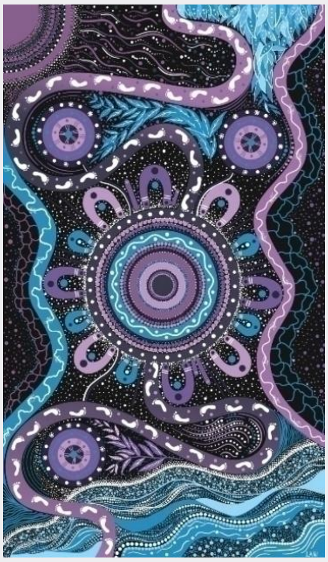
2026 Electricity Statement of Opportunities

for the National Electricity Market

August 2026

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.

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

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 2026 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.

Anyone proposing to use the information in this publication (which includes information and forecasts from third parties) should independently verify its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Copyright

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 2026-27 to 2035-36. It identifies where investment, demand flexibility and consumer energy resources (CER) may be needed to maintain reliability as demand grows, coal-fired generation retires, and the supply mix becomes more variable and distributed.

The 2026 NEM ESOO highlights that the NEM has a stronger pipeline of grid-scale generation and storage than in recent years, but maintaining reliability as demand grows and coal-fired generation retires remains highly dependent on timely delivery, operational availability, and the ability of resources to sustain supply during extended periods of system stress.

A pathway to maintaining reliability is clear, but delivery uncertainty remains.

Electricity demand is growing through electrification, new industries and large loads such as data centres, while consumers are playing a more active role in the power system through CER, energy efficiency and demand flexibility. At the same time, ageing coal-fired generation is retiring and being replaced by renewable generation, firming capacity and consumer resources.

Maintaining reliability increasingly depends on the timely delivery of these new resources, and ongoing investment will be needed in new sources of electricity supply to ensure sufficient electricity production and peak capacity is available to meet consumer needs throughout the next ten years.

The 2026 NEM ESOO highlights that electricity supply can be maintained at the level required by the reliability standard for much of the outlook period. This depends on the timely delivery of committed and anticipated developments, additional generation and storage under development that is supported through government schemes, actionable transmission developments identified in the 2026 *Integrated System Plan* (ISP), growth in coordinated CER, and greater demand flexibility. It also assumes coal-fired generators retire on their announced closure dates while maintaining high levels of availability and reliability prior to closure.

Under the ***Government Schemes and Actionable Developments*** reliability assessment, reliability is projected to be maintained within the reliability standard until:

- 2033-34 in New South Wales, South Australia and Victoria, and
- 2034-35 in Tasmania.

However, many of the developments underpinning this assessment have not yet progressed sufficiently to satisfy AEMO's commitment criteria, and are therefore subject to greater delivery uncertainty. For this reason, the NEM ESOO separately assesses reliability only including 'committed' and 'anticipated' developments, and reflecting commissioning delays observed in recent years. Under this ***Committed and Anticipated Developments*** assessment, the reliability standard is forecast to be exceeded:

- from 2030-31 in New South Wales and Victoria,
- from 2031-32 in South Australia,
- from 2032-33 in Queensland, and
- from 2033-34 in Tasmania.

Consumer and market investments are strengthening the pathway to maintain reliability.

- In 2025-26, approximately 9.1 gigawatts (GW) of new developments reached full output, more than double the capacity connected in 2024-25. Since the 2025 ESOO, approximately 24 GW of newly committed and anticipated generation and storage projects are progressing through the development pipeline, increasing total committed and anticipated capacity to 40 GW – more than half the total NEM capacity today. These developments must be delivered to improve the power system's ability to replace retiring coal-fired generation and meet growing electricity demand.
- A further 33 GW (approximately) of publicly announced generation and storage projects have been awarded government investment support, and were taken into account in the *Government Schemes and Actionable Developments* reliability assessment.
- These utility-scale developments complement significant uptake of home batteries, supported by the federal Cheaper Home Batteries Program (CHBP) which has added 2.4 GW/7.4 gigawatt hours (GWh) of household batteries since 1 July 2025[1], along with continued growth in rooftop photovoltaics (PV). In the past year, for every 1 megawatt (MW) of rooftop PV installed, 2.5 MW/7.7 megawatt hours (MWh) of storage has been installed in households across the NEM.

Reliability depends on timely delivery of a diverse mix of resources.

- Reliability will increasingly depend on multiple resources working together to provide sufficient energy, capacity and system flexibility. No single technology can provide all of the required services, and a diverse mix of technologies will be needed to maintain reliability through the transition.
- As coal-fired generation retires, timely delivery of renewable generation that is firmed by storage and backed up by gas, connected by networks and supported by growing consumer participation including demand flexibility will be needed.
- This diversity becomes increasingly important in winter, as households and businesses electrify heating, contributing to stronger growth in electricity demand at a time when solar resource availability in particular is lower.
- Maintaining reliability through this transition will also depend on existing ageing coal-fired generators remaining available and operating reliably until their announced retirement dates.

Reliability gaps are not identified at relevant Retailer Reliability Obligation (RRO) timings, and AEMO has the operational tools to mitigate supply scarcity risks as needed.

- Under the RRO framework, the 2026 NEM ESOO indicates:
  - no reliability gaps in 2027-28; no T-1 reliability instruments are requested, and
  - no reliability gaps in 2029-30; no T-3 reliability instruments are requested.
- Although supply scarcity risks are projected to be within the relevant reliability standard in the short term, AEMO will assess seasonal readiness and procure reserves through the Reliability and Emergency Reserve Trader (RERT) process as needed, to safeguard consumers in a cost-effective manner against a variety of adequacy risks.

A reliable power system also depends on ongoing investment in system security.

Alongside maintaining reliability, the energy transition is increasing the focus on system security. Timely investment in grid-supporting capabilities and essential system services will be required to support a secure and resilient power system as the share of inverter-based resources (generation and loads) continues to grow.

[1] Based on data available as at March 2026.

Definitions

The following definitions apply to this 2026 NEM ESOO:

- **Power system reliability** in the NEM ESOO refers to the sufficiency of electricity supply to meet demand in all periods of the year. This NEM 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.
- **Supply scarcity risk** refers to the risk that some level of involuntary load shedding may occur based on simulated outcomes.
- 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 supply scarcity risks, although events may be less probable.
- The **Retailer Reliability Obligation (RRO)** is a National Electricity Rules (NER) mechanism designed to maintain power system reliability at least cost by identifying forecast reliability gaps in advance and, where necessary, requiring liable market participants to secure sufficient generation, storage, demand response or contracting arrangements to support reliability.
- 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 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 eight hours) at a frequency of approximately one in every 15 years[2].
- 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 approximately one in every five years[2].
- 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.

[2] These frequencies are illustrative and based on 2026 NEM ESOO modelling where expected USE is close to the relevant threshold. They indicate the chance of these outcomes occurring in a year, rather than how often they will occur, and may vary between regions and years.

Electricity consumption and peak demand is forecast to grow significantly as business and households electrify and data centres emerge, even though investment in consumer energy resources are increasing self-supply and supporting greater energy management

The forecast increase in electrification of households and industry, together with projected strong growth in large loads such as data centres, is driving an increase in electricity consumption, and ongoing investment in CER is changing when and how electricity is used.

AEMO's forecasts considered the potential development of 225 known data centre projects, though the sector's expansion is not without challenge, with more than 40% of data centre projects since 2025 either dropping out or regressing in connection status. Data centre usage is projected to increase seven-fold over the next decade from current levels of 5 terawatt hours (TWh) to around 34 TWh, and to grow from approximately 3% of operational demand to approximately 13%. Data centre operators often indicate that new facilities may take five to 10 years to reach capacity. Consistent with international experience[3], mature data centres in aggregate are projected to utilise around 50% of their network connection capacity, and operate constantly with only minor increases in consumption during working hours, relative to non-working hours.

At the same time, consumers are continuing to invest in rooftop PV, household batteries and electric vehicles (EVs). These CER are becoming an important source of system flexibility, supporting reliability alongside investments in generation, storage and transmission.

Consumers are also investing in energy efficiency improvements that are tempering the increases in electricity consumption. By 2035-36, AEMO's *Step Change* scenario forecasts more than 20 TWh of avoided consumption, or approximately 9.5% of forecast wholesale-supplied consumption.

Together, these investments are changing how consumers use and supply electricity, influencing the shape and size of operational demand that needs to be supplied from the grid. Seasonal consumption changes are also being observed, with greater electrified heating loads increasing winter growth relative to growth in summer, a season that naturally has greater renewable energy resource scarcity due to the shorter days.

To maintain reliability, new supply must be delivered on time to replace retiring coal and meet growing demand

The NEM's generation mix is changing as ageing coal-fired power stations retire, increasingly replaced by renewable generation, firmed by storage, backed up by flexible gas generation, connected by transmission and complemented by consumer resources. As the generation mix evolves, reliability will increasingly depend on these resources working together to provide sufficient energy, capacity and system flexibility. No single technology can provide all of these services, and a diverse mix of technologies will be needed to maintain reliability through the transition.

While the development pipeline is strong for storage and solar investment, pathways for some technologies remain less certain. Although there are a number of proposed wind farms in early stages of development, a range of factors including project economics, contracting arrangements, transmission access, approvals, community acceptance and connection requirements can affect the ability of projects to progress to financial close and subsequently enter construction on anticipated timeframes. Given the complementary role different technologies play in maintaining reliability, delays in one

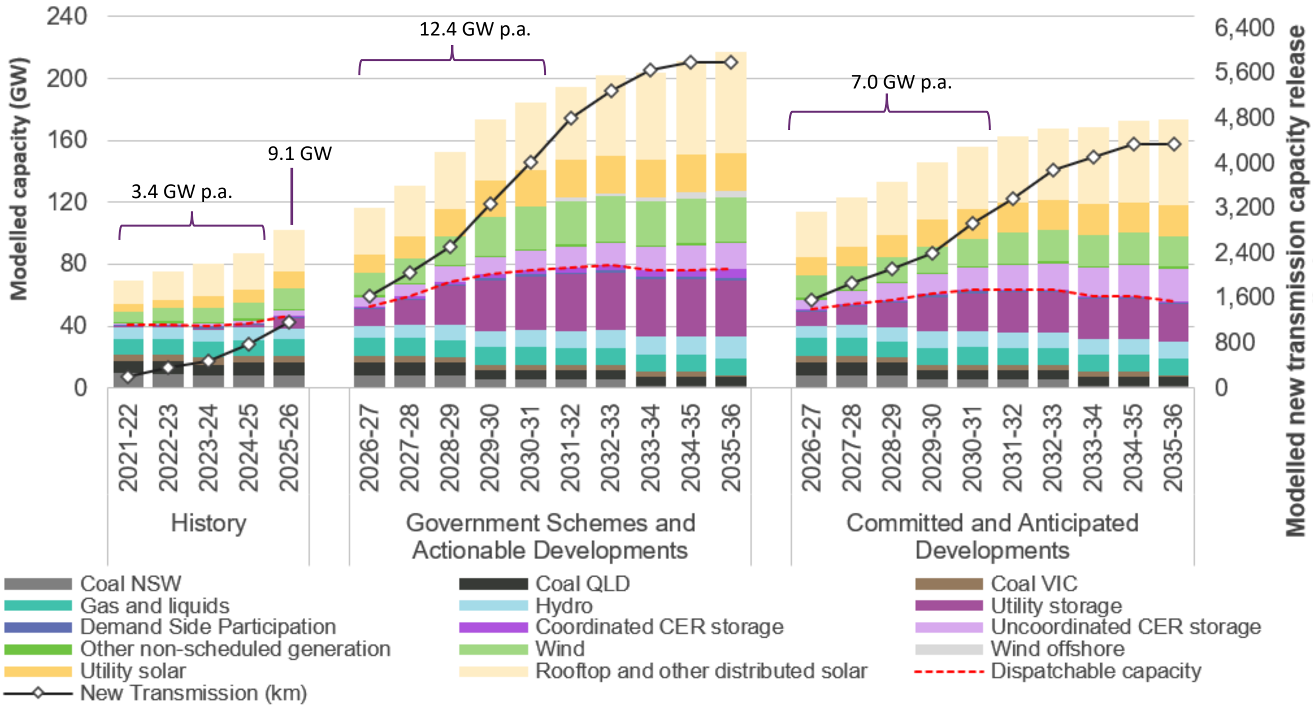
[3] Assumptions informed by analysis undertaken by the International Energy Agency. See https://www.iea.org/reports/energy-and-ai/.

part of the generation mix can increase reliance on the timely delivery and availability of others. In addition, gas generation can play an important role in supporting reliability during extended periods of low wind and solar output. Investment in new gas generation may also depend on complementary investment in gas infrastructure and fuel supply developments that cannot be facilitated by any individual project proponent. Broader support and clearer investment pathways from governments, customers, developers and fuel suppliers may therefore be needed to enable timely investment in the mix of resources needed to maintain reliability.

Figure 1 illustrates the scale of this transition over the next decade under two 2026 ESOO reliability assessments. The pace of new development has increased in recent years, with connected capacity increasing by 9.1 GW in 2025-26 alone. This growth is projected to accelerate as the current 40 GW pipeline of committed and anticipated renewable generation and battery storage developments connects, and as transmission expands to support their connection and effective operation[4].

While the development pipeline has strengthened materially since the 2025 ESOO, additional investments are needed to continue that momentum over time to replace the announced retirement of generators, particularly as the development pipeline for new generation plateaus from 2031-32.

