissioning.
  - Reliability risks in **South Australia** continue to be forecast above the relevant reliability standard under both development outlooks, resulting in a 390 MW reliability gap in **2026-27 when Torrens Island B is advised to retire**, and Project EnergyConnect, a new transmission interconnector, is not expected to be fully commissioned. While the official closure date of 30 June 2026 was applied in this ESOO, on 13 August 2025 AGL reported[4] an in-principle agreement with the South Australian Government to extend the operation of Torrens Island B for two years. Should such an extension become formalised, no reliability gaps would be forecast in these years.
  - Reliability gaps previously identified following the advised retirement of **Eraring Power Station in 2027-28 in New South Wales are no longer forecast**. However, while this ESOO forecasts that there will be enough instantaneous energy production capacity to meet consumer demand consistent with the relevant reliability standard, **system security and operability challenges remain.** These challenges include meeting minimum system strength (fault current) and other system security requirements, and scheduling planned outages.
  - Reliability gaps previously identified after the advised retirement of **Yallourn Power Station in 2028-29 in Victoria are no longer forecast**, highlighting that in-train developments are now likely enough to provide for reliability consistent with the relevant reliability standard in this year. System security challenges in Victoria after this retirement are still being assessed, and operability challenges are forecast, including potential challenges scheduling planned outages and managing potential gas shortfalls.
- Where AEMO identifies reliability gaps, AEMO will request the Australian Energy Regulator (AER) to put an obligation on retailers and liable entities to enter sufficient contracts to cover their customers' peak demand needs, through the retailer reliability obligation (RRO), for relevant periods. For this ESOO, AEMO will request the AER to consider making a T-1 reliability instrument for South Australia in 2026-27. AEMO will also take prudent action and seek to procure additional reserves where appropriate, safeguarding consumers in a cost-appropriate manner.

Alongside energy-related investments that support reliability, investments are also required to ensure that the power system remains stable and resilient. As existing synchronous generators retire, there is a need for system security services across the NEM[5] and for urgent implementation of the recently published National CER Roadmap[6]. AEMO will provide updated information on system security services in December 2025.

[4] See AGL's Annual Report, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/who-we-are/our-company/250813-2-agl-energy-limited-annual-report-2025.pdf?a=d.

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

[6] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/consumer-energy-resources-working-group/national-cer-roadmap.

Definitions

The following definitions apply to this 2025 ESOO:

- **Power system reliability** in the ESOO refers to the sufficiency of electricity supply to meet demand in all periods of the year. This ESOO includes reliability assessments prepared for two development outlooks.
- **Unserved energy (USE)** represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply) in the absence of out of market intervention.
- AEMO forecasts **expected USE** by calculating the weighted-average USE over a wide range of simulated outcomes. Because expected USE is the average of many possible outcomes, a forecast over the relevant standard does not guarantee that a USE event is going to happen, while forecasts below the standard do not mean there are no reliability risks, although events may be less probable.
- 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. Current National Electricity Rules (NER) provisions specify that the IRM expires for the purposes of the RRO on 30 June 2028. When reliability is forecast consistent with the IRM, that represents a statistical probability of larger USE events (on average 10% of average regional demand for five hours) at a frequency of one in every 10 years.
- The **reliability standard** is a measure of expected USE in each region of no more than 0.002% of energy demanded in any financial year. For the purposes of the RRO, it applies when the IRM expires. When reliability is forecast consistent with the reliability standard, that represents a statistical probability of larger USE events (on average 10% of average regional demand for nine hours) at a frequency of one in every five years.
- A **forecast reliability gap** occurs when expected USE is forecast in excess of the relevant standard (IRM or reliability standard) in a region in a year. If AEMO reports a forecast reliability gap, this may trigger a reliability instrument request under the RRO.

This 2025 ESOO contains reliability analysis of two development outlooks which identify investment needs to replace retiring assets and to meet forecast demand growth

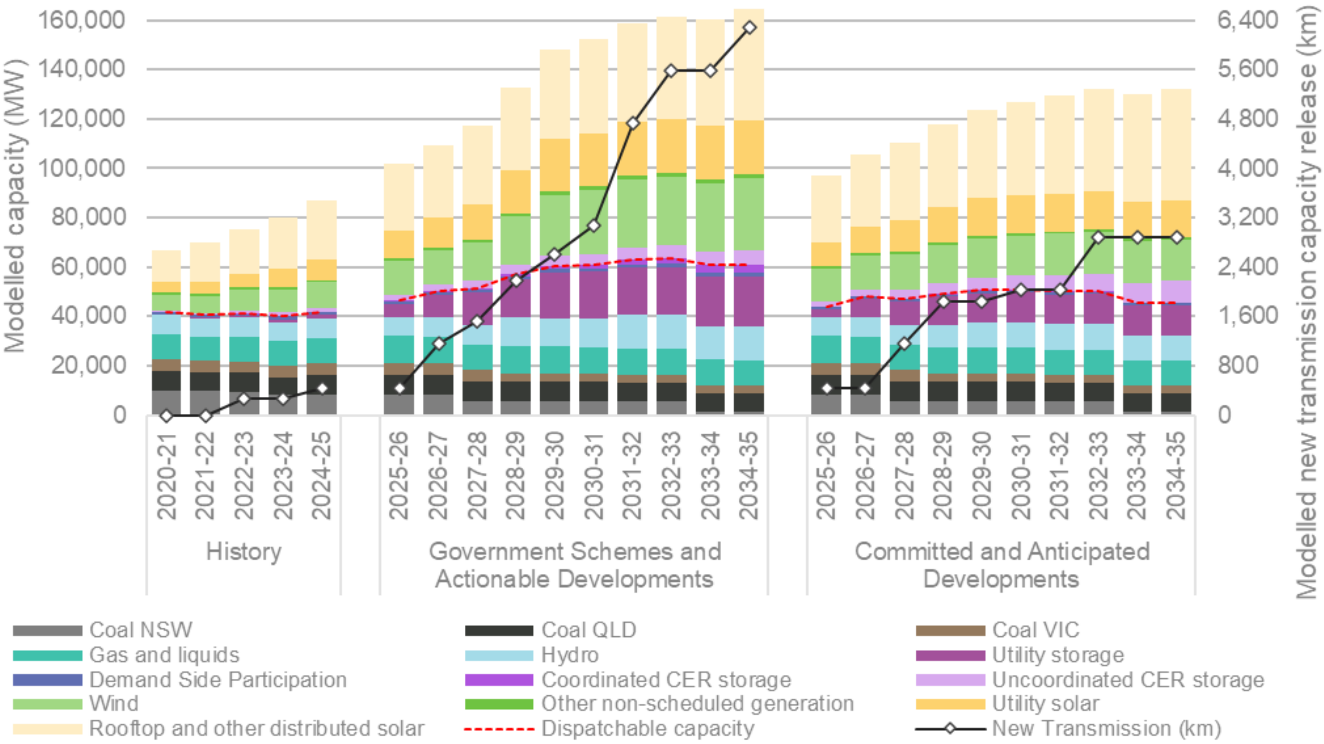
Several large generator retirements are expected prior to 2030, as advised by relevant operators. This is providing opportunities for significant investment to be available to meet reliability and system security requirements ahead of their closure. Significant retirements include:

- Torrens Island B Power Station (800 MW) in South Australia on 30 June 2026[7],
- Eraring Power Station (2,880 MW) in New South Wales on 19 August 2027, and
- Yallourn Power Station (1,450 MW) in Victoria on 1 July 2028.

[7] AGL has reported ongoing discussions with the South Australian Government regarding a potential extension of Torrens Island B Power Station for two years. Such an extension could resolve reliability gaps forecast in South Australia in 2026-27 and 2027-28, however the official closure date of 30 June 2026 has been applied in all ESOO analysis in the absence of formal advice to extend. See AGL's Annual Report, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/who-we-are/our-company/250813-2-agl-energy-limited-annual-report-2025.pdf?a=d.

The 2025 ESOO provides two alternative reliability assessments that consider differing levels of capacity investment over the forecast horizon. **Figure 1** shows the 10-year generation, storage, CER, demand flexibility and new transmission development outlooks[8] for the two ESOO reliability assessments in this 2025 ESOO, and compared to the past five years.

Figure 1 2025 ESOO 10-year infrastructure development outlooks under typical summer availability assumptions



Note: the ESOO applies generator closures at the closure dates/years advised by the relevant plant operator, whereas the *Integrated System Plan* (ISP) may identify earlier plant closures to meet the broader objectives of that assessment, including to meet policy and emissions reduction targets.

The ***Government Schemes and Actionable Developments*** outlook includes all developments progressed sufficiently to meet AEMO's commitment criteria, all developments associated with the Capacity Investment Scheme (CIS) as agreed through Renewable Energy Transformation Agreements (RETAs) with the states, as well as state-based schemes and actionable transmission developments. Further stages of the CIS were not included because the location, timing, and technology of the tenders is not yet specified. This assessment considered:

- the Federal CIS (currently awarded projects, and RETA targets totalling 18,400 MW of generation or storage capacity only),
- the New South Wales Electricity Infrastructure Roadmap, and its firming tenders,
- a total of 18,636 MW/55,050 megawatt hours [MWh] of storage developments across the NEM,
- a total of 19,489 MW of wind and 13,248 MW of utility-scale solar developments,

[8] The NEM's transmission backbone is the world's longest interconnected system of around 40,000 km of existing transmission lines and cables, supplying a population in excess of 23 million people, and is augmented regularly with minor network projects to support ongoing customer growth. New transmission development outlooks in this context represent an important means to strengthen the system's capability to continue to service electricity consumers.

- transmission projects identified in the 2024 *Integrated System Plan* (ISP) as actionable, including Victoria – New South Wales Interconnector West (VNI West), Gladstone Project and Marinus Link,
- projected coordination of CER (largely behind-the-meter battery systems), and flexible demand response, and
- all projects considered in the *Committed and Anticipated Developments* outlook, noting that it is assumed that all unawarded government targets are fully additional to those projects already considered Committed or Anticipated.

Further investments in dispatchable capacity and renewable energy generation under these schemes are also expected, but are not sufficiently identifiable to be modelled at this time.

The ***Committed and Anticipated Developments*** outlook includes only those supply developments that are sufficiently progressed to meet AEMO's commitment criteria. Few developments are identified beyond the first four years, because developments in those later years are not yet sufficiently progressed to meet AEMO's commitment criteria. This assessment included:

- Hunter Power Station (750 MW open cycle gas turbine [OCGT]) in New South Wales from September 2025,
- Snowy 2.0 (2,200 MW/350,000 MWh) in New South Wales from 2028,
- various utility-scale battery developments (10,364 MW / 28,716 MWh) across the NEM,
- a total of 6,663 MW of wind and 6,621 MW of utility-scale solar generation developments, and
- transmission projects including Project EnergyConnect, Waratah Super Battery Project, HumeLink, Central West Orana REZ Network Infrastructure Project and Western Renewables Link.

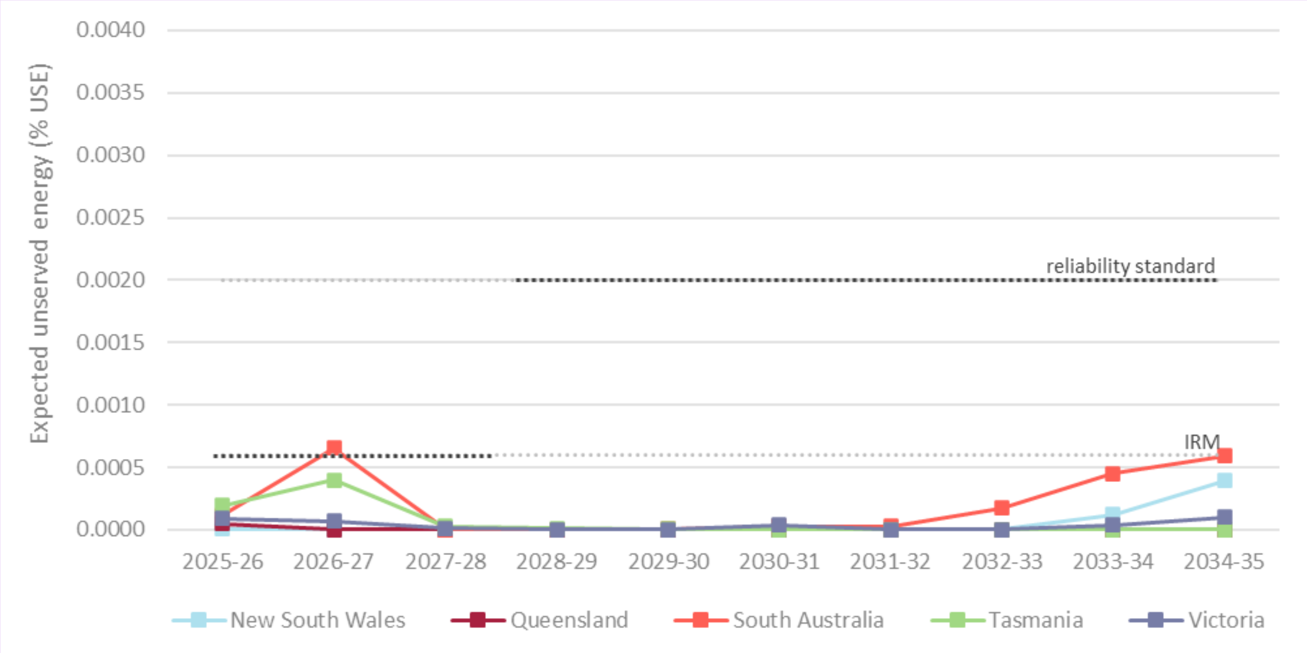
Over the near term, on-time and in-full delivery of committed, anticipated and federal and state government-supported generation projects, as well as actionable transmission developments and the coordination of embedded consumer resources, is critical for reliability

There are many federal and jurisdictional policies and programs that are actively funding and supporting new developments. Delivering these investments in full, and ahead of generator closures, is critical to maintaining reliability within the relevant standards in most regions, in most years.

Figure 2 shows that these investments in renewable generation, dispatchable capacity, transmission and coordinated CER are forecast to provide reliability levels within the relevant reliability standard in most regions in most years.

During the transition to new forms of energy supply, it is critical that existing ageing coal generators maintain high levels of availability and reliability prior to closure. Project development delays and broader international and domestic supply chain challenges are emerging as material risks to the delivery of transmission, generation and storage projects. Delays to the delivery of any of the identified projects, relative to the dates envisioned by the schemes and proponents, have the potential to result in periods of high risk throughout the 10-year horizon.

Figure 2 Expected USE, *Government Schemes and Actionable Developments*, 2024-25 to 2033-34 (%)



The ***Government Schemes and Actionable Developments*** assessment in this ESOO included existing, committed and anticipated developments to meet the *Step Change* demand forecast, delivered to the schedules advised by developers, as well as:

- actionable transmission investments and forecast growth in coordinated CER and flexible demand resources, and
- firming and some renewable energy developments that have specific funding, development or contracting arrangements under federal, state and territory government schemes and programs.

This sensitivity included only announced and identifiable components of announced federal and state schemes, including various tender stages that have been concluded. Delivering planned subsequent tender stages will support further improvements to this reliability assessment.

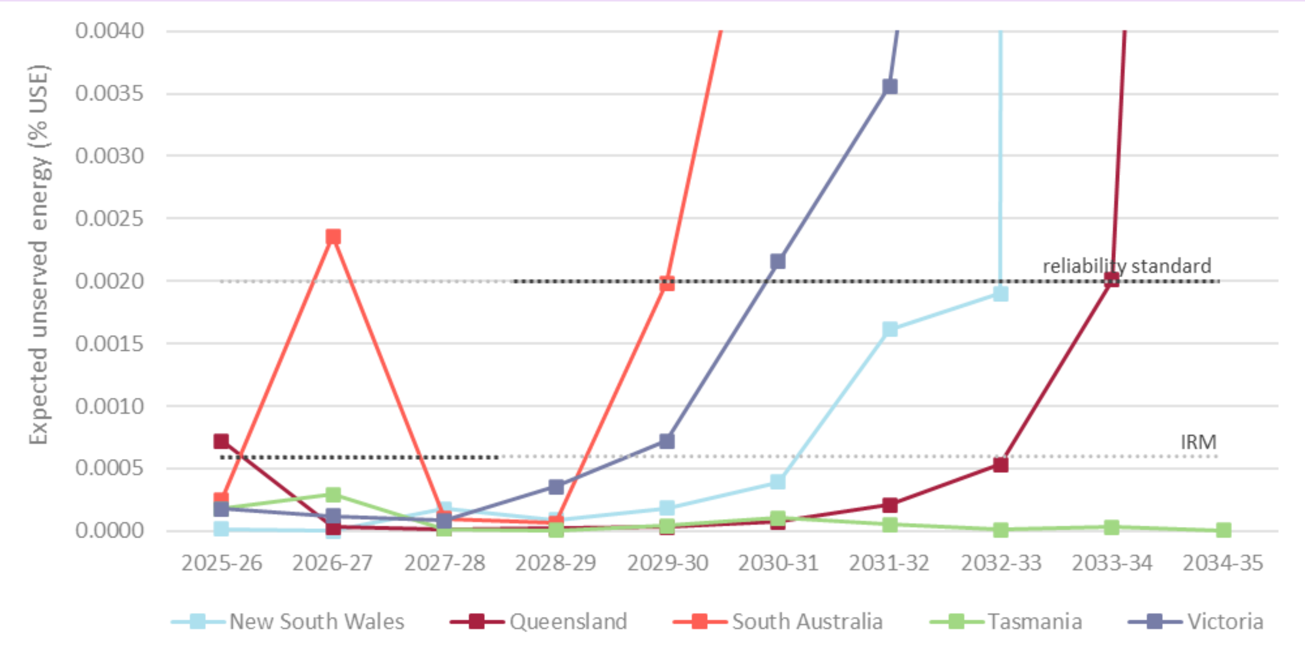
If only those projects already committed or anticipated proceed, and if risks of commissioning delays eventuate as they have been observed to in recent years, reliability gaps are forecast in Queensland, South Australia, Victoria and New South Wales

When considering only those energy supply infrastructure developments that have made sufficient progress against AEMO's commitment criteria, reliability gaps are forecast in Queensland, South Australia, Victoria and New South Wales in the next decade. This underscores the importance of the support from federal and state schemes to deliver additional generation, transmission, flexible demand resources, and consumer assets such as batteries that can be coordinated to reduce utility-scale investment needs.

In this reliability assessment – which is used by AEMO under the NER to produce a reliability forecast and identify further actions to minimise risks under the RRO and AEMO's operational summer readiness processes – Queensland, New South Wales, South Australia and Victoria are forecast with reliability risks above the relevant reliability standard (the IRM of 0.0006% USE until 30 June 2028, and the reliability standard of 0.002% USE after that point). This means that if committed and anticipated projects only are delivered, and if they are delivered later than proponents advise (as has been observed in recent years), then these regions are more likely to experience tighter supply conditions during extreme conditions in summer when customer demand is extreme. During these conditions, out of market reserves may be used by AEMO to operate the system and further reduce the probability of involuntary customer load shedding.

Figure 3 shows the *Committed and Anticipated Developments* reliability assessment for the 2025 ESOO. This particular assessment, which applies for multiple regulatory requirements, considers only the sub-set of known developments that have demonstrated sufficient commitment towards commissioning in the NEM.

Figure 3 Expected USE, *Committed and Anticipated Developments*, 2025-26 to 2033-34 (%)



The ***Committed and Anticipated Developments*** assessment (the reliability forecast and indicative reliability forecast) includes existing, in commissioning, committed and anticipated generation, storage and transmission projects, according to AEMO's commitment criteria, as well as committed investments in demand flexibility and consumer batteries that are coordinated to minimise investment needs in utility-scale solutions. With only this pipeline of developments commissioning, and allowing for historically observed commissioning delays, reliability gaps emerge in Queensland, South Australia, Victoria and New South Wales at several points across the forecast horizon.

Actions will be triggered in response to this *reliability forecast*

The Committed and Anticipated Developments reliability assessment, which is used for AEMO's reliability forecast, identifies reliability gaps in the first five years of the horizon in:

- Queensland in 2025-26, and
- South Australia in 2026-27.

> Where this 2025 ESOO reliability forecast identifies a forecast reliability gap for a region in either the T-1 (2026-27) or T-3 year (2028-29), AEMO must request the AER to consider making a reliability instrument under Chapter 4A of the NER (**Retailer Reliability Obligation** [RRO]). In this 2025 ESOO, the forecast reliability gaps above require AEMO to request the AER to consider making a T-1 reliability instrument for 2026-27 in **South Australia** at least 3 months before the T-1 cut-off day.

AEMO maintains a panel of Reliability and Emergency Reserve Trader (RERT) providers in all NEM regions that can provide short notice reserves if required should reliability challenges emerge operationally. AEMO will continue to procure additional short notice reserves where appropriate, safeguarding consumers in a cost-appropriate manner.

While AEMO identifies a small (80 MW) reliability gap in Queensland in 2025-26, this gap does not meet the requirements for AEMO to procure additional long notice RERT[9]. However, short notice RERT panels available in Queensland exceed the 80 MW reliability gap identified in this ESOO.

The indicative reliability forecast in the second five years of the horizon, which considered only currently committed and anticipated developments, shows expected USE is above the reliability standard of 0.002% USE in:

- South Australia from 2030-31,
- Victoria from 2030-31,
- New South Wales from 2033-34, and
- Queensland from 2033-34.

Additional investments in security and stability services and implementation of the National CER Roadmap are required to enable a reliable and secure power system

A reliable power system requires more than just sufficient levels of installed capacity and available energy supplies. The system must also maintain an underlying set of security and stability services to ensure that it remains both stable and resilient under normal operating conditions, and following disturbances[10].

Over the coming decade, the rapid energy transition will result in a significant need for new assets and providers of these essential system services, including for system strength (both fault current and voltage waveform

[9] NER 11.128 provisions regarding Interim Reliability Reserves expired on 31 March 2025, and long notice reserve requirements are assessed against the reliability standard of 0.002% USE.

[10] See AEMO's *Power System Requirements* documents for more information, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

stability), frequency management, voltage control, ramping capability, and system restart services. Key drivers of emerging system security requirements include:

- reduced operation of synchronous generators, and a shift towards periods dominated by inverter-based resources (IBR),
- rapid growth in variable renewable energy (VRE) sources,
- the shift from a highly centralised to highly decentralised system, and
- an increasingly active role for consumers in the way they consume and generate electricity.

Installation of CER

The level of resources being installed by consumers in their premises has continued at high levels. Other resources such as electric vehicles (EVs) are also now growing. Integrated operation of these resources with the broader power system is necessary to ensure power system security can be maintained. The National CER Roadmap sets out a range of initiatives that will support integration and help to ensure all consumers can benefit from these resources. Action both in the short and long term is needed as the level of CER continues to grow. This is particularly important for periods where high distributed photovoltaics (PV) relative to underlying demand results in minimum operational demand levels where action may be required to maintain power system security.

Development and operation of large loads

AEMO has updated its methodology for forecasting, and its forecasts of consumer demands for this 2025 ESOO, which is improving its prediction of large loads in the coming years, including from prospective industrial loads and data centres. While these loads remain uncertain in their development, their predictable operation will influence the needs of the power system, and reforms to improve the predictability of large loads will be important as new loads in emerging areas (such as data centres and green manufacturing) or the electrification of existing loads that use other energy forms increase in the coming decade.

Contents

1 Introduction, assumptions and modelling approach

The ESOO forecasts electricity supply reliability in the NEM to inform market participants, investors and policy-makers on investments needed over the next 10 years to maintain a reliable power system for electricity consumers.

The ESOO includes reliability assessments which demonstrate the electricity investments required to maintain reliability in the NEM at the relevant reliability standard, and provides information on, and projections of:

- electricity demand and energy requirements,
- electricity supply capability from generators and demand flexibility, considering normal transmission and power system limitations, and
- power system reliability, including the reliability forecast and indicative reliability forecast developed in accordance with the RRO.

As new infrastructure takes time to develop and commission, there are fewer infrastructure solutions that can be implemented in the short term to resolve any reliability risks identified. Should shortfalls be identified in the first one to four years of the horizon, AEMO has obligations to procure emergency reserves or to request an RRO instrument, which would require retailers and other liable entities to hold contracts or to invest directly in generation or demand response to support reliability in the NEM. Over the longer term, there is enough time for further transmission, generation, storage developments and/or demand flexibility to be developed to reduce reliability risks.

This publication also incorporates the Energy Adequacy Assessment Projection (EAAP, see **Appendix A2**), which provides analysis of reliability risks under a range of alternate conditions that may affect electricity generation capabilities affecting coal, gas and water availability, and the impact on reliability risks over a two-year period.

In addition to providing reliability assessments and forecasts, AEMO has power system security assessment obligations under the NER. AEMO releases annual assessments of system strength, inertia and network support and control ancillary services (NSCAS) needs and a Transition Plan for System Security in December, including declarations of shortfalls and gaps which are required to be addressed by transmission network service providers (TNSPs)[11]. Discussion and further information on some of these services is in **Chapter 5**.

[11] AEMO's system security assessments are at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

1.1 National Electricity Rule (NER) requirements

Information that should be considered part of this 2025 ESOO for NER 3.13.3A purposes	Information that should be considered as key components or inputs for the reliability forecast under NER 4A
• This 2025 ESOO report and all supplementary information published on the 2025 ESOO webpage • The demand forecasting data portal [A] • The July 2025 Generation Information page [B] • The August 2025 Transmission Information page [C] • The 2025 *Inputs, Assumptions and Scenarios Report* (IASR), accompanying assumptions workbook and supplementary material [D]	• The reliability forecast and indicative reliability forecasts published in Appendix A1, RRO • Consumption and demand forecasts (Chapter 2, the demand forecasting data portal [A] and the demand traces) • Supply forecasts (Chapter 3) • The July 2025 Generation Information Page [B] • Sections of the 2025 IASR [D] that comprise the forecasting components of the forecasting approach for ESOO and Reliability Forecast purposes: – Annual consumption forecast components (Section 3.3) – CER forecasts (Section 3.37) – Renewable generation traces (Section 3.6.2) – Demand-side participation forecasts (Section 3.3.15)
Information published as part of this ESOO to meet NER 3.7C purposes	
• Appendix A2, the EAAP	

A. See https://aemo.com.au/energy-systems/data-dashboards/electricity-and-gas-forecasting/.
B. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
C. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
D. See https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

1.2 Forecasting power system reliability

Following extensive stakeholder consultation, AEMO has updated its NEM forecasts and supply adequacy assessment published in this ESOO:

- Updated demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in behaviour by household and business consumers, including electrification impacts. The forecasts for operational consumption and demand also reflect forecasts for energy efficiency measures and growth in CER, including distributed PV generation, battery energy storage systems (BESS) and EVs. AEMO applied its updated Forecasting Approach[12], specifically its updated *Electricity Demand Forecasting Methodology* consulted on throughout 2024-25, in forecasting electricity consumption and demand in this ESOO.
- Updated the supply available to meet this demand to include the latest information on generation and transmission investments in the NEM, as well as expected generator closures.
- Reviewed the performance of existing scheduled generators based on historical performance data, and incorporated forward-looking projections of plant reliability for coal and large gas-powered generators that take into account the impact of maintenance plans, plant deterioration due to age, and reductions in maintenance as generators approach retirement.

[12] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

- Applied a statistical simulation approach[13] which assessed the ability of storage, generators and demand flexibility to meet forecast demand at all times in the year. The model calculated expected USE over a number of forecast conditions impacting demand and renewable generation (based on 23 historical reference years of weather) and random generator outages, weighted by likelihood of occurrence.

1.3 Explaining unserved energy

USE represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply) in the absence of out-of-market interventions, such as the RERT[14] or other voluntary curtailment.

For example, USE could be caused by:

- insufficient levels of generation capacity, generation energy output, or demand response relative to consumer demand,
- insufficient levels of transmission capacity within each region, assuming that this transmission is never subject to any outages, or
- insufficient levels of transmission capacity between regions, assuming that this transmission is only ever subject to single-circuit, credible outages.

All USE events will be described operationally as ‘Lack of Reserve 3’ (LOR3) events, but not all LOR3 events are USE events. Other events that may result in involuntary load shedding, but that are not defined by NER 3.9.3C as USE, include:

- distribution and transmission network outages that directly impact local supply,
- transmission outages that curtail generation, resulting in insufficient levels of supply relative to demand,
- power system security events, for example a double-circuit outage on a transmission line, and
- prolonged generator or transmission outages that persist following power system security events, resulting in insufficient levels of supply relative to demand.

AEMO forecasts expected USE by calculating the weighted-average USE over a wide range of simulated outcomes. While this ESOO may forecast expected USE in its reliability assessments, it also provides information on the scale of developments required to maintain reliability. If these responses are developed ahead of the expected USE event, or if supply or demand conditions do not occur as simulated, then loss of customer supply may be avoided.

This ESOO identifies reliability risks arising from shortfalls of both generation capacity (the instantaneous generation output required to meet peak demand) and energy production (the production of electricity over periods of hours, days or weeks) that vary across the horizon and assessments. Over time as the energy transition progresses, it is likely that energy production shortfalls will become larger drivers of reliability risk as demand

[13] See *ESOO and Reliability Forecast Methodology Document*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[14] In this report, RERT may include interim reliability reserves, as per NER 3.20 and 11.128.

needs are met from a combination of variable resources, short and medium duration storages and energy limited generation.

1.4 Reliability measures in the NEM

The ESOO measures reliability risks relative to two standards determined by the Australian Energy Market Commission's (AEMC's) 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. Current NER provisions specify that the IRM applies for the purposes of the RRO until 30 June 2028. The IRM does not apply to the EAAP. For information purposes, AEMO reports on reliability against this measure for all periods in the ESOO's reliability assessments.
- The **reliability standard** is a measure of expected USE in each region of no more than 0.002% of energy demanded in any financial year. For the purposes of the RRO, it applies at this level unless the IRM applies. For the purposes of the EAAP, it applies over the entire two-year horizon.

Table 1 shows the approximate reliability outcomes when expected USE is forecast in a region at the level of either of the reliability standards. Given the statistical modelling approach, load shedding events of even greater magnitude than these averages are possible (the probability distribution for 2025-26 forecast reliability outcomes is discussed in **Section 4.4**) particularly if more extreme power system conditions emerge such as transmission outages, and/or persistent generator or transmission outages following power system security events. Out-of-market mechanisms may be available and could be used to mitigate some of the risks to consumers, with associated costs.

Table 1 Expected reliability outcomes when expected USE is forecast at the level of the reliability standards

Outcomes	Under the IRM of 0.0006% expected USE	Under the reliability standard of 0.002% expected USE
Any USE	Statistically, USE events would occur approximately once every five years.	Statistically, USE events would occur approximately once every three years.
Larger USE outcomes [A]	Statistically, larger USE outcomes would occur approximately once every 10 years. Events would be equivalent to approximately 10% of average region demand for five hours, or multiple events that aggregate to this total.	Statistically, larger USE outcomes would occur approximately once every five years. Events would be equivalent to approximately 10% of average region demand for nine hours, or multiple events that aggregate to this total.

A. A 'larger USE outcome' is assessed as an individual annual USE outcome above the reliability standard of 0.002% USE.

For information purposes, AEMO reports on reliability risks against this measure for all periods in the ESOO and EAAP horizons.

1.5 Demand definitions

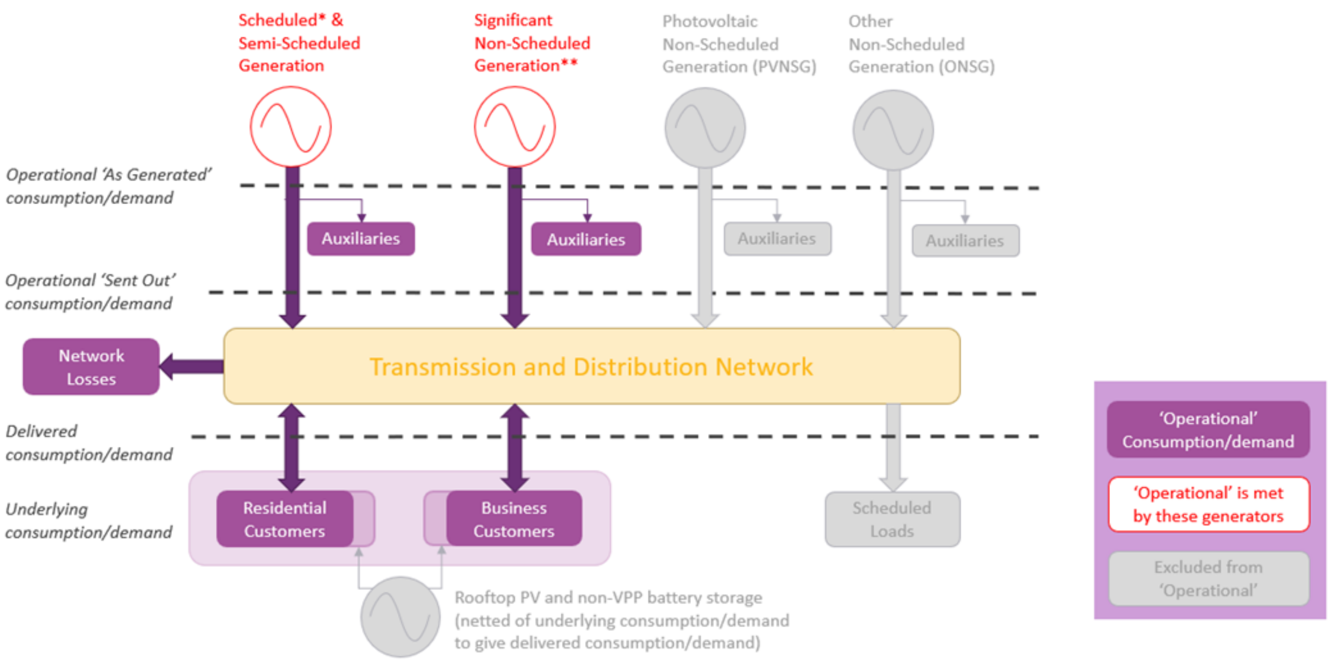
Electricity **consumption** represents electricity consumed over a period of time – in the context of this report, annually – while **demand** is used as a term for the instantaneous consumption of electricity at a particular point in time, typically reported at times of maximum and minimum demand. **Figure 4** shows AEMO's demand definitions.

Consumption and demand can be measured at different locations in the electricity network. Unless otherwise stated, the forecasts in this report refer to **operational consumption/demand (sent out)**[15]. This is the supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (net of their auxiliary loads – that is, the electricity used by the generator itself). Also excluded from this definition is consumption/demand from scheduled loads (typically pumping load from pumped hydro energy storage [PHES] or large-scale batteries).

This ESOO reports consumption forecasts for each sector (residential and business) as **delivered consumption**, meaning the electricity delivered from the transmission system to household and business consumers. Annual operational consumption forecasts include delivered consumption for all consumer sectors, plus electricity expected to be lost in transmission and distribution.

Underlying consumption/demand means all electricity used by consumers, which can be sourced from the transmission system but also, increasingly, from other sources including CER, including distributed PV and battery storage.

Figure 4 Demand definitions used in this report



* Including virtual power plants (VPPs) from aggregated behind-the-meter battery storage.
** For definitions, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

Maximum and minimum operational demand means the highest and lowest level of electricity drawn from the transmission system, measured and averaged from the power system in half-hour intervals in either **summer** (November to March for mainland regions and December to February for Tasmania) or **winter** (June to August). These forecasts are presented as **sent out** (the electricity measured at generators' terminals) and **as generated** (including auxiliary loads).

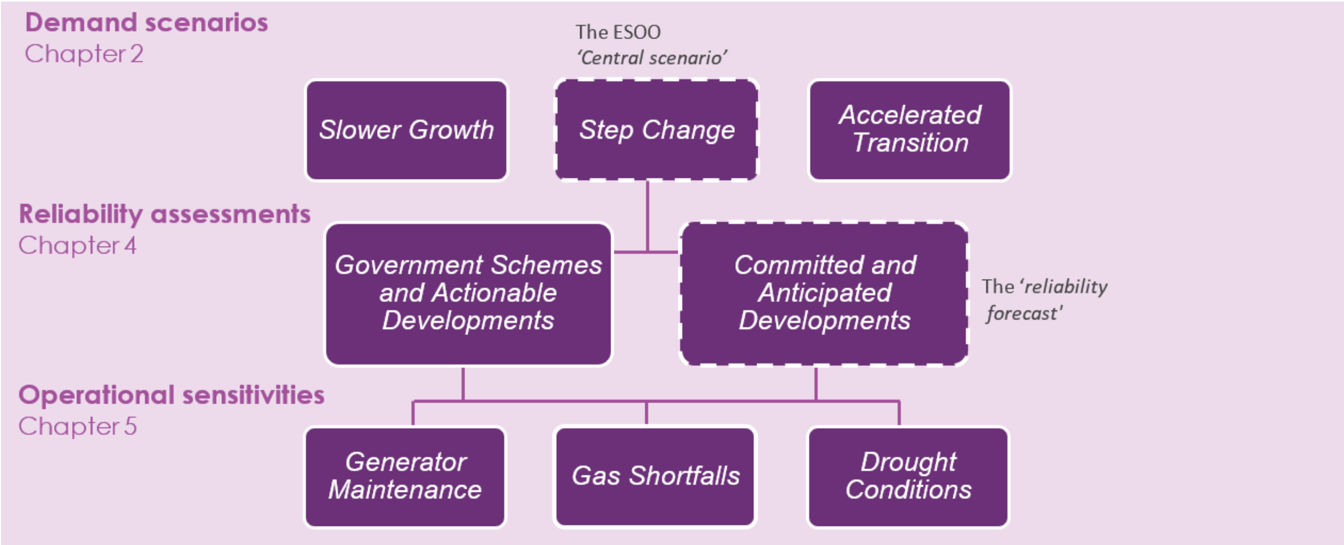
Maximum and minimum operational demand forecasts can be presented with:

[15] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

- a **50% probability of exceedance (POE),** meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions (also called one-in-two-year),
- a **10% POE** (for maximum demand) or **90% POE** (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called one-in-10-year), and
- a **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be exceeded nine years in 10.

1.6 Scenarios, assessments and sensitivities

Figure 5 Demand scenarios, reliability assessments and operational sensitivities in this ESOO



In consultation with a range of stakeholders, AEMO developed the 2025 *Inputs, Assumptions and Scenarios Report* (IASR) for use in its forecasting and planning publications, including the 2025 ESOO and the 2026 ISP. The 2025 IASR included definitions of three scenarios to plan the power system and identify its investment needs. **Table 2** shows the application of these scenarios in the 2025 ESOO.

Unlike the ISP, which identifies an optimal mix of generation, storage and network solutions to meet future power system needs and achieve eligible government policy, the ESOO performs its reliability assessment by applying the demand components of these scenarios and identifying the additional supply requirements to maintain reliability, considering only specified generation, storage, transmission and CER developments. While consumption and demand has been forecast for each of these three scenarios, across a forecast period of approximately 30 years, the ESOO's reliability assessment focuses on the next 10 years. See **Table 2** and the IASR for details of these scenarios, and **Chapter 2** of this ESOO for demand and consumption forecasts.

For the purposes of the ESOO reliability analysis and RRO, AEMO considers the *Step Change* demand scenario the most likely, and AEMO has considered this demand scenario in all reliability assessments and operational sensitivities.

This 2025 ESOO includes two reliability assessments in **Chapter 4** that explore varied supply and network development assumptions over a 10-year forecast period:

- One assessment – *Government Schemes and Actionable Developments* – assumed all in-commissioning, committed and anticipated generation, storage and transmission developments are delivered on time, and also the on-time delivery of government schemes supported by delivery mechanisms.
- The other assessment – *Committed and Anticipated Developments* – assumed all in-commissioning, committed and anticipated generation, storage and transmission developments are delivered subject to recently observed commissioning delays.

In **Chapter 5,** AEMO considers additional sensitivities, applying further challenging operational conditions to both reliability assessments to examine the reliability and resilience of the power system to such conditions. While **Figure 5** only shows three specific operational sensitivities, **Chapter 5** discusses broader operational challenges.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2025 ESOO

Parameter	*Slower Growth*	*Step Change*	*Accelerated Transition*
Description	This scenario describes a world that aims to achieve Australia's current Paris Agreement commitments of 43% emissions reduction by 2030, and other government policies to support the energy system's transition, amid economic circumstances that are more challenging. The scenario features slower and weaker economic growth domestically, with consumers and commercial businesses facing greater investment environment challenges. In these circumstances, the industrial sector faces greater risk of closures.	This scenario achieves the objectives of Australia's government policies in transitioning the energy system. The scenario experiences moderate economic conditions on average, with population growth that is also moderate, reflecting long term average trends. Recent economic challenges and current economic conditions affect the starting conditions for the scenario. Consumers continue to provide a key role in the transition, with strong investments in electrification, CER and energy efficiency measures. There is also strong transport electrification. Australia's businesses follow growth trends observed historically, with growing opportunities for emerging commercial and industrial loads. Data centres and electrification of transportation and larger industries, as well as the establishment of likely prospective industrials, lead to material new electricity consumption.	This scenario reflects very strong decarbonisation activities domestically, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification. Higher economic growth internationally (and locally) increases technology developments, and the global demand for green energy is very high given the strong global appetite for low and zero emissions fuel sources. Australia's buoyant economy and renewable energy potential enables creation of emerging industries such as green commodity production. Consumers in this scenario continue to invest in CER, with the greatest relative uptake of these assets, and the greatest relative acceptance of coordination opportunities.
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower, with near-term economic growth calibrated with current economic conditions	Moderate economic growth, with near-term economic growth calibrated with current economic conditions	Higher, with near-term economic growth calibrated with current economic conditions
CER investments (batteries, PV and EVs)	Lower	High	Higher
Energy efficiency	Moderate	High	Higher

Table 3 below has details of the generation, storage, transmission and demand flexibility development assumptions for each assessment, and the development outlooks are reported in **Chapter 3**.

The *Committed and Anticipated Developments* assessment applies for the purposes of the RRO as the *reliability forecast*, and is used by AEMO to identify RERT procurement needs.

Table 3 Key parameters of ESOO reliability assessments

Parameter	*Government Schemes and Actionable Developments*	*Committed and Anticipated Developments*
Demand forecasts	*Step Change* demand forecasts.	
Generation and storage developments	On time delivery of all in commissioning, committed, anticipated developments. The on time delivery of government schemes supported by delivery mechanisms.	Delivery of all in commissioning, committed and anticipated developments, subject to recently observed commissioning delays.
Generation and storage retirements	All retirements applied at the dates advised by operators.	
Transmission developments	On time delivery of all committed, anticipated and actionable transmission developments.	Delivery of all committed and anticipated transmission developments, subject to recently observed commissioning delays.
CER coordination and demand flexibility	The uptake of CER coordination and demand flexibility as projected by AEMO's 2025 IASR.	The currently committed levels of CER coordination and demand flexibility only.
Operability assumptions	No generator or transmission maintenance considered. No limits on gas, coal or other fuel availability. Expected USE reflects average outcomes for all 23 weather reference years modelled.	

2 Electricity consumption and demand forecasts

Consumer demand is a key consideration in the assessment of supply adequacy. This chapter discusses the consumption and maximum and minimum demand forecasts in the 2025 ESOO. It focuses commentary on the next 10 years, and includes forecasts over the next 30 years. The key observations are that:

- annual consumption over the next decade is stronger than forecast in the 2024 ESOO, driven by the rapid expansion of data centres, the broader inclusion of prospective industrial load and accelerating business electrification, despite stronger energy efficiency measures and a downward revision in hydrogen production expectations,
- as a result of the stronger annual consumption forecasts, maximum operational demand is projected to grow at a faster rate than projected in the 2024 ESOO, and
- minimum operational demand continues to decline, primarily due to continued uptake of distributed PV systems, although at a more moderate pace as consumption grows.

2.1 Drivers of electricity consumption and demand

Australia's transition to a net zero emissions economy by 2050 continues to shape electricity consumption and demand, as consumers increasingly rely on the NEM's declining emissions intensity to reduce their carbon footprint. Relevant drivers in the *Step Change* scenario include rising digitalisation, AI uptake and cloud adoption driving data centre demand, the influence of policies supporting decarbonisation, residential growth and CER, alongside rising industrial activity and a declining outlook for hydrogen production.

Among these drivers, the rapid expansion of data centres to meet growing digital demand – specifically with the rise of larger hyperscale facilities – has the potential to be a catalyst for substantial increases in electricity consumption, for Sydney and Melbourne, in particular. Despite soaring increases in computational energy efficiency, the energy consumption of data centres in Australia is forecast to outstrip these savings.

Australian policies supporting decarbonisation and electrification are expected to have an impact on electricity consumption across sectors. For example, the New Vehicle Efficiency Standard (NVES) is promoting rising EV uptake, while Victoria's Gas Substitution Roadmap is supporting fuel-switching in residential and commercial sectors.

Population growth and a corresponding increase in residential new builds will continue to drive underlying demand from the residential sector. State and federal incentives to improve housing affordability will also contribute to a substantial uplift in the number of new connections, especially in the short-term. Meanwhile, increasing rooftop PV penetration continues to influence residential consumption patterns, while energy efficiency measures, particularly in Victoria through the Victorian Energy Upgrade (VEU) program, are forecast to deliver significant energy savings, moderating demand growth.

Industrial and commercial consumption is also shaped by economic conditions and sectoral developments. Metal ore mining in particular accounts for the largest share of projected load growth for large industrial loads (LILs) over the next decade, with South Australia receiving an unprecedented level of prospective projects. Some sectors continue to face uncertainty – hydrogen production has been revised downward due to project cancellations, reduced policy support and delayed green commodity demand.

Drivers of annual electricity consumption for business and residential users also influence maximum (and minimum) demand forecasts, but random weather-driven elements and co-incident customer behaviours have a larger influence on the magnitude of underlying demand peaks, while the extent of co-ordination of consumer battery charging and discharging will also impact operational demand peaks. As previous ESOOs have noted:

- Maximum operational demand periods are forecast to frequently occur outside daylight hours in all regions. While these maximum operational demand forecasts are lower than the underlying maximum demand forecasts – reflecting the role of distributed PV in reducing operational demand – further installations of distributed PV are not expected to reduce operational maximum demand further.
- Minimum operational demand is continuing to decline, driven by passive distributed PV output that is eroding daytime operational demand with limited coordinated response from load shifting opportunities during these periods.
- Weather extremes drive peak operational demand variability, which increases reliability risks and makes operability more challenging.

2.2 Underlying consumption continues to increase, with CER and energy efficiency slowing operational consumption growth

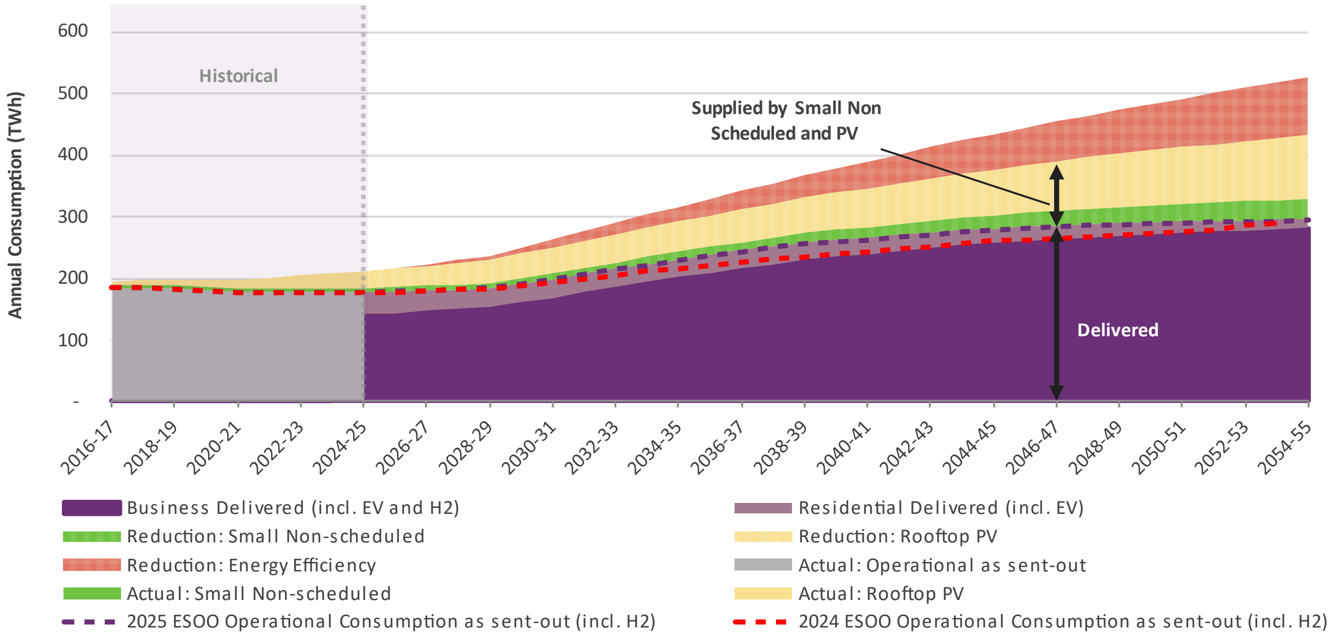
The key drivers shaping the consumption forecasts – new and evolving electricity-intensive sectors, government policy supporting decarbonisation, and economic activity – affect residential, business, and industrial customer segments differently.

Figure 6 to **Figure 8** show forecast annual consumption by segment in the 2025 ESOO's *Step Change* forecast over the next 30 years, and highlight influencing factors contributing to projected changes in consumption over the next decade.

Figure 9 provides a breakdown of the different components for forecast consumption in 2034-35 for each of the three scenarios, providing a snapshot of what consumption might look like in a decade.

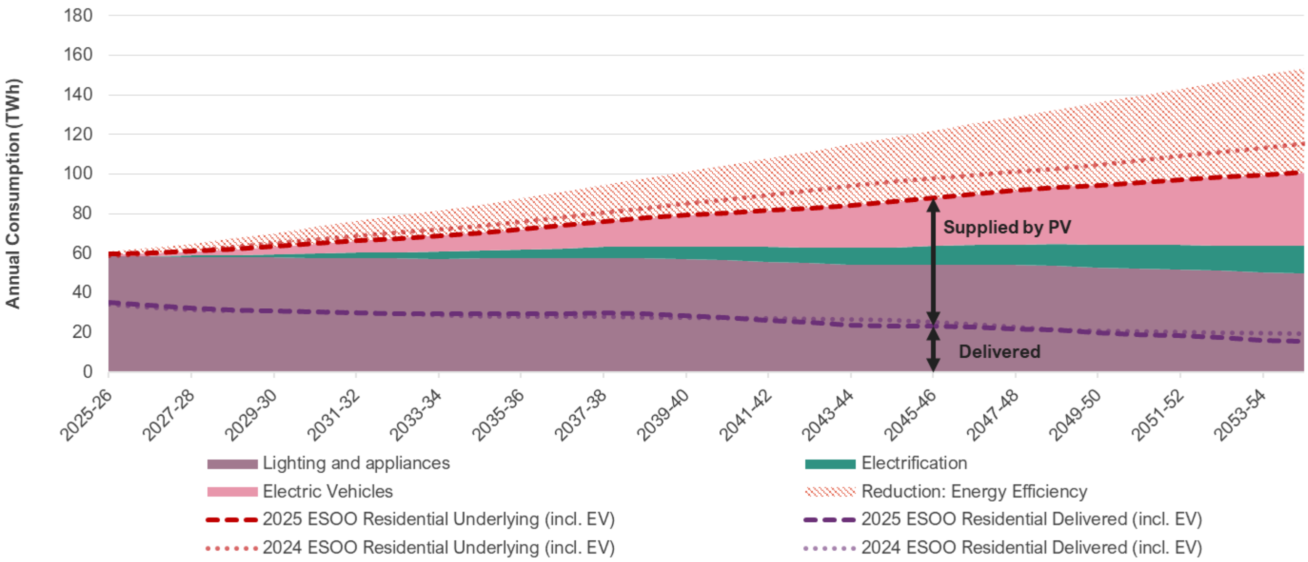
In all these charts, components that are forecast to increase operational consumption are drawn in solid colours, while components that are forecast to reduce operational consumption are drawn with a shaded pattern, with the net operational consumption forecast marked either with a dashed line or with an 'X'. Each region in the NEM has similar macro level drivers for population and economic activity, although differences in the size and composition of each sector give rise to regional nuances.

Figure 6 Actual and forecast NEM electricity consumption, *Step Change*, 2016-17 to 2054-55 (TWh)



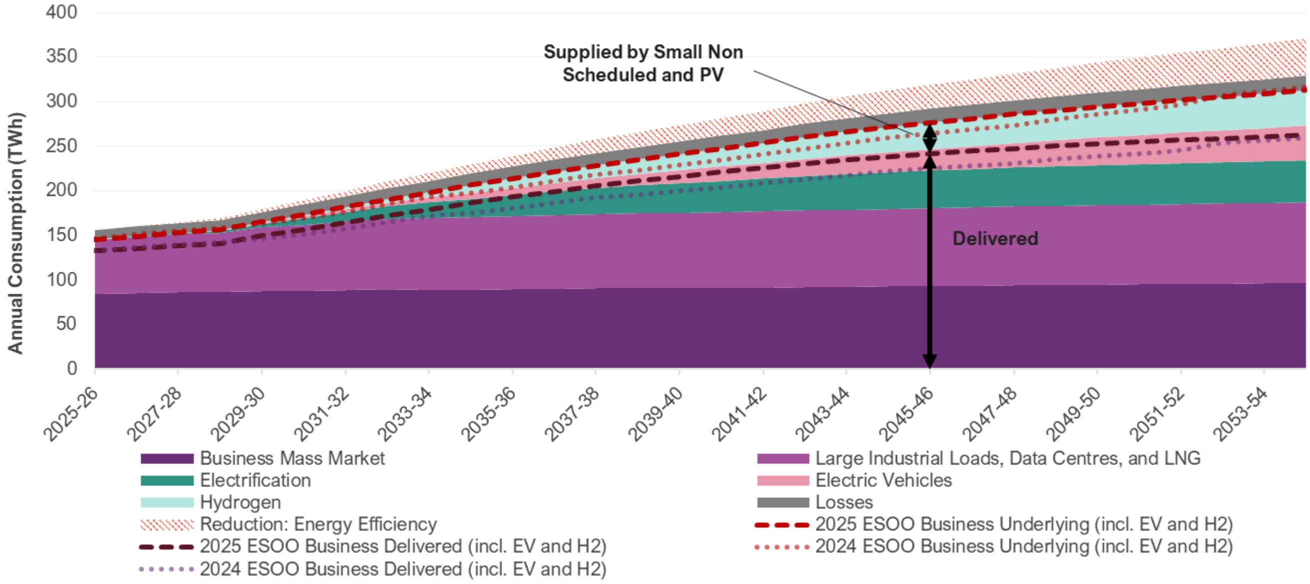
Note: 'small non-scheduled' combines PV non-scheduled generation (PVNSG) and other non-scheduled generation (ONSG).
TWh: terawatt hours. H2: hydrogen production.

Figure 7 Components of residential consumption forecast, *Step Change*, 2025-26 to 2054-55 (TWh)



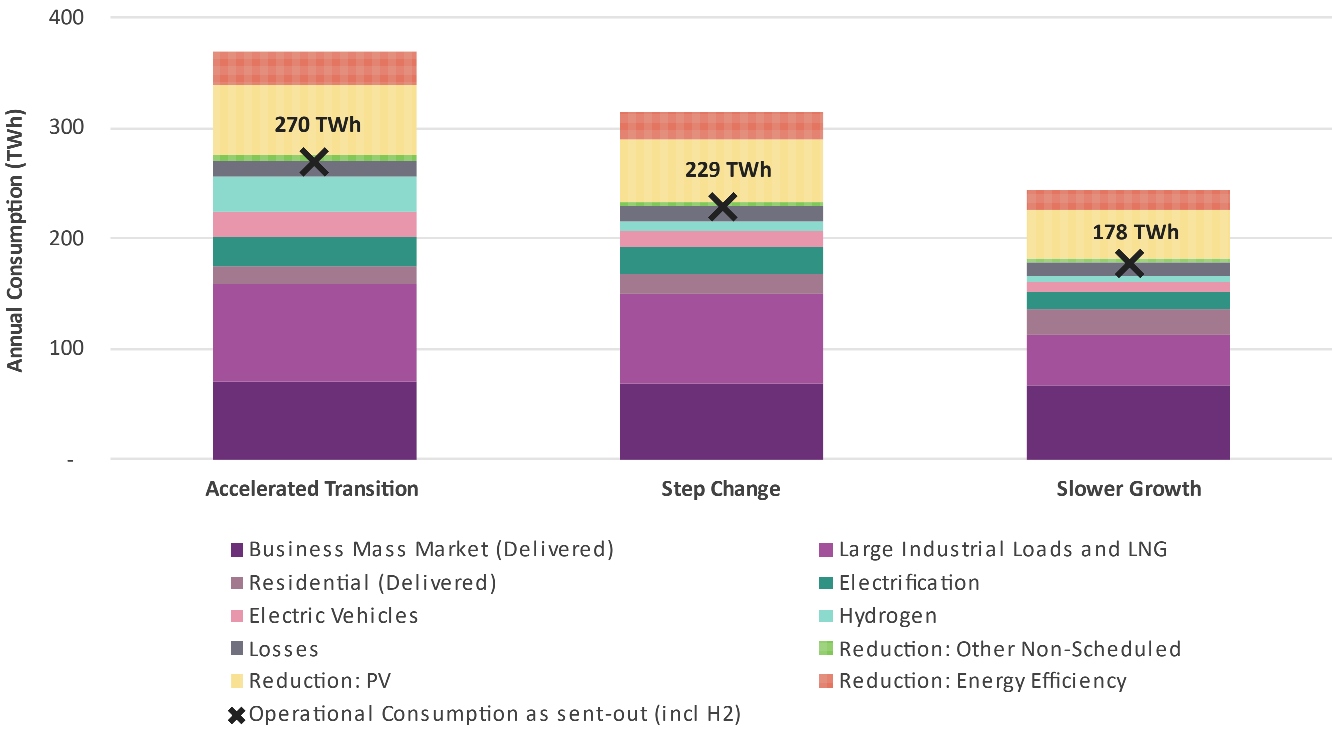
Note: 'Lighting and appliances' includes residential battery losses.

Figure 8 Components of business consumption forecast, *Step Change*, 2025-26 to 2054-55 (TWh)



Note: 'Business mass market' includes business battery losses.

Figure 9 Forecast NEM consumption (by component) for the three scenarios, 2034-35 (TWh)



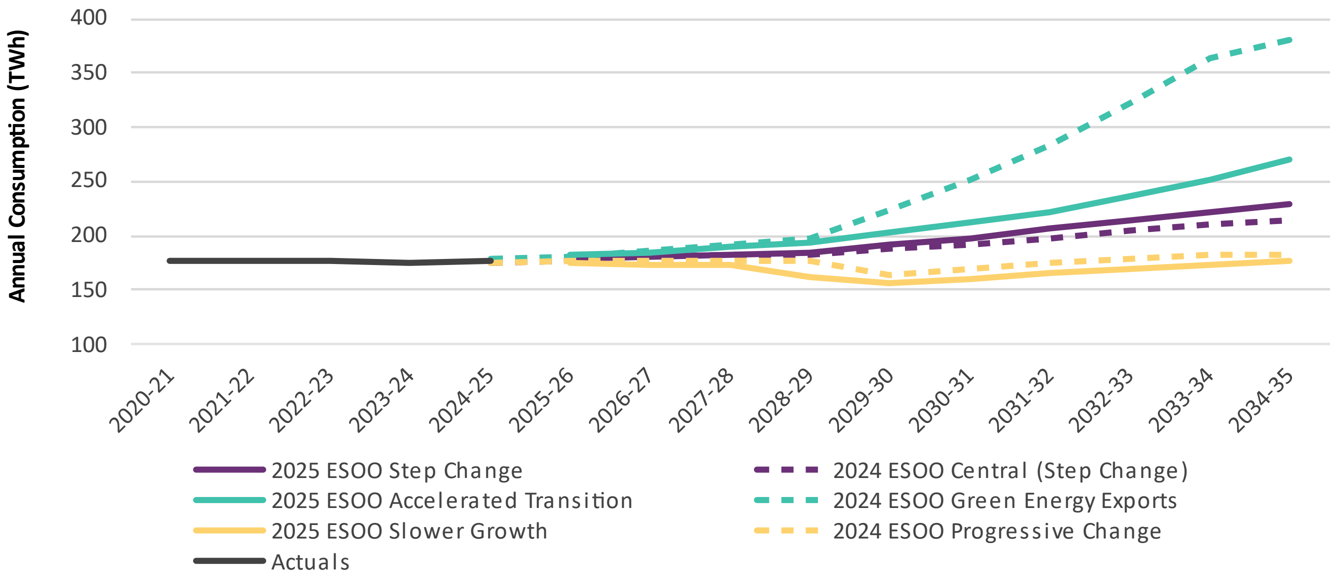
Under the *Step Change* scenario, operational consumption is forecast to increase from 178 terawatt hours (TWh) in 2024-25 to around 229 TWh by 2034-35. This forecast growth is predominantly driven by the potential rapid expansion of data centre projects and accelerating business electrification, which is forecast to gain momentum through the 2030s and surpasses the levels projected in the 2024 ESOO. From 2034-35 to 2044-45, growth is forecast to continue, supported by rising EV uptake and further electrification across the business sector.

However, this upward trend is forecast to be partially offset by the continued adoption of rooftop PV systems, which reduce grid demand. From 2045-46 to 2054-55, the forecast pace of growth in consumption begins to moderate, with slowing forecast growth in data centres and sustained uptake of rooftop PV and PV non-scheduled generation (PVNSG), while EVs and hydrogen production provide key contributions to the overall growth during this period.

The *Step Change* forecast remains broadly aligned with the 2024 ESOO until the early 2030s, after which it diverges. By 2034-35, the forecast is 15 TWh higher, driven by stronger growth from forecast data centre load, greater consideration of prospective LILs, particularly in South Australia, and lower projections for rooftop PV uptake. By 2054-55, the two forecasts reconverge, reflecting a more conservative outlook in the 2025 ESOO – particularly a 30 TWh downward revision in hydrogen production and increased residential energy efficiency, notably in Victoria. Meanwhile, stronger business electrification, sustained growth in data centre loads (although slowing in the longer term), an increase in prospective LILs and a slower uptake of rooftop PV all contribute to the forecast growth trajectory.

AEMO forecasts multiple scenarios, to capture a range of possible future outcomes. As **Figure 10** illustrates, the spread of the scenarios in the 2025 ESOO is generally narrower than the 2024 ESOO, predominantly driven by the reduced outlook for hydrogen production, while the 2025 ESOO also forecasts greater downward risks.

Figure 10 Actual and forecast NEM operational consumption, including hydrogen, all ESOO scenarios and compared to 2024 ESOO, 2020-21 to 2034-35 (TWh)



As in the 2024 ESOO's *Progressive Change* scenario, the 2025 ESOO's renamed *Slower Growth* scenario captures downside risks including weaker economic conditions and potential industrial closures across the NEM in the short to medium term. Consumption under this scenario grows steadily, primarily driven by EV uptake and electrification. The *Slower Growth* scenario consistently projects lower consumption than *Step Change*, largely due to lower data centre growth, a higher incidence of LIL closures (largely within the next five years), reduced electrification, and slower general business growth and EV uptake.

The gap between the *Accelerated Transition* and *Step Change* scenarios widens with time. The markedly higher forecast under the *Accelerated Transition* scenario is driven by a substantial forecast increase in consumption attributed to the potential scale-up of hydrogen production, and faster forecast adoption of data centres due to economic growth and investment in onshore AI training. *Accelerated Transition* also has higher forecast EV uptake and greater forecast growth in the broader business sector (generally referred to as business mass market, or BMM) due to more favourable economic conditions. Compared to the 2024 ESOO, forecast growth in hydrogen production is slower in all scenarios. This is due to increased focus on local use of hydrogen for value-add commodities rather than hydrogen exports, limited progress achieved to date in hydrogen cost reduction, and the related deferral or cancellation of several large-scale projects.

2.2.1 Residential consumption is driven by EV uptake, electrification and new housing, with energy efficiency tempering the overall increase

Underlying residential consumption is forecast to grow at an average rate of 2% per annum over the outlook period. Growth in consumption is driven by a rising population, the uptake of EVs, electrification, and demand from new dwelling construction, partially offset by increasing energy efficiency savings.

Underlying residential electricity consumption is driven by growth in electricity connections, which in turn reflects rising population and increased dwelling completions. Compared to the 2024 ESOO, the 2025 connections forecast shows a short-term uplift in new connections due to state and federal incentives to improve housing affordability[16]. While these provide a short-term boost, these are expected to erode early in the 2030s, with connections growth returning to a growth rate strongly aligned with economic factors. By 2054-55, the number of residential electricity connections in the NEM is forecast to grow to around 16 million, up from nearly 10 million today.

EV uptake is a major driver of residential consumption as more consumers embrace electrified transport options. While vehicle numbers are 3% higher by 2034-35 under *Step Change* compared to the 2024 forecasts, consumption is 5% lower. This reduction is attributed to improved vehicle efficiency and an NVES-driven increase in the projected share of small and mid-size EVs, that consume less electricity per kilometre than larger EVs.

Residential electrification has high potential, particularly in regions like Victoria where there is widespread reliance on gas for heating and hot water. Governments are encouraging a shift toward greater electrification in both residential and commercial sectors, such as from the Australian Capital Territory's ban on new gas connections, and Victoria's Gas Substitution Roadmap. Residential electrification of space heating, hot water systems, and gas cooking is expected to add nearly 0.5 TWh annually. Presently, space heating accounts for 60-70% of this load; electrification of space heating will therefore provide another driver for strong seasonal variation, with increased demand during the colder months akin to the increased demand during the warmer months for space cooling.

Victoria accounts for around 65% of forecast consumption from residential electrification, followed by New South Wales, and to a lesser extent Queensland, South Australia, and Tasmania. Compared to the 2024 forecasts, this 2025 ESOO includes slightly lower residential electrification due to greater investment in energy efficiency (due to more favourable costs) and improved emissions levels from gas appliances (due to potential penetration of

[16] See https://www.pm.gov.au/media/meeting-national-cabinet-working-together-deliver-better-housing-outcomes.

biomethane within the gas system), making residential electrification forecasts 1 TWh lower in 2030 and 2.5 TWh lower in 2050 relative to the 2024 ESOO.

Energy efficiency measures significantly moderate growth in consumption. Under *Step Change*, energy efficiency savings are projected to reach 14 TWh by 2034-35 and 53 TWh by 2054-55. Long-term consumption growth is tempered by stronger market-led energy efficiency improvements and updated policy assumptions. Compared to the 2024 ESOO, it is estimated that there will be an additional 14% reduction in projected energy consumption by 2034-35 due to energy efficiency savings. These savings are led by Victoria and its VEU program which is funding a range of household energy efficiency upgrades.

Rooftop PV continues to reshape residential operational consumption. Around 39% of houses and semi-detached dwellings in the NEM currently have a PV system, and this is projected to increase to 56% by 2050 under the *Step Change* scenario. Rooftop PV is expected to reduce operational consumption by 49 TWh in 2034-25, rising to 103 TWh by 2054-55. Compared to the 2024 ESOO, the projected number of installed systems has increased – driven by higher expectations of energy prices resulting in reduced investment payback periods – but average system sizes in this 2025 ESOO are smaller than previously forecast, resulting in lower overall capacity.

Finally, the 'PV rebound effect' – where lower bills lead to increased household consumption – has been lowered, as AEMO's updated methodology for this component focuses on household load rather than PV system size[17].

2.2.2 Business consumption is driven by the rapid expansion of data centres, industrial developments, and continued uptake of electrification and EVs

Underlying business consumption is forecast to increase by approximately 49% over the next 10 years, from 139 TWh in 2024-25 to 207 TWh in 2034-35 under the *Step Change* scenario. This growth is driven by data centre expansion and forecast growth in prospective LIL projects, particularly in South Australia. By 2054-55, business consumption is forecast to reach 313 TWh, with around 47 TWh attributed to business electrification. Although the outlook for hydrogen production has significantly declined, strong growth in other key sectors has led to an upward revision of the sector for the 2025 forecasts, compared to the 2024 ESOO.

Data centre locational insights

Data centres are now a separate business customer segment, recognising that their growth patterns are fundamentally different from other business customers. In 2024-25, data centres consumed around 4 TWh of electricity across the NEM, accounting for around 2% of grid-delivered supply. A substantial rise in energy consumption is forecast over the outlook period, driven by a significant increase in grid connection requests since the 2024 ESOO, in response to the anticipated rapid adoption of AI technologies and the increasing adoption of cloud-based computing services.

Sydney has a more extensive and established pipeline of existing and committed data centre projects, making it the dominant hub for data centre development. Meanwhile, Melbourne is also forecast to be a key data centre hub, with a substantial pipeline of prospective projects. Its share of data centre energy consumption is expected to increase from 20% in 2024-25 to around 40% by 2034-35 and beyond. Activity outside of Sydney and Melbourne

[17] See *Electricity Demand Forecasting Methodology*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

is forecast to be limited, with an estimated 1.4 TWh in electricity consumption forecast for South Australia by 2054-55, 0.9 TWh for Southern New South Wales (including Canberra), and 0.5 TWh for Tasmania. These unconstrained forecasts reflect the current locational preferences for data centre development, however network capability to support these levels of investment may mean this changes.

The following key drivers are anticipated to influence business sector consumption over the outlook period[18]:

- Data centre consumption is forecast to reach 21.4 TWh by 2034-35 and 35.7 TWh by 2054-55 under the *Step Change* scenario, the equivalent of around 9% and 12% of the NEM's grid-supplied electricity. In comparison, data centre growth under *Accelerated Transition* is forecast to reach nearly 24 TWh by 2034-35 and around 12 TWh in *Slower Growth*. The varied outlook reflects the uncertainty regarding the scale of prospective data centre developments and scenario-specific demand for data centre services, including AI adoption and cloud-based services[19], although in all scenarios the customer segment is anticipated to present a material growth driver, even under weaker economic conditions, given the penetration of digital technologies and the expected growth in AI.
- LIL consumption is forecast to grow steadily over the next decade, driven primarily by an increase in metal ore mining, and to a lesser extent, metal manufacturing and water supply services. Consumption is forecast to peak by 2033-34, before slowly declining by the end of the outlook period, reflecting a lower economic outlook for mining overall in the medium to longer term. Compared to the 2024 ESOO, the *Step Change* scenario is higher until 2034-35. This is largely driven by increased consideration of prospective projects in South Australia, Queensland and Victoria, providing 6.4 TWh additional consumption (with 4.9 TWh from South Australia alone). The 2025 ESOO has also re-allocated some business customers from the BMM sector that currently consume around 2.5 TWh.
- Business electrification encompasses the industrial, commercial, and non-road transport sectors, with industrial electrification accounting for the largest share. Compared to the 2024 ESOO, this ESOO forecasts lower electrification levels in the 2020s due to slower-than-expected advancements in industrial electrification. However, acceleration is expected in the 2030s, starting with low-temperature industrial processes (< 200 °C), and later extending to high-temperature processes (> 600 °C) in the 2040s. Queensland leads regional forecasts, followed by New South Wales, Victoria, South Australia, and Tasmania, reflecting the distribution of industrial activity and gas consumption, particularly in manufacturing, agriculture, mining, and mineral processing.
- EV uptake is also a major driver of business consumption and reflects similar factors to residential EV uptake. However, business EV uptake includes larger electric vehicles, that have not achieved the same energy efficiency improvements as smaller EVs that are dominant in residential uptake.

[18] For more on these drivers, see the 2025 IASR, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf.

[19] See *Electricity Demand Forecasting Methodology*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf, and OEA's Data Centre Energy Demand Final Report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf.