Figure 1 Actual and forecast 10-year infrastructure development outlooks under typical summer availability assumptions (GW)



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

To assess reliability, the 2026 NEM ESOO provides two alternative reliability assessments. The ***Government Schemes and Actionable Developments*** reliability assessment included all developments identified as 'committed' or 'anticipated', as well as those developments supported by specific government schemes and funding programs, including completed

[4] 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 of over 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.

tenders[5] of the federal Capacity Investment Scheme[6] (CIS) as agreed through Renewable Energy Transformation Agreements (RETAs) with the states, other state-based schemes and other funding programs[7]. This assessment also included actionable transmission developments, growth in CER coordination through virtual power plants (VPPs), and forecast demand flexibility. The government-supported or actionable developments included in this assessment were:

- the Federal CIS (currently awarded projects, and RETA targets totalling 18.4 GW of generation or storage capacity only),
- the New South Wales Electricity Infrastructure Roadmap, and its firming tenders,
- a total of 11.5 GW/50.5 GWh of additional government-supported new storage developments across the NEM,
- a total of 14.4 GW of additional government-supported new wind developments,
- a total of 5.0 GW of additional government-supported new utility-scale solar developments,
- transmission projects identified in the 2026 ISP as actionable projects, including Victoria – New South Wales Interconnector West (VNI West), Sydney Ring North, Sydney Ring South, and Project Marinus Stage 2, and
- a total of 5.0 GW of new projected coordination of CER (largely behind-the-meter battery systems) – more than nine times the current level of coordinated CER – alongside 0.7 GW of new flexible demand response capacity.

Further investments in dispatchable capacity and renewable energy generation under these schemes and other proposed government initiatives such as the Electricity Services Entry Mechanism (ESEM) are also expected, but were not sufficiently identifiable to be modelled at this time.

The criteria for the ***Government Schemes and Actionable Developments*** assessment included a number of government-supported projects not yet identified as ‘committed’ or ‘anticipated’ and therefore subject to greater delivery uncertainty.

The RRO framework is designed to provide early signals to the market, allowing sufficient time for investment in or contracting of new capacity to address emerging reliability gaps at the lowest cost to consumers. Therefore, for RRO purposes, AEMO strictly applied commitment criteria in the ***Committed and Anticipated Developments*** reliability assessment, so reliability gaps are not masked due to reliance on projects with a higher degree of delivery uncertainty.

Specific projects included in this assessment for RRO purposes were:

- Kurri Kurri Power Station (750 MW open cycle gas turbine [OCGT]) in New South Wales from September 2026,
- Snowy 2.0 (2.2 GW/350 GWh) in New South Wales from December 2028,
- various utility-scale battery developments (18.9 GW /50.6 GWh) across the NEM,
- a total of 6.8 GW of wind and 9.1 GW of utility-scale solar generation developments, and
- transmission projects including Project EnergyConnect, HumeLink, Central-West Orana Renewable Energy Zone (REZ) Network Infrastructure Project, Hunter-Central Coast REZ Network Infrastructure project, Western Renewables Link, Gladstone Project, Project Marinus Stage 1, and New England REZ Network Infrastructure Project.

[5] All unawarded government targets are fully additional to those projects already considered committed or anticipated.

[6] This included up to CIS Tender 8; the tender winners for this round were announced on 24 June 2026. Further stages of the CIS were not included because the location, timing, and technology of the tenders is not yet specified.

[7] Including New South Wales Infrastructure Investment Objectives, Victorian Targets, Queensland funded projects, South Australian Firm Energy Reliability Mechanism (FERM), and Australian Renewable Energy Agency (ARENA)-funded projects.

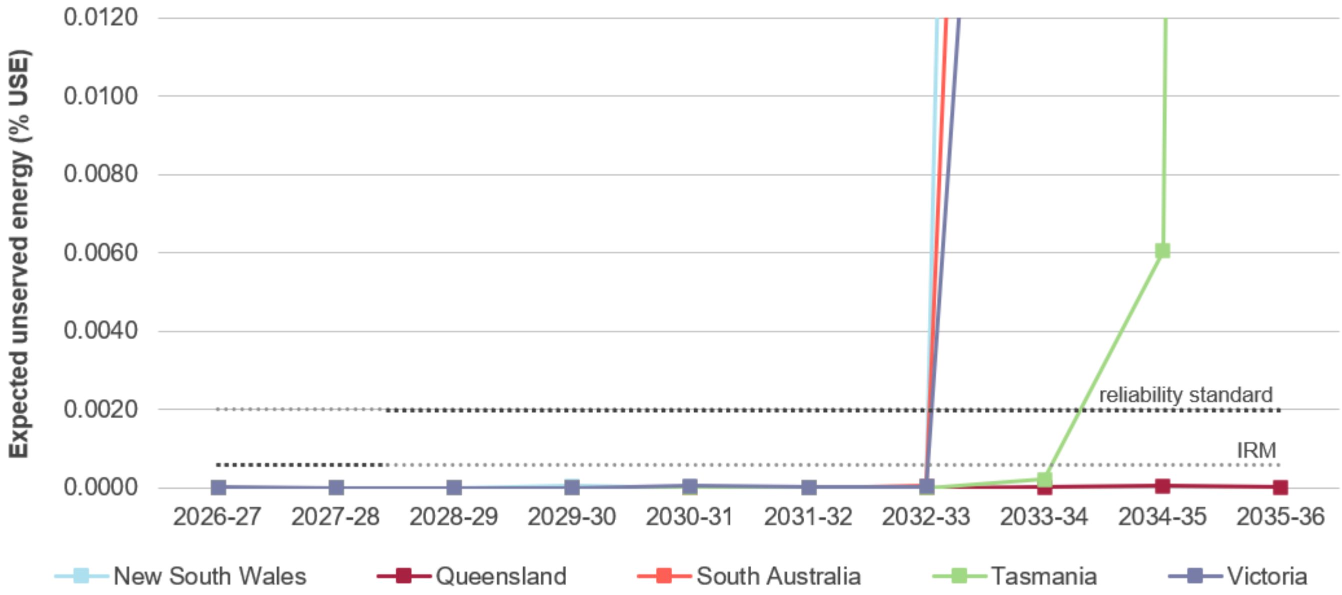
This assessment captured a materially smaller development pipeline than the ***Government Schemes and Actionable Developments*** assessment, with around 40% less capacity included on average over the next five years, and a plateau of new investment after 2031-32.

Maintaining reliability while generators retire depends on delivering new dispatchable capacity alongside generation resources that can supply rising consumption

The 2026 NEM ESOO shows that reliability increasingly depends on the interaction between growing electricity demand, the pace of coal-fired generator retirements, and the operational availability of energy-limited resources during periods of system stress. Sufficient energy, capacity and system flexibility is required to manage the impacts of weather variability.

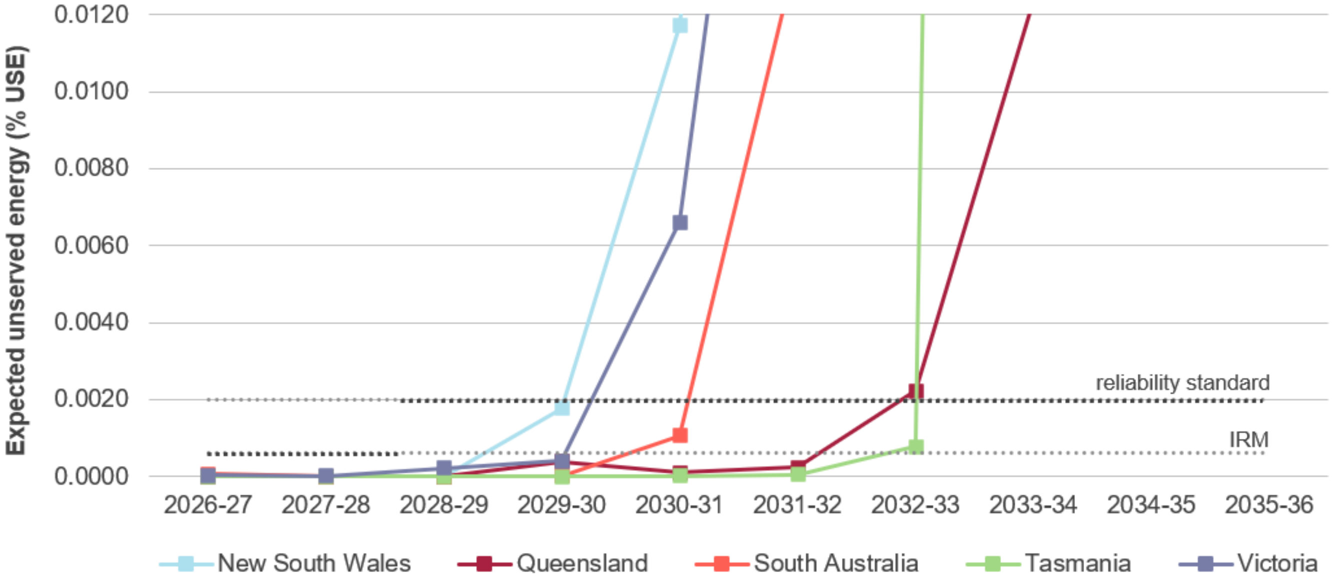
The outlook under the ***Government schemes and Actionable Developments*** assessment (shown in **Figure 2**) indicates that much of the capacity to replace retiring capacity is progressing, with indicative reliability gaps only emerging from 2033-34, although timely delivery is critical and further developments will still be required. Delays to major infrastructure projects could increase supply scarcity risks in some regions and years, particularly where replacement capacity is not available before generator retirements occur.

Figure 2 Expected unserved energy, *Government Schemes and Actionable Developments*, 2026-27 to 2035-36 (%)



With only those developments sufficiently mature to meet AEMO's commitment criteria progress, and recognising the risk of commissioning delays to these projects, as modelled in the ***Committed and Anticipated Developments*** assessment and shown in **Figure 3**, AEMO forecasts reliability gaps emerging in all NEM regions during the outlook period. To maintain reliability in the medium term, new generation, storage, transmission and flexible demand resources, such as those included in the ***Government schemes and Actionable Developments*** assessment, must become operational before retiring coal-fired generation exits the market.

Figure 3 Expected unserved energy, *Committed and Anticipated Developments*, 2026-27 to 2035-36 (%)



Replacement resources need to provide not only peak capacity, but the energy output that has historically been provided from retiring generators. The 2026 NEM ESOO includes consideration of fuel limits, hydro resource availability and asset maintenance requirements, which reveal that supply scarcity risks increase if insufficient resources to sustain energy supply are developed. AEMO's broader energy adequacy assessments similarly highlight increased energy adequacy risks during prolonged periods of low wind and solar output, reduced generator availability, and transmission constraints. Effective management of fuel supplies, water resources, and limited energy storage is critical to maintain reliability, alongside the timely delivery of replacement infrastructure and growing demand-side flexibility.

Reliability instruments and AEMO's operational toolkit will protect consumers by encouraging further investment and procurement of reserves, as needed

The *Committed and Anticipated Developments* reliability assessment, which is used for AEMO's reliability forecast, identifies reliability gaps[8] over the outlook period in:

- New South Wales from 2030-31,
- Victoria from 2030-31,
- South Australia from 2031-32,
- Queensland from 2032-33, and
- Tasmania from 2033-34.

[8] These forecast reliability gaps are identified against the current reliability standard (0.002% USE), and in the *Committed and Anticipated Developments* reliability assessment, the timing of reliability gaps is equivalent if assessed against the Australian Energy Market Commission (AEMC)-proposed revised reliability standard (0.003% USE).

Where this 2026 NEM ESOO reliability forecast identifies a forecast reliability gap for a region in either the T-1 (2027-28) or T-3 year (2029-30), AEMO must request the Australian Energy Regulator (AER) to consider making a reliability instrument under Chapter 4A of the NER (RRO).

No forecast reliability gaps are identified that require AEMO to request the AER to consider making a reliability instrument.

The reliability assessment used for RRO purposes in this 2026 NEM ESOO included about 26 GW of anticipated projects. By definition, these projects have reached fewer delivery milestones than committed projects and are therefore exposed to greater risk of delay or non-delivery. Their inclusion means no forecast reliability gaps are identified that would require AEMO to request the AER to consider making a reliability instrument.

Anticipated developments play a significant role in this outcome. If they had been excluded from the reliability assessment for RRO purposes, T-3 reliability instruments would have been requested in Queensland and New South Wales for 2029-30, following the closure of Gladstone and Eraring power stations. Under the RRO framework, because a T-3 reliability instrument will not be requested, there will be no opportunity to subsequently request a T-1 instrument for 2029-30 if anticipated developments do not proceed as expected.

While reliability is forecast to remain within the reliability standard, uncertainty remains around the timely delivery of future developments. If delivery risks were to materialise, operational measures such as the RERT may need to be relied on more heavily to manage emerging supply scarcity risks.

AEMO's reliability assessments included thousands of simulations that tested a wide range of weather conditions, demand outcomes and generation availability assumptions. While reliability is forecast to remain within the relevant reliability standard and IRM in the next few years, there remains a long tail of supply scarcity risk, meaning some combinations of events could still result in USE.

To manage these risks, AEMO maintains a panel of RERT providers across all NEM regions, which can be activated at short notice during periods of system stress if operational reliability challenges emerge. AEMO also undertakes seasonal readiness assessments and may procure additional short notice reserves where required. These arrangements provide additional safeguards for consumers and help manage operational risks in a cost-appropriate manner.

Maintaining a reliable power system will need investment to support continuing system security

The continuing retirement of synchronous generation, increasing penetration of inverter-based resources, growing uptake of CER and more frequent periods of low operational demand are changing how the power system is planned and operated. As identified in the 2025 *Transition Plan for System Security*, these changes increase the need for system strength, inertia, voltage management, frequency management and other essential system services to be available to maintain grid operability in all conditions, particularly during low load conditions.