- The BMM consumption forecasts reflect the re-allocation of connections to LILs, and the creation of a separate data centre segment. This lower base level of consumption contributes to the *Step Change* and *Accelerated Transition* trajectories remaining lower than the 2024 forecasts across the entire outlook period. In contrast, *Slower Growth* consumption is now higher than the 2024 ESOO's *Progressive Change*, largely due to significantly lower energy efficiency assumptions for this scenario. A slightly weaker economic outlook also contributes to lower trajectories across all scenarios[20]. In *Step Change*, BMM consumption is forecast to grow from 82 TWh in 2024-25 to 89 TWh in 2034-35, reaching 97 TWh in 2054-55. In the medium to longer term, higher estimated savings from energy efficiency compared to the 2024 forecasts (particularly from the VEU program in Victoria but also from updated forecasts for other measures) tempers growth under this scenario.
- Hydrogen production remains a long-term driver for electricity consumption, although its outlook has been substantially dampened relative to the 2024 ESOO forecasts. In the 2025 ESOO, domestic hydrogen production is primarily expected to support the industrial, transport and green commodity sectors. Under the *Step Change* scenario, electricity use for hydrogen production is projected to grow from <1 TWh in 2024-25 to 9.3 TWh by 2034-35. By 2054-55, electricity consumption to produce hydrogen reaches around 40 TWh, 40% lower than in the 2024 ESOO in the *Step Change* scenario. This downward revision reflects lower demand assumptions for exports, commodity processing, and lower domestic volume driven by high hydrogen costs. The combined hydrogen volumes for export and commodity processing have also been reduced, based on stakeholder feedback to the Draft 2025 IASR.
- As highlighted in the 2024 NEM ESOO, businesses install PV systems to offset their energy costs, with limited incentive to install oversized systems relative to their consumption. For the 2025 forecasts, average commercial PV system sizes are now expected to be smaller, contributing to almost 12% lower commercial PV generation in *Step Change* in 2034-35 relative to the 2024 ESOO forecasts.

The above key drivers result in underlying business consumption forecasts (including hydrogen and EVs) of between 159 TWh and 264 TWh in 2034-35, depending on the scenario, with this consumption spread continuing to widen by 2054-55.

Forecast uncertainties for prospective business loads

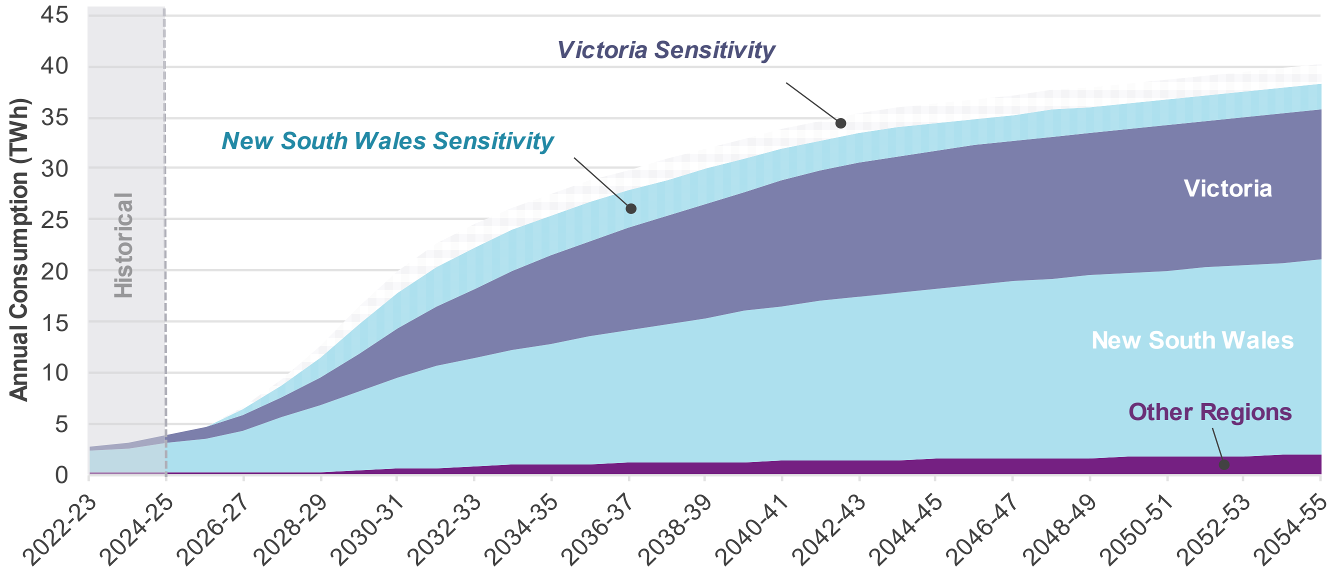
AEMO's forecasts in the 2025 ESOO include greater consideration of prospective data centre and industrial loads, to ensure appropriate planning activities can occur to support consumer needs over the planning horizon. The scale, timing and location of these developments are forecast, and therefore capture a degree of uncertainty that is best explored through sensitivity analysis, as appropriate. The 2025 ESOO provides two sensitivities to *Step Change*, to consider the effects on consumption from these two drivers. While this 2025 ESOO does not examine the reliability impacts of these uncertainties, the sensitivities provide an alternate forecast appropriate for other planning processes by AEMO, such as for potential use in the 2026 ISP, or by stakeholders.

The *Accelerated Data Centre Growth* sensitivity explored the implications of even higher growth in data services relative to *Step Change*, with more prospective data centre projects reaching completion. This sensitivity considered additional large-scale projects not in *Step Change*, where multiple connection requests exist of a

[20] Deloitte Access Economics (DAE) developed the economic forecasts before recent changes to global political, economic and trade conditions. DAE provided an update in June 2025 indicating that the impacts on Australia are likely to be minimal. See the 2025 IASR for further information, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?la=en.

similar capacity, either for the same ISP sub-region, or from the same developer. The sensitivity is forecast to reach 27.4 TWh by 2034-35, 6.0 TWh greater than *Step Change*. **Figure 11** shows the additional load resulting from the sensitivity analysis; around 65% of the additional load is forecast in New South Wales over the first decade, with the remainder in Victoria.

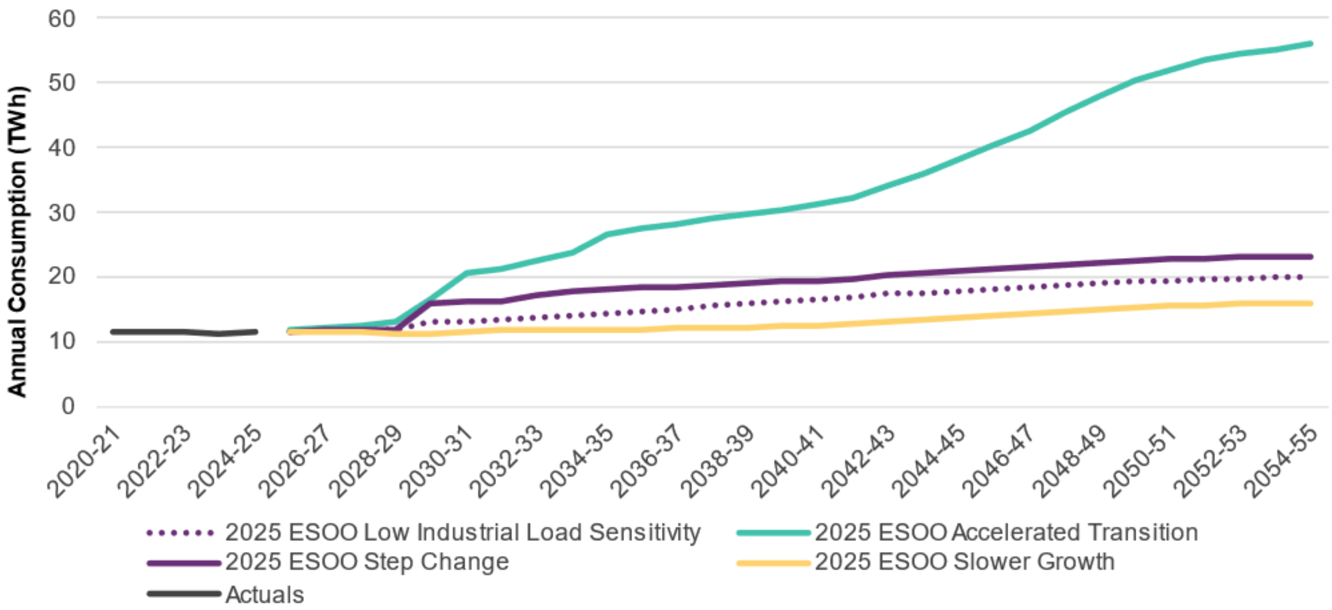
Figure 11 Assumed location of data centre load in the *Accelerated Data Centre Growth* sensitivity compared to ESOO *Step Change* scenario, 2022-23 to 2054-55 (TWh)



The *Low Industrial Load* sensitivity examined the potential for under-realisation of prospective loads, particularly in South Australia which has a significant share of prospective industrial load growth within *Step Change*.

As **Figure 12** demonstrates, nearly 3 TWh of load is not included in this *Low Industrial Load* sensitivity in 2029-30. From that point onward, the forecast consistently tracks 3-4 TWh below the *Step Change* scenario.

Figure 12 Actual and forecast South Australia operational consumption, including hydrogen, *Low Industrial Load* sensitivity compared to all ESOO scenarios, 2020-21 to 2054-55 (TWh)



2.3 Maximum operational demand forecast to grow

AEMO prepares maximum demand forecasts as a distribution, represented by the 10%, 50%, and 90% POE forecasts, rather than single-point forecasts – see **Section 1.5** for definitions.

The ESOO maximum operational demand forecast represents the highest level of operational demand within a year, that is, the electricity drawn from the transmission system as defined in **Section 1.5**, calculated on an unconstrained and uncontrolled basis. This means the forecast represents consumer operational demand assuming there is no USE and supply is always sufficient to meet demand, and the forecast does not account for any market-based or nonmarket-based interventions that might reduce system load during peak events (such as RERT, the Wholesale Demand Response [WDR] mechanism, or demand side participation [DSP]). Unconstrained and uncontrolled operational demand forecasts are developed specifically such that AEMO's planning and forecasting activities can identify potential system needs and the value of utility-scale and consumer-led solutions to meet consumer demand.

The primary influences on maximum operational demand forecast trends are the residential and business drivers discussed in **Section 2.1**. Compared to the 2024 ESOO, this 2025 ESOO forecasts a steeper growth trajectory, particularly in the medium- to long-term horizon. A key contributor to this uplift is projected stronger growth of electrification in the business sector, particularly in Queensland, New South Wales, and Victoria. Data centre growth is also a major driver in New South Wales and Victoria, while new connection of prospective LILs is a key driver in South Australia.

In some cases, the forecast trend in maximum demand differs from consumption trends, due to some drivers impacting the load shape differently across the day and across seasons. For example:

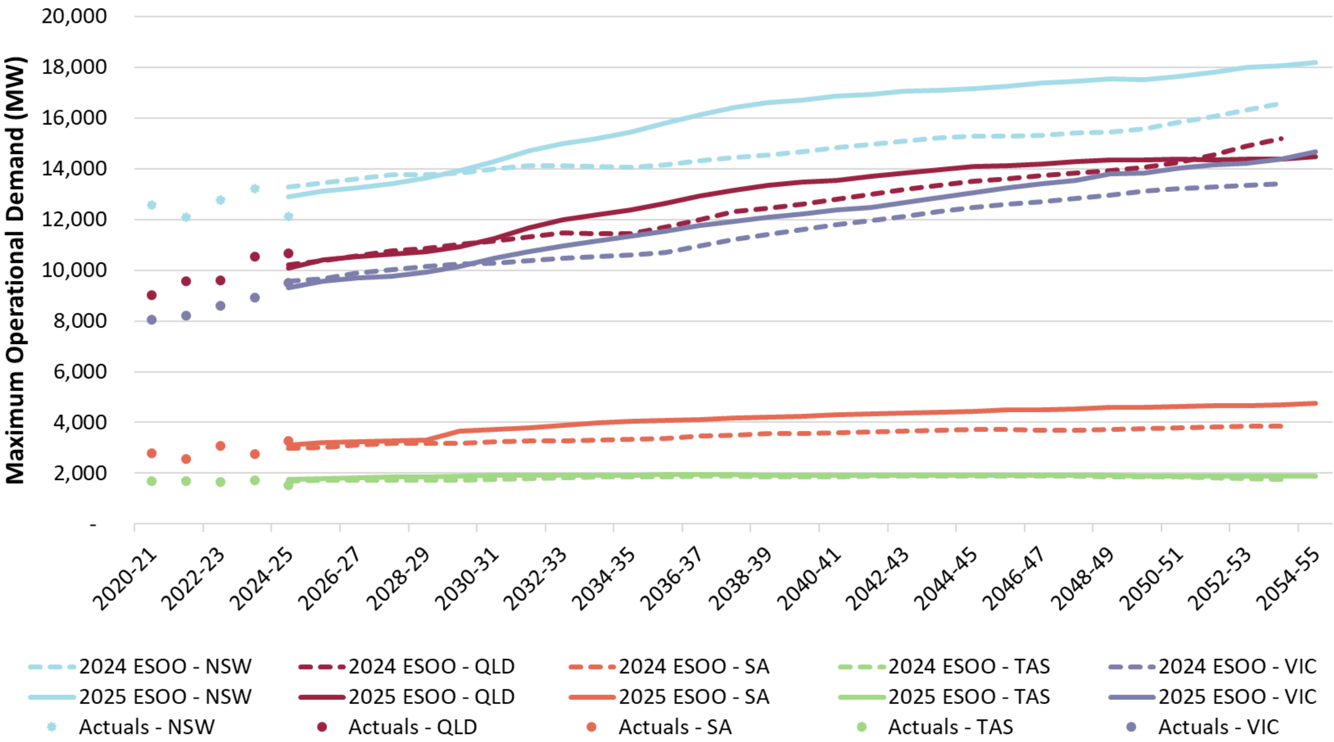
- Distributed PV generation reduces operational consumption, but generally has relatively little impact on maximum operational demand (with maximum demand now generally falling in the early evening in mainland states, around or after sunset, or in winter [for Tasmania] when PV generation is also lower due to fewer daylight hours).

- Heating and cooling loads represent a small proportion of overall annual electricity consumption, but on particularly extreme hot or cold days, temperature can contribute up to half the demand in some instances. Relevant additional maximum operational demand drivers therefore include uptake of air-conditioners, electrification of households currently using gas heating, and building energy efficiency initiatives affecting heating/cooling requirements.
- The impact of battery storage operation on annual consumption is limited to the efficiency associated with battery use (that is, battery losses), which comprises a very small amount relative to overall consumption. The impact on maximum operational demand, however, is significant, as the level of battery discharge during the evening peak directly impacts the required energy to be supplied from the grid (operational demand). Batteries which are coordinated through an aggregator or retailer under a virtual power plant (VPP) are expected to have an even greater impact on lowering peak operational demand. The degree of battery coordination is a key uncertainty, and has been considered explicitly in AEMO's reliability assessment approach (see **Section 4.2**). All AEMO's scenarios include varying levels of CER coordination, as well as other developments.
- EV uptake likewise is forecast to increase annual consumption, however, maximum operational demand is not simply proportional to uptake because of varying intra-day charging behaviours. For example, EV owners may charge during peak demand periods out of convenience, or avoid them if appropriately informed and/or incentivised. Charging behaviours are also dependent on the availability of charging infrastructure. In general, AEMO forecasts that as EV ownership increases, greater availability of infrastructure and greater awareness of charging impacts and/or incentives to minimise potential charging disruption will occur over time, with less impact at time of peak (and potentially an increasing influence on daytime minimum demands).
- Emerging loads, such as hydrogen electrolysers, are assumed to be flexible within operational limits, capable of providing a natural demand response during high price events such as those associated with extreme demand days or limited supply availability. Hydrogen-associated demand is expected to reduce at time of peak, even when annual consumption is substantial, to minimise operating costs and lower the effective cost of hydrogen.

The maximum operational demand forecast presented in this chapter is unconstrained, and only accounts for customer-controlled battery and EV charging that is not coordinated. The forecasts presented also do not incorporate potential hydrogen load, which are anticipated to operate flexibly and lower output at time of peak demand, and do not incorporate potential coordinated battery and EV charging or discharging, which are anticipated to discharge to support the grid given high price signals for VPP and vehicle-to-grid (V2G) operators.

Figure 13 shows the annual actual and forecast maximum operational demand (sent-out, 50% POE) for all NEM regions from 2020-21 to 2054-55 for the 2025 ESOO *Step Change* scenario, and compared to the 2024 ESOO Central scenario.

Figure 13 Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2025 ESOO *Step Change* and 2024 ESOO Central scenario, 2020-21 to 2054-55 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. This definition also excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage (PHES) or large-scale batteries, as well as hydrogen loads.

The key insights from these forecasts, focusing on the next decade, are as follows:

- In **New South Wales**, the base year maximum operational demand forecast is slightly lower than forecast in the 2024 ESOO. This is primarily due to the influence of milder weather conditions observed in the most recent year of demand. Maximum demand forecasts prior to 2029 also are below the 2024 ESOO, driven by subdued underlying consumption forecasts for BMM and lower-than-expected electrification uptake in the business sector in the short term. From 2030 onwards, rising data centre growth contributes to significantly higher maximum demand compared to the 2024 ESOO. Under the 50% POE, maximum operational demand is forecast to reach 15,429 MW by 2034-35, 1,370 MW higher than the 2024 ESOO projection.
- In **Queensland**, maximum operational demand is projected to grow steadily through to 2030, supported by consistent increases in underlying consumption across both BMM and LILs. From 2030 onwards, demand growth accelerates, primarily driven by stronger electrification, particularly within the business sector. The 2025 ESOO forecast is slightly higher than the 2024 ESOO in some years, although with a similar overall trajectory. The 50% POE maximum operational demand is forecast to reach 12,364 MW by 2034-2035, approximately 912 MW higher than the 2024 ESOO projection.
- In **South Australia**, maximum operational demand is projected to increase steadily through to 2029, supported by consistent growth in consumption across both LIL and BMM sectors. From 2030 onwards, increased consideration of prospective industrial loads drives a material uplift in peak demand, with the 50% POE maximum operational demand forecast to reach 4,044 MW by 2034-35, 708 MW higher than the corresponding forecast in the 2024 ESOO.

- In **Victoria**, maximum operational demand is projected to grow steadily through to 2030, supported by gradual increases in forecast consumption from data centres, LILs, and electrification. From 2030 onwards, demand growth accelerates, primarily driven by a substantial uplift in projected data centre consumption. This results in a divergence from the 2024 ESOO, with 50% POE maximum operational demand reaching 11,334 MW by 2034-35, approximately 723 MW higher than the corresponding forecast in the 2024 ESOO.
  - **Victoria is projected to transition to a winter-peaking region** by around 2040-41, primarily driven by fuel-switching from gas to electricity in new developments. This shift is expected to result in a winter peak demand that exceeds the summer peak by approximately 500 MW by the end of 2044-45.
- In **Tasmania**, maximum operational demand is projected to show a slight upward trend across the outlook period, supported by forecast consumption growth in BMM, LILs, EVs, and electrification. The 2025 ESOO forecasts are approximately 70 MW higher than those in the 2024 ESOO, primarily reflecting a more favourable outlook for BMM in 2025 ESOO forecasts.

2.4 Minimum operational demand forecast to rapidly decline

The minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of operational measures to constrain PV generation and market-based solutions that might increase operational demand in periods of excess supply (including coordinated storage and EV charging, scheduled loads such as pumping load).

AEMO prepares the forecasts as a distribution, given by the 10%, 50%, and 90% POE forecasts (see **Section 1.5**), which reflect uncertainty in weather conditions and do not account for operational interventions or demand side responses.

Minimum operational demand is shaped by the same underlying factors outlined in **Section 2.1**. Broadly, increases in population, electrification, appliance uptake and economic activity are expected to exert upward pressure on minimum demand over time, whereas increasing uptake of distributed PV including rooftop PV and PVNSG reduces the grid supply required at times of high daytime PV output. Passive distributed PV is now the primary driver of minimum operational demand, and has shifted the timing of minimum demand from overnight periods to around midday.

Annual minimums are typically recorded on mild weekend days or public holidays, when underlying demand is subdued due to limited heating and cooling requirements. For each megawatt of installed passive distributed PV capacity, minimum operational demand typically decreases by approximately 0.7 MW to 0.8 MW, accounting for the diversity in panel orientation and solar irradiance across different locations within the regions. In contrast, the impact of distributed PV on total consumption aligns with its annual capacity factor, which is generally around 15%.

While uptake of distributed PV drives a rapid decline in minimum demand, other technologies push in the opposite direction:

- Daytime charging of battery storage systems and EVs, aimed at utilising abundant solar generation, can increase operational demand during periods that would otherwise exhibit minimum levels. As with their operation at time of maximum demand, consumer behaviour and the degree of coordination can have a significant impact on how these technologies affect minimum demand. For example, morning charging of passive battery devices may lead to these resources being fully charged before midday, resulting in little benefit from these devices to increase minimum demand. Coordinating the timing of battery charging can be challenging, as the price signals consumers receive, and thus their incentive to shift charging, depend heavily on their electricity tariff or retail plan. Some consumers on flat-rate tariffs may see little or no price difference throughout the day, while those on time-of-use or dynamic tariffs may be more responsive to intraday price variations, particularly during periods of high solar generation and low demand. Similarly, vehicles may not always be connected to charging infrastructure during daytime periods, further limiting the ability to coordinate charging. **It is important to note that coordinated battery charging is optimised as a supply side resource in the ESOO and is therefore not included in the minimum operational demand forecasts presented in this section.**

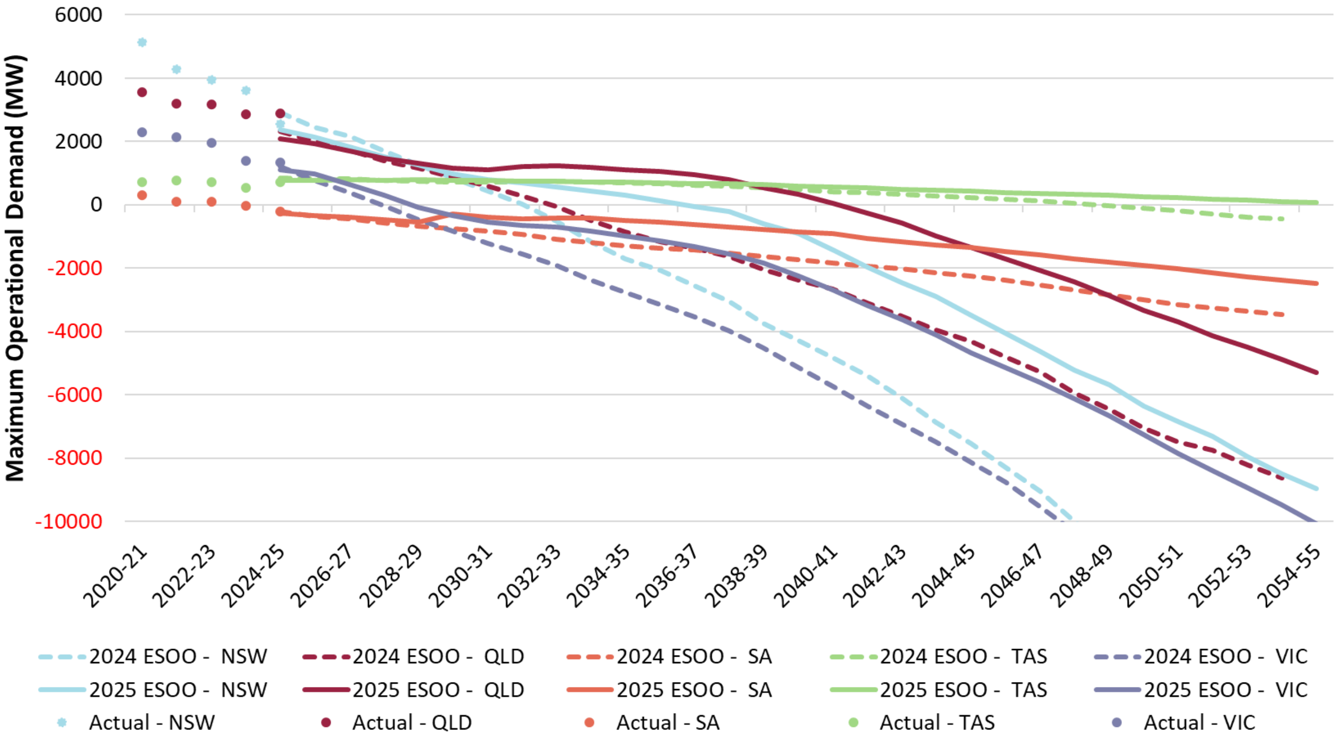
- Electricity demand for hydrogen production is expected to increase minimum operational demand. However, consistent with the treatment of maximum operational demand, this potential load is not reflected in the minimum operational demand forecasts. Instead, hydrogen production facilities are assumed to operate flexibly, responding to market signals and system conditions. This assumption allows for potential alignment with periods of high renewable generation, although the actual impact on minimum operational demand will depend on the operating behaviours and scheduling of these facilities, which may vary in practice.

Variations in demand from LILs can materially influence the minimum operational demand. This is particularly evident in Tasmania, where LILs at the time of minimum demand can represent more than half the total demand. As a result, any planned or unplanned outages of these large loads during minimum demand periods can significantly alter the magnitude of the observed minimum, introducing volatility and uncertainty into demand forecasts. The minimum operational demand forecasts presented in this 2025 ESOO do not capture the potential operational variability of LILs that go beyond that observed in historical operation, meaning that lower minimums than presented may occur if LILs are not operating, which may require greater consideration when developing appropriate operational controls to support a secure operating environment.

Figure 14 compares the annual actual and forecast minimum operational demand (sent-out) from the 2025 and 2024 ESOOs for NEM regions from 2020-21 to 2054-55 for the ESOO Central scenario.

The 2025 ESOO *Step Change* minimum operational demand forecasts continue to show a declining trend, driven by continued forecast investments in distributed PV. The forecasts are higher across all regions compared to the 2024 ESOO, due primarily to weaker growth in distributed PV than forecast in the 2024 ESOO, and increased electrification, particularly in the business sector. In New South Wales and Victoria, the anticipated expansion of data centres, and in South Australia, the growth in LILs, are also key contributors, adding significant load across the day, including during minimum operational demand conditions.

Figure 14 Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2025 ESOO *Step Change* scenario and 2024 ESOO central scenario, 2020-21 to 2054-55 (MW) for five regions



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. This definition also excludes demand from scheduled loads, typically pumping load from PHES or large-scale batteries, as well as hydrogen loads.

Key additional insights from these forecasts, focusing on the next decade, are:

- In **New South Wales** and **Victoria**, the decline in minimum operational demand remains steady across the forecast horizon, but the rate of the decline slows beyond 2030 under the 2025 ESOO *Step Change* scenario as data centre loads increase and electrification growth also increases, particularly in the business sector. As a result, minimum operational demand in New South Wales is forecast to reach 298 MW by the end of the horizon in the 2025 ESOO, which is 2,012 MW higher than that projected in the 2024 ESOO. In Victoria, minimum operational demand is expected to reach -987 MW, an increase of 1,777 MW relative to the 2024 ESOO outlook.
- **Queensland** shows a similar declining trend in minimum demand until 2030; however, overall minimum operational demand is forecast to be higher than those projected in the 2024 ESOO. The slower rate of decline reflects lower PV and PVNSG projections, a higher electrification forecast for business sector, and growth in the consumption of LILs. From 2030 onwards, the trend slows, reflecting a substantial acceleration in electrification of business sector.
- In **South Australia**, the short-term decline in minimum operational demand is more gradual than projected in the 2024 ESOO, largely due to lower uptake forecasts for PV and PVNSG. As a result, the 50% POE minimum operational demand is expected to reach -542 MW by 2029, approximately 141 MW higher than the 2024 forecast. Broader inclusion of prospective LILs materially lifts the declining minimum trend.
- **Tasmania** remains distinct, with minimum operational demand influenced primarily by LILs rather than weather conditions. The downward trend continues due to ongoing uptake of PV and PVNSG, but the forecast starts

lower than the 2024 ESOO mainly due to the reduced projected operation of LILs. However, the rate of decline is milder than in the 2024 ESOO, reflecting an improved BMM outlook and a lower PV forecast.

2.5 Flexible demand can enhance the NEM's ability to meet forecast peak demand

Flexible demand supports the power system's ability to reliably operate through periods of high prices, or system constraints. By providing short-term reductions in demand in response to market signals, reliability risks, network constraints or DSP help alleviate pressure on generation and network infrastructure during extreme conditions.

While flexible demand broadly refers to the capacity of consumers to shift or curtail electricity use, DSP is a defined subset used in AEMO's reliability and planning studies. DSP specifically refers to flexible demand resources that are not already embedded within demand or supply forecasts and are expected to occur in response to high prices or reliability events. These resources include both market-driven and reliability-driven mechanisms, such as participation in demand response programs, industrial curtailment, and network-coordinated actions.

For the 2025 ESOO, AEMO has updated its estimate of DSP, incorporating contributions from WDR. These estimates are based on data submitted by registered market participants through the Demand Side Participation Information Portal (DSP IP) as of 31 March 2025, in accordance with AEMO's published *DSP Forecasting Methodology*[21]. In line with the treatment of generation and transmission developments, the reliability forecast for the *Step Change* scenario includes only existing and committed DSP.

Projected DSP across the NEM for summer 2025-26 is 973 MW, as shown in **Table 4**. This is lower than the 1,189 MW reported in the 2024 ESOO, reflecting updated participant submissions, reclassification of programs, and revised assumptions regarding demand-side responsiveness.

AEMO has applied a flat forecast for reliability-responsive DSP across all NEM regions over the full 10-year outlook of the ESOO *Committed and Anticipated Developments* assessment. In equivalent assessments in previous ESOO forecasts, the New South Wales Peak Demand Reduction Scheme (PDRS)[22] was assumed to lift DSP growth as it was considered a committed policy. However, this was based on an assumption that the PDRS provided incentives for event-driven demand response. While the PDRS provides incentives for consumers to register a battery with a VPP, the PDRS has mostly encouraged energy efficiency and battery installation activities. AEMO has therefore adjusted the PDRS as an influence on the DSP forecast, to reflect reduced impact on peak demand reduction which would support reliability outcomes or price-responsive DSP triggers. Its impact continues to be captured in the underlying demand forecast.

As the NEM continues to evolve, demand-side flexibility remains a critical component in maintaining reliability and supporting the cost-effective operation of the power system.

[21] At https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

[22] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme.

Table 4 Projected demand side participation for summer 2025-26 (MW)

Price trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
$300-$500/MWh	1	30	26	1	1
$500-$7,500/MWh	21	70	46	5	3
> $7,500/MWh	108	144	46	5	189
Reliability response	350	189	46	5	383

Note: The reliability response is the estimated response during actual LOR 2 and LOR 3 events. For the definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf.

Potential sources of future demand flexibility – data centres

Data centres is an emerging customer segment, with strong development interest to support an expected rise in AI and cloud computing applications. AEMO's 2025 ESOO forecasts recognise this emerging trend, and in developing a bespoke forecast of this customer segment, AEMO has had close engagement with various Australian data centre developers to ascertain the potential flexibility of these loads, and only a small number of data centres are contributing to DSP programs. AEMO's data centre forecast does not incorporate demand flexibility, because developers anticipate these facilities will prefer reliable data service uptime and reliability. While data centres may include on-site alternative supply forms, the operational demand forecasts do not anticipate these to operate to reduce operational demand.

The potential exists, however, for data centres to provide more demand flexibility than has been assumed in the forecast. Potential load shifting may be plausible, as well as leveraging onsite generation and uninterruptible power supply (UPS) systems. However, there is likely to be a gap between theoretical flexibility and its practical availability. Potential demand flexibility solutions include:

- Load shifting, such as adjusting the timing of non-urgent computing tasks to align with renewable generation peaks, is technically feasible and has been demonstrated internationally. However, consultations with Australian data centre operators revealed economic and operational barriers. A flat load profile allows for greater server optimisation, and shifting demand may require additional hardware investment. This flexibility is more viable for hyperscalers than co-location centres, which host independent customers and lack control over workload timing.
- Onsite backup generation (from UPS systems or embedded diesel generators) offer further avenues for flexibility. UPS units can discharge stored energy during peak periods, similar to BESS, while backup generators—typically diesel—can be activated during peak demand events. However, in Australia, customer service agreements often restrict the use of these systems to emergency backup only. Additionally, environmental compliance requirements may impact the frequency of diesel backup operation. These constraints underscore the gap between theoretical flexibility and practical implementation, reinforcing the need for cautious assumptions in reliability forecasting and highlighting the importance of targeted policy signals and incentives to unlock future potential.

Sufficient market mechanisms and reforms will be needed to enable and build confidence in the ability of large loads, like data centres, to support the power system when required. Such action would help unlock demand flexibility potential, improve technical visibility for grid operations, and minimise investment requirements to maintain ongoing customer reliability.

3 Supply and network infrastructure forecasts

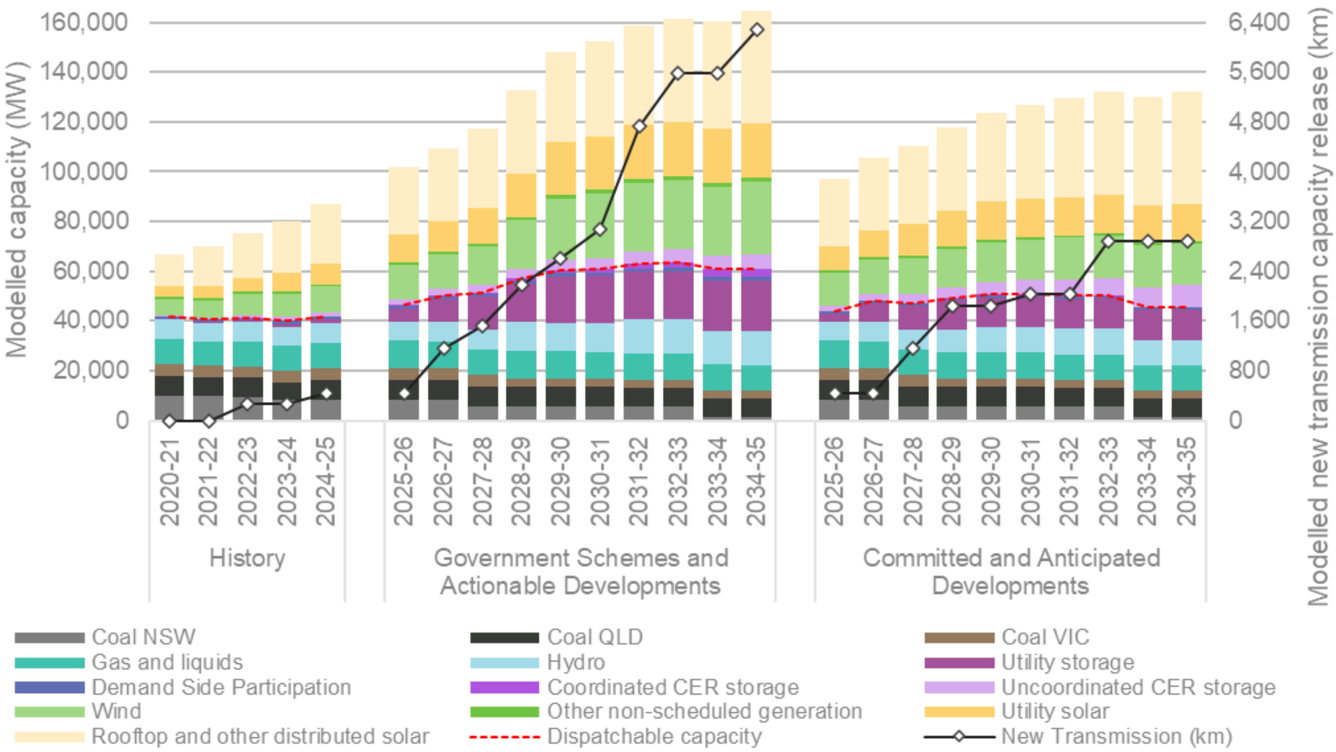
A reliable power system relies on the capability to generate and securely transmit electricity to consumers. This chapter outlines the infrastructure development outlook assumptions for the two reliability assessments considered in this ESOO, including:

- generator commissioning and decommissioning assumptions,
- generator seasonal capacities and reliability assumptions, and
- transmission commissioning and reliability assumptions.