System readiness for synchronous generation retirements therefore depends on the availability of replacement infrastructure and services to meet both reliability and system security requirements. As the power system continues to transition, maintaining system security will need timely investment in grid services to support secure operation of an increasingly high-renewable power system. Updated assessments of system security requirements, transition points and operational priorities will be provided in the 2026 *Transition Plan for System Security*.

Contents

1 Approach and requirements for assessing reliability

The ESOO in the NEM supports governments, market participants, investors and consumers by forecasting future consumer electricity demand and identifying emerging reliability gaps and the investments that can maintain reliability over the next 10 years.

The ESOO combines forecasts and projections of electricity demand, generation, storage, transmission capability, demand flexibility and CER to assess whether sufficient resources are expected to be available to reliably meet consumer needs within relevant reliability standards.

Prepared in accordance with clause 3.13.3A of the National Electricity Rules (NER), the NEM ESOO includes:

- projections of electricity demand and energy consumption for each region,
- electricity supply capability from generators, storages and considering demand flexibility, as well as network transfer capabilities from existing and relevant new developments,
- consideration of various power system limitations, including transfer capabilities under system-normal transmission capabilities, and the impacts of energy-generation limits for generators affected by resource constraints, and
- projections of regional power system reliability, including the reliability forecast covering the first five years of the assessment horizon developed in accordance with the requirements of the RRO.

The ESOO supports operation of the RRO through the publication of reliability forecasts and reliability gap assessments where required under the NER (see Appendix A1).

This publication also incorporates the Energy Adequacy Assessment Projection (EAAP, see Appendix A2), which provides an assessment of reliability over a two-year period under a range of alternate conditions that may affect electricity generation capabilities due to limited coal, gas or water availability.

In addition to providing reliability assessments and forecasts, AEMO has power system security assessment obligations under the NER. AEMO releases annual assessments of security requirements in the *Transition Plan for System Security*, which was first released in December 2024. This included declarations of shortfalls and gaps in system security services which are required to be addressed by transmission network service providers (TNSPs)[9].

1.1 Forecasting power system reliability

The ESOO assesses reliability by calculating expected USE per NEM region for each year of the forecast period. Expected USE represents the proportion of forecast consumer demand that cannot be supplied because available electricity

[9] 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.

resources and infrastructure is projected to be insufficient in the conditions forecast. Expected USE is a probabilistic measure based on many simulated operating conditions and should not be interpreted as the average customer experience of electricity interruptions.

Forecast expected USE is compared with the reliability thresholds specified in the NER to assess whether forecast electricity resources are sufficient to maintain reliability to the determined standards. These thresholds define the maximum acceptable level of expected USE over a financial year in any region.

There are two relevant standards that are considered in the 2026 NEM ESOO – the IRM and the reliability standard. Together, these measures provide the framework for identifying emerging reliability gaps and assessing whether additional investment or regulatory actions may be required. Further information on the reliability framework established under the NER, including expected USE, the IRM and reliability standard, is in Section 2.3.

1.1.1 Updates and improvements for forecasting reliability in this 2026 NEM ESOO

Following consultation on the 2025 *Forecast Accuracy Report*[10] and *Forecast Improvement Plan*[11], together with other stakeholder engagement during the development of the 2026 ESOO, AEMO has updated its NEM forecasts and supply adequacy assessment published in this ESOO by:

- updating demand forecasts for all regions, reflecting updated information on population and economic growth, electrification, large industrial loads (LILs), emerging data centre developments and consumer behaviour – the forecasts also incorporate updated assumptions for energy efficiency and the uptake of CER, including rooftop PV systems[12], battery energy storage systems (BESS) and EVs. Section 1.2 provides further information on the demand forecasts,
- updating available utility-scale electricity supply by reflecting the latest information on generation, storage and transmission investments in the NEM, as well as expected generator closures in AEMO's most recent *Generation Information* update[13],
- updating generator reliability assumptions through:
  - an enhanced outage forecasting methodology, including expanded outages representation to include planned and maintenance outages, and
  - forward-looking generator reliability for coal and large gas-powered generators that consider historical availability, maintenance plans, asset aging, and advised and/or estimated reductions in maintenance as generators approach retirement, and
- enhancing consideration of energy adequacy by including fuel and resource availability, represented by station-level generator energy limits and hydro weather reference year inflows.

[10] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/2025-forecast-accuracy-report.pdf.

[11] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-forecast-improvement-plan-consultation.

[12] 'Rooftop PV' means residential and small commercial systems up to 100 kW. Distributed PV also includes larger systems in the distribution network from 100 kW to 30 MW, referred to as PV non-scheduled generation (PVNSG). Rooftop PV accounts for about 90% of distributed PV capacity.

[13] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

AEMO has published relevant updated methodologies to support this 2026 NEM ESOO, in the *ESOO and Reliability Forecast Methodology*[14] and the *Electricity Demand Forecasting Methodology*[15].

Discussion and further information on how to interpret the reliability assessment outcomes is in Section 2.3.

1.2 The terminology of demand

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.

Electricity consumption and demand forecasts for the 2026 NEM ESOO were developed using AEMO's updated Forecasting Approach, specifically its updated *Electricity Demand Forecasting Methodology*, following stakeholder consultation during 2025-26. Consistent with the improvements identified and consulted on through the 2025 Forecast Improvement Plan, the 2026 NEM ESOO incorporates several enhancements to the demand forecasting methodology. These include:

- improved distributed PV modelling using metered data and machine learning techniques,
- explicit incorporation of consumer behaviour trends where residual demand growth is observed,
- introduction of outage factors for LILs, and
- refined modelling of business energy intensity.

These enhancements improve the representation of changing consumer behaviour and electricity use, resulting in greater accuracy confidence in the forecasts of electricity consumption and operational demand.

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)**[16]. Operational consumption/demand (sent out) is, the electricity supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators. It excludes the electricity that generators use themselves to operate equipment such as pumps, fans and cooling systems. This definition also excludes electricity consumed by scheduled loads, such as pumped hydro energy storage (PHES) when pumping water and large-scale batteries when charging.

This ESOO also reports consumption forecasts for each sector (residential and business). This is provided 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.

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

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

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

Electricity consumption and demand may be forecast at two alternative 'measurement points':

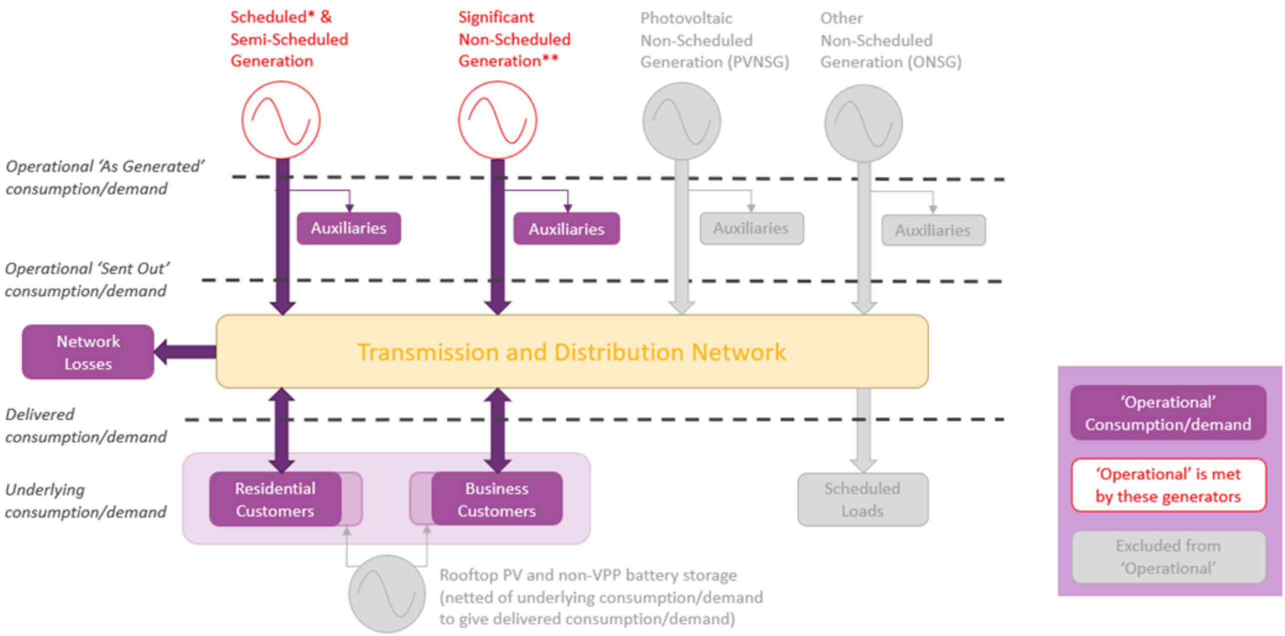
- as **sent out** (the electricity measured at generators' terminals), or
- **as generated** (including auxiliary loads).

Maximum and minimum operational demand forecasts can be presented with:

- 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 exceeded 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.

Figure 4 summarises the demand definitions used throughout this report. Section 3.1 presents the demand and energy forecasts using these definitions.

Figure 4 Demand definitions used in this report



* Including VPPs, representing an aggregation of resources coordinated to deliver services for power system operations and electricity markets. VPPs enable the coordinated control of consumer-scale batteries and other distributed energy resources.
** 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.

1.3 Regulatory requirements and supporting information

The 2026 NEM ESOO has been prepared in accordance with clause 3.13.3A of the NER. The NEM ESOO should be read together with the supporting information published on AEMO's website. These supporting materials provide the assumptions, forecasts and input datasets that underpin the reliability assessment and form part of the NEM ESOO for the purposes of the NER.

Table 1 summarises the information published with the 2026 NEM ESOO and identifies the supporting material that forms part of the reliability forecast and related regulatory obligations.

Table 1 National Electricity Rule (NER) requirements

Information that should be considered part of this 2026 NEM 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 2026 NEM ESOO report and all supplementary information published on the 2026 NEM ESOO webpage • The demand forecasting data portal [A] • The July 2026 Generation Information page [B] • The August 2026 Transmission Augmentation Information page [C] • The 2025 *Inputs, Assumptions and Scenarios Report* (IASR), accompanying assumptions workbook and supplementary material [D] • The 2026 Forecasting Assumptions Update [E], accompanying assumptions workbook and supplementary material.	• The reliability forecast and indicative reliability forecasts published in Appendix A1, RRO • Consumption and demand forecasts (Section 3, the demand forecasting data portal [A] and the demand traces) • Supply forecasts (Section 3) • The July 2026 Generation Information Page [B] • Sections of the 2026 Forecasting Assumptions Update [E] that comprise the forecasting components of the forecasting approach for ESOO and Reliability Forecast purposes: – Annual consumption forecast components (Section 2.2) – CER forecasts (Section 2.2.1) – Demand-side participation forecasts (Section 2.2.8) – Generator outage rates (Section 2.3.1) – Inter-regional transmission unplanned outage rates (Section 2.3.2) – Generator energy limits (Section 2.3.3)
Information published as part of this NEM 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.
E. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

2 Reliability assessment framework and interpretation

This section explains the assessments used to forecast reliability in the ESOO. It describes the core reliability assessments and targeted sensitivities. It also sets out how reliability outcomes are assessed against the IRM and reliability standard.

2.1 Overview of forecast scenarios, reliability assessments and sensitivities

In consultation with stakeholders, AEMO developed the 2025 *Inputs, Assumptions and Scenarios Report* (IASR) for use in its forecasting and planning publications, including the 2026 NEM ESOO and the 2026 ISP. Further, AEMO has developed the 2026 *Forecasting Assumptions Update* to update a subset of inputs and assumptions relevant to the 2026 NEM ESOO.

The 2025 IASR included definitions of three scenarios to plan the power system and identify the investment needs. **Table 2** provides descriptions of these scenarios, and a subset of key parameters most relevant to forecasting and assessing reliability.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2026 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 a challenging investment environment. 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 and globally, 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 policy coordination	Moderate economic growth, stronger policy coordination	High economic growth, stronger policy coordination

Parameter	*Slower Growth*	*Step Change*	*Accelerated Transition*
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

The NEM ESOO performs its reliability assessment by applying the demand components of these scenarios and identifying the additional supply requirements to maintain reliability. For the purposes of the ESOO reliability analysis and evaluating the RRO, AEMO considers the *Step Change* scenario as the most likely and AEMO has considered the demand outlook of this scenario in all reliability assessments and targeted sensitivities.

In conducting reliability analysis, the ESOO's reliability assessments considered only those generation, storage, transmission and CER developments sufficiently meeting AEMO's commitment criteria or otherwise adequately progressing with government support. By reflecting only those developments sufficiently under active development, the ESOO identifies further investment opportunities needed to maintain reliability. This compares to the ISP, which identifies an optimal mix of generation, storage and network solutions to meet future power system needs and achieve eligible government policy, including developments that extend past identifiable project in the development pipeline.