This 2025 ESOO provides two reliability assessments – *Government Schemes and Actionable Developments* and *Committed and Anticipated Developments* – based on differing power system development assumptions.

Figure 15 shows the generation, storage, CER and demand flexibility summer typical development outlook for these two reliability assessments, and compares them to recent history[23]. The utility-scale development assumptions that make up the two development outlooks are described in the following sections.

Figure 15 2025 ESOO 10-year infrastructure development outlooks under typical summer availability assumptions



[23] The NEM's transmission backbone is the world's longest interconnected system of around 40,000 km of existing transmission lines and cables, supplying a population in excess of 23 million people, and is augmented regularly with minor network projects to support ongoing customer growth. New transmission development outlooks in this context represent an important means to strengthen the system's capability to continue to service electricity consumers.

3.1 Generation commissioning assumptions

There is a substantial pipeline of utility-scale generation and storage projects in various stages of development in the NEM, from proposed projects to those that are close to finishing their commissioning. AEMO collects information from generation and storage project proponents, which is published on AEMO's Generation Information web page[24]. To assess project progression, AEMO applies commitment criteria that consider a project's progress across land, finance, planning, contracts and construction categories[25].

Table 5 shows the categorisation of the known generation pipeline in the July 2025 Generation Information publication, considering the commitment criteria. This is the pipeline considered in this ESOO's power system outlooks.

Table 5 New generation pipeline as of July 2025 Generation Information, nameplate capacity (MW)

Category		Existing and in commissioning	Committed	Anticipated	Proposed
Description		Existing generation and storage plants, and those that have completed commissioning for at least 30% of their capacity.	Projects that meet all five of AEMO's commitment criteria but have not yet commissioned at least 30% of their capacity.	Projects that have made progress towards at least three of AEMO's commitment criteria.	Projects that have not progressed sufficiently to meet the requirements of an in commissioning, committed or anticipated project.
Capacity (MW)	New South Wales	21,346	7,619	3,210	109,296
	Queensland	18,714	3,771	5,793	113,423
	South Australia	7,403	252	110	21,085
	Tasmania	3,230	0	382	9,477
	Victoria	17,523	2,866	1,933	72,167
	NEM	68,216	14,508	11,427	325,449

While a strong pipeline exists, delays against developer intended commissioning timeframes have been observed in recent years. As part of the Generation Information survey process, AEMO collects 'full commercial use dates' from all developers that reflect their current intentions and best estimates for each project to complete commissioning.

Figure 16 shows the difference between the full commercial use dates provided by developers and actual commissioning for developments that completed commissioning in the last 18 months. AEMO has assessed the difference, for the period projects were classified by AEMO as 'committed', against two key commissioning milestones:

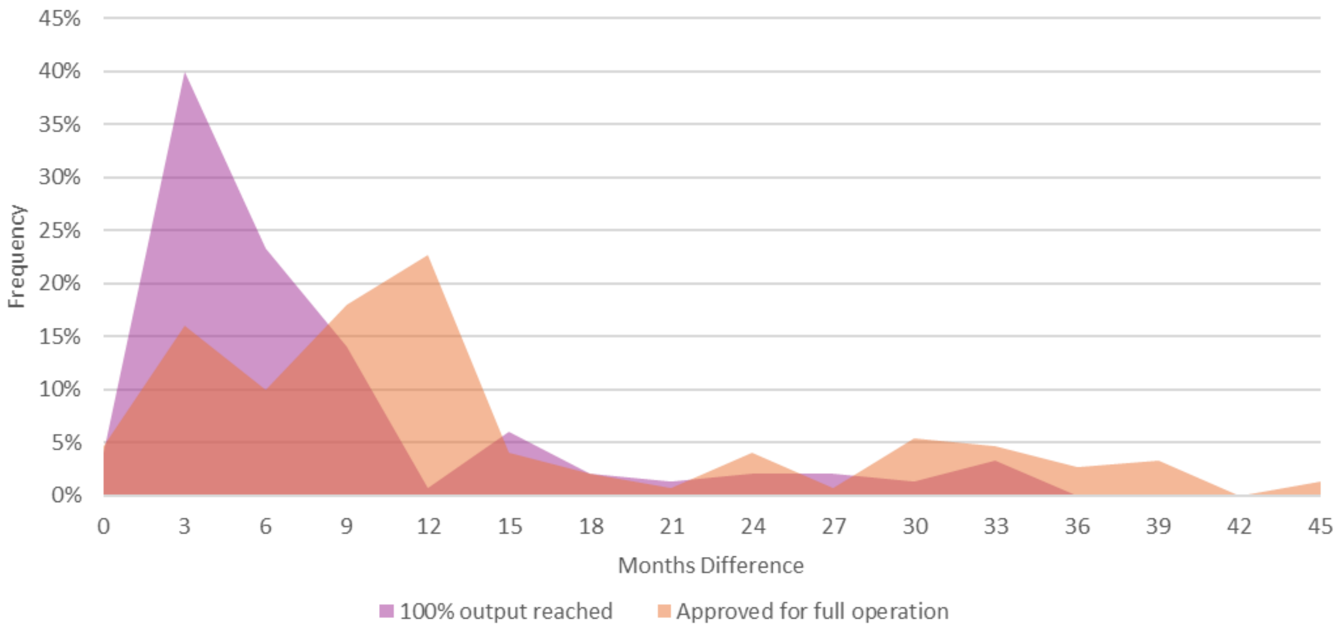
- **100% output reached** – the first date at which the development reaches its full output. At this point in the commissioning process, the generator may be able to generate at 100% output for testing purposes, but is still subject to numerous commissioning requirements. The average difference is seven months delayed, and the median difference is four months delayed.

[24] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[25] For details of commitment criteria, see the Background Information tab on each Generation Information publication.

- **Approved for full operation** – a later date at which the development achieves approval to operate at its full output (this commissioning milestone matches the definition of full commercial use date requested by AEMO). The average difference is 13 months delayed, and the median difference is 10 months delayed.

Figure 16 Difference between full commercial use dates provided by developers, and actual achievement of commissioning milestones



To increase the accuracy of the ESOO's reliability assessments, AEMO applied development delays in the *Committed and Anticipated Developments* reliability assessment that are consistent with delays observed for recently commissioned projects. A six-month delay to committed projects was selected, as it is between the median and mean of recently observed delays for developments reaching 100% output.

The *Government Schemes and Actionable Developments* reliability assessment assumed development delays are avoided and the projects delivered on schedule.

Table 6 lists how AEMO applied the generation pipeline to each development outlook.

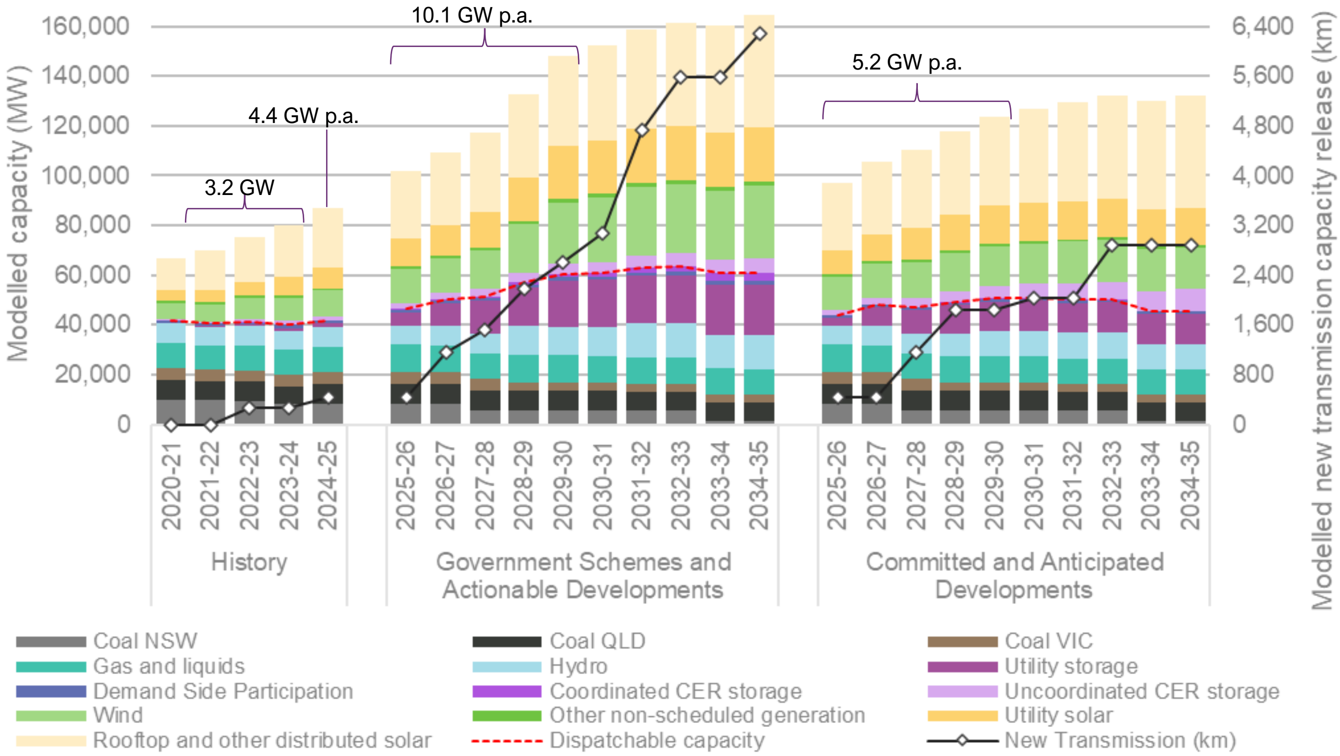
Table 6 Modelling implementation for new generation and storage developments

Development category	*Government Schemes and Actionable Developments*	*Committed and Anticipated Developments*
Existing and in commissioning	Applied consistent with operator advice	Applied consistent with operator advice
Committed	Applied at the developer advised full commissioning date.	Applied with a six-month delay to the developer advised full commissioning date.
Anticipated	Applied at the developer advised full commissioning date.	Applied at the latest of: • 1 July 2027 (for this 2025 ESOO) • 1 year after the developer advised full commissioning date
Federal Government Capacity Investment Scheme[A]	• All awarded projects applied at the advised full commissioning date. • All RETAs negotiated with each state and territory, that are not yet awarded are applied in 2028-29 and 2029-30. • Further stages of the CIS, not specified in a RETA are not applied, as there is not yet sufficient detail.	Included only where committed or anticipated.
New South Wales Infrastructure Investment Objectives (IIO)[B]	• All awarded projects applied at the advised full commissioning dates. • Long duration storage, generation, and firming targets that are not yet awarded are applied in advance of their relevant target dates.	Included only where committed or anticipated.
Australian Renewable Energy Agency (ARENA) funded projects[C]	All projects awarded under the ARENA Large Scale Battery Storage funding round, applied at the advised full commissioning dates.	Included only where committed or anticipated.
Victorian Targets[D]	• All projects awarded under the Victorian Renewable Energy Target 2 (VRET2) applied at the advised full commissioning dates. • Victorian offshore wind targets applied in advance of the 2032 and 2035 target years. • All State Electricity Commission (SEC) funded projects applied at the advised full commissioning dates. • Victorian storage targets not applied, as these are assumed to be met through other mechanisms.	Included only where committed or anticipated.
Queensland funded projects[E]	All projects with funding allocated under the 2025 Queensland budget are applied at the proponent advised full commissioning dates.	Included only where committed or anticipated.
South Australian funded projects	• Hydrogen jobs plan no longer applied due to deferral. • Firm Energy Reliability Mechanism (FERM) is under development and will be applied in future ESOOs once there is sufficient detail	Included only where committed or anticipated.

A. See https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme.
B. See https://aemoservices.com.au/en/our-role/infrastructure-investment-objectives-report.
C. See https://arena.gov.au/funding/large-scale-battery-storage-funding-round/.
D. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.
E. See https://budget.qld.gov.au/.

Figure 17 shows the capacity outlook assumed, with the annual utility-scale generation and storage commissioning quantities identified for the two 2025 ESOO reliability assessments.

Figure 17 2025 ESOO 10-year infrastructure development outlooks under typical summer availability assumptions with annual new utility-scale generation and storage commissioning quantities identified



Both development outlooks reflect an increased pace of new utility-scale generation and storage commissioning compared to the 3.2 GW that completed commissioning on average each year between 2021-22 and 2023-24, and the 4.4 GW that completed commissioning in 2024-25[26]:

- An average of 10.1 GW of new utility-scale capacity is expected to commission each year for the first five years of the horizon under the *Government Schemes and Actionable Developments* assessment that assumed no development delays. Beyond the first five years, fewer projects and schemes are currently in place. This outlook includes:
  - all projects considered in the *Committed and Anticipated Developments* assessment, but without development delays,
  - Brigalow Gas Turbine (GT, Kogan Creek, 400 MW) in Queensland in December 2028,
  - Phoenix Pumped Hydro (810 MW/9,720 MWh) in New South Wales in March 2029,
  - a total of 18,636 MW/55,050 MWh of utility storage, 13,248 MW of utility solar and 19,489 MW of wind generation sufficiently advancing to meet criteria for inclusion over the 10-year horizon, and
  - more than 30 GW more capacity than was considered in the equivalent reliability assessment published in the 2024 ESOO.

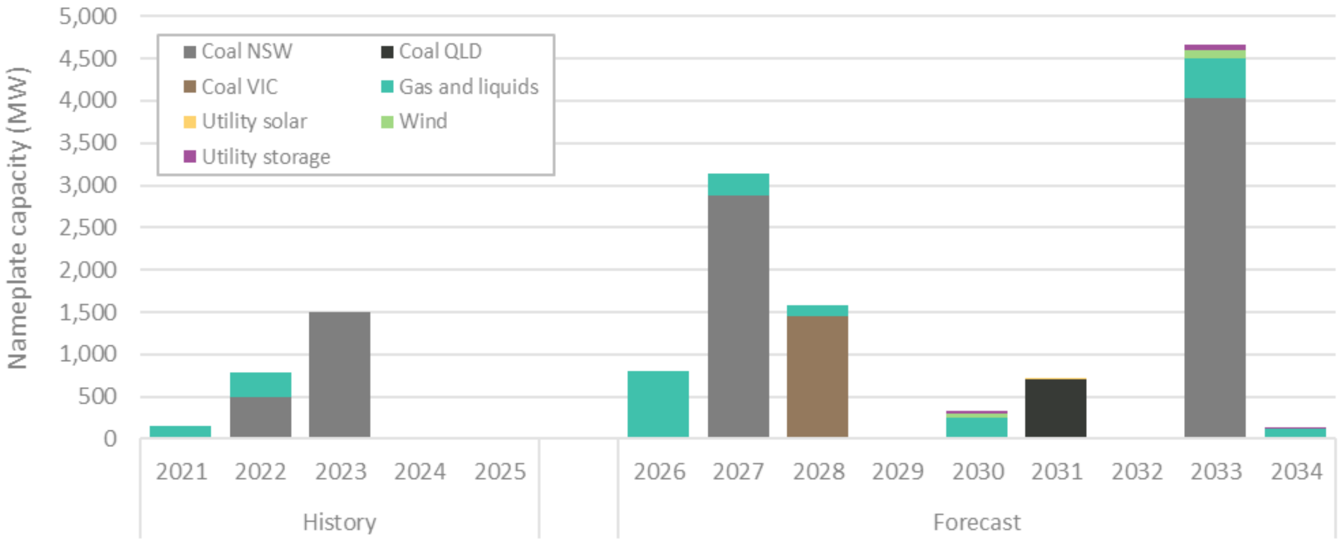
[26] See the Connections scorecard for more detail, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

- An average of 5.2 GW of new utility-scale capacity is expected to commission each year for the first five years of the horizon under the *Committed and Anticipated Developments* assessment, which applies recently observed development delays. Beyond the first five years, there are very few projects sufficiently advanced to meet the criteria to be considered committed or anticipated. The 10-year development outlook includes:
  - Hunter Power Station (750 MW) in New South Wales in September 2025,
  - Kidston Pumped Hydro (250 MW/2,000 MWh) in Queensland in January 2026 (delays applicable),
  - Snowy 2.0 (2,200 MW/350,000 MWh) in New South Wales in December 2028 (delays applicable),
  - a total of 10,364 MW/28,716 MWh of utility storage, 6,621 MW of utility solar and 6,663 MW of wind generation sufficiently advancing to meet criteria for inclusion over the 10-year horizon, and
  - more than 10 GW of projects which have become committed or anticipated in 2025 since the 2024 ESOO.

3.2 Generation decommissioning assumptions

All ESOO reliability assessments assume generator retirements occur on dates provided by participants – either on the specific closure date provided under the three-and-half-year notice of closure rules, or on 31 December of the provided expected closure year. **Figure 18** shows future retirements advised by generator operators, and compared to generation retirements in recent years.

Figure 18 Actual and forecast retiring generation capacity, 2021 to 2034 (MW)



Based on participant advice, the following generators have announced retirements over the ESOO horizon:

- Torrens Island B (800 MW) in South Australia on 30 June 2026[27] (Unit B1 is advised to remain mothballed[28] until then),
- Eraring (2,880 MW) in New South Wales on 19 August 2027,
- Osborne (124 MW) in South Australia on 31 December 2027,
- Yallourn W (1,450 MW) in Victoria on 1 July 2028,
- Port Lincoln GT (73.5 MW) and Snuggery (63 MW) in South Australia on 1 January 2028 (both are advised to remain mothballed until then),
- Dry Creek GT (156 MW), Mintaro GT (90 MW) and Dalrymple BESS (30 MW) in South Australia in 2030,
- Callide B (700 MW) in Queensland in 2031,
- Bayswater Power Station (2,715 MW) and Vales Point B (1,320 MW) in New South Wales in 2033,
- Mt Stuart (292 MW) in Queensland and Somerton (170 MW) in Victoria in 2033,
- Ballarat Energy Storage System, Gannawarra Energy Storage System and Queanbeyan BESS (65 MW combined) in 2033,
- Roma Power Station and Barcaldine Power Station (117 MW total) in Queensland in 2034, and
- Lake Bonney Battery Energy Storage (25 MW) in South Australia in 2034.

3.3 Generator seasonal capability

AEMO collects existing and committed scheduled and semi-scheduled generation capabilities over the next 10 years to capture seasonal generator availability. Scheduled capacity values are collected for three seasonal periods, where generator operators and proponents provide ratings consistent with the ambient temperatures associated with the following periods:

- **Summer peak** – applies to near-maximum demand periods (minimum of five days per year), where generator ratings are reflective of the ambient conditions associated with 10% POE maximum demand events (typically at temperatures 37°C or greater for mainland regions, depending on the region).
- **Typical summer** – aligned with average summer temperatures and is applied in all other summer periods (November to March for mainland regions, December to February for Tasmania). Ambient conditions across these periods are in excess of 30°C, and between 5°C and 10°C cooler than those that define summer peak.
- **Winter** – applied to all non-summer periods.

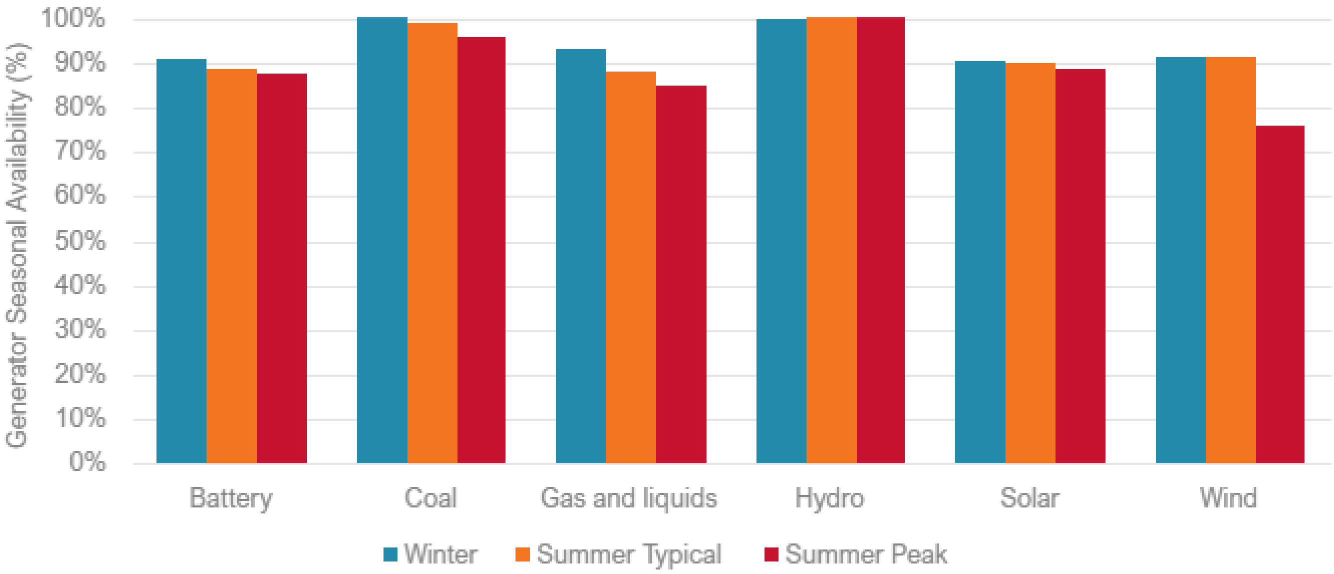
[27] AGL has reported ongoing discussions with the South Australian Government regarding a potential extension of Torrens Island B Power Station for two years. Such an extension could resolve reliability gaps forecast in South Australia in 2026-27 and 2027-28, however the official closure date of 30 June 2026 has been applied in all ESOO analysis in the absence of formal advice to extend. See AGL's Annual Report, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/who-we-are/our-company/250813-2-agl-energy-limited-annual-report-2025.pdf?a=d.

[28] Mothballing refers to when generating units are unavailable for service but can be brought back with appropriate notification, typically weeks or months. While these mothballed generators are not formally retired, the operator has advised that it is not its current intent or expectation to operate these units.

In addition to the above seasonal definitions that define temperature derated available capacity, most generators are subject to energy production limits, and VRE generators are also subject to the availability of wind and solar resources and their variability across hourly, seasonal, and annual timeframes.

Figure 19 shows average winter, typical summer, and summer peak availability relative to nameplate capacity by type of generation. It generally indicates the reduced availability reported in summer peak temperatures compared to winter and typical summer conditions. This is especially noticeable for wind generators, due to some reporting severe high temperature cut-offs for this generation category, including up to 100% derating during summer peak temperatures. See the *ESOO and Reliability Forecast Methodology Document*[29] for more detail about generation availability.

Figure 19 Season availability for various generation technologies relative to nameplate capacity



3.4 Generator unplanned outage rates

AEMO conducts an annual survey to collect information on unplanned outages from all existing scheduled production units. Participants provide historical data detailing the timing, duration and cause of all unplanned outages that occurred in the last year. Operators of coal and large gas-powered generators also submit unplanned outage rate (UOR) projections, taking into account expected changes in plant reliability as units age, approach retirement, or undergo maintenance.

AEMO reviews these projections against historical outages and consultant derived projections[30]. In limited circumstances where operator-provided projections are misaligned with historical and consultant derived trends, and/or are not sufficiently justified, AEMO applies consultant projections in consultation with each relevant operator. For gas, liquid-fuelled, hydro and battery units, which often operate infrequently, AEMO applies

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

[30] AEP Elical, *Assessment of Ageing Coal-Fired Generation Reliability*, June 2020, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

technology-level UORs based on the average performance of the relevant technology category over the past four years, or in the case of batteries, three years.

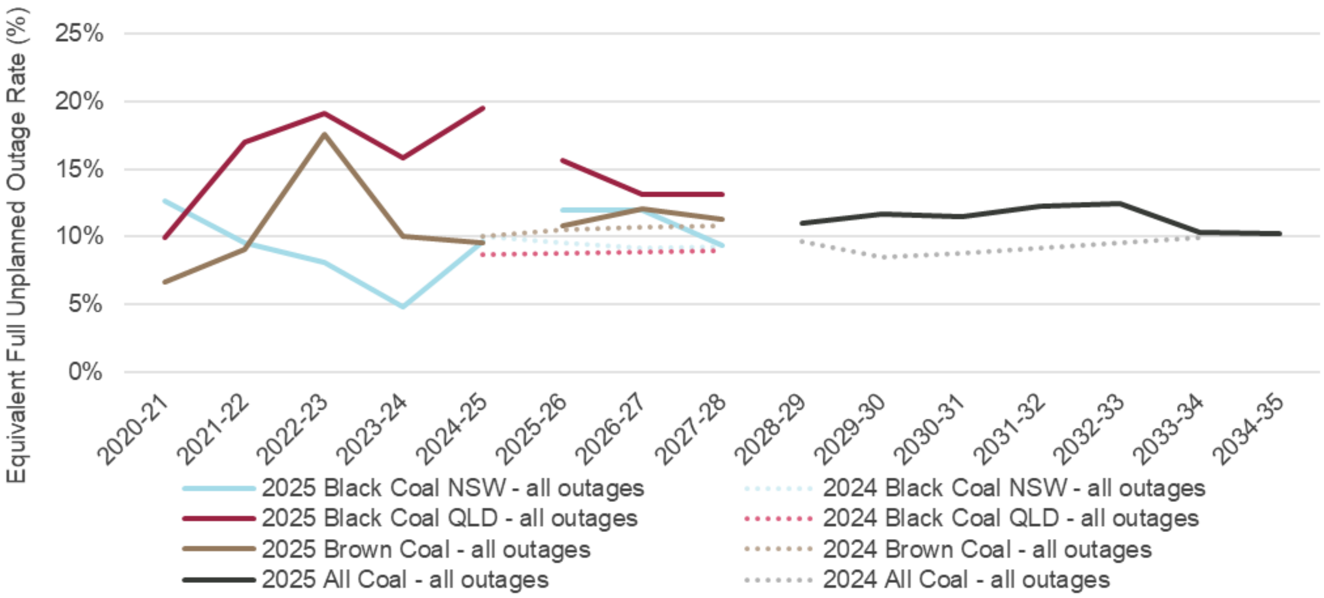
Using this information, AEMO has developed projections of full and partial UORs across the 10-year ESOO outlook period consistent with the consulted on *ESOO and Reliability Forecasting Methodology*[31].

The consulted on ESOO methodology for reliability assessments considers only unplanned outages, and not planned outages. This methodology assumes that participants will always schedule planned outages optimally, such that they never overlap periods of supply scarcity.

AEMO's forecasting accuracy assessments[32] have, however, identified that planned outages are regularly occurring during periods of supply scarcity. An operational sensitivity is included in **Section 5.3** to explore the impact of planned outages on generator availability, energy production and power system reliability. Given the changing nature of power system supply arrangements, AEMO may consider the role of planned outages in the *ESOO and Reliability Forecast Methodology* for future ESOO publications.

Figure 20 and **Figure 21** show the 10-year projections for equivalent full UORs across aggregated types of generation technologies, incorporating full outages, partial outages and long-duration outages (those lasting more than five months). Further details on the long duration UORs are available in the 2025 IASR[33]. To protect confidentiality, UORs are presented at the aggregated technology level only. Due to a declining number of coal power plants in some regions, coal UORs are combined into an 'All Coal' category from 2028-29 onwards.

Figure 20 Actual and projected equivalent full unplanned outage rates for coal generation technologies, 2020-21 to 2034-35

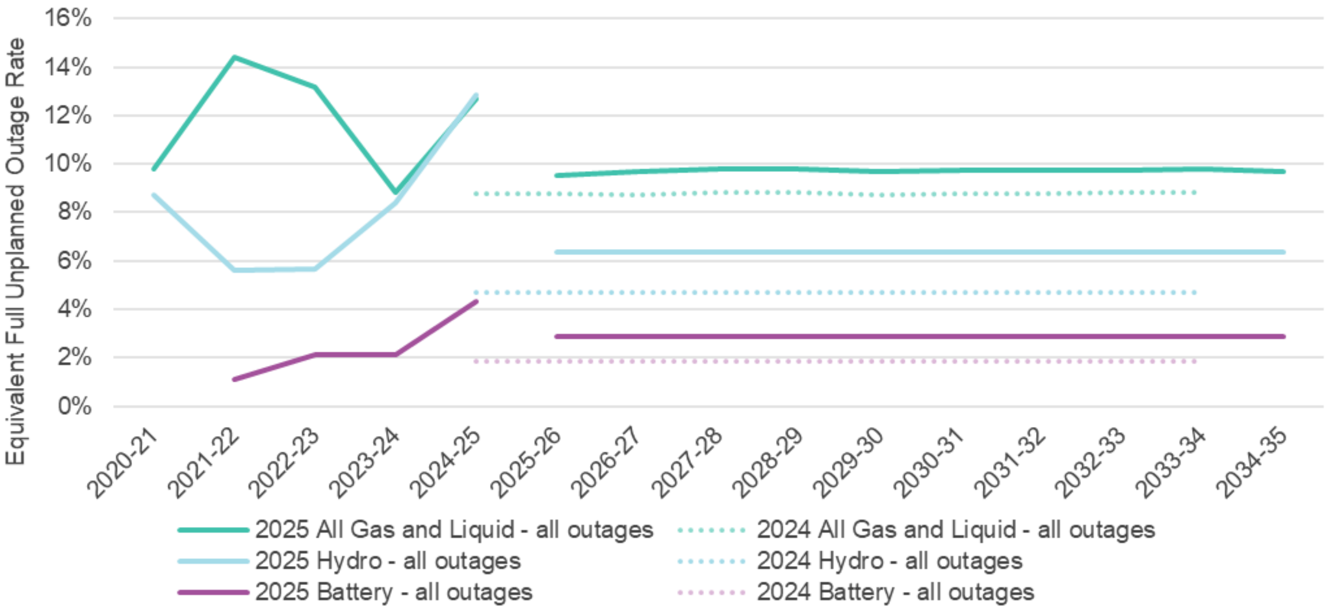


[31] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[32] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

[33] At https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

Figure 21 Actual and forecast equivalent full unplanned outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2020-21 to 2034-35



While strong trends are not evident in historical outage rates, a notable increase in equivalent full UORs observed in 2024-25 has resulted in higher forecast UORs than those presented in the 2024 ESOO.

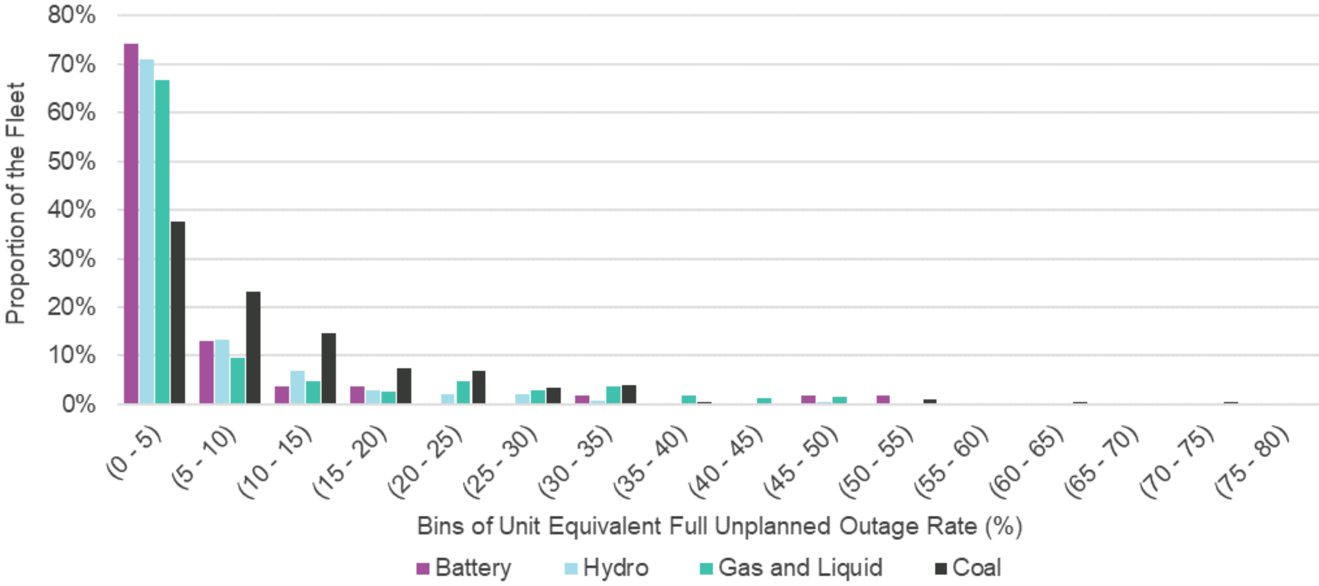
Coal generators are projected to have the highest UORs of all scheduled generation technologies. These rates are expected to decline over the forecast period as aging plants retire in line with current schedules, improving the average reliability of the remaining fleet. In Queensland, some black coal units have experienced extended long duration unplanned outages in recent years, which has significantly increased the historical UORs for the fleet. These prolonged outages are not expected to occur as frequently in the future; hence these are less evident over the forecast horizon. In addition, participants have advised that the Queensland Government's Electricity Maintenance Guarantee Scheme[34] will improve the performance and reliability of the Queensland coal fleet from 2025-26 onwards.

Gas and liquid-fuelled generators generally show moderate UORs, while hydro generators maintain relatively low UORs. In recent years, battery technologies have experienced increased UORs as more facilities have become operational, and forecasts reflect this upward trend.

While the aggregated-level UOR projections summarise fleet-level reliability by technology, **Figure 22** shows the distribution of individual units' equivalent full UORs for each technology type based on recent historical data. These distributions consistently highlight that while most units maintained low outage rates, a small number of units experienced high outage rates, driving the overall average outage rate upward across each technology.

[34] See https://statements.qld.gov.au/statements/101647.

Figure 22 Performance distribution: in-service coal, gas and liquid, hydro, and battery units' annual equivalent full unplanned outage rate between 2021-22 and 2024-25



3.5 Transmission capability and commissioning assumptions

The ESOO model applies a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM, as well as projecting potential future constraints across the ESOO time horizon with consideration of network investments that are considered committed or anticipated. These constraint equations act at times to limit interconnector transfer capacity, as well as intra-regional transfer capacity, to operate within the expected physical capability of the power system.

AEMO collects information from transmission project proponents, which is published on AEMO's Transmission Augmentation Information web page[35]. To determine if a transmission project is committed or anticipated, AEMO applied commitment criteria consistent with the *ISP Methodology*[36] and the AER's *Cost Benefit Analysis Guidelines* (and the Regulatory Investment Test for Transmission [RIT-T][37]).

Consistent with AEMO's *ESOO and Reliability Forecast Methodology Document*[38], **Table 7** shows the timing applied to the assumed commissioning of transmission infrastructure in both development outlooks.

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

[36] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[37] At https://www.aer.gov.au/system/files/2025-05/AER%20-%20Regulatory%20Investment%20Test%20for%20Transmission%20instrument%20-%202024%20-%20Version%203..pdf .

[38] See Section 2.6, 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.

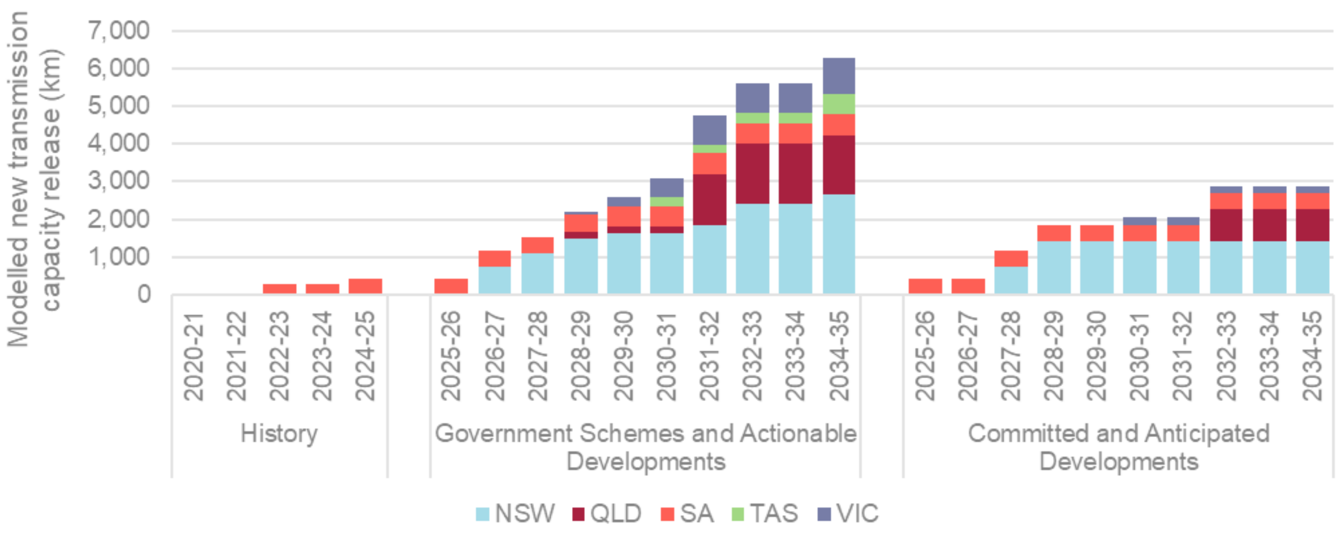
Table 7 Modelling implementation for new transmission developments

Development category	*Government Schemes and Actionable Developments*	*Committed and Anticipated Developments*
Existing and in commissioning	Applied consistent with operational advice [A]	Applied consistent with operator advice [A]
Committed	Applied at the full capacity release date advised by the developer.	Applied with a six-month delay to the full capacity release date advised by the developer [B].
Anticipated	Applied at the full capacity release date advised by the developer.	Applied with a 12-month delay to the full capacity release date advised by the developer.
Projects identified as Actionable as part of the 2024 ISP, or other actionable frameworks	Applied at the full capacity release date advised by the developer.	Not applied

A. Basslink, an existing transmission interconnector between Tasmania and Victoria, was modelled consistent with its technical limits, being a maximum flow of 594 MW northwards and 478 MW southwards, subject to daily energy limits as advised by the operator that reflect that maximum flows cannot be sustained indefinitely. This approach reflects the capability of the asset, rather than any bidding strategies that may apply while it operates as a Market Network Service Provider.
B. A six-month delay was applied to large transmission projects with an advised in-service timing after August 2026.

Figure 23 shows the committed, anticipated and actionable transmission construction assumed over the 10-year horizon in the two 2025 ESOO reliability assessments, associating all kilometres built with the assumed full capacity release date for each project. This new transmission is in addition to the over 40,000 km of existing transmission lines and cables that provides the interconnected backbone of the NEM. The *Committed and Anticipated Developments* assessment included nearly 3,000 km of new transmission developments, while the *Government Schemes and Actionable Developments* assessment considered 6,000 km, with most developments in New South Wales and Queensland.

Figure 23 Cumulative new transmission capacity release assumed over the 10-year ESOO horizon



Transmission developments that are significant for the *Committed and Anticipated Developments* assessment included:

- Stage 2 of Project EnergyConnect, a new interconnector between New South Wales, Victoria and South Australia, which begins releasing capacity from February 2027 and completes by December 2027, and

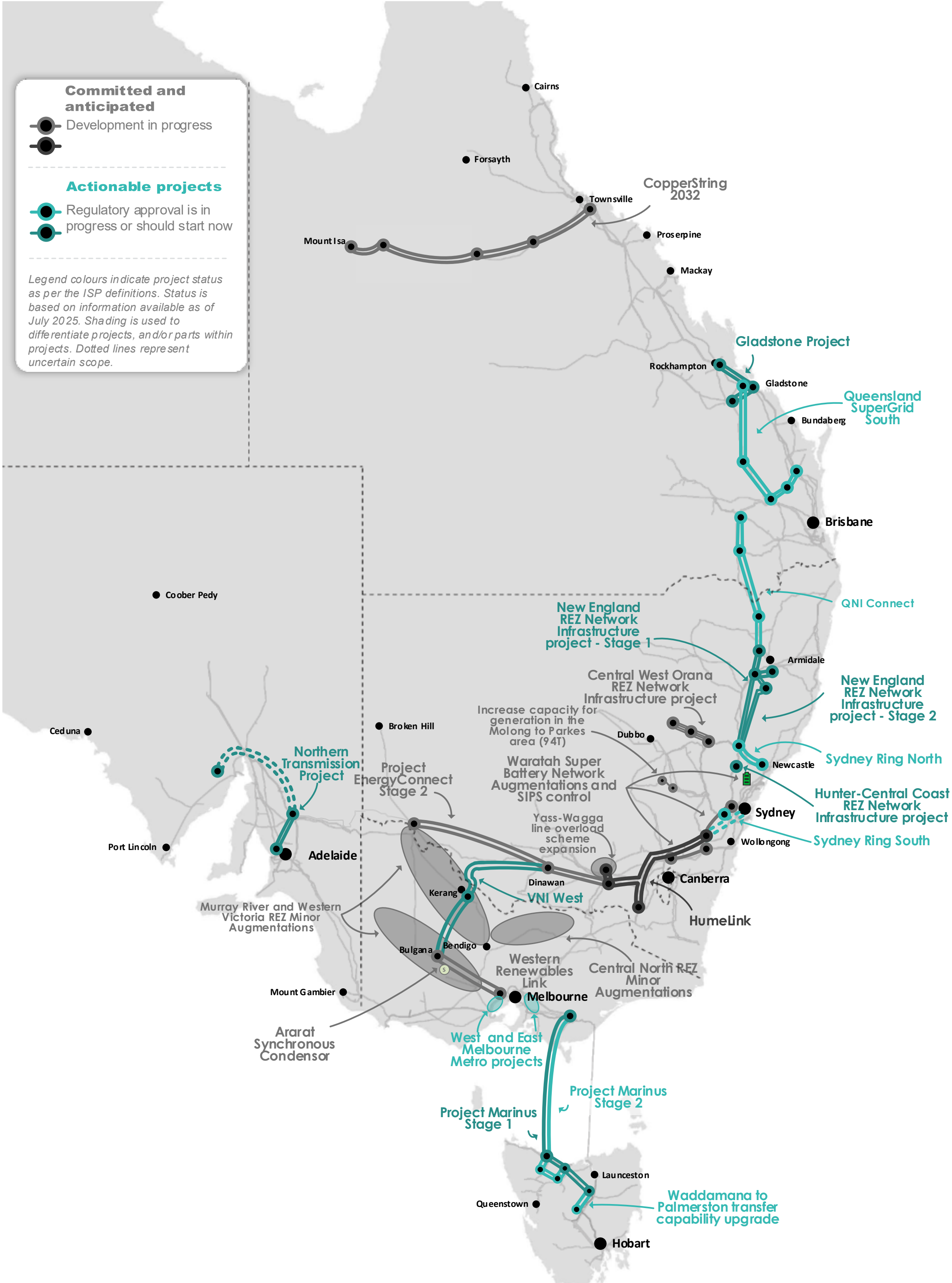
- HumeLink, in New South Wales, which releases full capacity in December 2027.

Further transmission developments that are significant for the *Government Schemes and Actionable Developments* assessment included:

- Marinus Link, an actionable interconnector project between Victoria and Tasmania, which releases full capacity on the first cable in December 2030,
- VNI West, an actionable interconnector project between Victoria and New South Wales, which releases full capacity in December 2031, and
- Queensland to New South Wales Interconnector (QNI) Connect, an actionable interconnector project between Queensland and New South Wales, which releases full capacity in March 2033.

Figure 24 shows all committed, anticipated and actionable projects on a map. A list of all considered projects is in the Excel workbook that accompanies this publication.

Figure 24 Map of network investments considered by status



† Grey bubbles indicate anticipated and committed REZ augmentation projects that may include non-network augmentations. Teal bubbles indicate transmission projects that are progressing through other relevant regulatory processes and are included in the Actionable Transmission sensitivity. Dotted lines represent uncertain scope.

3.6 Transmission reliability assumptions

In forecasting the reliability of the NEM in the ESOO, AEMO applied transmission unplanned outage constraints to account for the potential impacts of single credible contingencies and reclassification events on certain inter-regional transmission flow paths. Consistent with the NER 3.9.3C definition of USE, AEMO did not consider any planned or unplanned outages on transmission elements that do not contribute to inter-regional energy transfer. For more information on the modelling of transmission outages, see the *ESOO and Reliability Forecasting Methodology*[39].

Table 8 shows the rates used in the 2025 ESOO. All rates are annual and static over the 10-year horizon, except for those on the Mortlake – South East flow path. The rates for this path are set to zero when Project Energy Connect Stage 2 is modelled to release full capacity, as the impact of a single circuit outage is less impactful when there are more circuits interconnecting South Australia.

Table 8 Projected unplanned outage rates for inter-regional transmission flow paths

Flow path	2025 ESOO transmission unplanned outage rate (%)	2025 ESOO Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (New South Wales to Queensland) Credible Contingency	0.29	21.1	Annual static
Liddell – Bulli Creek (New South Wales to Queensland) Reclassification	1.76	3.9	Annual static
Murraylink – Credible Contingency	1.32	65.3	Annual static
Basslink – Credible Contingency	4.53	189.5	Annual static
Mortlake – South East (Victoria to South Australia) Credible Contingency	0.03	2.2	Annual, set to 0% post Project EnergyConnect Stage 2
Mortlake – South East (Victoria to South Australia) Reclassification	0.01	4.7	Annual, set to 0% post Project EnergyConnect Stage 2

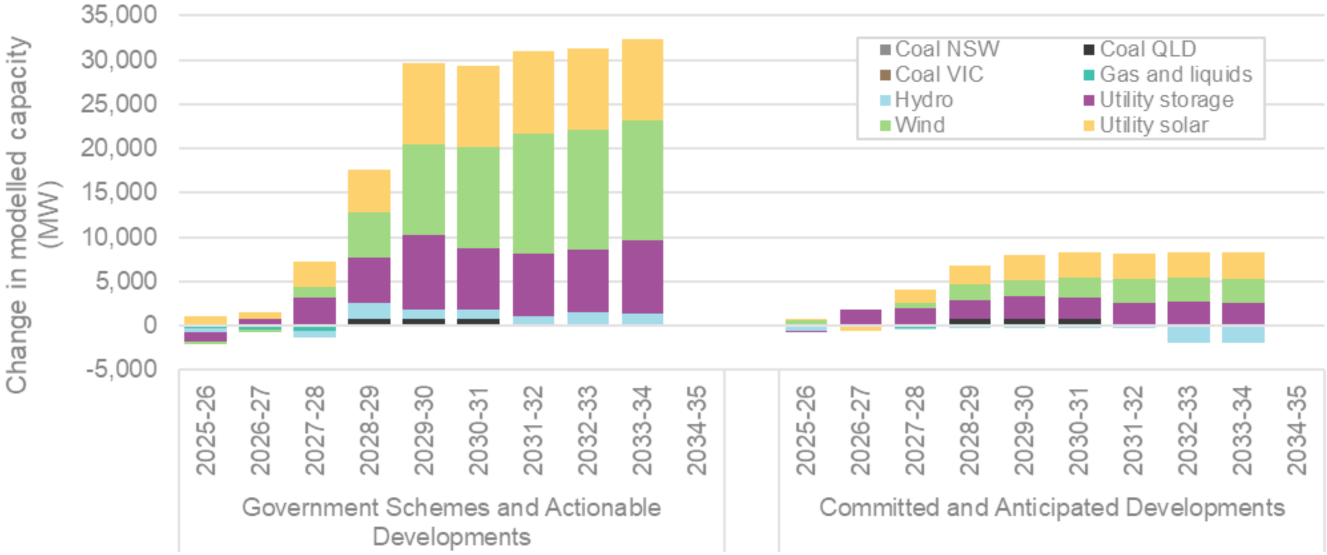
3.7 Capacity developments have progressed significantly since the 2024 ESOO

Compared to the 2024 ESOO, the 2025 reliability assessments include significantly more generation and storage developments over the 10-year horizon, as a record number of projects progress sufficiently against AEMO's commitment criteria. In addition, RETAs negotiated between the Federal Government and most states and territories are firming the location, capacities and technologies anticipated to be delivered under government schemes.

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

Figure 25 shows the aggregate difference in summer typical capacity between the reliability assessments included in this ESOO and those in the 2024 ESOO.

Figure 25 Change in capacity considered in each outlook relative to the 2024 ESOO



For the *Government Schemes and Actionable Developments* reliability assessment, more than 30 GW of additional capacity was assumed to develop over the 10-year horizon, relative to the 2024 ESOO. These are key insights:

- At the beginning of the horizon, further delays are noted relative to the *Committed and Anticipated Developments* assessment, where participants awarded a contract as part of a considered Federal or state scheme have revised their full commercial use date expectations.
- Since the 2024 ESOO, many more RETAs have been signed between the Federal Government and most states and territories as part of the CIS, allowing AEMO to model this scheme in far greater detail. The equivalent assessment in the 2024 ESOO included all awarded CIS projects, but the 2025 ESOO included the achievement of these RETAs by building any capacity required – but not yet awarded – in 2028-29 and 2029-30. The RETAs total more than 18 GW of capacity, while 7 GW has been awarded so far. Future generation and storage projects are assumed to be well located in relevant renewable energy zones that can operate largely unconstrained.
- The equivalent assessment in the 2024 ESOO included awarded projects, firming targets and long duration targets as part of the New South Wales Infrastructure Investment Objectives (IIO) Report. The 2025 ESOO includes the same New South Wales targets, some of which are expanded, and now also includes renewable generation targets (nearly 6 GW more capacity across a variety of technologies).
- The 2025 ESOO includes in this assessment Victorian offshore wind targets (2 GW by 2032 and 4 GW by 2035), which are expected to be supported by a delivery mechanism.
- Some projects listed in the 2025 Queensland budget are included for the first time in 2025, including Mount Rawdon (2,040 MW/20,000 MWh) and Big T (400 MW/4,000 MWh) pumped hydro projects.

For the *Committed and Anticipated Developments* reliability assessment, more than 10 GW (nameplate capacity) of developments have progressed sufficiently to be considered committed or anticipated since the 2024 ESOO. Conversely, a small number of projects previously considered committed or anticipated no longer meet the criteria, or have been discontinued. These are key insights:

- At the beginning of the horizon, some delays are noted where participants have revised their submitted full commercial use date, resulting in a negative change in capacity.
- Between 2028-29 and 2030-31, a positive change in Queensland coal capacity is shown due to the change of expected closure year of Callide B from 2028 to 2031.
- From 2032-33, a negative change in hydro capacity is shown due to the revised full commercial use date for Borumba pumped hydro in Queensland, from 2032 to 2035.
- There is 2,910 MW/7,118 MWh of additional utility storage capacity considered, including the following projects which are larger than 250 MW:
  - Supernode BESS unit 1 (260 MW/ 620 MWh) and unit 2 (260 MW / 1240 MWh) expected for full commercial use in December 2025 and June 2026 respectively in Queensland,
  - Pine Lodge BESS (250 MW/550 MWh) in Victoria in October 2026,
  - Gnarwarre BESS (290 MW/550 MWh) in Victoria in June 2027, and
  - Mortlake Energy Hub BESS (316 MW/1,200 MWh) in Victoria in December 2027.
- There is 3,969 MW of additional utility solar capacity considered, including the following projects which are larger than 250 MW:
  - Aldoga Solar Farm (387 MW) in Queensland in November 2025,
  - Punch's Creek Renewable Energy (799 MW) in Queensland in January 2026,
  - Goorambat East Solar Farm (250 MW) in Victoria in October 2026,
  - Goulburn River Solar Farm (588 MW) in New South Wales in March 2027,
  - Northern Midlands Solar Farm (361 MW) in Tasmania in October 2027,
  - Mortlake Energy Hub (334 MW) in Victoria in December 2027, and
  - Haughton Solar Farm Stage 2 (300 MW) in Queensland in January 2028.
- There is 2,982 MW of additional wind capacity considered, including:
  - Golden Plains Wind Farm West (557 MW) in Victoria in February 2027,
  - Coppabella Wind Farm (290 MW) in New South Wales in September 2027,
  - Lotus Creek Wind Farm (285 MW) in Queensland in December 2027,
  - Gawara Baya Wind Farm (408 MW) in Queensland in October 2028, and
  - three units of Valley of the Winds (919 MW total) in New South Wales to come online in steps in December 2029, April 2030 and July 2030.
- There is 137 MW of additional gas capacity considered, including:

  - Hunter Economic Zone (20 MW) in New South Wales, which is currently operational, and
  - Lockyer Valley Energy Project (117 MW) in Queensland, expected to be operational by February 2028.
- Numerous projects are no longer included in this assessment as they have been discontinued, or have been reassessed as no longer meeting the relevant commitment criteria due to changes to the project proposal, resulting in a less advanced commitment categorisation:
  - Hydrogen Jobs Plan (204 MW) in South Australia,
  - Mt Fox BESS (300 MW/600 MWh) in Queensland,
  - Saphire Wind Farm battery (30 MW/38 MWh) in New South Wales,
  - Tamworth Solar Farm (65 MW) in New South Wales, and
  - Cultana Solar Farm (358 MW) in South Australia.

4 Reliability assessments

This chapter provides AEMO's 10-year reliability assessments under different sensitivities, which include different levels of supply with varying degrees of development certainty.

- The ***Government Schemes and Actionable Developments*** assessment considered whether the combination of market led, and government assisted developments – including all those government schemes with current delivery mechanisms – are sufficient to meet the level of demand forecast by the *Step Change* scenario.
- The ***Committed and Anticipated Developments*** assessment considered whether only those developments which are sufficiently progressed to be considered 'committed' or 'anticipated' are sufficient to meet the level of demand forecast by the *Step Change* scenario.

The assessments affirm that continued investments in supply developments are required to maintain reliability to replace retiring capacity and to support forecast load developments.

Table 9 lists key parameters of the two ESOO reliability assessments.

Table 9 Key parameters of the 2025 ESOO reliability assessments

Parameter	*Government Schemes and Actionable Developments*	*Committed and Anticipated Developments*
Demand forecast	*Step Change* demand forecasts are applied to both assessments.	
Generation and storage developments	On time delivery of all in commissioning, committed, anticipated developments. The on time delivery of government schemes supported by delivery mechanisms.	Delivery of all in commissioning, committed and anticipated developments, subject to recently observed commissioning delays.
Generation and storage retirements	Retirements applied at the dates advised by operators for both assessments.	
Transmission developments	On time delivery of all committed, anticipated and actionable transmission developments.	Delivery of all committed and anticipated transmission developments, subject to recently observed commissioning delays.
CER coordination and demand flexibility	The uptake of CER coordination and demand flexibility as projected by AEMO's IASR.	The currently committed levels of CER coordination and demand flexibility only.
Operability assumptions	No generator or transmission maintenance considered. No limits on gas, coal or other fuel availability. Expected USE reflects average outcomes for all 23 weather reference years modelled.	

4.1 With government schemes and actionable developments, reliability standards are forecast to be met in most years

The *Government Schemes and Actionable Developments* assessment considered whether the combination of committed and anticipated market-led developments, and government-assisted developments supported by schemes with active delivery mechanisms, are sufficient to meet the demand forecast in the *Step Change* scenario.

In this reliability assessment, the following assumptions were applied:

- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the project developer.
- Actionable transmission developments were included at the full commercial use date advised by the project developer.
- The generation and storage developments supported by government schemes listed in **Table 6** (in **Section 3.1**) were applied at the dates targeted by governments. Where a specific recipient has not been announced, the projects were assumed to be developed in available renewable energy zones, or in relatively strong and available parts of the existing power system. For storage projects, the minimum storage duration was applied. For schemes that have not yet awarded recipients, the recipient was assumed to be additional to those projects already committed or anticipated.
- Forecast growth in coordinated consumer energy resources and flexible demand resources (including DSP, VPP and V2G projections) were applied in this assessment as forecast, in addition to existing and committed DSP, VPP and V2G developments.
- All other assumptions aligned with the *Committed and Anticipated Developments* reliability assessment described in **Section 4.2**

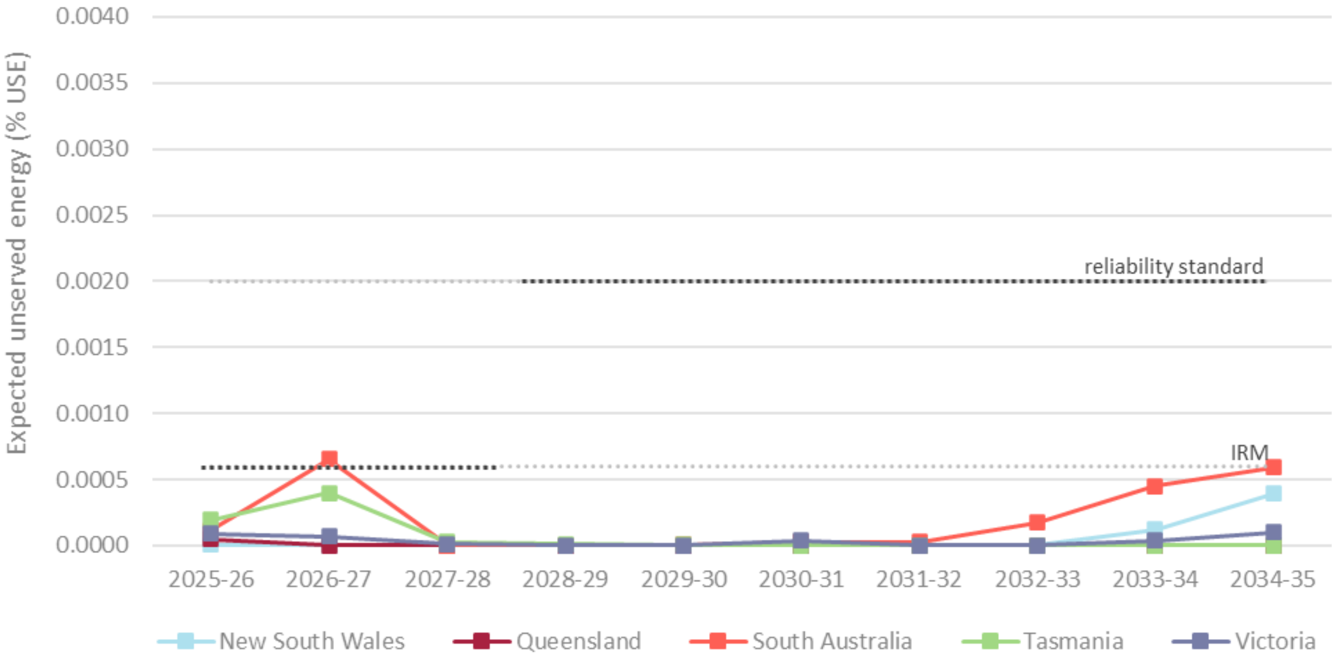
While this reliability assessment includes a significant level of new capacity, supported by a range of existing schemes under active development, there are numerous other government schemes still in development that have the potential to bring forward additional proposed projects. Additional schemes that are not yet sufficiently advanced to consider in this assessment include:

- **CIS (Federal)**, which seeks to unlock a total of approximately 40 GW of generation capacity – the assessment includes 18.4 GW only, including all tendered projects and the capacities agreed through RETAs,
- **Firm Energy Reliability Mechanism (South Australia)**, which is currently under active consultation and will seek to support long duration firm capacity,
- **Renewable Energy Targets (Victoria and Tasmania)**, which are schemes that do not yet specify a detailed delivery mechanism, and
- Further developments to support the Federal Government's commitment to increase renewable energy generation to 82% of NEM supply by 2030.

Figure 26 shows the results of the *Government Schemes and Actionable Developments* reliability assessment.

This reliability assessment demonstrates that with committed and anticipated developments and those currently supported by various government schemes, including actionable transmission projects and coordinated CER developments, there is expected to be sufficient capacity to meet the relevant reliability standards in most years of the forecast, so long as the developments are delivered in full, and on time to their currently advised schedules.

Figure 26 Expected USE for the *Government Schemes and Actionable Developments* reliability assessment, 2025-26 to 2034-35 (% USE)



Key regional insights from this assessment are as follows:

- In New South Wales:
  - From 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances by existing generation, and the expected commissioning of the 750 MW Hunter Power Station in advance of summer 2025-26.
  - In 2027-28 USE remains within the IRM after the retirement of Eraring Power Station (2,880 MW). The commissioning of a significant number of wind, solar and storage projects mitigate an increase in reliability risks associated with the retirement of Eraring Power Station, but system security challenges associated with this closure remain unresolved (see **Section 5.1**).
  - Reliability risks continue to remain low over the horizon due to the assumed commissioning of new projects such as Phoenix Pumped Hydro (800 MW/11,990 MWh), and the advised full commissioning of Snowy 2.0 (2,200 MW/350,000 MWh) in 2028-29.
  - Over the forecast horizon, demand is forecast to grow due to increase in industrial electrification and data centre demand, however reliability risks remain low due to the assumed completion of projects supported by the CIS and New South Wales roadmap, including an additional 7,100 MW of renewable energy capacity and 1,300 MW/5,200 MWh of dispatchable storage capacity.
  - From 2031-32, the actionable VNI West project is advised to commission, increasing transfer capacity from Victoria to New South Wales by approximately 1,900 MW, increasing inter-regional support from Victoria.

  - From 2032-33, the actionable QNI Connect project is advised to commission, increasing transfer capacity from Queensland to New South Wales by approximately 1,700 MW, increasing inter-regional support from Queensland.
  - From 2033-34, reliability risks increase due to the advised retirement of Bayswater (2,173 MW) and Vales Point (1,320 MW) power stations, however expected USE remains within the reliability standard due to the large number of transmission, generation and storage projects included in advance of these retirements.
- In Queensland:
  - In 2025-26, reliability risks are forecast within the IRM of 0.0006% USE due to the on time commissioning of Kidston Pumped Hydro (250 MW/2,000 MWh) and Swanbank Power Station battery (250 MW/500 MWh).
  - From 2028-29, reliability risks remain low due to the assumed commissioning of Big-T Pumped Hydro (400 MW/4,000 MWh) and Brigalow Gas Turbine (400 MW), as identified in the 2025 Queensland budget.
  - In 2031, Callide B (750 MW) is advised to retire, however reliability risks remain low from this point due to the assumed commissioning of Mt Rawdon Pumped Hydro (2,040 MW/20,000 MWh).
  - From 2032-33, the actionable QNI Connect project is advised to commission, increasing transfer capacity from New South Wales to Queensland by 1,260 MW, mitigating reliability risks associated with upcoming retirements in the region, including Mt Stuart (280 MW on 31 December 2033), Barcaldine and Roma (totalling 117 MW on 31 December 2034).
- In South Australia:
  - In 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances from the existing generation fleet.
  - In 2026-27, reliability risks are forecast above the IRM, due to the advised retirement of Torrens Island B[40] (800 MW), however the advised release of 350 MW of Project EnergyConnect capacity offsets some of this capacity withdrawal.
  - From 2027-28, reliability risks decrease due to the assumed full commissioning of Project EnergyConnect Stage 2, enabling 800 MW transfer capacity between New South Wales and South Australia, mitigating the expected reliability risks from the retirements of Torrens Island B (800 MW on 30 June 2026) and Osbourne Power Station (180 MW on 31 December 2027).
  - From 2029-30, demand in South Australia is forecast to increase rapidly due to significant growth in LILs. Despite this strong load growth, reliability risks remain low due to the assumed commissioning of additional projects supported by the CIS, including 1,200 MW of renewable energy developments and 900 MW/ 3,600 MW of dispatchable storage developments.
  - From 2030-31, Dry Creek (156 MW) and Mintaro (90 MW) gas generators are advised to retire.
  - From 2032-33, reliability risks start increase due to continued demand growth.

[40] AGL has reported ongoing discussions with the South Australian Government regarding a potential extension of Torrens Island B Power Station for two years. Such an extension could resolve reliability gaps forecast in South Australia in 2026-27 and 2027-28, however the official closure date of 30 June 2026 has been applied in all ESOO analysis in the absence of formal advice to extend. See AGL's Annual Report, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/who-we-are/our-company/250813-2-agl-energy-limited-annual-report-2025.pdf?a=d.

- In Tasmania:
  - Expected USE remains below the IRM and reliability standard over the reliability forecast horizon.
  - In 2025-26 and 2026-27, reliability risks are elevated due to advised winter unavailability of both Cethana (85 MW) and Poatina (300 MW) hydro power stations.
  - Reliability risks in Tasmania are forecast to occur mostly in winter, during high demand periods with coincident generator and Basslink outages, when there is not enough available capacity in Tasmania to meet its load.
  - In 2030-31, the actionable Project Marinus Stage 1 project is expected to commission, enabling an additional 750 MW transfer capacity between Tasmania and Victoria, improving reliability results in both regions.
  - From 2034-35, the actionable Project Marinus Stage 2 project is expected to commission, releasing a further 750 MW of transfer capacity between Tasmania and Victoria.
- In Victoria:
  - From 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances from the existing generation fleet.
  - In 2028-29, Yallourn Power Station (1,450 MW) is advised to retire. Reliability risks remain low due to the assumed completion of a large number of renewable generation and storage projects.
  - By 2029-30, it is assumed that the state's RETA under the CIS of 5,000 MW of renewable generation and 1,700 MW/6,800 MWh of dispatchable storage will be commissioned.
  - In 2030-31, forecast demand is expected to increase, driven by industrial electrification and data centre demand, however the expected commissioning of the actionable Project Marinus Stage 1 project, enabling 750 MW of transfer capacity between Tasmania and Victoria, eases the impact of higher demand on reliability outcomes.
  - From 2031-32, the actionable VNI West project is expected to commission, increasing transfer capacity between New South Wales and Victoria. A further 2,000 MW of offshore wind is assumed, supported by Victoria's Offshore Wind Target.
  - From 2033-34, reliability risks slightly increase due to the advised retirement of Somerton gas generator (170 MW) and forecast demand growth.
  - In 2034-35, the actionable Project Marinus Stage 2 project is expected to commission, enabling a further 750 MW transfer capacity between Tasmania and Victoria.

Table 10 shows the additional capacity that would be required to reduce expected USE below the reliability standard and the IRM for the *Government Schemes and Actionable Developments* reliability assessment. This assessment considers each region separately, without any allowance for the ability for additional capacity to offset reliability gaps across regions. The values reflect the firm, dispatchable, continuously available, and fully unconstrained capacity required, noting that many generation and storage technologies in different locations can contribute to meeting this requirement with varied efficacy. Consistent with the favourable reliability outlook, firm capacity requirements are only identified in one region, for one year, in this assessment.

Table 10 Additional firm capacity required to meet the reliability standards, *Government Schemes and Actionable developments* (MW)

Standard	Region	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
IRM of 0.0006% USE	New South Wales	-	-	-	-	-	-	-		-	-
	Queensland	-	-	-	-	-	-	-	-	-	-
	South Australia	-	25	-	-	-	-	-	-	-	-
	Tasmania	-	-	-	-	-	-	-	-	-	-
	Victoria	-	-	-	-	-	-	-	-	-	-
Reliability standard of 0.002% USE	New South Wales		-	-	-	-	-	-	-	-	-
	Queensland	-	-	-	-	-	-	-	-	-	-
	South Australia	-	-	-	-	-	-	-	-	-	-
	Tasmania	-	-	-	-	-	-	-	-	-	-
	Victoria	-	-	-	-	-	-	-	-	-	-

Note: cells coloured in red reflect the relevant reliability standard applicable for that year.

4.2 Committed and anticipated developments alone are insufficient to meet reliability standards

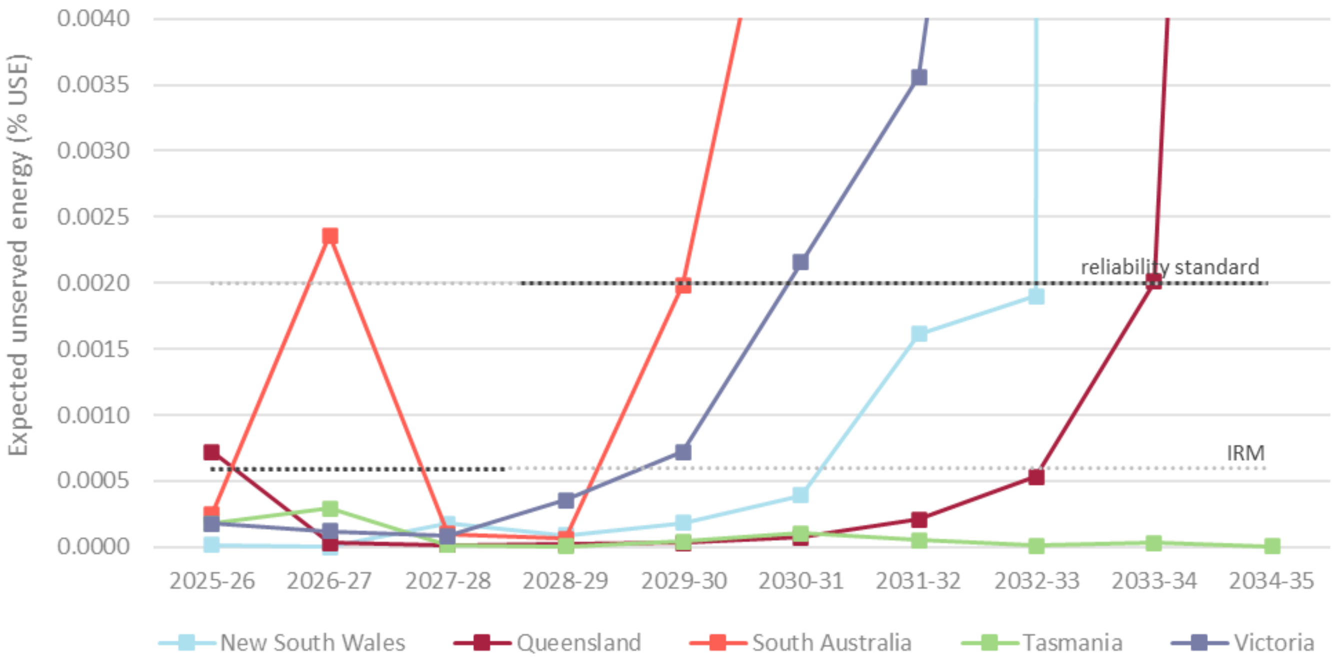
The *Committed and Anticipated Developments* reliability assessment is AEMO's reliability forecast and indicative reliability forecast in this 2025 ESOO. It applies for the purposes of the RRO and AEMO's summer readiness preparations. This is not a prediction of what will eventuate over the 10-year forecast horizon, because there are many projects in the pipeline of developments and many state and federal schemes currently supporting further investment. However, as AEMO's reliability forecast and indicative reliability forecast, it may be used by AEMO, governments and industry to prepare actions to mitigate these forecast reliability risks.

In this reliability assessment, the following assumptions were applied:

- The generation and storage developments and schemes listed as 'committed' or 'anticipated' in **Table 5** (in **Section 3.1**) were applied subject to default development delays.
- Committed and anticipated generation and transmission projects were applied subject to default development delays.
- Only existing and committed levels of coordinated consumer energy resources and flexible demand resources (including DSP, VPP and V2G) were applied.

Figure 27 shows the results of the *Committed and Anticipated Developments* reliability assessment.

Figure 27 Expected USE for the *Committed and Anticipated Developments* reliability assessment, 2025-26 to 2034-35 (% USE)



In this reliability assessment, forecast reliability risks are higher across the forecast horizon in all mainland regions compared to the *Government Schemes and Actionable Developments* assessment, due to:

- later commissioning of committed and anticipated generation and storage projects, reflecting recently observed delivery delays (See **Section 3.1** for more detail),
- reduced transmission capabilities, without actionable transmission projects being developed, and
- reduced capacity with only committed and anticipated projects, without additional capacity supported by federal and state government schemes.