This 2026 NEM ESOO includes two reliability assessments that explore varied supply (including supply from consumers' own energy resources) and network development assumptions over a 10-year forecast period:

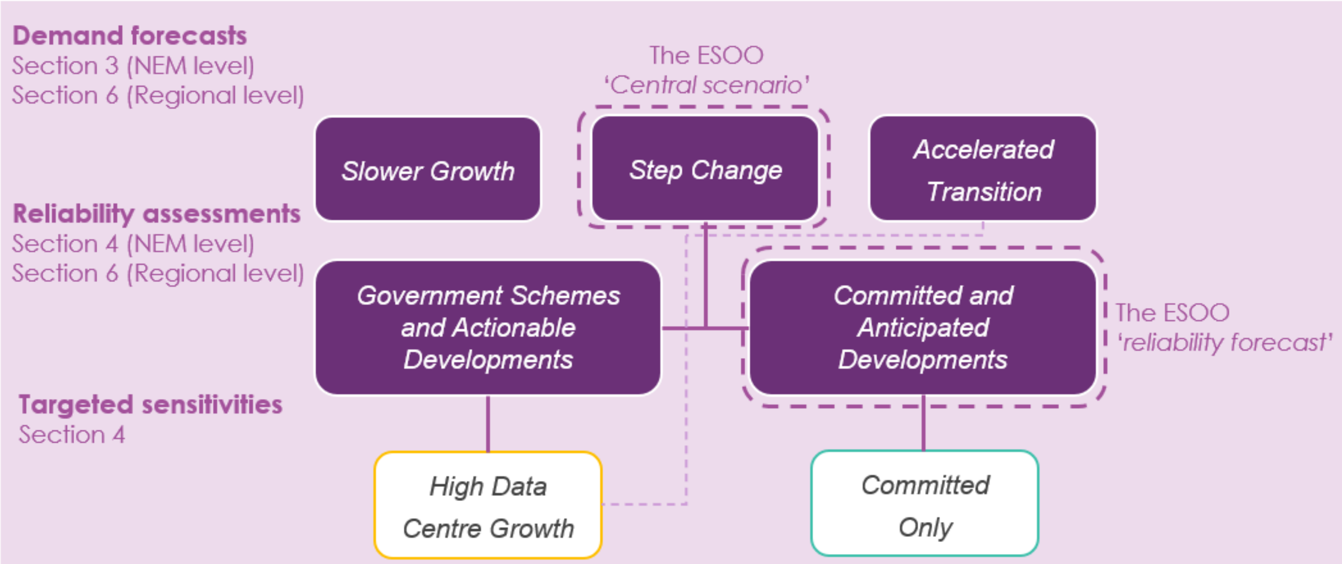
- *Government Schemes and Actionable Developments* – assumed all in-commissioning, committed and anticipated generation, storage and transmission developments are delivered on time. In addition, on-time delivery of projects and generation technologies specifically supported by government schemes that have clear delivery mechanisms, forecast levels of CER coordination and demand-side participation (DSP), and the on-time development of actionable transmission projects identified in the 2026 ISP.
- *Committed and Anticipated Developments* – assumed all generation, storage and transmission developments that were existing or classified as committed or anticipated against AEMO's commitment criteria. These projects are delivered subject to recently observed commissioning delays. The assessment also included existing and committed levels of CER coordination and demand flexibility identified by DSP providers. Developments that had not yet reached AEMO's committed and anticipated classifications, including actionable transmission projects and many government- supported projects that were within the *Government Schemes and Actionable Developments* assessment but still progressing through funding, planning, or regulatory processes, were excluded in this assessment.

In addition to these core reliability assessments, the 2026 NEM ESOO includes two additional sensitivities to explore key areas of uncertainty that may impact investment opportunities and supply scarcity risks. These are explained in greater detail in **Section 2** and include:

- *High Data Centre Growth* that considered the impact of faster growth of this emerging industry, and
- *Committed Only* developments, to demonstrate the importance of continuing to progress the development of projects that are anticipated.

Figure 5 highlights the relationship between the scenarios, the reliability assessments, and targeted sensitivities in this NEM ESOO.

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



2.2 Reliability assessments and sensitivities

The NEM ESOO presents two core reliability assessments, complemented by several targeted sensitivities. Together, they assess future power system reliability by considering different development pathways and testing how reliability may change under important sources of uncertainty.

The core reliability assessments examined the reliability outlook under different assumptions about the delivery of generation, storage, transmission and consumer resources. The targeted sensitivities explored specific uncertainties that may influence reliability, such as project delivery, coordination of consumer resources, and emerging electricity demand.

Together, these assessments help identify:

- the projected reliability outlook under different development pathways,
- what need there is to trigger consumer protection mechanisms such as the RRO, to support timely investment to maintain reliability,
- what additional investments are needed to maintain reliability over the outlook period, and
- how sensitive that outlook is to key uncertainties affecting the future power system and consumer demand.

2.2.1 Reliability assessments

The two core reliability assessments of this NEM ESOO illustrate how reliability outcomes may differ under alternative assumptions about project delivery for utility-scale developments, transmission developments, and CER. These assessments identify whether more investments are needed to support reliability, may trigger development support via the RRO to protect consumers, as well as assisting to demonstrate the significance of projects being delivered in time for, and ahead of, announced generator closures.

Both assessments applied the *Step Change* demand forecast along with generator retirements in accordance with advice provided by market participants while maintaining high levels of availability and reliability until closure.

Comparing the assessments highlights the actions that are necessary to maintain reliability across the forecast horizon, including potentially placing obligations on retailers to protect consumers from forecast reliability gaps via the RRO. The comparison between the assessments also demonstrates the role that on-time project delivery, consumer resource coordination and policy-supported developments are projected to play in maintaining reliability over the outlook period.

The two core reliability assessments in this 2026 NEM ESOO are:

- *Committed and Anticipated Developments*, and
- *Government Schemes and Actionable Developments*.

The ***Committed and Anticipated Developments*** assessment considered only those developments that meet or exceed AEMO's project commitment criteria of anticipated projects. This included existing generation and storage assets, projects in commissioning, and committed and anticipated generation, storage and transmission developments.

The assessment applied commissioning delays to project commencement dates provided by project proponents for committed and anticipated generation, storage, and transmission projects to reflect recently observed commissioning delays.

This assessment represents the most reliable estimate of generator, storage and transmission projects that are in development and will be operational to support of energy needs in the next three years. By including only those projects sufficiently progressed to meet AEMO's committed and anticipated commitment criteria, it included advanced developments without assuming further supply developments that are yet to sufficiently demonstrate their commitment to proceed. This assessment therefore is aligned to AEMO's *Reliability Standard Implementation Guidelines*[17], and forms the basis of AEMO's reliability forecast and indicative reliability forecast under the NER. A s such, it is the primary assessment used for regulatory purposes, including informing the RRO framework, and identifying potential requirements for the Reliability and Emergency Reserve Trader (RERT).

The ***Government Schemes and Actionable Developments*** assessment provides a forward-looking view of how reliability may evolve if additional government-supported generation and storage developments, actionable transmission projects and coordinated consumer resources are delivered as planned.

The assessment builds on the *Committed and Anticipated Developments* assessment by including additional developments supported through government policies, schemes, and targets, together with actionable transmission investments, forecast coordination of CER and flexible demand resources.

This assessment assumed these additional developments are delivered on schedule and did not apply commissioning delays to project commencement dates provided by project proponents, and assumed on-time delivery.

[17] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines.

2.2.2 Targeted sensitivities

In addition to the core reliability assessments, the ESOO considered two additional sensitivities to explore key uncertainties influencing future reliability, examining key assumptions.

The 2026 ESOO includes the following targeted sensitivities:

- ***High Data Centre Growth*** – assessed how stronger forecast growth in electricity demand from data centres could impact reliability outcomes over 2030-31 to 2035-36, when data centre demand is projected to grow materially beyond the already significant levels included in AEMO's *Step Change* forecast. Considering high uncertainty associated with data centres development growth and digital services usage, the sensitivity examined the investments that may be required to support reliable supply for all consumers with higher data centre development and use.
- ***Committed Only*** – examined the extent to which future reliability depends on projects currently in the development pipeline. This sensitivity was based on the *Committed and Anticipated Development* assessment but excluded anticipated projects. Since the 2025 NEM ESOO, AEMO has identified approximately 18 GW of newly anticipated projects (and a further 5 GW of newly committed projects), which is a significant volume of projects and scale of capacity. The sensitivity is important therefore to demonstrate the critical role that the large pipeline of anticipated projects is providing to maintain reliability, and therefore demonstrate the additional reliability gaps that could arise if those projects do not proceed as expected. The sensitivity was assessed for 2028-29 to 2031-32, reflecting the period when most anticipated projects are assumed to enter service and when their commissioning overlaps with major coal-fired generator retirements across the NEM.

Table 3 outlines the purpose of each assessment and sensitivity, including the questions they are designed to inform and guidance on how the results can be interpreted. **Table 4** highlights the key assumptions that distinguish the assessments. Together, these tables provide a reference to support interpretation of the reliability results presented in this report.

Table 3 Purpose of each reliability assessment and targeted sensitivity

Assessment	Type	Purpose	Interpretation
Committed and Anticipated Developments	Reliability assessment	What is the outlook based on developments that satisfy AEMO's project committed and anticipated commitment criteria?	Forms AEMO's *reliability forecast* and *indicative reliability forecast* under the NER and supports regulatory processes including the RRO.
Government Schemes and Actionable Developments	Reliability assessment	How could reliability improve if government-supported generation, storage, actionable transmission and coordinated CER are delivered broadly as planned?	Illustrates how government-supported investment, transmission delivery and coordinated consumer resources could influence future reliability.
High Data Centre Growth	Targeted sensitivity	How could stronger-than-forecast growth in data centre demand affect investment needs?	Illustrates how higher data centre loads could increase reliability needs and create opportunities for additional investment to maintain customer reliability.
Committed Only	Targeted sensitivity	How dependent is future reliability on projects that have not yet progressed beyond committed status?	Illustrates the importance of projects currently progressing through the development pipeline and the potential implications of slower project progression.

Table 4 Key assumptions of each reliability assessment and targeted sensitivity

	Reliability assessment		Targeted sensitivity	
Modelling inputs	***Government Schemes and Actionable Developments***	***Committed and Anticipated Developments***	***High Data Centre Growth***	***Committed Only***
Demand forecast (see Section 3.1)	*Step Change*	*Step Change*	*Step Change* with higher data centre growth from *Accelerated Transition*	*Step Change*
CER coordination and demand flexibility (see Section 3.1.1)	The uptake of CER coordination and demand flexibility as projected by AEMO's 2026 *Forecasting Assumptions Update*	The currently committed levels of CER coordination and demand flexibility only. Forecast CER uptake beyond committed levels remain consistent with the 2026 *Forecasting Assumptions Update*, and assumed to operate passively.	Same as *Government Schemes and Actionable Developments*	Same as *Committed and Anticipated Developments*
Generation and storage developments (see Section 3.2.1)	On time delivery of all in commissioning, committed, anticipated developments. On time delivery of government schemes supported by delivery mechanisms [A].	Delivery of all in commissioning, committed and anticipated developments, subject to recently observed commissioning delays [B]	Same as *Government Schemes and Actionable Developments*	Delivery of all in commissioning and committed developments, subject to recently observed commissioning delays.
Transmission developments (see Section 3.2.6)	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	Same as *Government Schemes and Actionable Developments*	Same as *Committed and Anticipated Developments*
Generation and storage retirements (see Section 3.2.2)	All retirements applied at the dates advised by operators.			
Operability assumptions (see Sections 3.2.4 and 3.2.5)	Included generator and storage forced, planned, and maintenance outages, as well as station level energy limits. Expected USE reflects average outcomes for all 24 weather reference years modelled.			

A. Section 3.2.1 outlines the government schemes considered under the *Government Schemes and Actionable Developments* assessment. Refer to the 2026 *NEM ESOO Results Workbook* for the specific projects included in each region in this assessment.
B. For the *Committed and Anticipated Developments* assessment, committed projects were assumed to be delayed by six months from the developer-advised full commissioning date. Anticipated projects were assumed to be delayed to the later of 1 July 2028 or one year after the developer-advised full commissioning date.

2.3 Understanding unserved energy and reliability measures

This section explains the reliability measures used throughout the ESOO and how they relate to the reliability assessments presented in later sections and required under the NER. Reliability in the NEM is assessed against the applicable standards, including the IRM and reliability standard, using the measure of 'expected USE'.

2.3.1 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[18] or other voluntary curtailment. For example, USE could be caused by:

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

- 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 (LOR) 3 events[19], but not all LOR 3 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 network outages that curtail generation, resulting in insufficient levels of supply relative to demand, while not materially affecting power transfers between regions[20],
- 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 the 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 gaps 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 gaps as demand needs are met from a combination of variable resources, short and medium duration storages and energy limited generation.

Expected USE provides a consistent measure of whether forecast electricity resources are sufficient to meet consumer demand under a wide range of operating conditions and forms the basis of AEMO's reliability assessments. Comparing forecast expected USE with the applicable standard enables AEMO to assess whether forecast reliability meets the requirements of the NER and whether further regulatory actions may be required.

2.3.2 Reliability measures in the NEM

The ESOO measures reliability forecasts relative to two standards determined by the Australian Energy Market Commission's (AEMC's) Reliability Panel:

- The **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.

[19] The Lack of Reserve Framework is explained in the fact sheet at https://www.aemo.com.au/-/media/files/learn/fact-sheets/2023/lor-fact-sheet.pdf?rev=9cb9157ee6874695bb827415e4c98b49&sc_lang=en.

[20] See Section 3.2.7 for the inter-regional transmission flow paths for which unplanned outages are represented in the ESOO reliability modelling.

- 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.

The Reliability Panel has recommended a revised reliability standard of 0.003% expected USE, proposed to take effect from 1 July 2028[21], subject to the completion of consultation and the necessary NER amendment processes. As these processes have not yet concluded, the revised standard does not apply to the 2026 NEM ESOO. Accordingly, all reliability assessments and any associated RRO obligations were assessed against the relevant reliability standards currently prescribed in the NER.

While a potential relaxation of the reliability standard does not impact whether reliability is forecast to be met or not in the 2026 NEM ESOO, a relaxed standard would broaden the gap between the investment identified to support forecast reliability in the ESOO and the actions that may be needed ahead of and during operational timeframes to maintain reliable supply in dispatch.