With only committed and anticipated generation developments, and recognising delivery delays that have been observed recently, all mainland regions have expected USE over the reliability standard by 2033-34 or earlier, due to insufficient committed or anticipated developments to replace several large generator retirements currently advised across the NEM, combined with demand growth. Without additional developments, significant supply shortfalls are anticipated.

Key regional insights from this assessment are as follows:

- In New South Wales:
  - From 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances by existing generation, and the expected commissioning of the 750 MW Hunter Power Station in advance of summer 2025-26.
  - The reliability gap previously forecast in 2027-28 following the advised retirement of the 2,880 MW Eraring Power Station is no longer forecast. This gap is no longer forecast due to a reduction in forecast maximum

demand for this year, and the significant number of well-located batteries (totalling 3,001 MW/ 8,173 MWh) expected to commission in advance of this retirement.

  – In 2028-29, risks decrease slightly following the capacity release of HumeLink and Snowy2.0 (2,200 MW/ 350,000 MWh).
  – From 2031-32, reliability risks increase, following forecasts for higher maximum demand and the retirement of Callide B in Queensland.
  – In 2033-34, reliability risks increase significantly due to the advised retirement of both Bayswater (2,173 MW) and Vales Point (1,320 MW) power stations, signalling that investments beyond those currently committed and anticipated are required to provide for a reliable power system.
- In Queensland:
  – In 2025-26, reliability risks are forecast above the IRM of 0.0006% USE. This reliability gap was not previously forecast but has emerged due to an upward revision to maximum demand forecasts in Queensland (reflecting recent consumer trends during periods of high demand), higher black coal generator unplanned outage rates (reflecting recent poor performance for numerous coal generators), and reduced availability from both Townsville and Condamine steam turbines.
  – From 2026-27, reliability risks are forecast to return to levels below the IRM due to the return to service of Townsville and Condamine steam turbines (total 132 MW), commissioning in advance of summer of Kidston pumped hydro (250 MW), and battery developments totalling 1,460 MW/3,761 MWh.
  – In 2031-32, reliability risks start to increase due to demand growth and the advised retirement of the 700 MW Callide B Power Station. Reliability risks are greater in this 2025 ESOO assessment than in the 2024 ESOO assessment, due to increased maximum demand forecast and the inclusion of the Borumba Pumped Hydro project, which revised its commissioning date beyond the reliability forecast horizon period since the 2024 ESOO.
  – From 2033-34, Mt Stuart (423 MW) has advised expected retirement, alongside New South Wales's Bayswater and Vales Point power stations, further increasing reliability risks.
  – From 2034-35, Barcaldine (37 MW) and Roma (80 MW) are advised to have retired, further increasing reliability risks, signalling that investments beyond those currently committed and anticipated are required to provide for a reliable power system.
- In South Australia:
  – In 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances from the existing generation fleet.
  – In 2026-27, all units of Torrens Island B Power Station[41] (total 800 MW) are advised to retire, however the second stage of Project EnergyConnect – a new interconnector between New South Wales and South

[41] AGL has reported ongoing discussions with the South Australian Government regarding a potential extension of Torrens Island B Power Station for two years. Such an extension could resolve reliability gaps forecast in South Australia in 2026-27 and 2027-28, however the official closure date of 30 June 2026 has been applied in all ESOO analysis in the absence of formal advice to extend. See AGL's Annual Report, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/who-we-are/our-company/250813-2-agl-energy-limited-annual-report-2025.pdf?a=d.

Australia – is not modelled to release capacity, and insufficient alternative generation is scheduled to be commissioned to adequately replace the retiring capacity, resulting in expected USE above both the IRM and the reliability standard.

  – From 2027-28, Project EnergyConnect Stage 2 is advised to release its full 800 MW transfer capacity, reducing reliability risks associated with the advised retirement of both Torrens Island B (800 MW, on 30 June 2026) and Osborne Power Station (180 MW, on 31 December 2027).
  – From 2029-30, reliability risks are forecast above the IRM of 0.0006% USE due to a rapid increase in forecast demand, driven by a steep increase in forecast LILs.
  – From 2030-31, reliability risks continue to increase above the reliability standard of 0.002% due to the advised retirement of Dry Creek (156 MW) and Mintaro (90 MW) gas generators and continued demand growth.
- In Tasmania:
  – Expected USE remains below the IRM and reliability standard over the reliability forecast horizon.
  – In 2025-26 and 2026-27, reliability risks are elevated due to advised winter unavailability of both Cethana (85 MW) and Poatina (300 MW) hydro power stations.
  – Reliability risks in Tasmania mostly occur in winter. When USE is forecast, it is occurring during high demand periods with coincident generator and Basslink outages; during these periods there are some intervals with insufficient available capacity to meet forecast winter maximum demand.
- In Victoria:
  – From 2025-26, reliability risks are forecast within the IRM of 0.0006% USE, as demand is forecast to be met under most circumstances from the existing and in commissioning generation fleet.
  – The reliability gap previously forecast in 2028-29 following the advised retirement of the 1,450 MW Yallourn Power Station is no longer forecast. This gap is no longer forecast due to a reduction in forecast maximum demand for this year, and the significant number of well-located batteries (totalling 2,959 MW/7,541 MWh) expected to commission in advance of this retirement, even after considering potential development delays.
  – From 2029-30, reliability risks progressively increase in this outlook, due to growth in forecast demand and reducing inter-regional support due to retirements in neighbouring regions. Western Renewables Link is modelled to be available in this year, which will enable further generation developments, but it is not associated with direct reliability benefits itself.
  – In 2033-34, Somerton (170 MW) is expected to retire, exacerbating existing trends.

Table 11 shows the additional capacity that would be required to reduce expected USE below the reliability standard and the IRM for the *Committed and Anticipated Developments* reliability assessment. This assessment considers each region separately, without any allowance for the ability for additional capacity to offset reliability gaps across regions. The values reflect the firm, dispatchable, continuously available, and fully unconstrained capacity required, noting that many generation and storage technologies in different locations can contribute to meeting this requirement with varied efficacy.

Table 11 Additional firm capacity required to meet the reliability standards, *Committed and Anticipated Developments* (MW)

Standard	Region	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
IRM of 0.0006% USE	New South Wales	-	-	-	-	-	-	690	825	5,560	6,240
	Queensland	80	-	-	-	-	-	-	-	690	1,760
	South Australia	-	390	-	-	245	690	920	1,305	2,455	2,750
	Tasmania	-	-	-	-	-	-	-	-	-	-
	Victoria	-	-	-	-	110	775	1,105	1,820	2,780	4,005
Reliability standard of 0.002% USE	New South Wales		-	-	-	-	-	-	-	5,145	5,930
	Queensland	-	-	-	-	-	-	-	-	5	1,255
	South Australia	-	55	-	-	-	310	440	845	2,240	2,485
	Tasmania	-	-	-	-	-	-	-	-	-	-
	Victoria	-	-	-	-	-	55	400	1,165	2,195	3,500

Note: cells coloured in red reflect the relevant reliability standard applicable for that year.

4.3 Investments across multiple asset categories are required to deliver a reliable outlook

Considering only developments that are classified by AEMO as committed or anticipated, reliability gaps are forecast, with assessments of firm capacity requirements equalling approximately 6 GW in New South Wales alone. At the end of this *Committed and Anticipated Developments* reliability assessment, there are shortfalls in both generation capacity (instantaneous dispatchable generation output capability, measured in MW) and energy production (the capability to produce energy over minutes, hours, days and months, measured in MWh).

The *Government Schemes and Actionable Developments* reliability assessment, however, identifies that the majority of these reliability risks are resolved once a broad range of transmission, generation, storage and coordinated CER solutions are considered.

Both energy producing and dispatchable generation assets are required to meet forecast consumer demand

To illustrate the contributions of various technologies to reducing expected USE, AEMO undertook an analysis to identify indicative technology combinations that could help lower reliability risks to meet the reliability standard. **Figure 28** shows the additional capacity required in South Australia in 2030-31 under the *Committed and Anticipated Developments* reliability assessment where expected USE is forecast to exceed the reliability standard. A similar analysis for New South Wales, Queensland, and Victoria, focused on a selected year where expected USE exceeds the reliability standard, is available in the accompanying ESOO results workbook. Build ratios between VRE and storages were guided by the 2024 ISP, although they may not be optimal in this application.

This analysis was conducted under the following scope and assumptions:

- It did not consider any reliability improvements that could be achieved with transmission developments, CER coordination or DSP developments.
- It considered each region separately and did not consider the inter-regional reliability benefits of sharing new capacity. Actual capacity requirements may therefore be lower for some regions considering developments in neighbouring regions, the relative strength of inter-regional transmission, and the degree of coincidence for peak demands with neighbouring regions.
- It identified the capacity required assuming adequate transmission connectivity with fully unconstrained access to supply the major demand centres within each region. Actual capacity requirements may therefore be greater considering power system constraints.
- It considered the reliability needs of the region for the year of study in isolation, without consideration for the long-term requirements of the region and the impact of stored energy use on future supply conditions during near-peak conditions. Over the longer term, longer duration storage or energy generating plant may prove more effective at mitigating reliability risks that emerge less frequently, but require prolonged dispatch.

This analysis is not intended to recommend a specific technology mix or provide an optimised solution for addressing reliability risks across the forecast period.

Figure 28 Additional capacity required, considering a variety of technology combinations to reduce expected USE to the reliability standard, South Australia, *Committed and Anticipated Developments* assessment, 2030-31 (MW)

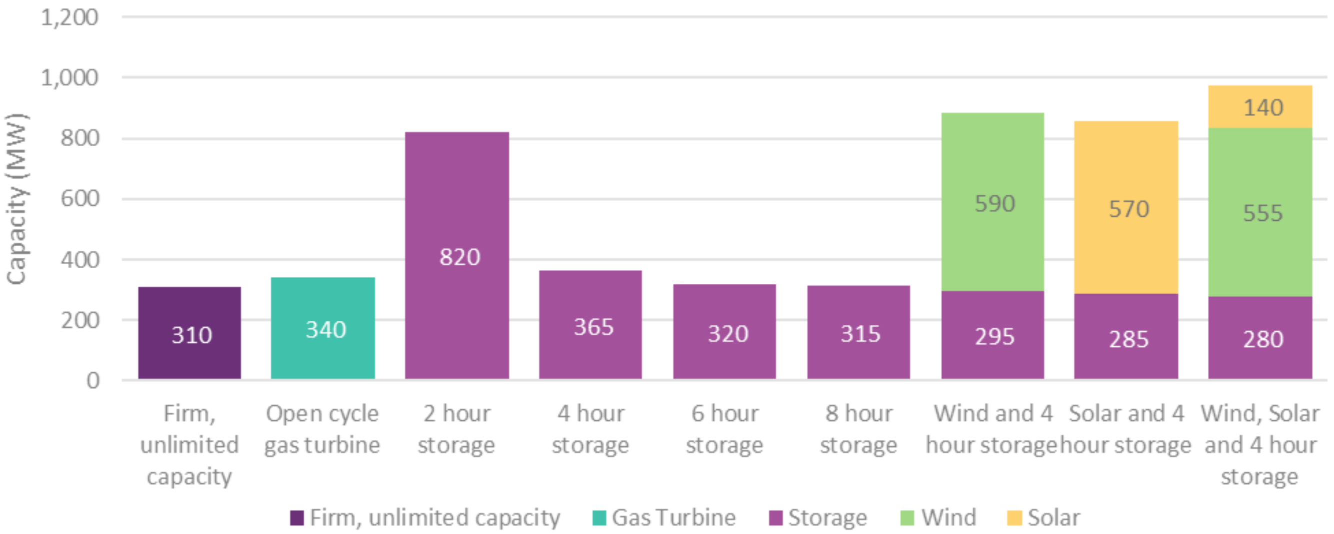


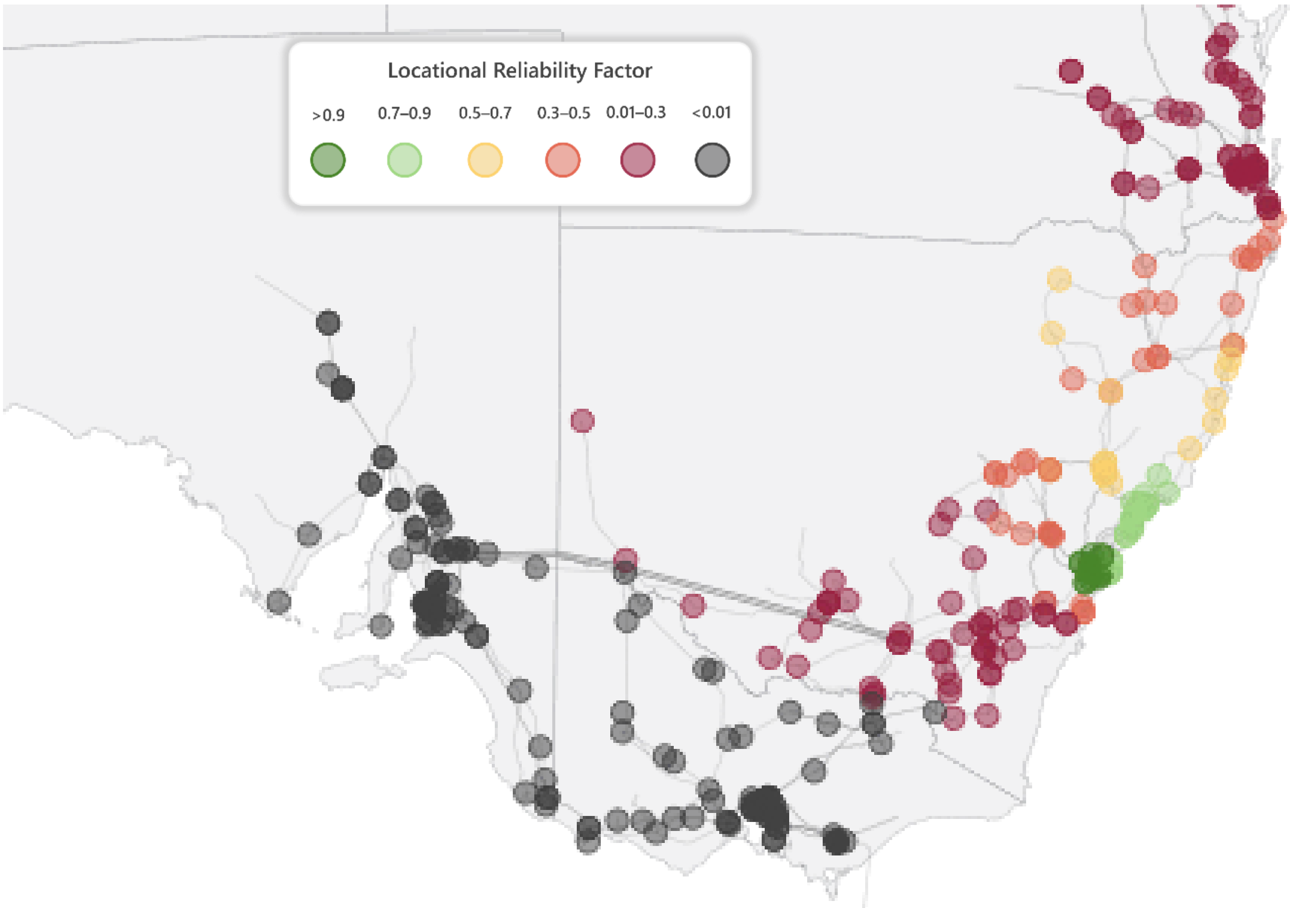
Figure 28 above shows that 820 MW of two-hour duration storage would be required to reduce expected USE to meet the reliability standard in South Australia in 2030-31. In contrast, less than half that capacity is needed if the storage has a duration of four hours or more. These findings are consistent with outcomes under the *Government Schemes and Actionable Developments* assessment, which considers an additional 954 MW of storage with an average duration nearing four hours by 2030-31, and results in negligible levels of expected USE.

This analysis shows that longer duration storage (four-hour or more) is more effective at reducing reliability risks than shorter duration storage. In 2030-31, expected USE in South Australia is forecast to exceed the reliability standard, with some shortfall events that last more than four hours. In such conditions, two-hour batteries are typically exhausted early, providing no reliability benefits for later hours of the forecast USE event. By contrast, longer duration storage can sustain output over a larger portion or even across the full duration of these USE events. When paired with wind and/or solar generation, this approach provides additional energy to the system and for storage to charge during the periods of otherwise likely limited energy availability, improving both the availability and timing of supply.

Transmission developments are key enablers of reliability risk reduction

During periods of high demand, when reliability risks typically occur, transmission network capability limits are often reached. For example, **Figure 29** shows an extract from AEMO's *Enhanced Locational Information*[42] publication under near-term operating conditions.

Figure 29 Near-term locational reliability factors for New South Wales USE as published in *Enhanced Locational Information*



This figure shows which locations in the NEM will be able to allow additional generation dispatch at times of New South Wales reliability risk:

[42] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/enhanced-locational-information.

- Locations with a reliability factor approaching 1 are forecast to be unconstrained during periods of New South Wales reliability risk – allowing new generation to meet consumer demand and reduce reliability risks.
- Locations with a reliability factor near 0.5 are forecast to be able to dispatch 50% the energy of a more favourable location, suggesting that new generators in these locations would have a partial contribution towards reducing reliability risks.
- Locations with a reliability factor approaching 0 are forecast to be fully constrained towards Sydney during periods of New South Wales reliability risk, suggesting that these locations are unable to reduce reliability risks.

This analysis highlights the importance of ensuring that generation and storage assets are well located in the power system, to minimise congestion and meet consumer demand but also demonstrates the importance of new transmission assets that increase transfer capability and minimise generator curtailment. The *Government Schemes and Actionable Developments* assessment considers more than 6,000 km of new transmission developments which reduce the projected curtailment of existing, proposed and future generation and storage assets, allowing greater energy production and instantaneous generation output at times of reliability risk.

4.4 Unserved energy remains possible, even when forecast within the relevant reliability standard

The 2025 ESOO applied a Monte Carlo simulation methodology to simulate the likelihood of USE considering the various statistical likelihoods of generator unplanned outages, alongside 23 alternative patterns of weather conditions observed between 2002-03 and 2024-25, that influence the associated availability of VRE resources and the conditions that drive peak demand. The modelling approach was applied to each forecast maximum demand and weather reference year, creating statistically robust results which capture the impact of uncertainties around key parameters.

A weighted average was applied to these Monte Carlo simulations to represent the 'expected' outcome for each simulated year[43]. Within the simulations, there are combinations of inputs that lead to USE events in all regions, however the probability of these events varies between regions, and over time.

Expected USE, being the average of many possible outcomes, is forecast to exceed the IRM for Queensland for the coming year under the *Committed and Anticipated Developments* sensitivity. While this means the expected USE is above the relevant standard, it does not guarantee that a USE event will occur. In fact, the most likely outcome is that supply will be sufficient to meet peak demand if extreme conditions eventuated, and that weather conditions are relatively unlikely to reach the levels associated with 10% POE peak demand. Even when a region is forecast to remain within the IRM, it is not immune to reliability risks, although events may be less probable.

As an example, **Figure 30** shows a bubble plot of the distribution of USE outcomes that are forecast in Queensland for the 2025-26 summer, under a neutral/unknown climate outlook (that is, by considering all historical reference years equally). Queensland was selected as the example because reliability risks are forecast above the IRM, however data for all regions is available in the excel file accompanying this ESOO publication. The figure includes the total USE duration and average depth of all USE events in each simulation. The area of each

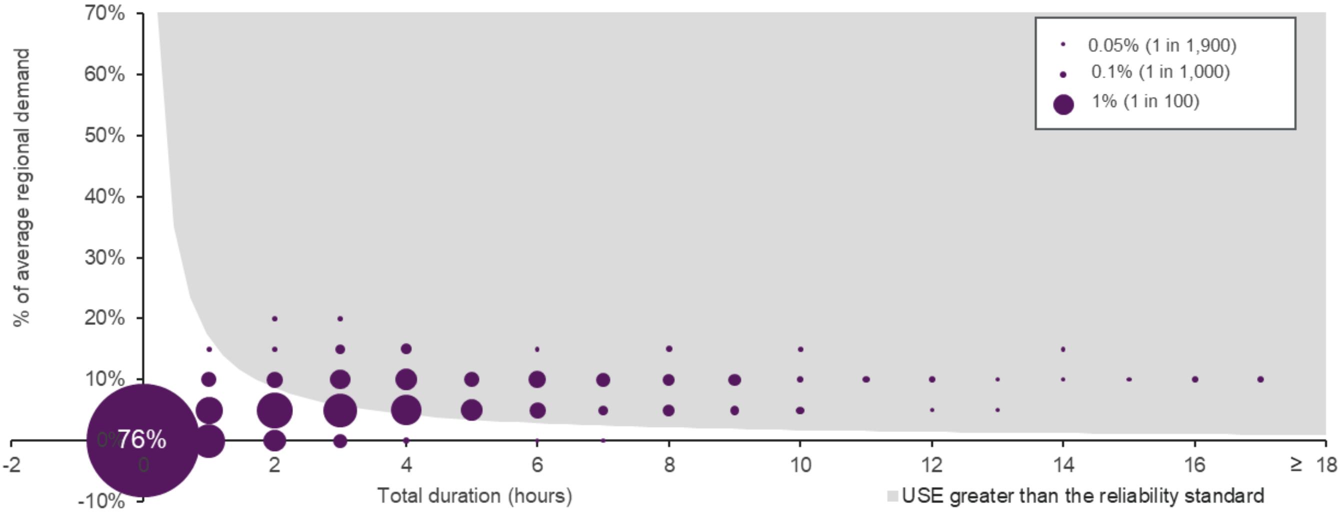
[43] AEMO calculates expected USE using 10% POE, 50% POE, and 90% POE maximum demand outcomes. 10% POE and 50% POE outcomes are weighted at 30.4% and 39.2% respectively, with the remaining 30.4% weighting assigned to 90% POE outcomes with zero USE assumed.

bubble represents the probability of an outcome in proximity of that point. Analysis for all regions for the coming year is available in an accompanying ESOO results workbook.

The figure shows the following:

- The most likely outcome for the coming summer is that no USE events will occur in Queensland. This outcome is 76% probable and is represented by the large circle at the intersection of zero USE hours and 0% USE depth, as a measure of the proportion of average regional demand. The remainder of simulations, which are collectively 24% probable, are represented by the other bubbles on the chart.
- Should USE occur in the simulations, it is most likely to be forecast for between one hour and six hours and be of an average USE magnitude equivalent to between 5% and 10% of average regional demand. Within each event, larger magnitudes of USE than the average may occur during the duration of the event.
- There is a very low probability for USE to be forecast as deep as 20% of average regional demand, or as long as 17 hours, which may occur over multiple individual USE events, for example across four different evenings – either independent events, or during sustained heatwave conditions.
- Bubbles within the grey section represent individual forecast USE outcomes that each exceed the reliability standard of 0.002% USE. These forecast USE outcomes are collectively 11% probable in the coming year in Queensland.

Figure 30 Forecast USE duration and depth in Queensland, *Committed and Anticipated Developments* assessment, 2025-26



Should 10% POE demand conditions occur in the coming summer (which is only statistically likely in one in 10 years), the probability of USE increases.

Table 12 shows the probability of any USE outcome occurring, and the probability of a larger USE outcome[44], in all NEM regions for 2025-26.

[44] When expected USE is forecast at the IRM of 0.0006% USE, a larger USE outcome (among the many individual outcomes simulated) is typically 10% probable. A larger USE outcome is assessed as an individual USE outcome above the reliability standard of 0.002% USE.

Table 12 Probability of USE by NEM region, *Committed and Anticipated Developments* assessment, 2025-26

Region	Probability of any USE		Probability of a larger USE outcome, above the reliability standard	
	Under all maximum demand outcomes	Under 10% POE demand conditions	Under all maximum demand outcomes	Under 10% POE demand conditions
New South Wales	1%	2%	<1%	<1%
Queensland	24%	61%	11%	33%
South Australia	5%	17%	3%	11%
Tasmania	5%	8%	2%	3%
Victoria	7%	19%	3%	7%

In addition to the reliability risks described above, numerous factors excluded from ESOO modelling may further impact consumer outcomes in operational timeframes. These include the following:

- The risk of abnormal transmission system conditions – the ESOO applies a 'system normal' forecast to transmission availability, where the transmission system in each region is presumed to be available and in full working order. Likely and regular occurrence of security and reliability incidents on the regional transmission systems can have a prolonged impact on the ability for generation to be transmitted to meet customer needs.
- The risk that generator maintenance affects generator operational capabilities – the ESOO forecast was developed assuming that planned outages would be scheduled in such a way that they do not impact power system reliability. **Section 5.3** explores the potential impact of generator maintenance on power system reliability and operability.
- The risk that fuel availability is more limited than foreseen by participants, affecting generator operational capabilities – the ESOO forecast was developed assuming adequate fuel supplies during periods of high demand. **Sections 5.4** and **5.5** explore the impact of gas shortfall and drought conditions respectively.

Collectively, these factors may lead to conditions that challenge the operation of the power system. The tail of the USE distribution – the small probability of extreme outcomes – may therefore be a useful indicator of possible reliability risks, beyond the single USE (%) outcome that the ESOO reports.

Operationally, AEMO needs to be prepared to manage the power system under all reasonable and plausible operating conditions, and establishes a comprehensive summer readiness program to mitigate reliability risks ahead of the risk period:

- As in previous years, AEMO will collaborate with industry to identify the preparedness of the system for summer, and develop operational options to mitigate these risks.
- AEMO can mitigate some of the supply adequacy risks with the use of supply scarcity mechanisms such as RERT, where appropriate.

4.5 Low wind conditions, generator outages and high demand are key drivers of reliability risk

Power system reliability risks are often characterised by the infrequent forecast occurrence of USE in circumstances when factors combine to tighten the balance between available supply and demand. The level of reliability risk varies over the horizon, as demand increases, new developments commission, and ageing generators retire. However, for a given level of installed capacity, the factors which contribute to forecast supply shortfall conditions are:

- the magnitude of maximum demand when coincident consumer behaviour in response to high temperatures results in large increases in demand, the number of high demand periods and the coincidence of peak demand conditions in connected regions,
- the degree to which demand flexibility and CER can offset underlying demand,
- low wind availability at the time of high demand (the contribution of solar generation at the time of peak demand is already low, as peak demand typically occurs in the early evening),
- the availability of scheduled generators to meet demand, including the impact of scheduled generator outages,
- the availability of battery storage, and the degree to which batteries are charged in advance of supply scarcity events – battery storage duration and the energy management practices that battery operators follow to retain stored energy during peak demand events will also influence the capability for battery projects to mitigate reliability risks, particularly for longer duration events, and short duration battery projects are unlikely to be as effective in mitigating for many USE risks relative to longer duration projects, and
- the availability of fuel and water for use in electricity generation.

AEMO applies historical 'reference years' in the ESOO model to capture the impact of weather conditions that impact the power system, in different locations and across all times of the day and year. Weather conditions impact forecasts differently because of their effect on wind generation, solar generation, consumer demand patterns, high temperature periods for thermal plant deratings, and some transmission line ratings (those with dynamic line ratings).

The 2025 ESOO applied 23 reference years (from financial year 2002-03 through to 2024-25), each of which have different combinations of peak demand timing, wind and solar availability, and other power system weather impacts. Where USE varies significantly between reference years, it suggests that weather variability is a material factor in the reliability assessment. Conversely, where USE varies little between reference years, it suggests that generator unplanned outages are a more material driver.

Figure 31 shows the level of expected USE forecast in Victoria for 2025-26 as an example, based on each of the historical reference years modelled as an example of the variance that may exist depending on renewable generation availability[45]. It also shows the average capacity factor of Victorian wind generators during forecast Victorian high demand periods. Variation in expected USE is due to the relative contribution of VRE during times of high demand (mostly wind, as peak demand typically occurs after sunset), the level of coincidence in high demand between regions, or the length of time that consumer demands were at near-peak levels during each of the reference years. Information on the impact of weather reference years on expected USE, and wind capacity factors at time of high demand is available in the accompanying ESOO results excel file for all regions.

These are the key observations from the figure:

[45] Similar variances exist in all regions, to varying extent depending on the tightness of supply versus demand, the penetration of renewable generation, and the geographical concentration of the renewable resources.

- There is a negative correlation between wind availability and reference year USE, suggesting that wind availability at time of high demand is a material driver of reliability risk. Across high demand periods, Victorian wind farms typically contribute approximately 27% of their rated output; when output is lower then USE events are more likely.
- If the weather conditions associated with the 2003-04, 2004-05, or 2018-19 years were to re-emerge next summer, expected USE would be higher than the IRM, meaning the occurrence of high demand and low generator availability could lead to involuntary load shedding. These reference years have weather patterns leading to conditions that have high evening demands (when solar generation is low) often in multiple regions which coincide with lower wind speeds creating a greater risk of supply shortfall.
- If the weather conditions associated with other reference years were to re-emerge next summer, expected USE would likely be below the IRM, and many reference years are noted to have negligible levels of risk given the abundance of wind generation at time of high demand.

Figure 31 Impact of weather reference years on expected USE in Victoria 2025-26 (%)

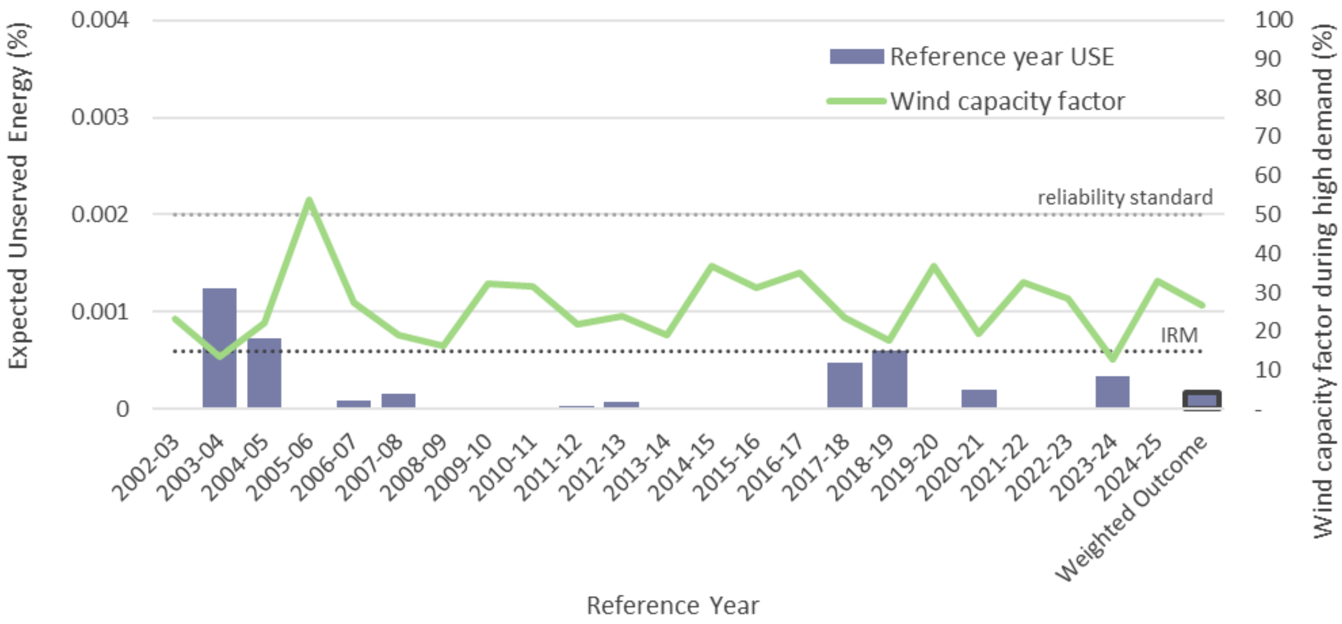
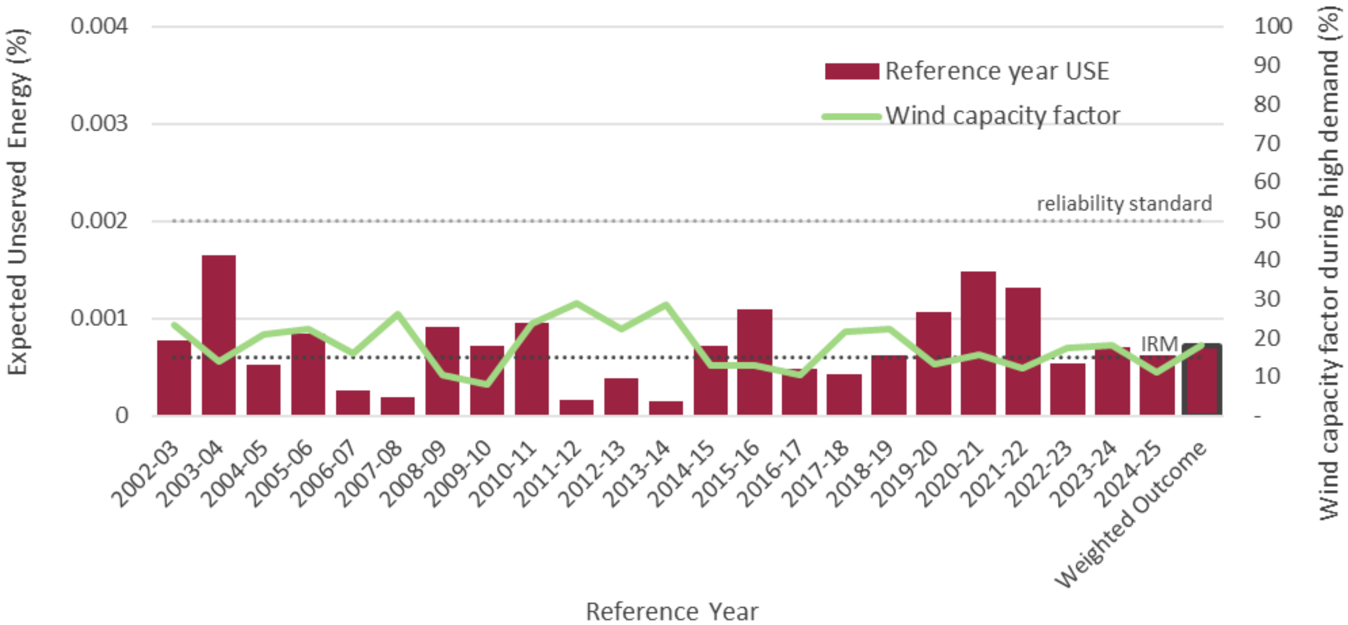


Figure 32 shows the level of expected USE forecast in Queensland for 2025-26 on the same basis as shown for Victoria above, highlighting that:

- while there is a negative correlation between wind availability and reference year USE, USE is noted in all reference years, suggesting that generator unplanned outages at time of high demand are the most material driver of reliability risk, or that a tighter supply and demand balance is expected, meaning any under-availability of VRE will more likely result in energy scarcity challenges, leading potentially to a USE event,
- if weather conditions associated with the 2007-08, 2011-12 or 2013-14 years were to re-emerge, expected USE would be relatively low, due to the forecast abundance of wind resources at time of high demand,

- if weather conditions associated with other reference years which are associated with average to low wind conditions were to re-emerge, reliability risks are forecast to be higher, and are often above the IRM of 0.0006% USE, and
- wind generation expected to be operating during 2025-26 in Queensland has a materially lower average output during high demand periods, with the typical contribution from wind farms of approximately 18% of their rated output, materially lower than the 27% forecast in Victoria.

Figure 32 Impact of weather reference years on expected USE in Queensland 2025-26 (%)



4.6 Reliability outlooks have improved since the 2024 ESOO

Table 13 lists all major changes since last year which have led to revised reliability outlooks in the 2025 ESOO.