The reliability thresholds are expressed as the cumulative proportion of expected USE relative to the total energy consumed in a region for a financial year, as determined through statistical analysis of potential conditions that may impact the scale of demand and the capability to supply that demand. They do not specify how frequently USE may occur, or the size or duration of individual load shedding events.

Table 5 presents insights from the 2026 ESOO probabilistic modelling where forecast expected USE in a region is close to either standard. It is intended to help readers interpret these reliability thresholds by relating annual expected USE to indicative frequencies and magnitudes of unserved energy. Unlike the threshold equivalencies, these results reflect the distribution of simulated USE outcomes and may vary by region and year.

Given the statistical modelling approach, load shedding events of even greater magnitude than these averages are possible 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 5 Expected reliability outcomes when expected USE is forecast at the level of the reliability standards [A]

Outcomes	Under the IRM of 0.0006% expected USE	Under the reliability standard of 0.002% expected USE	What this means
Frequency of any USE	Statistically, USE events would occur approximately one year in 10.	Statistically, USE events would occur approximately one year in three.	The frequency of USE depends on the distribution of simulated annual USE outcomes and is not defined by the thresholds.
Frequency of larger USE outcomes [B]	Statistically, larger annual USE outcomes would occur approximately one year in 15. An illustrative equivalent is an event involving approximately 10% of average regional demand for eight hours, or multiple events that aggregate to a similar annual USE.	Statistically, larger annual USE outcomes would occur approximately one year in five. An illustrative equivalent is an event involving approximately 10% of average regional demand for nine hours, or multiple events that aggregate to a similar annual USE.	Larger annual USE outcomes are less frequent than any USE events but occur more often under the reliability standard. The illustrative annual USE outcomes assume the same event magnitude under both thresholds. The higher expected USE under the reliability standard is mainly reflected in larger USE outcomes occurring more often, resulting in similar illustrative event sizes.

A. The frequencies shown are illustrative and are based on the 2026 NEM ESOO *Committed and Anticipated Developments* reliability assessment modelling. They are intended to help interpret the IRM and reliability standard and should not be interpreted as fixed properties of these thresholds. Actual reliability outcomes vary between regions and years.
B. Larger USE outcomes are defined as annual USE exceeding the reliability standard (0.002% of annual regional demand). These frequencies are illustrative. They indicate the chance of these outcomes occurring in a year, rather than how often they will occur, and may vary between regions and years.

[21] See https://www.aemc.gov.au/market-reviews-advice/2026-reliability-standard-and-settings-review.

2.3.3 Reliability gaps and reliability instruments

The NEM ESOO publishes two forms of reliability assessment under the NER: the **reliability forecast** and the **indicative reliability forecast**. Together, these forecasts provide both the regulatory assessment required under the NER and a longer-term view of potential reliability gaps that may warrant future investment or planning.

For the purposes of the RRO:

- The reliability forecast is the first five years of the *Committed and Anticipated Developments* reliability assessment. For the 2026 ESOO, the reliability forecast covers the financial years 2026-27 to 2030-31.
- The indicative reliability forecast is the second five years of the *Committed and Anticipated Developments* reliability assessment. For the 2026 ESOO, the indicative reliability forecast covers the financial years 2031-32 to 2035-36.

A **reliability gap** exists where the assessed expected USE exceeds the applicable reliability threshold for a region and year.

The identification of a reliability gap does not mean involuntary load shedding is certain to occur. Rather, it indicates that, under the assumptions adopted in the reliability assessment, expected USE is forecast to exceed the applicable reliability threshold and additional investment, operational or regulatory actions may be required to maintain reliability.

Where forecast reliability gaps are identified within the reliability forecast period, AEMO must apply the processes specified in the NER, including requesting the AER to consider making reliability instruments under the RRO where required. AEMO may also consider operational measures, including the RERT, where appropriate to maintain power system reliability. Further information on the RRO framework and reserve procurement arrangements for the 2026 NEM ESOO is in Appendix A1.

3 Forecast electricity demand, and the infrastructure to supply it

Electricity consumption and demand are central to AEMO’s assessment of reliability outcomes across the NEM. Forecasting of economic activity that uses electricity, new growth trends such as electrification and data centre developments, and the ways that consumers use, avoid or reduce their electricity usage through self-supply and energy savings activities are critical to assessing reliability.

Key trends continue to follow AEMO’s 2025 NEM ESOO forecasts, with several key exceptions:

- CER are forecast at greater levels than the 2025 NEM ESOO, reflecting continued consumer trends and a variety of state and federal policies, including the CHBP.
- Although consumers’ own supply is forecast higher, stronger electricity consumption growth is projected compared to the 2025 NEM ESOO, driven by continued expansion of data centres, increased industrial load from mining and metallurgy, and increasing underlying consumption per residential dwelling as more households switch to using electricity to provide thermal comfort and transportation.
- Maximum operational demand forecasts are broadly similar to the 2025 NEM ESOO, with projected growth aligned with the factors that influence rising electricity consumption across the year, particularly from increasing electrification, data centre development, and industrial load activity. Electrification is also reshaping seasonal electricity demand, with increased use of electricity for space heating contributing to faster growth in winter demand than in summer.
- Minimum operational demand continues to decline, driven primarily by increasing rooftop PV uptake, although the rise of home battery adoption (in stationary home batteries, and in vehicles) and the growth of business and industrial loads, including for digital services provided by data centres, is helping to slow this rate of decline.

As a consequence of these trends, both the volume and pattern of operational consumption continue to evolve. Increasing uptake of CER is changing the amount of electricity consumers draw from the grid and making operational consumption more sensitive to solar availability and battery charging and discharging behaviour. At the same time, electrification, data centre development and industrial load growth are increasing electricity consumption and reshaping when electricity is used. As a result, operational consumption is becoming more variable throughout the day and increasingly sensitive to seasonal and weather-related conditions.

3.1 Electricity consumption and demand outlook

Electricity consumption and demand across the NEM is being reshaped by a combination of structural, policy-driven and economic factors that are forecast to increase overall consumption and materially change demand profiles:

- **CER,** including rooftop PV and batteries, continue to shape operational demand and reduce grid consumption that would have otherwise been required, while introducing new dynamics through storage and load shifting which are helping moderate demand during peak periods.

- **Underlying residential consumption** is forecast to increase, reflecting trends towards higher appliance, and higher temperature responsiveness, in many regions.
- Rapid growth in **data centres**, driven by increased artificial intelligence (AI) adoption and cloud services, remains one of the most significant sources of forecast growth and uncertainty as a strong pipeline of projects is evident in grid connection enquiries.
- **Industrial activity**, particularly in mining and smelting, continues to represent a large portion of electricity consumption and demand, with a mix of new projects driving growth and near-term site closures impacting the forecast.
- **Electrification of households, industrial processes and transport through EV uptake** is a dominant structural driver of long-term growth across both residential and business sectors, affecting electricity consumption and demand and the balance of consumption between summer and winter, as consumers use more electric heating appliances.
- **Hydrogen production and green commodities** continue to be a potential source of long-term growth, though investments in these opportunities are slow to impact power system needs, reflecting observed delays and cancellations of some projects under consideration.

3.1.1 Growth in electricity consumption is forecast to accelerate although energy efficiency is helping moderate this growth

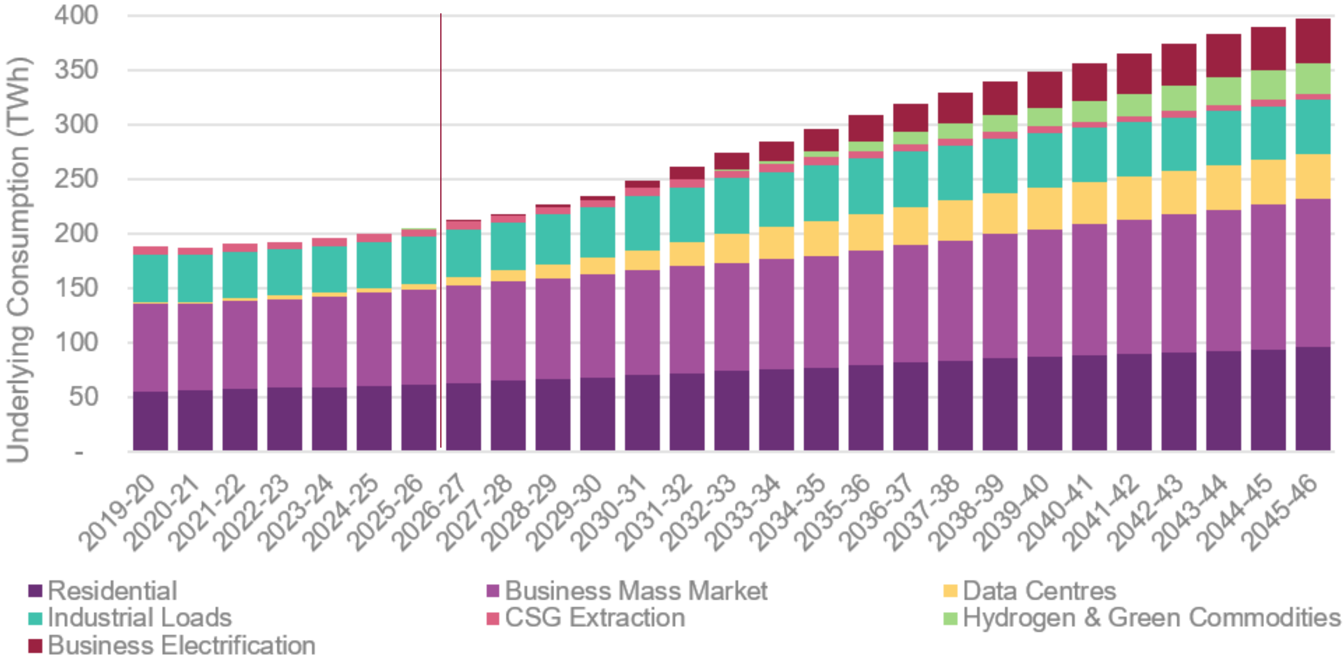
Underlying electricity consumption across the NEM is projected to increase over the outlook period, with stronger growth in underlying consumption forecast across almost all customer sectors. This growth in underlying consumption is driven by:

- the expansion of emerging industries such as data centres, as well as potential for hydrogen and green commodities,
- the electrification of transport, residential gas use and business and industrial processes, and
- increasing consumption and heating/cooling temperature sensitivity per residential household (see Section 3.1.4).

This growth in underlying consumption is moderated by savings that occur as energy efficiency improves. More energy-efficient processes, appliances and buildings, particularly in business and industry, have delivered a strong dividend in reduced consumption over the past decade. The *Step Change* scenario assumed this dividend would accelerate so long as supportive policies are in place. Without this ongoing improvement in energy efficiency, AEMO forecasts that underlying consumption would be 9.5% or 23.8 TWh higher than the *Step Change* projection by 2035-36.

Figure 6 shows the forecast annual underlying consumption by customer category in the 2026 NEM ESOO's *Step Change* forecast over the next 20 years. Underlying consumption in this scenario is forecast to increase from 204.2 TWh in 2025-26 to 308.4 TWh in 2035-36.

Figure 6 Actual and forecast NEM underlying electricity consumption by component, *Step Change*, 2019-20 to 2045-46 (TWh)



Note: in this figure, residential electrification is embedded within the residential sector, and transport electrification (EVs) is embedded within the residential and business mass market (BMM) sectors for residential and business EVs respectively. Other business electrification is reflected in the Business Electrification category.

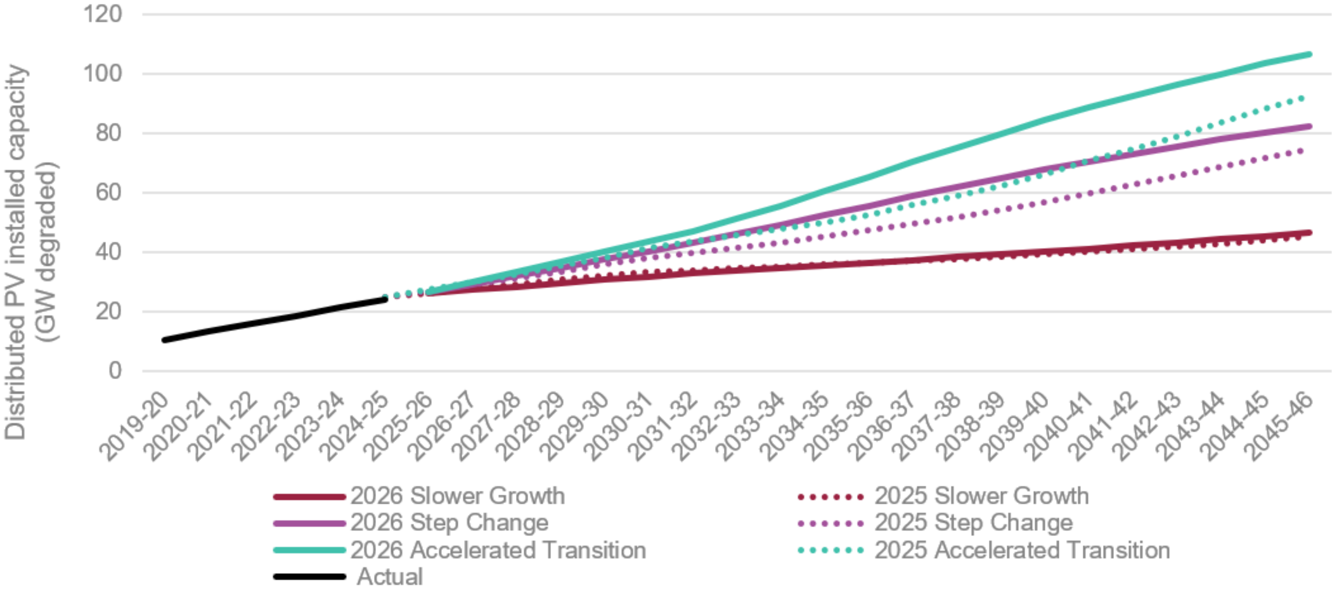
3.1.2 Consumer energy resources forecast to meet an ever-growing share of underlying demand

Consumers are continuing to invest in their own electricity supply through distributed PV systems[22] and reducing their energy use through energy efficiency improvements. Investments in PV systems continue to be a primary driver of reductions in the operational demand from residential consumers, and particularly of lower minimum demand outcomes across the NEM. **Figure 7** shows the actual and forecast level of distributed PV installed capacity considered in this 2026 NEM ESOO.

Growth in distributed PV is driven by declining system costs, increasing average system sizes, consumer expectations on their exposure to retail electricity prices, and continued growth in the number of suitable dwellings and commercial premises. Growth is forecast over the horizon, though the rate of growth will depend on various factors affecting consumer investment decisions, including investment competition with other household investments and consumer priorities, and increasing market saturation. The increases relative to the 2025 NEM ESOO are largely driven by increased PV system sizes along with improved calibration of the consumer response to changes in payback, while being tempered by more explicit inclusion of market saturation effects that limit uptake.

[22] Distributed PV includes rooftop PV systems (residential and small commercial systems up to 100 kW) and larger systems in the distribution network from 100 kW to 30 MW, referred to as PVNSG. Rooftop PV accounts for about 90% of distributed PV capacity.

Figure 7 Actual and forecast NEM distributed PV installed capacity, July 2019 to June 2046 (GW degraded)



Note: forecasts incorporate installation data to March 2026 and updated tariff and incentive settings, including the Solar Sharer Offer and Victorian Midday Power Saver Offer. These arrangements are expected to reduce the financial attractiveness of additional PV installations and may moderate export volumes and future uptake.

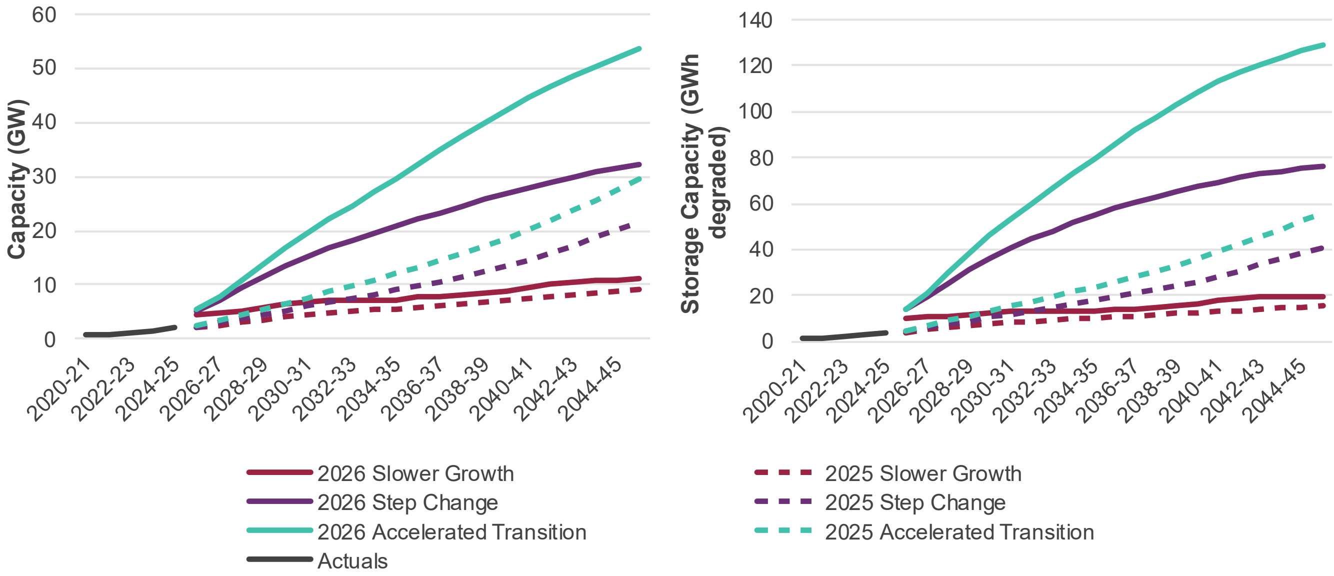
Consumer battery uptake has increased materially in the last year, supported by government programs and improving consumer economics. Key drivers include the Federal Government's CHBP, declining battery costs, and increased consumer interest in maximising the value of their rooftop PV generation through storage solutions. Average system sizes have also increased, increasing both the instantaneous discharge capacity and the volume of energy able to be stored. Average storage duration has increased to around three hours for residential batteries and that duration is assumed to remain steady for the forecast horizon. Since the start of the CHBP, for every 1 MW of new rooftop PV capacity, around 2.5 MW and almost 8 MWh of consumer batteries have been installed.

Figure 8 shows the forecast level of installed distributed battery capacity in this 2026 NEM ESOO. The figure represents the *degraded* storage capacity, which captures the estimated reduction in available storage over time due to the degradation of the battery cells from ongoing use.

Batteries reduce operational demand during peak periods and absorb excess generation during low demand periods, supporting system flexibility. If effectively coordinated (for example, under a VPP arrangement through a retailer or independent aggregator), then greater reductions in utility-scale investment needs may eventuate, as observed and quantified in the 2026 ISP. The degree of VPP coordination is highly uncertain, with around 14% of consumer batteries estimated to be under coordination in the NEM to date.

Compared with the 2025 NEM ESOO, the 2026 NEM ESOO's *Step Change* scenario considered a larger pool of battery capacity that could participate in VPPs, reflecting continued growth in consumer battery installations. However, the expected level of VPP participation has been reduced to reflect the slower uptake of VPP enrolment and coordination observed to date. Growing distributed battery assets will have an increasing influence on managing operational demand and improving system flexibility, though the magnitude of impact and the degree to which utility-scale supply alternatives can be avoided is highly uncertain.

Figure 8 Forecast NEM distributed battery installed capacity (GW) and storage capacity (GWh degraded), 2020-21 to 2045-46



Note: forecasts incorporate installation data to March 2026, updated subsidy settings, revised battery size assumptions, and expected participation in VPPs. Uptake remains uncertain and depends on future subsidy settings, cost reductions, and realised consumer value.

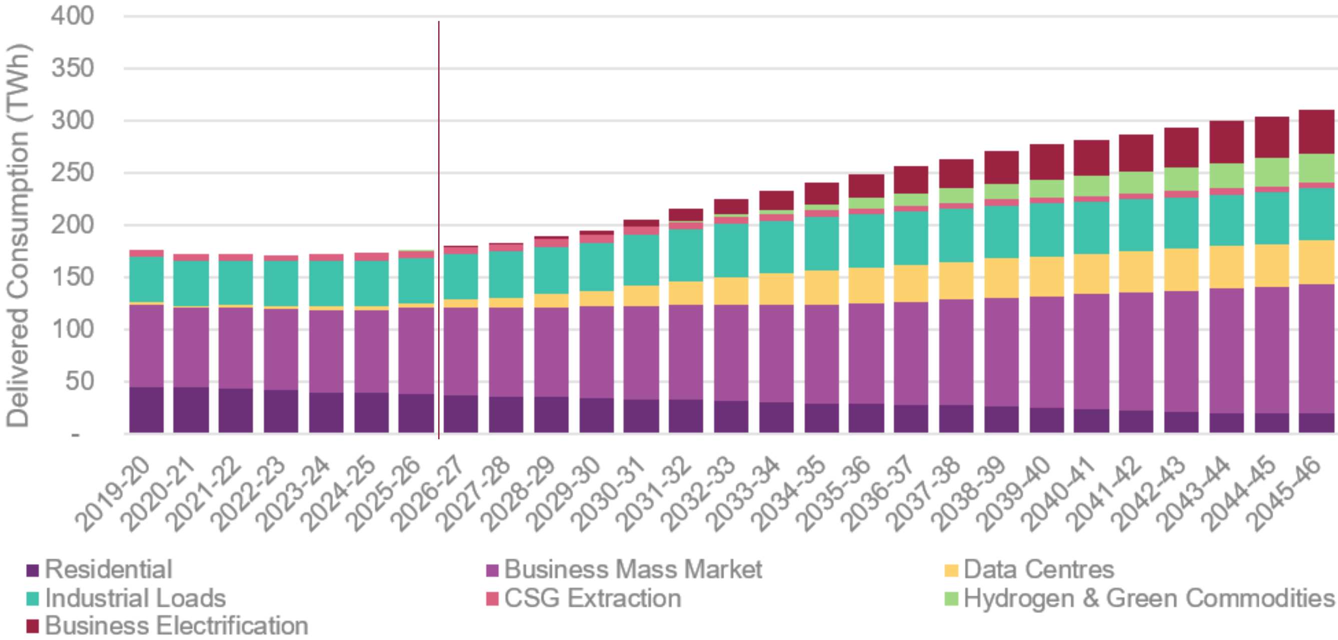
3.1.3 Delivered consumption for residential customers forecast to reduce, but increase for business and industrial customers

Delivered electricity consumption across the NEM is also forecast to increase over the outlook period, though the level of electricity delivered from wholesale NEM supply for residential customers is forecast to reduce, due to the high penetration of PV systems and operation of consumer batteries.

Delivered consumption reflects the demand that is drawn from the grid by consumers, net of generation sent back to the grid, with this net supply typically met by wholesale NEM supply. For most non-residential customers, delivered consumption closely aligns with underlying consumption, reflecting the relatively low contribution from distributed PV in these sectors.

Figure 9 shows the forecast annual delivered consumption by customer category in the 2026 NEM ESOO's *Step Change* forecast over the next 20 years. Delivered consumption in this scenario is forecast to increase from 175.7 TWh in 2025-26 to 249.4 TWh in 2035-36.

Figure 9 Actual and forecast NEM delivered electricity consumption by component, *Step Change*, 2019-20 to 2045-46 (TWh)



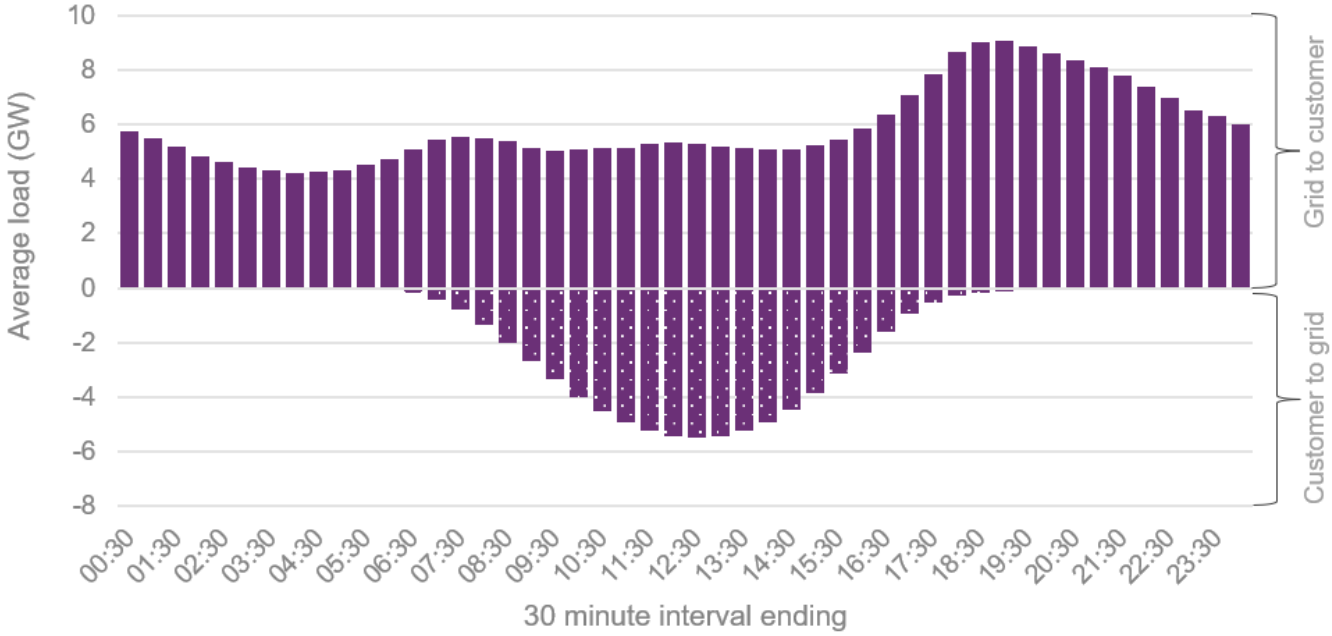
Residential customers have declining forecasts for delivered consumption. However, while annual consumption may reduce over the outlook period, the grid must cater for increasing flows to and from home-scale systems, with some households generating more electricity than they use, and others relying primarily on grid-supplies. To provide adequate customer reliability, sufficient supply must also exist to meet consumer needs during periods of low solar output (especially when peak demands occur, which are typically after sunset in mainland NEM regions).

Figure 10 below leverages analysed customer meter data[23], showing the relatively large intra-day variability that exists even within the average demand shape, with greatest demand in morning and evening periods. Residential customers are a key driver of evening demand, and have high flows back to the grid during the middle of the day from their distributed PV systems, particularly as systems have over-sized relative to average household load. While some residential customers will generate more than they need, other customers with smaller PV systems, or no self-supply, will continue to rely on grid-supplied electricity for their daytime energy needs. Consumer batteries are already helping to smooth the average residential intra-day profile, particularly by reducing imports from the grid to customers during evening peaks[24], with even greater potential if co-ordinated through VPP.