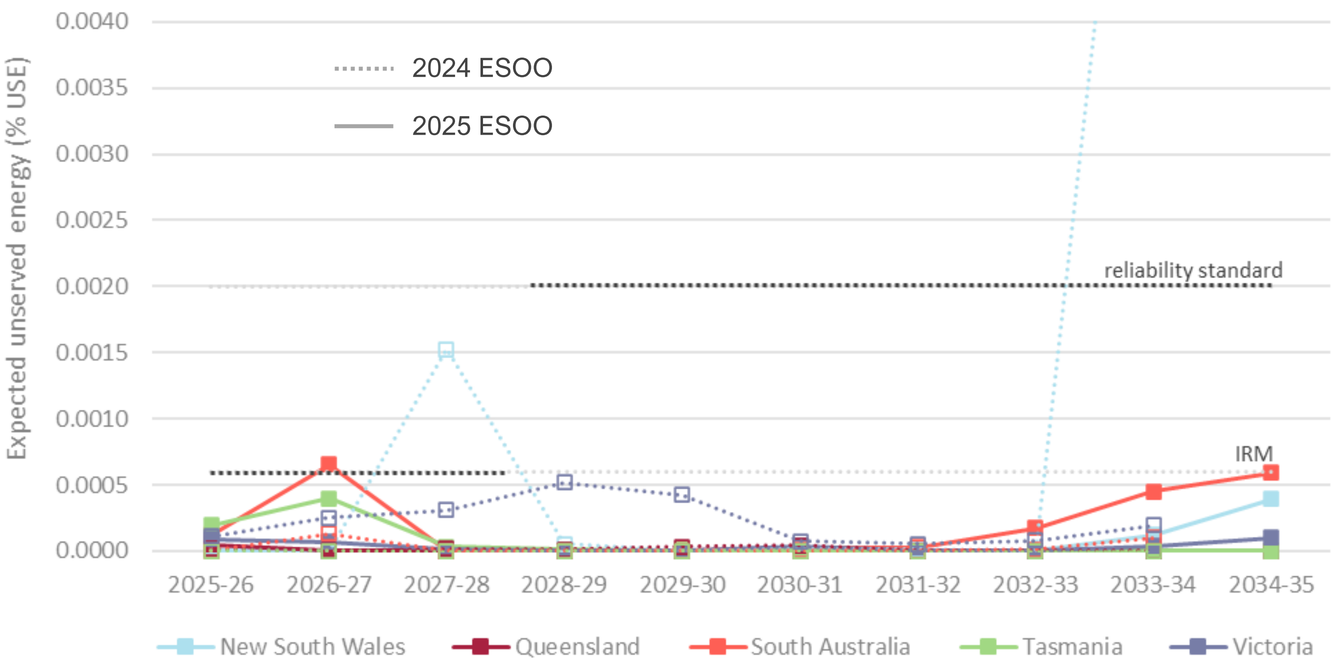
Table 13 Major changes between the 2024 and 2025 ESOOs

Category	Change between 2024 ESOO and 2025 ESOO
Demand	In New South Wales and Victoria, lower maximum demand is forecast in the first five years of the horizon, but higher maximum demand is forecast in the last five years of the horizon. Forecast maximum demand is higher across the entire horizon in Queensland, South Australia and Tasmania.
Demand flexibility	Forecast capacity available for DSP in New South Wales has decreased, other regions remain similar. Forecast VPP has decreased from 2028-29 onwards across all regions.
Sub-regional demand distribution	Subregional demand allocations have been revised to use dynamic proportions compared to flat rate proportions, improving the spatial representation of consumer demand.
Generator and storage commitments	More than 10 GW of additional projects have met AEMO's commitment criteria for committed or anticipated status. More than 30 GW of additional projects are considered in the *Government Schemes and Actionable Developments* assessment. New commissioning dates are provided for many near term projects.

Category	Change between 2024 ESOO and 2025 ESOO
Transmission developments	New commissioning dates are provided for many projects.
Unplanned Outage rates	Unplanned outage rates have increased across all regions and fuel technologies.
Generator retirements and mothballing	Callide B has advised a change of expected retirement from 2028 to 2031. Osborne has advised a change of expected retirement from 2026 to 2027. AGL Hallet has advised change of expected retirement for some units from 2032 to 2036.

Figure 33 shows the *Government Schemes and Actionable Developments* assessment relative to the equivalent assessment from the 2024 ESOO.

Figure 33 2025 *Government Schemes and Actionable Developments* reliability assessment relative to the equivalent sensitivity from the 2024 ESOO, 2025-26 to 2034-35



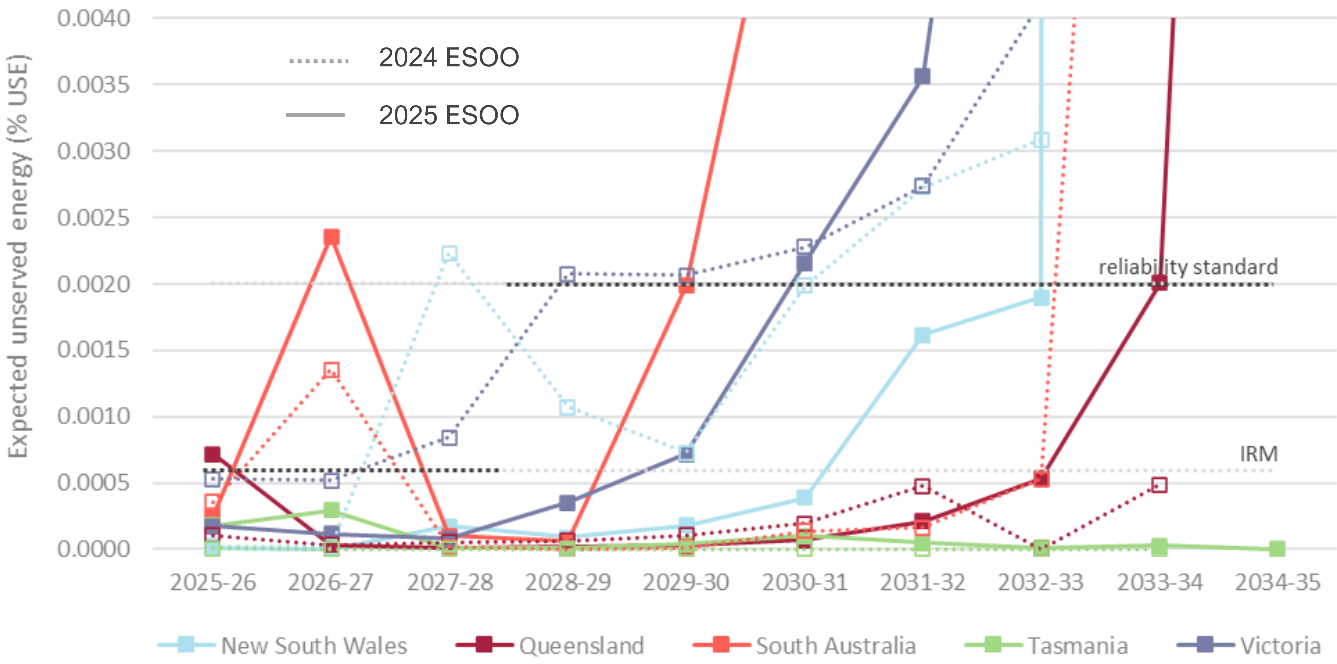
These are the key insights from this comparison:

- In **South Australia**, the 2025 assessment shows higher USE forecast in 2026-27 when Torrens Island B has advised retirement, due to higher forecasts of maximum demand, the discontinuation of the Hydrogen Jobs Plan hydrogen generator (204 MW), and higher projected generator outage rates. From 2032-33, reliability risks are higher than the 2024 assessment due to higher forecast demand and increased unplanned outage rates.
- In **New South Wales**, the reliability gap previously forecast in 2027-28 when Eraring is advised to retire is no longer forecast, due to reduced maximum demand forecasts, the earlier and additional inclusion of numerous well-located battery projects, and small revisions to transmission transfer capacity on key corridors. Reliability risks remain low until the end of the horizon, even after the retirement of Bayswater (2,173 MW) and Vales Point (1,320 MW) power stations in 2032-33. Compared to the previous assessment, this year's assessment includes an additional 1,521 MW/5,475 MWh of storage capacity, 547 MW of VRE capacity, and several transmission projects.

- In **Tasmania**, reliability risks are higher in 2025-26 and 2026-27 due to an increase in forecast demand and additional planned winter unavailability of Cethana (95 MW) in 2025-26 and Poatina (342 MW) in 2026-27 relative to the 2024 ESOO assessment.
- In **Queensland**, reliability risks remain low across the horizon in both assessments despite numerous changes to assumptions.
- In **Victoria**, reliability risks are lower between 2026-27 and 2029-30, due to lower demand forecasts and the assumed commissioning of additional generation and storage projects which are now committed, anticipated or supported by government schemes.

Figure 34 shows the *Committed and Anticipated Developments* reliability assessment, relative to the equivalent assessment in the 2024 ESOO.

Figure 34 2025 *Committed and Anticipated Developments* reliability assessment relative to the equivalent sensitivity from the 2024 ESOO. 2025-26 to 2034-35 (% USE)



These are the key insights from this comparison:

- In **South Australia**, the 2025 assessment shows higher USE forecast in 2026-27 when Torrens Island B has advised retirement, due to higher forecasts of maximum demand, the discontinuation of the Hydrogen Jobs Plan hydrogen generator (204 MW), and higher projected generator outage rates. From 2029-30, reliability risks are higher than the 2024 assessment due to higher forecast demand and increased unplanned outage rates.
- In **New South Wales**, the reliability gap previously forecast in 2027-28 when Eraring is advised to retire is no longer forecast, due to reduced maximum demand forecasts, the earlier and additional inclusion of numerous well-located battery projects, and small revisions to transmission transfer capacity on key corridors. Reliability risks are higher from 2031-32 compared to the previous assessment, due to increased demand, lower forecast DSP and increased unplanned outage rates.

- In **Tasmania**, reliability risks are well below the relevant reliability standard but slightly higher in 2025-26 and 2026-27, due to an increase in forecast demand and additional planned winter unavailability of Cethana (95 MW) in 2025-26 and Poatina (342 MW) in 2026-27.
- In **Queensland**, reliability risks in 2025-26 are now forecast above the IRM of 0.0006% USE. This reliability gap was not previously forecast, but has emerged due to higher coal generator unplanned outage rates (reflecting recent poor performance for numerous coal generators),an upward revision to maximum demand forecasts in Queensland (reflecting recent consumer trends during periods of high demand), delayed commissioning of Kidston pumped hydro facility with development delays applied, and reduced availability from both Townsville and Condamine steam turbines, as advised by the relevant operators. Reliability risks again increase compared to the 2024 assessment in 2032-33, driven by the delayed expected commissioning of Borumba Pumped Hydro project and higher demand forecasts.
- In **Victoria,** expected USE outcomes are now lower between 2026-27 and 2029-30 a period which includes Yallourn Power Station retirement in 2028. During this time, demand forecasts in the region are lower and additional storage (an additional 942 MW/2,346 MWh) and VRE projects (an additional 1,537 MW) are considered. From 2031-32, reliability risks are higher due to higher demand forecasts in the region.

5 Maintaining a stable, secure and resilient power system

While this ESOO advises that there is a sufficient pipeline of committed, anticipated or government supported projects to meet consumer demand consistent with the relevant reliability standard in many years and regions, operability challenges often remain, and reliability challenges need these resources to be available ahead of the greatest periods of USE risk. This chapter explores these operability challenges, including:

- meeting system strength and other system security requirements,
- scheduling planned outages in an increasingly energy-limited power system, and
- ensuring sufficient redundancy in energy production to withstand low fuel and water availability.

5.1 Shortfalls of system security services continue to be forecast in response to generator closures and the development of inverter-based resources

In its 2024 system security reports[46], AEMO outlined the evolving security needs of the NEM over the next five years. Key drivers of emerging system security requirements include:

- reduced operation of synchronous generators, and a shift towards periods dominated by IBR,
- rapid growth in VRE sources,
- the shift from a highly centralised to highly decentralised system, and
- an increasingly active role for consumers in the way they consume and generate electricity.

These factors have increased the need for essential power system services to maintain a stable and secure power system. The 2024 system security reports confirmed the status of previously declared shortfalls, and identified a range of new system strength, inertia, and voltage control challenges and emerging risks across several regions. These are being worked through with the relevant transmission network businesses to scope action or further investigation.

Starting in 2025, the three system security reports will be combined with the *Transition Plan for System Security*. This combined report will provide a holistic overview of power system security challenges, key transition points, and actions underway to ensure the power system remains secure and reliable throughout the energy transition.

[46] These are the inertia, system strength and NSCAS reports at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

System strength (minimum fault levels)

Meeting minimum fault level requirements is likely to be the most onerous security need across the NEM and is projected to require significant investment in new assets and contracted services over the coming decade.

Key findings:

- There is a current operational requirement for an equivalent of approximately 25 large synchronous units, distributed across the NEM in particular locations, to remain online at all times to meet fault current requirements essential for protection operation. There are more than 40 large units capable of contributing to this need[47]. At this time, the only proven source of protection quality fault current is from synchronous plant of some type. Replacement investments will be needed to ensure minimum fault current (system strength) requirements can continue to be met in the required locations as large synchronous generators retire.
- In the medium term, TNSPs are progressing RIT-Ts to procure the services needed to meet system strength requirements across the NEM – both minimum system strength (fault current) and efficient levels of system strength. The preferred asset investment options for the five regional RIT-Ts include a range of network and non-network solutions. To meet the minimum fault level component of system strength, services must be capable of providing protection-quality fault current, and this could include new synchronous condensers, service contracts with existing thermal or hydro units, new gas turbine units fitted with clutches, or the retrofit of existing generators as they retire from the energy market. To meet the efficient (stable voltage waveform) levels of system strength, many TNSPs propose contracting with grid-forming BESS.
- AEMO's 2024 *System Strength Report*[48] identified 13 locations with existing or expected shortfalls against minimum system strength (fault current) requirements within the next five years and across four separate regions. These gaps deepen substantially following the announced closures of thermal plants. Replacement investments and commercial arrangements are being progressed aiming to resolve these gaps, although timing to address near-term gaps appears to be challenging .
- While grid-forming technology continues to develop, it has not yet been demonstrated to satisfy protection-quality fault current requirements at scale in the Australian system. The technology does form a key component of investment RIT-Ts for the local voltage waveform component of system strength (efficient level), and actions seeking to prove this technology for use in also meeting the minimum fault level component is a priority action in AEMO's engineering roadmap[49] over coming years.

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[47] The values here represent only those large synchronous units with significant contributions to regional system strength requirements. While additional small or remote gas and hydro generation can also contribute operationally, these typically provide only a fractional contribution towards the 25 units requirement.

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

[49] FY26_23: see page 40 of AEMO's priority actions report, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf, and FY26_23: see page 40 of AEMO's priority actions report, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf.

Inertia

Without new investment, available inertia is projected to fall sharply alongside declining thermal generator utilisation and retirements over the coming decade. This will offer opportunities for both synchronous and synthetic inertia providers to offer replacement services.

Key findings[50]:

- Operating levels of inertia are projected to fall significantly as existing generators close, and thermal generation utilisation declines. AEMO expects a variety of assets and services of various sizes and technologies will be required to meet the emerging inertia deficits.
- Inertia requirements are already being closely managed in Tasmania and a new shortfall is projected to emerge in Queensland from 2027-28. The existing shortfall in South Australia has been addressed, primarily through additional registrations in the 1-second frequency control ancillary services (FCAS) market. While Victorian capabilities are also forecast to fall, strong interconnection with other regions means that Victoria is able to meet local requirements from neighbouring regions.
- Rule changes introduced in March 2024 updated the inertia framework, including the introduction of a new minimum system-wide inertia level from 1 December 2024[51] and the removal of restrictions on the procurement of synthetic inertia. Throughout 2024, AEMO consulted[52] on the new system-wide requirement calculation approach, and on a proposed inertia network services specification, as part of the *Inertia Requirements Methodology*[53].
- While inertia is distinct from system strength, opportunities exist for optimised investment that meets both needs concurrently. This could include contracts with generators or batteries capable of providing both services, or the incremental addition of flywheels to new synchronous condensers.

Voltage control

Voltage control remains a key issue as the power system transitions from traditional large synchronous generators.

Key findings:

- In the near term, periods where the level of distributed PV generation is very high relative to the underlying demand are increasing and will present significant security risks that require active operational management. In the longer term, steady-state voltage control will be increasingly provided by the reactive capabilities of new IBR.

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[50] More information is in AEMO's 2024 *Inertia Report*, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.pdf, and Appendix 7 of the 2024 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

[51] At https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[52] At https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-the-inertia-requirements-methodology.

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

- Specifically for voltage control in South Australia, the magnitude and timing of the previously declared voltage control gap remains unchanged. AEMO has progressed commercial arrangements to meet this gap until new reactors can be installed by ElectraNet in 2025-26.
- AEMO has not identified any new thermal loading or voltage control gaps in Victoria. Risks have been observed for voltage control at Eildon during low demand conditions and these are being managed with an existing operational solution. AEMO has also confirmed the timing and magnitude of the previously declared thermal overloading and voltage control gaps at Deer Park, but notes that these are already being managed by AEMO Victorian Planning through a local control scheme and longer-term RIT-T. Overloading risks were also identified for transformation into Metropolitan Melbourne following Yallourn retirement, and AEMO Victorian Planning published the Project Specification Consultation Report (PSCR) for the eastern metropolitan grid reinforcement in Q4 2024 and published the western metropolitan grid reinforcement PSCR in Q1 of 2025[54].

5.2 Ongoing action is required to support the secure operation of the NEM with high levels of distributed resources

Australia's energy transition is being accelerated by the widespread deployment of CER, particularly rooftop PV. As highlighted in the 2025 IASR, rooftop PV continues to grow rapidly, with more than one-third of Australian homes now hosting solar systems. This transformation is empowering consumers to actively participate in the energy system, reducing emissions and energy costs while contributing to system reliability and resilience.

CER are reshaping the generation mix and unlocking new opportunities for flexible demand, energy storage, and decentralised system services. These resources are increasingly capable of supporting system security and reliability when effectively coordinated. However, realising the full potential of CER requires that system security can be maintained at times of high CER contribution, most notably, during minimum system load (MSL) conditions.

Periods of minimum system load occur when distributed generation, particularly passive rooftop PV, significantly reduces demand on the transmission system. Large-scale synchronous units are currently essential for delivering system security services, such as system strength (fault current), inertia, voltage control, and ramping. These services predominantly rely on synchronous generators, which need to operate at or above their minimum safe operating levels (MSOLs). Low operational demand may prevent dispatching enough large-scale generators to maintain system security.

Since 2017, AEMO has worked with NEM stakeholders to manage secure system operation during periods of high distributed PV generation and low demand, including through reporting in the ESOO since 2020[55]. Forecast periods of rapid minimum demand reduction have been identified as key transition points over the coming years. AEMO intends for a combined, annual system security report to be the primary vehicle for communicating transition readiness in the NEM. Going forward, MSL will be primarily addressed through that report rather than through the ESOO. This section provides a brief summary of actions required to manage MSL and recent progress against these actions, with further detail to follow in the December 2025 *System Security Report*. AEMO

[54] See https://www.aemo.com.au/initiatives/major-programs/western-metropolitan-melbourne-reinforcement.

[55] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf.

is also contributing or leading several workstreams of the National CER Roadmap[56], which is expected to support enduring solutions to MSL risks.

AEMO's Q4 2024 report *Supporting secure operation with high levels of distributed resources*[57] outlined four key strategies to manage MSL:

- store energy,
- reduce the amount of generation required online,
- increase daytime demand, and
- decrease non-essential generation.

Over the last year, progress has been made across all of these strategies, although more remains to be done.

Store energy

Over 2024-25, more than 1 GW of large-scale BESS progressed through the NEM connections process to achieve full output[58]. Deployment is expected to grow rapidly, with a further 23 GW in the connections pipeline. Charging from large-scale storage and other scheduled demand is not included in the minimum demand forecasts, but rather modelled on the supply side, so can be considered as a helpful mitigation for MSL events. However, most BESS deployed to-date have one- to two-hour durations, while MSL events have lasted up to 10 hours[59]. Longer-duration storage and coordinated charging are needed to better manage such events.

At present, most BESS charge at earliest opportunity, leaving them less available to store energy at times most needed to manage MSL. AEMO's procedures allow for directions to increase charging during MSL periods, but procurement is preferred. Following the Improving Security Frameworks rule change[60], AEMO is progressing procurement of Type 1 services from BESS in Victoria and South Australia[61], with a similar process in Queensland and New South Wales under consideration.

Beyond transitional services, market mechanisms may be considered in the future. The Clean Energy Council's proposed rule change to establish an MSL reserve service[62] is one such mechanism which AEMO is reviewing, while the AEMC prepares to initiate a rule change process.

Distributed storage is also an important tool to manage MSL. AEMO continues to forecast strong growth in this area[63] and the Commonwealth Cheaper Home Batteries Program[64] provides some confidence of that growth

[56] See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

[57] At https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf.

[58] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

[59] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf.

[60] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[61] See https://aemo.com.au/consultations/tenders/minimum-system-load-transitional-services-for-victoria-and-south-australia.

[62] See https://www.aemc.gov.au/rule-changes/minimum-system-load-reserve-service.

[63] See https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/draft-2025-inputs-assumptions-and-scenarios-report-stage-2.pdf.

[64] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

eventuating. Minimum demand forecasts already include the contribution of distributed storage optimised for solar self-consumption and retail tariffs.

As with large-scale BESS, most home batteries typically charge at earliest opportunity when excess rooftop solar energy is available. Coordinating distributed storage, for example through VPPs, is expected to enable more optimal charging patterns for both the power system and the battery owner themselves.

Similarly to scheduled demand, increased demand due to this coordination is not included in minimum demand forecasts but is instead modelled on the supply side. Increased coordination therefore remains an opportunity to maintain required operational demand levels in the long term, although the near-term impact is likely to be small due to the nascent VPP industry.

The Engineering Roadmap FY26 Priority Actions update[65] includes progress on several initiatives to enable more effective coordination, including:

- progress on implementation of the Integrating Price Responsive Resources and Unlocking CER Benefits through Flexible Trading rule changes[66,67], and
- consultation papers for DSMO and Data Sharing Arrangements[68,69], as prioritised in the National CER Roadmap[70].

Reduce the amount of generation that needs to remain online to provide essential services

AEMO's 2025 Thermal Audit aims to identify risks and opportunities associated with planned and potential changes to thermal generation capability and operational strategy, including the ability to provide essential system services at lower levels of system demand. Review findings will help to inform operational transition planning across the NEM.

Likewise, the *Transition Plan for System Security* highlighted the need for alternative sources of system security including synchronous condensers and grid-forming inverters, while noting that further investigation is needed to assess grid-forming capabilities, particularly for requirements such as protection quality fault current. The outlook for grid-forming deployment is strong, with over 20 GW in the connections pipeline.

Section 5.1 above outlines the technology options under consideration as replacements to synchronous generating units.

Increase demand in daytime periods

Section 2 of this ESOO presents forecast growth in data centres, business load, LILs, and industrial electrification, moderating the decline in minimum demand, particularly in later years.

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

[66] At https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/integrating-price-responsive-resources-into-the-nem.

[67] At https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/flexible-trading-arrangements.

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

[69] At https://consult.dcceew.gov.au/national-cer-roadmap-data-sharing-arrangements-m2.

[70] At https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

Demand flexibility can also be harnessed, with distribution network service providers (DNSPs) continuing to enable increased electric hot-water heating during the daytime, including shifting controlled load times to peak solar hours, both to manage network constraints and contribute to MSL management.

The AEMC pricing review[71] is also reviewing how network tariffs and retail pricing structures are best aligned with system needs, potentially facilitating load shifting, including for electric vehicle charging, to low-cost times during peak solar hours.

In the meantime, AEMO is exploring whether transitional services can support temporary demand increases during MSL events[72].

Decrease non-essential generation

If other measures are insufficient, AEMO may direct non-essential generators (for example, wind and solar) off to reduce large-scale generation to its minimum. If operational demand is below the minimum threshold, maintaining system security may require DNSPs to trigger emergency backstop mechanisms.

AEMO's Q4 2024 report *Supporting secure operation with high levels of distributed resources*[73] details these requirements extensively. Since its publication, New South Wales and Australian Capital Territory governments have consulted on introducing emergency backstop mechanisms[74,75], with the New South Wales mechanism to begin in March 2026.

AEMO has engaged deeply with industry to help increase compliance, conformance and overall effectiveness of these measures, culminating in a report released in July 2025 on *Learnings from industry implementation of emergency backstop mechanisms for distributed resources*[76].

MSL outlook

Section 2.4 of this ESOO shows minimum demand continuing to decrease in all regions, although less rapidly than in 2024. This shift reflects moderated projections of growth in distributed PV, and increased demand from data centres, business load, large industrial loads, and, in later years, industrial electrification. However, these input factors vary across regions and have a high degree of uncertainty, as evidenced by the difference between modelled scenarios.

All NEM mainland regions have already reached minimum demand levels that could require action to maintain system security in plausible scenarios, including activation of emergency backstop mechanisms. Continued reductions, as forecast, increase the likelihood and frequency of such actions. It is critical to maintain momentum on initiatives that enable secure operation under these conditions.

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[71] See https://www.aemc.gov.au/market-reviews-advice/pricing-review-electricity-pricing-consumer-driven-future.

[72] See p31, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/aemo-2024-transition-plan-for-system-security.pdf

[73] At https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf?la=en.

[74] At https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/public-consultations/solar-emergency-backstop.

[75] At https://yoursayconversations.act.gov.au/emergencysolarbackstop.

[76] At https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/learnings-from-industry-implementation-of-emergency-backstop.pdf.

Continued progress on energy storage, reduction in generation required for essential services, and load shifting is not expected to replace the need for emergency backstop mechanisms as an operational tool but will help to ensure that curtailment of rooftop solar via emergency backstop mechanisms is kept to a minimum. This will enable the energy system to continue benefitting from the enormous contributions of CER, while ensuring the system remains secure as CER growth continues.

5.3 Generator maintenance scheduling is observed to reduce generator availability during periods of supply scarcity

The consulted on ESOO methodology for reliability assessments considers only unplanned outages of generation and storage units, and not planned outages. This methodology assumes that participants will always schedule planned outages optimally, such that they never overlap periods of supply scarcity, however AEMO's forecasting accuracy assessments[77] have identified that planned outages of scheduled generators are occurring during periods of supply scarcity. Given the changing nature of power system supply arrangements, AEMO may consider the role of planned outages in the *ESOO and Reliability Forecast Methodology* for future ESOO publications.

Generator planned outages reduce available capacity and energy production over extended periods and sometimes overlap with seasonal demand peaks. This can narrow system reserve and increase the risk of USE, particularly in periods where renewable output is low and energy production shortfalls occur. These *Generator Maintenance* sensitivities are designed to help illustrate how planned outages can impact reliability and underscore the need for more coordinated, risk informed maintenance planning as the system transitions. In particular:

- As consumer demand grows and dispatchable, high capacity factor generation retires, energy production shortfalls may become increasingly likely alongside capacity shortfalls.
- The windows for scheduling maintenance – particularly if winter / shoulder season demands grow – will shrink, increasing reliability and energy adequacy risks.
- Energy limits, typically affecting peaking gas and diesel units, restrict the total energy that can be dispatched, thereby limiting the system's ability to respond during tight supply conditions, even if capacity is technically available.

These *Generator Maintenance* sensitivities that incorporate scheduled generators' planned outages into the *Government Schemes and Actionable Developments* and *Committed and Anticipated Developments* reliability assessments.

Since October 2023, participants are required to submit outage reason codes and recall times alongside their Medium Term Projected Assessment of System Adequacy (MT PASA) availability data for scheduled production units. This enhanced dataset allows AEMO to better identify the nature and flexibility of planned outages. Using this information, AEMO classifies planned outages as:

[77] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

- **flexible planned outages** – those with a recall time of seven days or less, or submitted within seven days of their start date, suggesting they can be rescheduled based on system conditions, or
- **inflexible planned outages** – all other planned outages, assumed to proceed as scheduled.

Analysis of the submitted MT PASA data reveals clear seasonal and regional patterns:

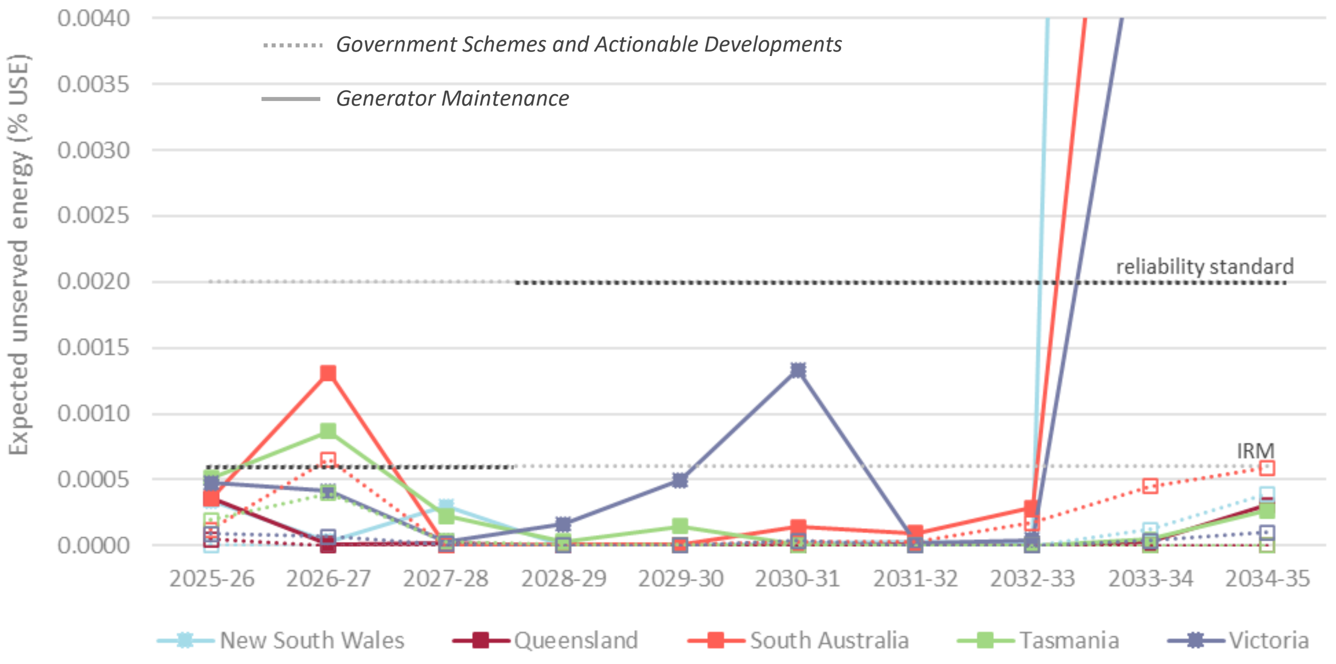
- Planned outages are most frequently scheduled in spring and autumn, when system demand is typically lower.
- While planned outages are not typically scheduled during the peak of summer, outage rates of approximately 2% are still observed during these periods in mainland regions.
- In Tasmania, planned outages generally show limited seasonal variations.

AEMO reflected these patterns in the two *Generator Maintenance* sensitivities by applying the following assumptions:

- Annual planned outage rates were applied by technology type and held constant over the outlook period.
- In mainland regions, average planned outage rates observed between October 2023 and March 2025 are applied using the observed monthly profile for inflexible planned outages.
- In Tasmania, seasonal shaping was not applied due to limited variation, instead, the model allocated unplanned outages to maximise reserves across the year.
- Additionally, energy limits sourced from the 2025 EAAP Central scenario (see **Appendix A2**) were applied to selected coal, gas, and diesel generators in New South Wales, Victoria and South Australia to reflect advised ongoing limits on sustained operation of each particular power station. These limits were assumed to persist throughout the outlook period.
- All other assumptions aligned with those applied in the *Government Schemes and Actionable Developments* (see **Section 4.1)** and *Committed and Anticipated Developments* (see **Section 4.2)** reliability assessments, respectively.

Figure 35 shows the results of applying the above generator maintenance assumptions to the *Government Schemes and Actionable Developments* reliability assessment.

Figure 35 Expected USE for the *Government Schemes and Actionable Developments* outlook, *Generator Maintenance* sensitivity, 2025-26 to 2034-35 (% USE)

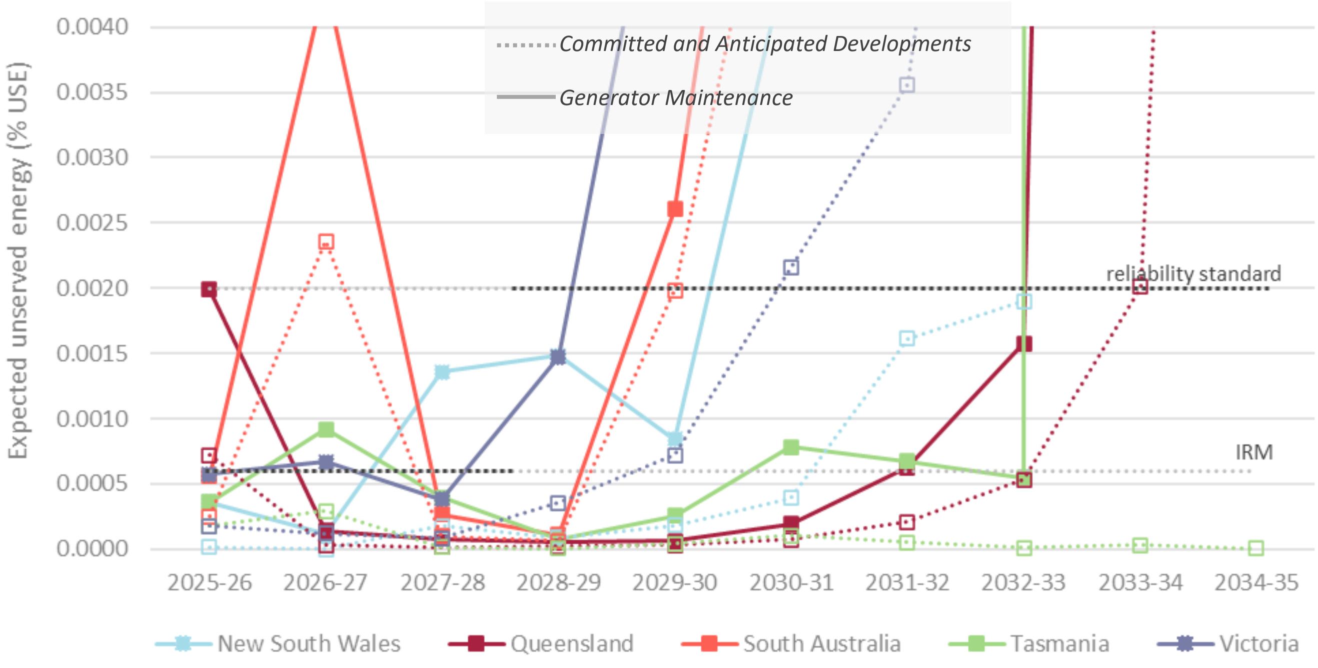


The sensitivity identifies that in years where there is tighter supply and demand conditions – identified as years of higher reliability risk in the *Government Schemes and Actionable Developments* assessment – the scheduling of maintenance may heighten the risk of USE:

- For regions in years with low levels of reliability risk, no increases in reliability risk – or only minor increases in risk – are noted, reflecting that such periods are often associated with sufficient redundancy.
- For regions in years with increased levels of reliability risk, larger increases in risk are noted, reflecting an increasing number of periods where energy production and capacity redundancy for the uncoordinated scheduling of planned outages is likely to be insufficient.
- New South Wales shows USE below the IRM, in 2027-28 when Eraring Power Station has advised retirement, although risks increase slightly.
- Reliability risks in Victoria rise from 2028-29 to 2030-31, when potential planned generator outages are combined with the Yallourn Power Station advised retirement and as operating reserves decline in response to higher demand forecasts, but reduces in 2031-32 when the release of VNI West capacity provides increased operational flexibility to share energy and capacity between regions, reducing risks even when planned outages are uncoordinated.
- From 2033-24, potential planned generator outages would compound the impact of scheduled retirements including Bayswater, Vales Point and Somerton. This leads to USE sharply exceeding the reliability standard in New South Wales, South Australia, and Victoria from 2033-34 onward in this outlook.