[23] For customers on accumulation meters, intra-day profiles have been estimated by using similar interval meter customer profiles.

[24] AEMO *Quarterly Energy Dynamics* Q2 2026 identified that 10,000 sampled households with PV and batteries had 73% lower imports from the grid to customers during evening peak (1600 hrs to 2100 hrs) than 10,000 sampled PV-only households across the quarter. See https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q2-2026.pdf.

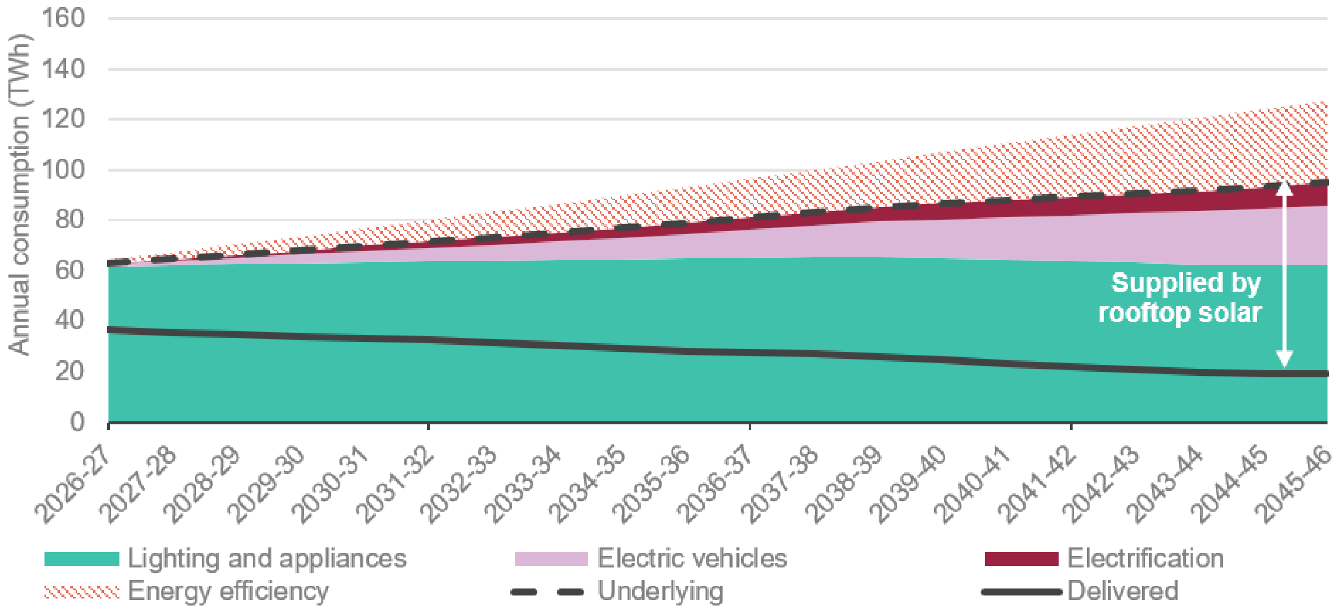
Figure 10 Average intra-day profile for metered consumption from residential NEM customers, 2025-26 (GW)



3.1.4 Residential consumption growth driven by electrification and EV uptake

Figure 11 shows the components of AEMO's 2026 residential consumption forecast under the *Step Change* scenario.

Figure 11 Components of residential consumption forecast, *Step Change*, 2026-27 to 2045-46 (TWh)



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

Electricity connections, which reflect population growth and dwelling completions, are a major contributor to the forecast growth in residential consumption. As reported in the 2026 *Forecasting Assumptions Update*[25], short-term growth in

[25] 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.

connections has been supported by housing supply initiatives, however is moderated in the near term due to capacity constraints in the construction sector. As these impacts ease, connection growth is forecast to return to align with broader economic and demographic trends. Compared to the 2025 NEM ESOO, the 2026 NEM ESOO connection forecast includes fewer connections, reflecting slightly lower population growth and updated dwelling stock forecasts that include both completions and demolitions.

EV uptake remains a key driver of residential consumption. Adoption is expected to grow strongly as consumers shift to electrified transport options, driven by economic and environmental advantages over internal combustion engine (ICE) vehicles. Electricity consumption associated with EVs is lower than the 2025 NEM ESOO, reflecting slightly lower population growth that reduces the demand for residential vehicles over the longer term. Furthermore, recent sales data shows stronger than expected uptake of hybrid and plug-in hybrid EVs (PHEVs), while battery electric vehicle (BEV) uptake has been lower than previously projected. This has reduced forecast electricity consumption impacts from EVs in the short to medium term.

Electrification (excluding transport electrification), particularly of gas appliances, continues to contribute to growth in residential consumption particularly for winter heating loads, and is estimated to reach 4.4 TWh by 2035-36. Electrification is highest in regions with greatest current use of gas for heating, such as Victoria, and is influenced by projected falling costs for heat pumps, electric water heaters, and cooktops. Policy settings that discourage new gas connections, such as Victoria's Gas Substitution Roadmap and new gas connection bans in the Australian Capital Territory and parts of New South Wales, further support this trend.

Energy efficiency plays a significant role in moderating overall consumption growth. Under the *Step Change* scenario, both policy-driven and autonomous efficiency improvements are expected to deliver substantial electricity consumption savings over time, reflecting continued uptake of more efficient appliances, building standards, and government programs. Without such efficiency improvements, AEMO forecasts that residential underlying consumption would be 17.9% or 14.1 TWh higher than the *Step Change* projection by 2035-36.

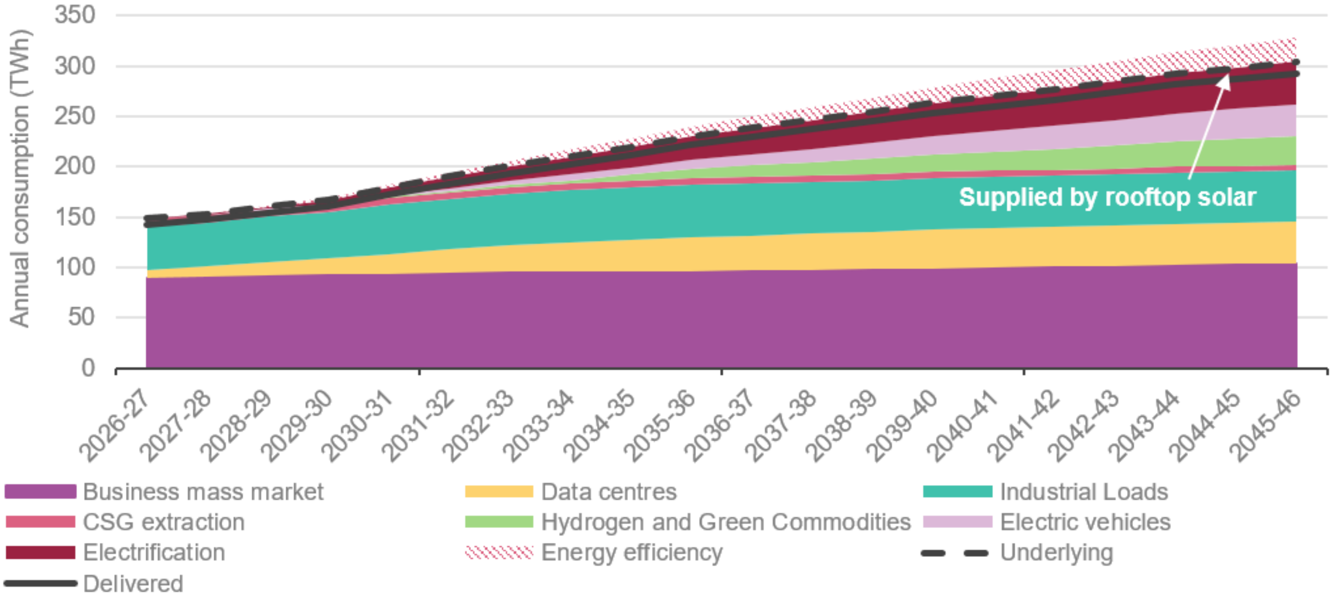
Consumer behaviour changes can increase or decrease the volume of electricity consumed depending on various influences that impact their willingness to spend or save money on discretionary usage. The 2026 NEM ESOO includes greater consideration of consumer consumption behaviours that are not directly attributable to other consumption categories. AEMO's analysis of consumption trends in recent years has indicated that consumers have tended to increase their electricity usage in some regions, including for the purposes of heating and cooling. Considering this, AEMO's 2026 NEM ESOO underlying residential consumption forecast is now up to 19% higher than the 2025 NEM ESOO in 2035-36, depending on region.

In contrast to the growth in underlying consumption, delivered residential consumption is forecast to decline by 25% over the next 10 years as consumers' rooftop PV generation provides a growing share of supply. As **Figure 11** above shows, increasing rooftop PV generation is projected to supply an expanding share of consumer electricity needs, reducing reliance on wholesale-supplied electricity and therefore widening the gap between underlying and delivered consumption from 23.3 TWh in 2025-26 to 50.5 TWh by 2035-36.

3.1.5 Strong growth in business consumption reflects increasing electrification and data centre demand

Under the *Step Change* scenario, underlying business consumption is forecast to grow strongly over the outlook period. Business delivered consumption is forecast to increase from 138.1 TWh in 2025-26 to 221.5 TWh in 2035-36, an increase of approximately 60%. As **Figure 12** below shows, this forecast growth is driven by emerging new industries such as the recent rise of data centres, increasing levels of transport, business and industrial process electrification, and the potential development in future for hydrogen and green commodities.

Figure 12 Components of business consumption forecast, *Step Change*, 2026-27 to 2045-46 (TWh)



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

Business mass market (BMM)

BMM consumption is forecast to grow moderately over the outlook period, with consumption forecast to grow 9% from 2025-26 to 2035-36 under *Step Change*, faster than the 5% growth forecast in the 2025 NEM ESOO. While electrification and underlying economic activity support growth, energy efficiency savings projected in the medium to long term lessen electricity consumption.

Compared with the 2025 NEM ESOO, the 2026 outlook reflects several structural and methodological updates. Reallocation of customers from the LIL to the BMM segments has revised historical consumption for this sector upward and contributed to slightly higher underlying demand.

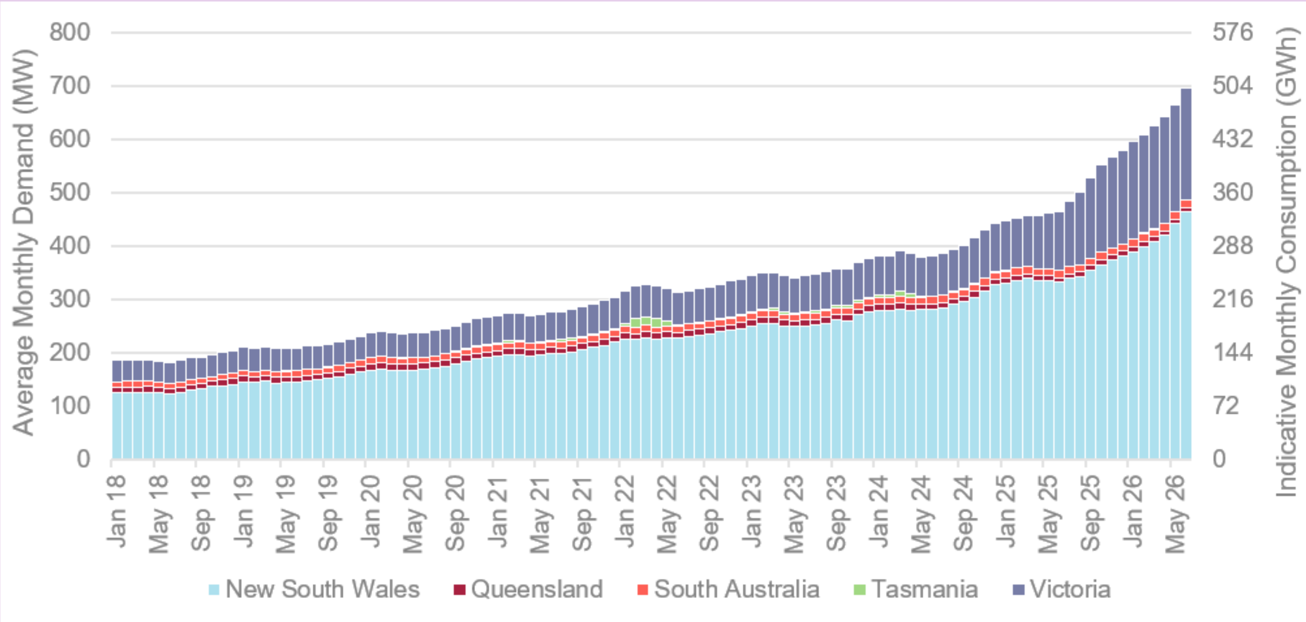
Data centres

Rapid growth in cloud computing and AI is driving increased electricity consumption from data centres across the NEM. Due to the growing penetration of data centres, the high pace of their development, and the uncertainty in the overall expected need for digital services in the medium to long term, AEMO forecasts data centre loads separately from traditional LILs. Forecasts combine project-level information gathered from developers and network service providers, with an economic outlook that reflects broader digital transformation and AI adoption under each scenario.