Figure 36 shows the results of applying the *Generator Maintenance* sensitivity to the *Committed and Anticipated Developments* reliability assessment.

Figure 36 Expected USE for the *Committed and Anticipated Developments* outlook, *Generator Maintenance* sensitivity, 2025-26 to 2034-35 (% USE)



In this reliability assessment, which included significantly less replacement capacity stimulated by various government schemes than was considered in the *Government Schemes and Actionable Developments* assessment, there is significantly less system resilience to potential maintenance planned generator outages. Incorporating maintenance into the *Committed and Anticipated Developments* assessment similarly reveals significantly heightened reliability risks in some years, particularly after coal closures:

- For regions in years with increasing levels of reliability risk, larger increases in risk are noted, reflecting an increasing number of periods where redundancy for the uncoordinated scheduling of planned outages is likely not present.
- Risks in **New South Wales** are higher in this sensitivity than in the *Committed and Anticipated Developments* assessment from 2027-28 when Eraring Power Station is advised to have retired. This suggests that there is insufficient redundancy in energy production to fully accommodate uncoordinated maintenance generator outages without investments that are yet to be committed or anticipated.
- Risks in **Queensland** are also higher in the sensitivity than the *Committed and Anticipated Developments* assessment.
- Risks in **Victoria** are higher in the *Generator Maintenance* sensitivity than the *Committed and Anticipated Developments* assessment, particularly from 2028-29 when Yallourn power station is advised to have retired.
- Risks increase in all regions from 2033-34, driven by energy production shortfalls, after the retirements of both Vales Point and Bayswater power stations in New South Wales.

The inclusion of planned outages increases expected USE in shoulder seasons as well as in summer, due to the high number of planned outages scheduled that sometimes overlap with periods of high demand. This is demonstrated in **Figure 37** and **Figure 38**, which provide a plot of monthly expected USE using Queensland in

2025-26 and New South Wales in 2029-30 as examples. The figures demonstrate that the shoulder months (September to November, and April to May) have the greatest maintenance scheduling, and the most capability for maintenance to be scheduled at these times, whereas relatively small amounts of maintenance outages of generators in summer and winter months can materially increase reliability risks.

Figure 37 Monthly expected USE, *Committed and Anticipated Developments* outlook, *Generator Maintenance* sensitivity, Queensland, 2025-26 (MWh)

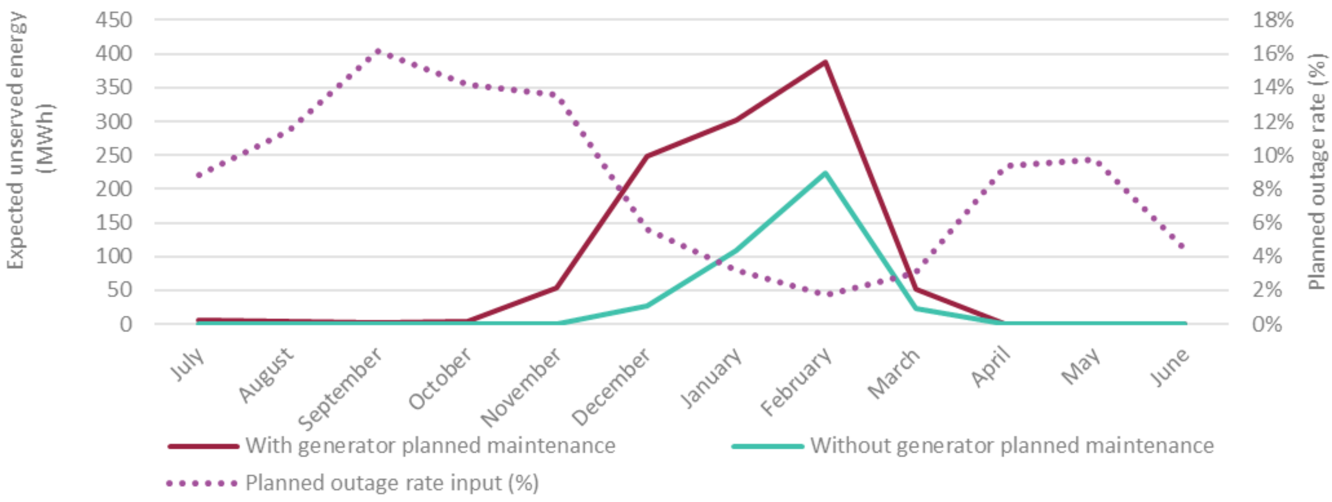
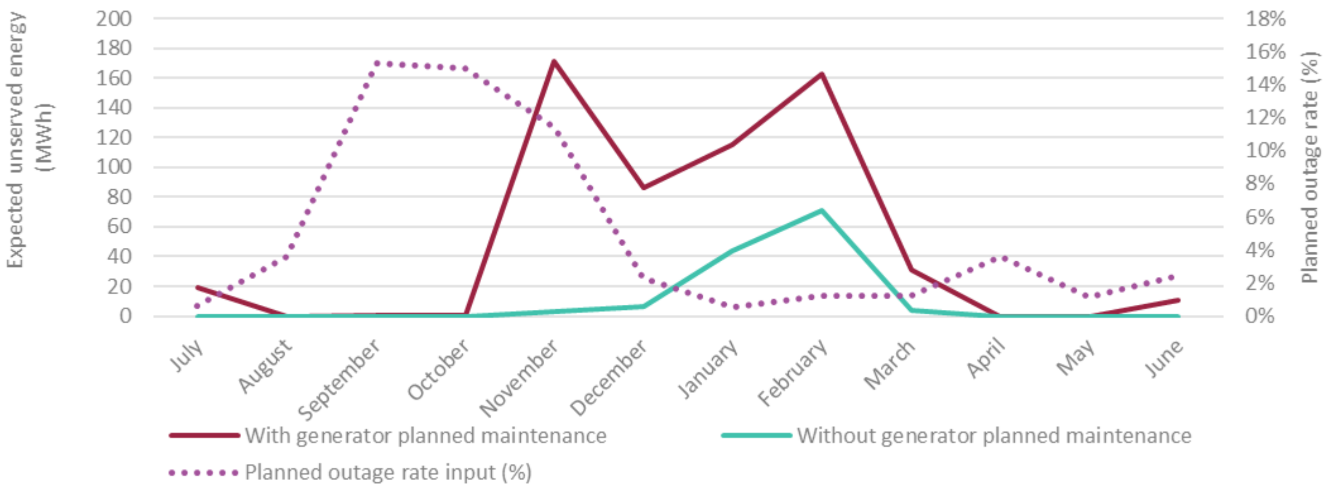


Figure 38 Monthly expected USE, *Committed and Anticipated Developments* outlook, *Generator Maintenance* sensitivity, New South Wales, 2029-30 (MWh)



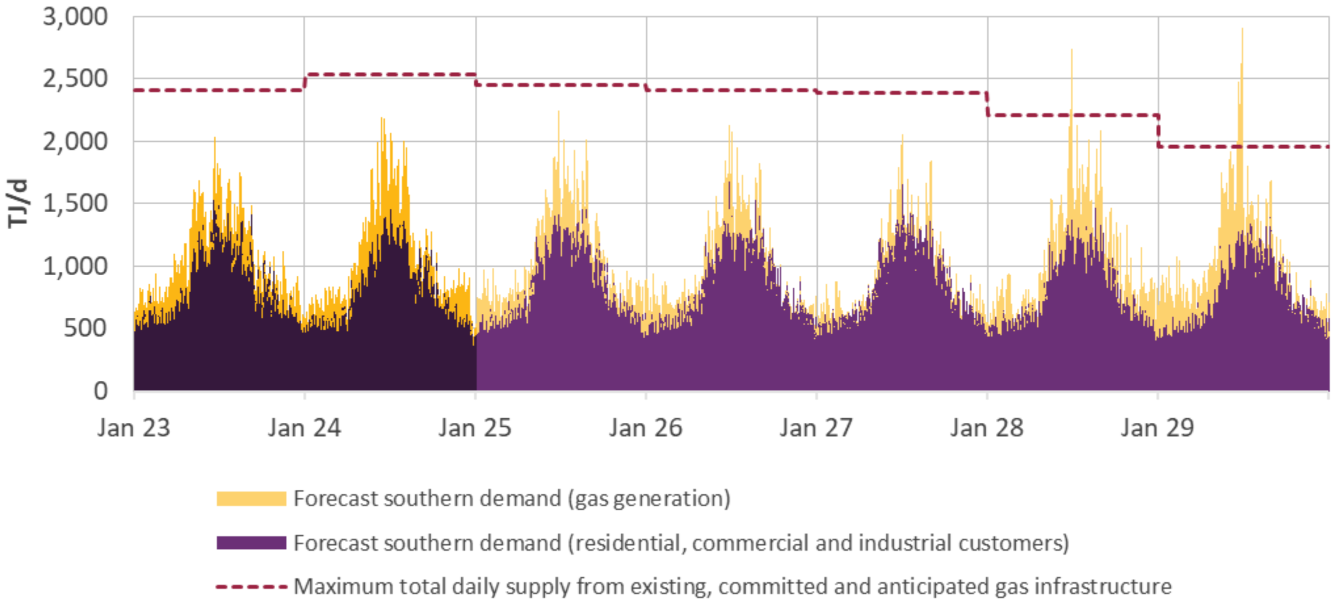
While applying empirical planned outage rates and profiles statically across the outlook period may not reflect an optimised scheduling approach under perfect foresight, the analysis indicates that increased coordination of generator maintenance will be required throughout key transition points, particularly as coal generators retire, to enable reliable supply while accommodating the ability for planned outages to be taken to support continued generator reliability.

These findings highlight the need for strategic, risk-aware outage scheduling to preserve system reliability. As dispatchable generation declines and supply variability increases, it becomes increasingly important to avoid planned maintenance during high-risk periods, particularly in summer. The analysis also shows that elevated USE can emerge in spring and winter, reinforcing the importance of a system-informed coordination strategy. Such a strategy should aim to shift flexible maintenance away from high-risk windows, minimise the overlap of planned outages, and support reserve adequacy across all seasons. Planning for, and appropriately scheduling, maintenance is essential to ensure that ageing generators continue to operate reliably; reducing redundancy to schedule planned maintenance may accelerate the decline of plant reliability.

5.4 Should identified gas shortfalls remain unresolved, NEM reliability risks may increase

In March 2025, AEMO published the 2025 *Gas Statement of Opportunities* (GSOO)[78], which identified gas peak day shortfall risks from 2028 in Southern Australia[79] and a structural need for new gas supply developments from 2029. **Figure 39** shows forecast gas demand in Southern Australia relative to the maximum total daily gas supply from existing, committed and anticipated gas production and infrastructure[80], identifying peak day gas shortfalls as reported in the 2025 GSOO.

Figure 39 Daily southern gas system adequacy forecast to 2029 using existing, committed and anticipated projects, as published in the 2025 GSOO (terajoules [TJ]/day)



AEMO developed a *Gas Shortfalls* sensitivity in this ESOO to understand the potential implications of these gas supply shortfalls on electricity power system reliability. This sensitivity builds on the *Generator Maintenance* sensitivity, limiting the ability of gas-powered generators in the NEM consistent with these 2025 GSOO forecasts.

[78] At https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

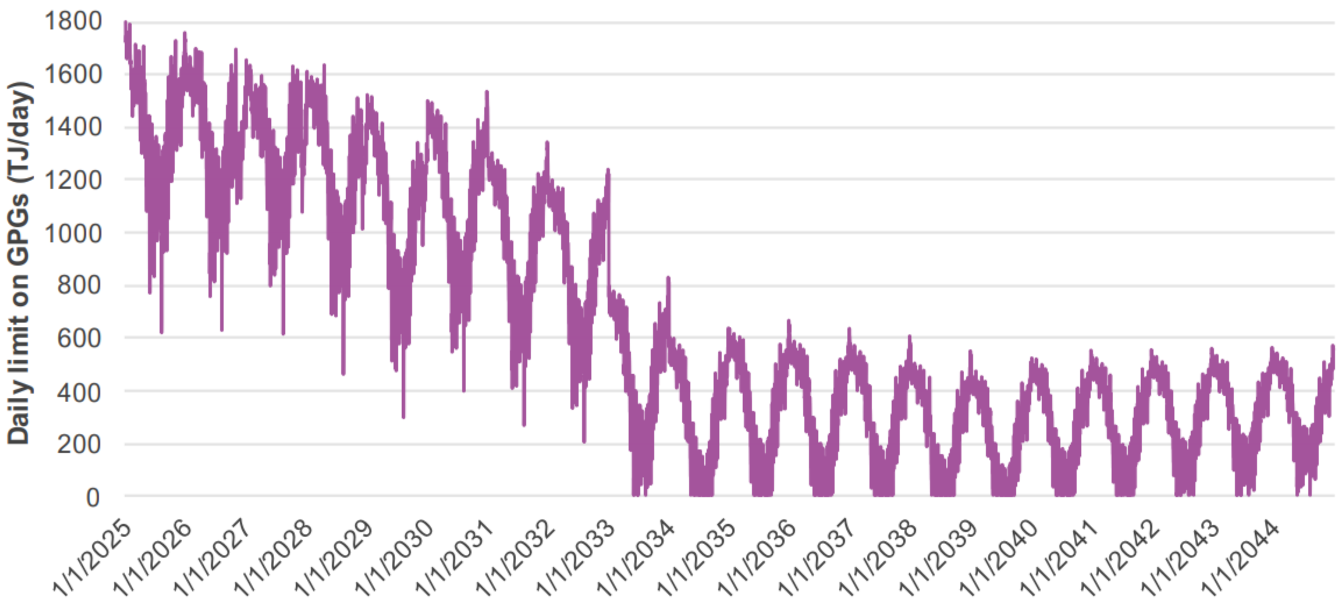
[79] Southern regions are New South Wales, including the Australian Capital Territory, South Australia, Tasmania and Victoria.

[80] This includes forecast existing, committed and anticipated gas supply from southern production, Northern Australia via the South West Queensland Pipeline, and both deep and shallow gas storages.

The sensitivity allows dual-fuel generators to switch between gas and liquid fuels, subject to assumed limits on liquid fuel delivery capabilities.

For the purposes of the *Gas Shortfalls* sensitivity, gas-powered generation limits were applied to each supply and pipeline zone for the East Coast Gas Market[81] as identified in the 2025 *Gas Infrastructure Options Report*[82]**.** As an example, the gas-powered generation limit for regions in southern Australia (including the Australian Capital Territory, New South Wales, Victoria, South Australia and Tasmania) – assuming only committed and anticipated gas supply and infrastructure developments – for the 2019 reference year is shown in **Figure 40.**

Figure 40 Gas fuel limits for all gas-powered generation in southern Australia, reference year 2019 (TJ/day), as published in the 2025 *Gas Infrastructure Options Report*



The following assumptions applied:

- Generator maintenance was applied consistent with the assumptions of the *Generator Maintenance* sensitivity. By including maintenance, energy production capabilities of existing and proposed generators reflect the need to undertake maintenance.
- Energy limits sourced from the 2025 EAAP Central scenario were applied to selected coal, gas, and diesel generators in New South Wales, Victoria, and South Australia to reflect advised ongoing station specific limits on sustained operation. These limits were assumed to persist throughout the outlook period.
- Gas-powered generation daily gas fuel usage limits were applied to each gas supply and pipeline zone as published in the *2025 Gas Infrastructure Options Report*, considering total forecast gas supply capacity (including supply, storage and infrastructure capacity limitations) minus forecast gas consumption from residential, commercial and industrial demand in that zone. As such, residential, commercial and industrial gas

[81] The GSOO includes forecasts for all Australian jurisdictions other than Western Australia, referred to as the East Coast Gas Market.

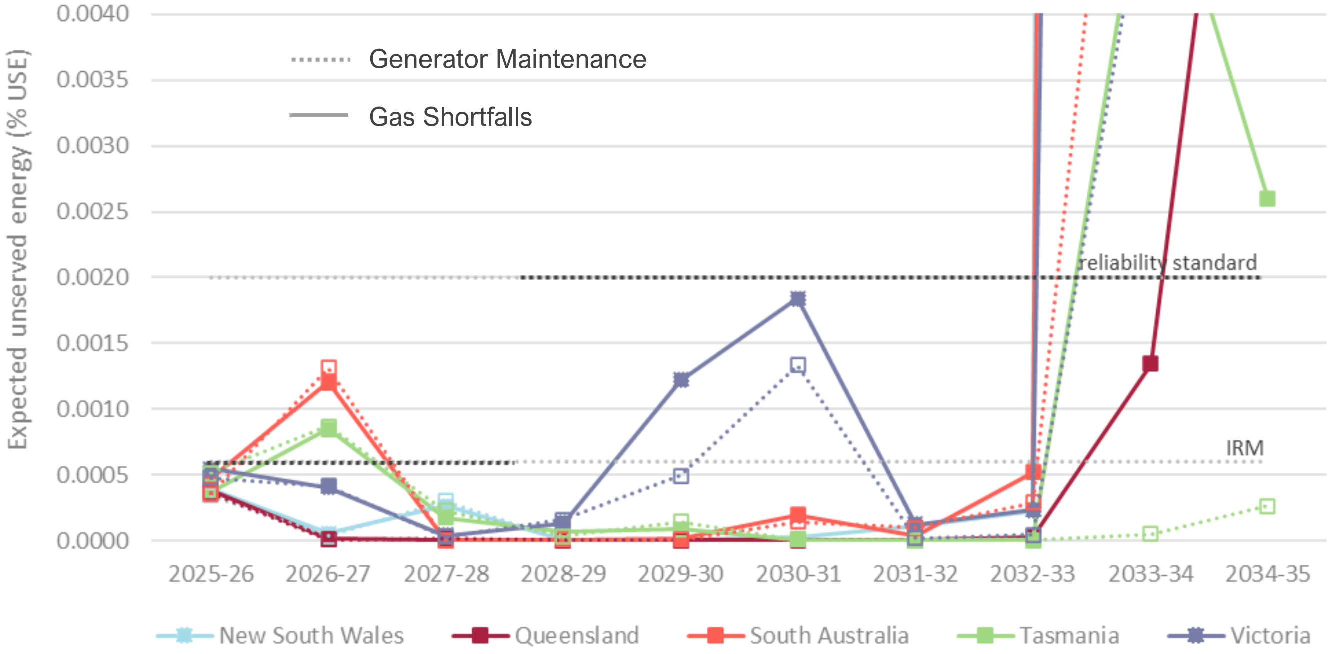
[82] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-gas-infrastructure-options-report/final/2025-gas-infrastructure-options-report.pdf?la=en.

customers have priority access to gas, and gas-powered generation is the first customer category to face gas unavailability[83].

- No further investments occur in the gas market beyond those identified as committed or anticipated in the 2025 GSOO.
- Generators that have advised access to liquid fuels[84] are able to switch between fuel types seamlessly – allowing ongoing operation in the absence of gas supply – but liquid fuel storages[85] are limited to refilling once a week only. While generators often advise the capability to receive liquid fuels daily, there are limits in the ability of Australia's transport fleet to deliver sufficient fuels to all generators at such a frequency.

Figure 41 shows the outcomes of the *Gas Shortfalls* sensitivity relative to the *Generator Maintenance* sensitivity for the *Government Schemes and Actionable Developments* reliability assessment, while **Figure 42** shows the outcomes of the *Gas Shortfalls* sensitivity relative to the *Generator Maintenance* sensitivity for the *Committed and Anticipated Developments* reliability assessment.

Figure 41 Expected USE for the *Government Schemes and Actionable Developments* outlook, *Gas Shortfalls* sensitivity, 2025-26 to 2034-35 (% USE)

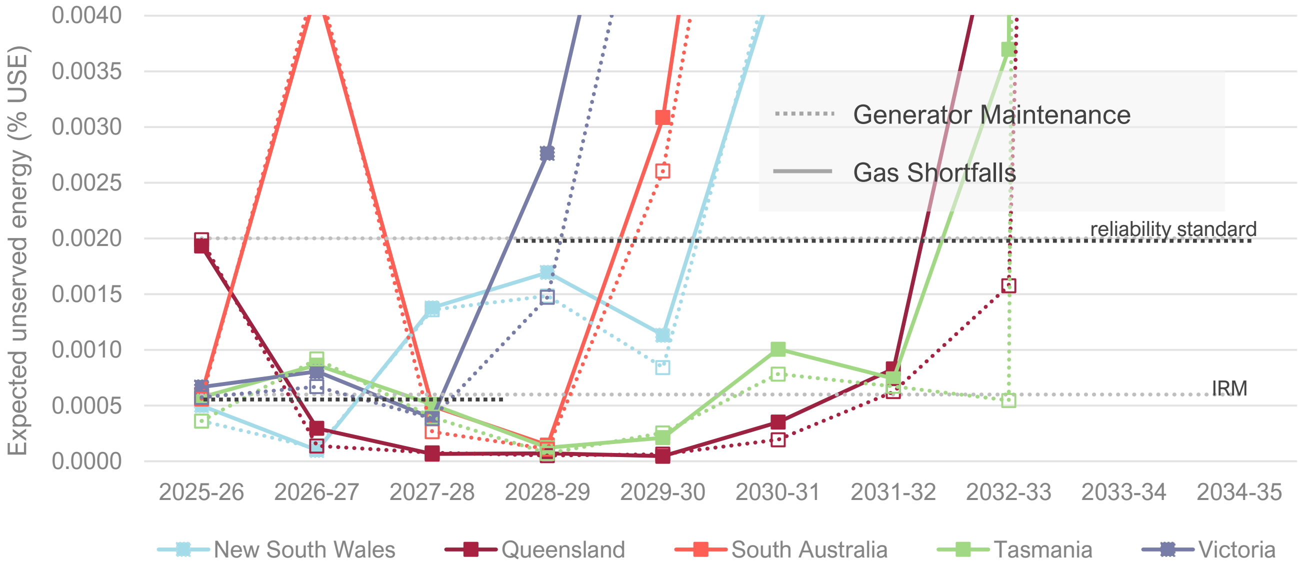


[83] For the purposes of this study, residential, commercial and industrial gas customers are prioritised ahead of gas-powered generation, which may not reflect the operational reality. The sensitivity serves to demonstrate the risk that exist to electricity reliability and/or gas adequacy.

[84] Liquid fuels include diesel and other similar fuels.

[85] Storage size based on Generator Energy Limitation Framework (GELF) data supplied for each generator.

Figure 42 Expected USE for the *Committed and Anticipated Developments* outlook, *Gas Shortfalls* sensitivity, 2025-26 to 2034-35 (% USE)



These sensitivities found the following:

- At the start of the horizon, applied gas limitations restrict gas usage on only a small number of days, and only impact a few generators. As such, only minor differences can be noted between the *Gas Shortfalls* and *Generator Maintenance* sensitivities. This is expected, given that the 2025 GSOO identified sufficient gas adequacy to meet gas consumers' and gas-powered generation's needs in these years.
- In many cases where gas supply shortfalls occur, power system reliability is not impacted in the simulated conditions, due to the ability of other generators and storages to dispatch instead of gas generation, and the use of liquid fuels, both potentially at a higher cost.
- From 2028-29, the *Gas Shortfalls* sensitivities show a higher level of risk than the *Generator Maintenance* sensitivities in southern regions, reflecting circumstances where the modelled gas supply limits are being reached, so gas-powered generation is not always able to support power system reliability.
  - This result aligns closely with the findings of the 2025 GSOO, which identified peak day gas supply shortfalls from winter 2028 in Southern Australia.
  - Under the *Government Schemes and Actionable Developments* reliability assessment, lower levels of risk are noted, reflecting the additional flexibility in operation of the NEM – resulting from assumed additional generation, storage and transmission capacity.
- From 2030-31, a greater frequency of limited gas supply is impacting gas generator operation, reflecting the structural supply shortfall identified in the 2025 GSOO. These gas shortfalls are forecast at a time when greater coal generator retirements are advised, such as the retirement of Bayswater and Vales Point power stations in New South Wales in 2033, which increases the impact of limited electricity production by gas supply shortfalls.

5.5 Reliability risks are forecast to increase should drought conditions occur across the NEM

Hydro generation makes up 12% of currently installed NEM generation and storage capacity, and its energy production capability varies year to year subject to precipitation across often highly complex systems of dams, aqueducts, tunnels and generating systems. To test the impact of potential drought conditions, a *Drought Conditions* sensitivity applied participant-provided energy production limits under drought conditions over the 10-year ESOO horizon. The following assumptions applied:

- Generator maintenance was applied consistent with the assumptions of the *Generator Maintenance* sensitivity. By including maintenance, energy production capabilities of existing and proposed generators reflect the need to undertake maintenance.
- Energy limits sourced from the 2025 EAAP Central scenario were applied to selected coal, gas, and diesel generators in New South Wales, Victoria, and South Australia to reflect advised ongoing limits on sustained operation. These limits were assumed to persist throughout the outlook period.
- Monthly energy production limits provided by participants as part of the Generator Energy Limitation Framework (GELF) for the Low Rainfall Scenario were applied to all hydro generators.

Figure 43 shows the outcomes of the *Drought Conditions* sensitivity relative to the *Generator Maintenance* sensitivity for the *Government Schemes and Actionable Developments* reliability assessment, while **Figure 44** shows the outcomes of the *Drought Conditions* sensitivity relative to the *Generator Maintenance* sensitivity for the *Committed and Anticipated Developments* reliability assessment.

Figure 43 Expected USE for the *Government Schemes and Actionable Developments* outlook, *Drought Conditions* sensitivity, 2025-26 to 2034-35 (% USE)

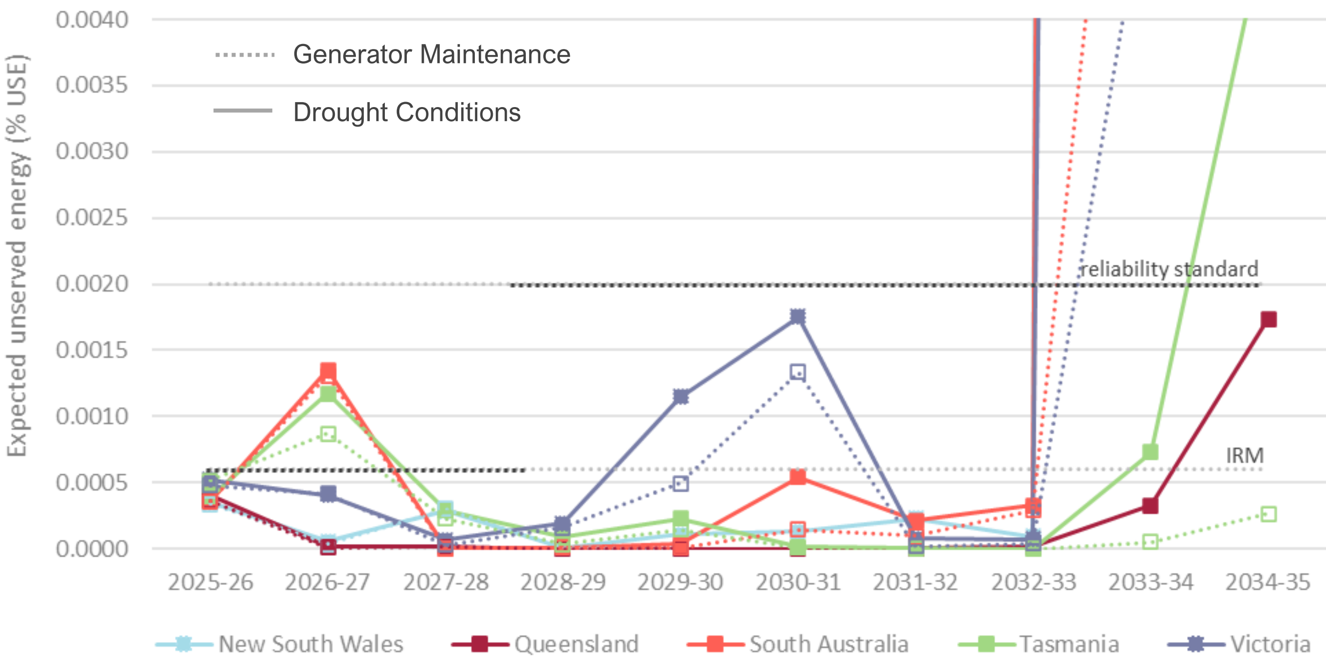
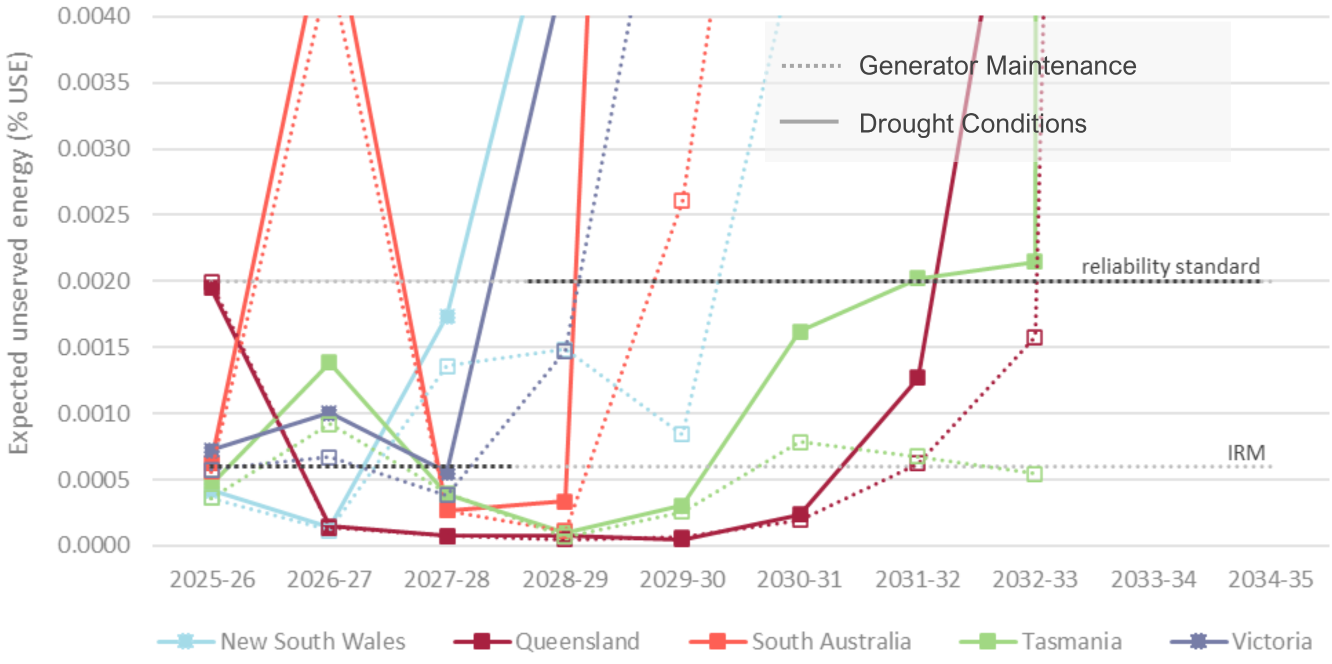


Figure 44 Expected USE for the *Committed and Anticipated Developments* outlook, *Drought Conditions* sensitivity, 2025-26 to 2034-35 (% USE)



These sensitivities applied drought conditions in all simulated years to enable comparison of normal versus drought condition results at any point of the 10-year horizon. The applied drought conditions would be extremely unlikely to persist across all simulated years, and if such conditions were expected then a greater structural response may be anticipated (through increased use of desalination facilities in the NEM to increase water supply). Increased desalination operation has not been applied in these sensitivities.

These sensitivities found the following:

- For the *Government Schemes and Actionable Developments* assessment:
  - In the first few years of the forecast there is little difference between the *Generator Maintenance* and the *Drought Conditions* sensitivities for each region, suggesting that risks identified are due to generator capacity shortfalls with ample energy production capability to replace lost hydro generation with alternative fuels and generator types during drought conditions.
  - From 2029-30, risks increase in Victoria and South Australia relative to the *Generator Maintenance* sensitivity, as there is insufficient redundancy in energy production capability to replace lost hydro generation without impacting power system reliability. While South Australia does not have any hydro generation, it is impacted by the reduced inter-connected support from hydro generation reductions in New South Wales and Victoria.
  - From 2033-34, energy supply shortfalls impact all regions under both sensitivities, which are worsened by the drought conditions.
- For the *Committed and Anticipated Developments* assessment:
  - Over the entire horizon, the *Drought Conditions* sensitivity consistently shows a higher level of risk than the *Generator Maintenance* sensitivity, suggesting that risks identified are due to both generator capacity

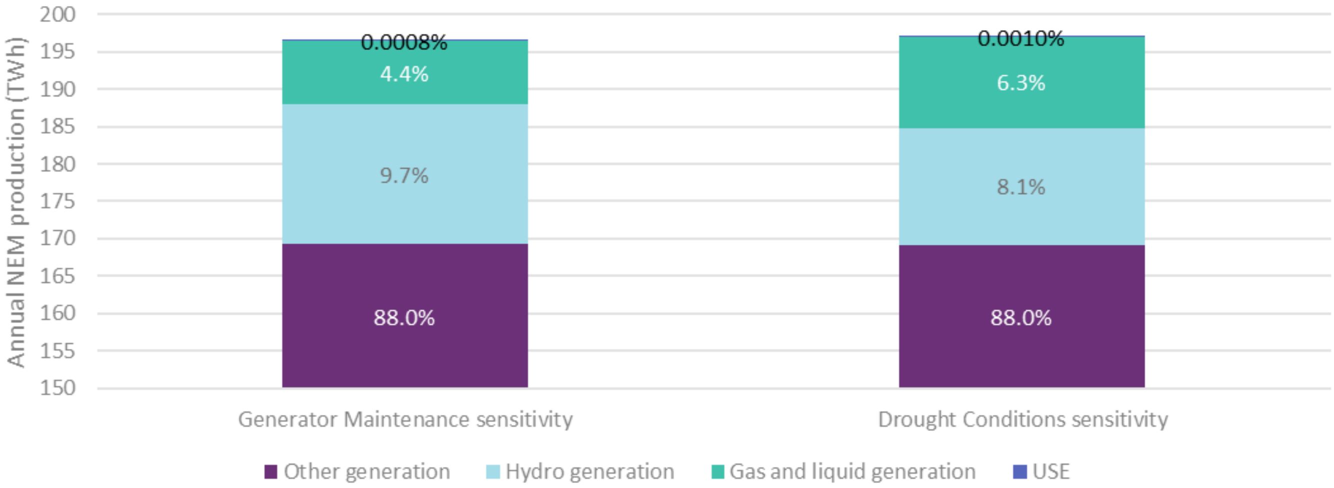
shortfalls and energy production shortfalls, and there is likely insufficient energy production capability to replace lost hydro generation with alternative fuels and generator types.

- When drought conditions occur, gas generation is the primary fuel or generation technology that is forecast to increase production to supply consumers and minimise power system reliability risks. **Figure 45** shows the annual modelled NEM generator production for the 2028-29 financial year for the *Drought Conditions* sensitivity on the *Committed and Anticipated Developments* assessment for the 2019 reference year. Gas and liquid fuel generation increase most significantly to offset the loss of hydro production capability, with only small fraction of reduced hydro generation leading to USE. The availability of gas supply to service this increase (as applied in the *Gas Shortfalls* sensitivity) has not been included, and the ability for gas and liquid fuel generators to increase operation to meet this higher needs to be a key consideration in such conditions.

This sensitivity:

- highlights that there are forecast conditions in which there is insufficient redundancy in energy production capability to fully accommodate drought conditions, and
- identifies the significant role gas generation is forecast to play in providing resilience to such events.

Figure 45 Total forecast NEM generation in 2028-29, *Generator Maintenance* and *Drought Conditions* sensitivities (TWh)



Note: Percentage labels reflect generation as a percentage of native demand, which sum to exceed 100% due to losses, battery and pumped hydro cycle efficiencies and other definitional differences.

List of tables and figures

Tables

Figures