Currently operating data centres remain below full utilisation

As of quarter 1 2026, operating data centres across the NEM are estimated to have a total of 2.2 GW of maximum connection capacity provided by distribution network service providers (DNSPs) and TNSPs. However, to date, data centres have been operating with a relatively flat load typically well below the maximum connection capacity. **Figure 13** shows the average monthly data centre demand observed across the NEM between January 2018 and June 2026. Actual demand in quarter 1 2026 suggests an aggregate utilisation of 27% of this maximum connection capacity for currently operating data centres, at a very high load factor nearing 90%. This current actual utilisation is relatively low, and AEMO estimates that a mature fleet of data centres, considering planned capacity redundancy and diversified compute profiles, will average 45-51% average utilisation depending on data centre type[26]. Data centres often advise an expectation to increase their utilisation over five to 10 years as they ramp towards full capacity, suggesting that existing data centres will continue to increase demand in the near term.

Figure 13 Actual average data centre monthly demand and consumption, by region (MW and GWh)

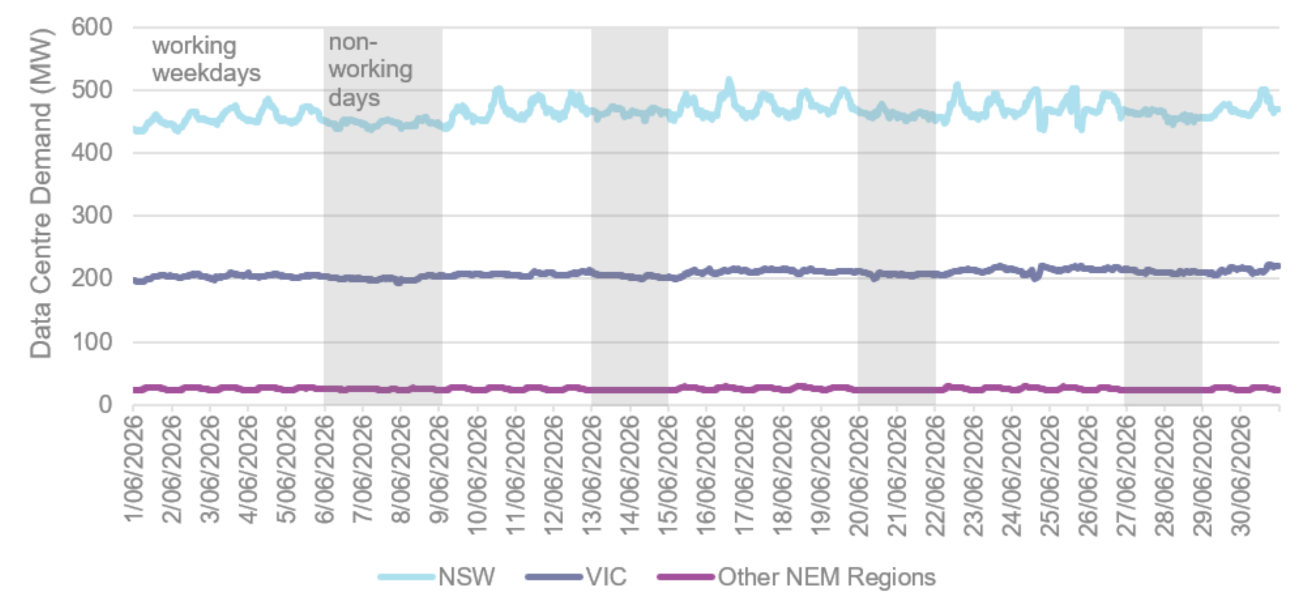


Data centres currently operate with a flat demand profile

Figure 14 shows the aggregate 30-minute demand for data centres across NEM regions in June 2026. As discussed above, data centre demand is observed to be relatively flat, with only small variation between peaks and troughs. While intra-day variation is observed between working weekdays, periods of lowest demand occur on non-working days, when compute requirements are lower.

[26] AEMO applied assumptions informed by analysis undertaken by the International Energy Agency. See https://www.iea.org/reports/energy-and-ai/.

Figure 14 Aggregate 30-minute data centre demand in the NEM for June 2026 (MW)

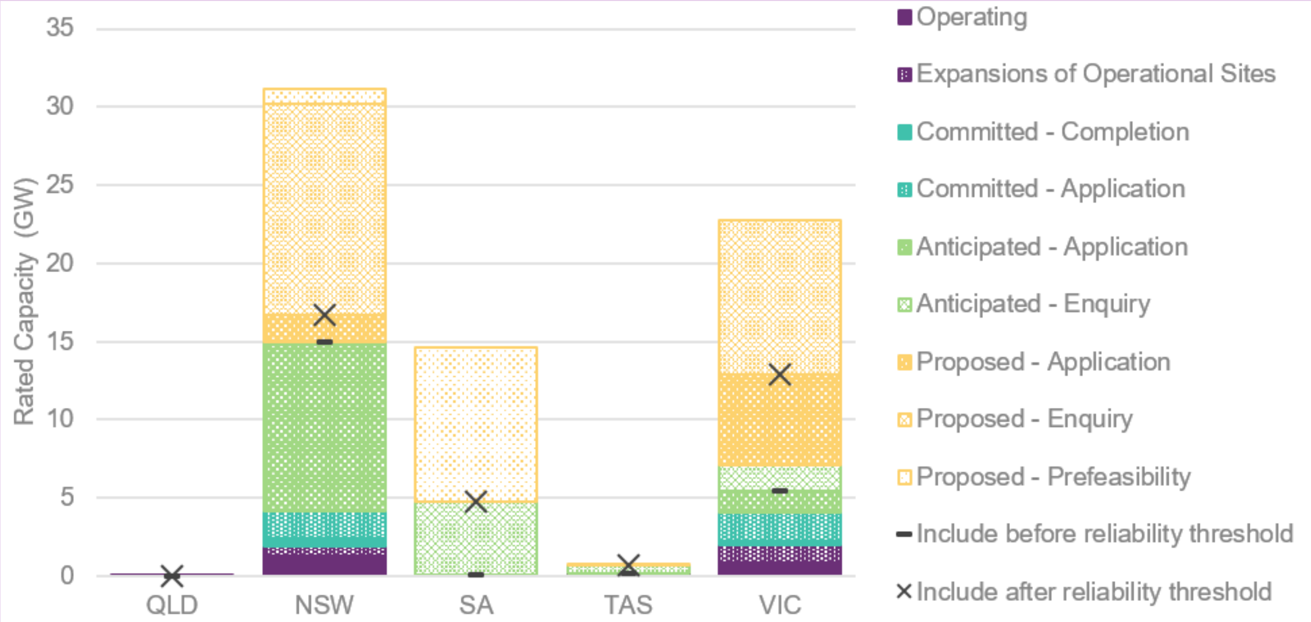


Since 2025, many new data centre projects have been proposed, while many have been cancelled

NSPs have reported a substantial increase in connection interest in data centres between 2025 and 2026, with 225 projects advised to be in various stages of the connection process in 2026 in the NEM. While many continue to be proposed and developed, approximately 36% of the known projects in AEMO's 2025 NEM ESOO project list have since been cancelled. Projects were cancelled in all stages of development, with more than 30% of projects cancelled that were previously classified by NSPs as 'committed'(which typically means that a connection agreement is in place).

Total proposed connection capacity across all development stages increased from 38 GW to 67 GW in AEMO's 2026 assessment. **Figure 15** shows the connection capacity advised by NSPs in 2026. Advanced developments are noted in New South Wales and Victoria, with less mature developments noted in South Australia and Tasmania. Given the pace and diversity of developers, data centres may also develop in locations currently not represented in the NSP connection queue.

Figure 15 2026 data centre connection capacity by region and development status (GW)



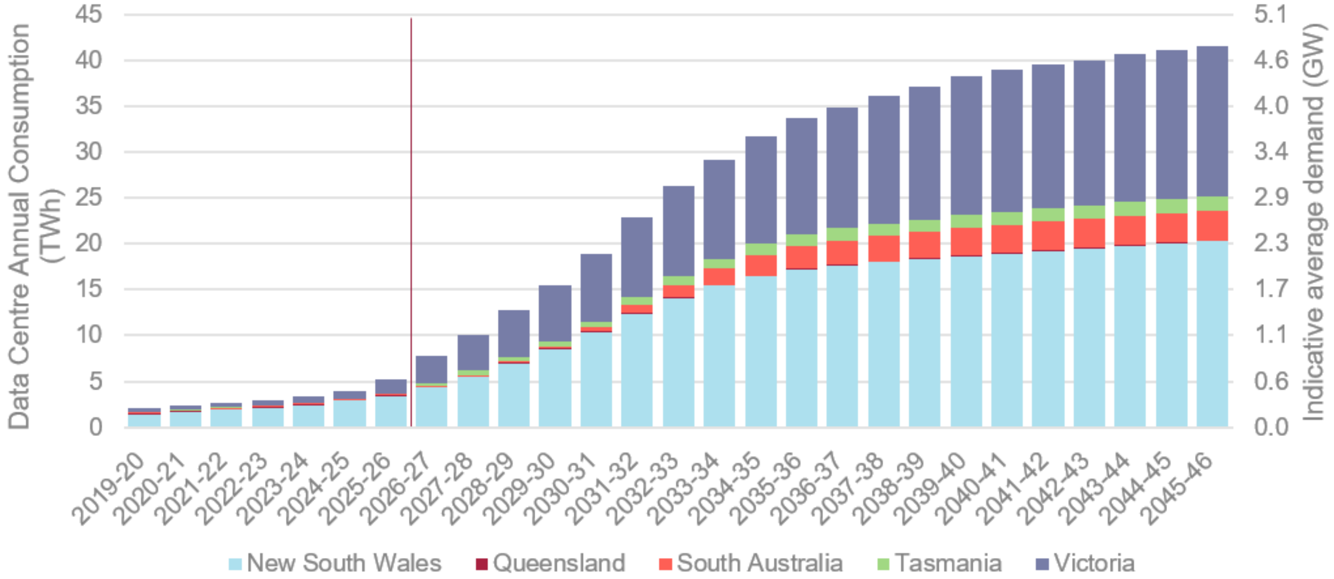
Note: data represents information provided by NSPs between February and May 2026. Since this information was advised, AEMO is aware of increasing interest in Queensland than is represented in these 2026 ESOO forecasts.

AEMO's data centre forecasts applied probability weightings to project pipelines to reflect the estimated likelihood of projects progressing to connection and operation. This estimated probability was based on a regression of actual project progression between 2025 and 2026 that identified key parameters such as project status, connection status and developer size as influential variables. This probability-weighted project level forecast was averaged with an economic-based outlook to develop the final forecast. For 2026, an updated economic-based forecast was developed to better reflect changing demand drivers, with greater consideration of Australia's potential role as an Asia-Pacific data centre hub. More information on the project-based outlook, the economic outlook, and the inputs and assumptions applied are available in the 2026 *Forecasting Assumptions Update* and the accompanying report from Oxford Economics Australia, which assisted AEMO in preparing this forecast[27].

Figure 16 shows AEMO's 2026 data centre consumption forecast. In 2025-26, data centres are estimated to consume around 5 TWh, representing 2.8% of NEM operational consumption. Under the *Step Change* scenario, consumption is forecast to triple to around 15 TWh or 7.8% of forecast operational consumption by 2029-30 and grow nearly seven times to around 34 TWh or 13% of forecast operational consumption by 2035-36, before growth starts to taper off.

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

Figure 16 Average data centre consumption and indicative average demand forecast by NEM region, *Step Change*, 2026-27 to 2045-46 (TWh and GW)



Note: Since this forecast was finalised, AEMO is aware of greater interest in Queensland than is represented in these 2026 ESOO forecasts.

Coal seam gas (CSG) extraction

CSG extraction occurs primarily in southern Queensland and supports liquified natural gas (LNG) exports. AEMO's forecast for electricity use of CSG extraction remains similar to previous forecasts, where consumption remains broadly stable over the period covered by existing export contracts, before declining later in the outlook period as resources are depleted and future export volumes become more uncertain.

Industrial loads

Industrial consumption forecasts are predominantly informed by operator surveys. In the short term, consumption is slightly lower than the 2025 NEM ESOO due to advised project delays, reduced electrification expectations, and closures or production slowdowns at several industrial sites due to supply chain issues and financial difficulties. Growth is forecast to resume from the late 2020s, surpassing the 2025 NEM ESOO from 2032 as existing operations ramp up and prospective projects (largely mining and smelting) come online. Over the longer term, forecast consumption remains relatively constant as new developments offset declines from retiring sites.

Hydrogen and green commodities

Hydrogen, green ammonia and green steel production continues to introduce potential load influencing long-term consumption growth as part of Australia's decarbonisation policies, but the outlook has been delayed across all scenarios compared with the 2025 NEM ESOO. This revised trajectory reflects the significant delays and cancellation of many projects under consideration in industry.

Business electric vehicles

EV uptake in the business sector also contributes to increasing consumption, with an increase in this year's forecasts compared to the 2025 NEM ESOO. Consideration of fuel-cell EV trucks has been removed from the 2026 forecasts due to delays and cancellations across the hydrogen sector, with uptake reallocated to battery EV and ICE vehicles. The rise in electricity consumption relative to previous forecasts in the later years is due to a modest rise in the number of articulated electric trucks and the associated higher electricity consumption rate per kilometre for these vehicles, that leads to a material impact on the total EV electricity consumption.

Electrification of business and industrial processes

Business electrification (excluding transport electrification) remains a key long-term driver of business electricity consumption, with very little change to the forecasts relative to the 2025 NEM ESOO. Electrification primarily involves the replacement of gas-, coal,- diesel- or biofuel-dependent business and industrial processes with electricity. This uptake was modelled by the CSIRO[28] as being appropriate to meet Australia's domestic and international emissions reduction requirements and is currently supported by the Safeguard Mechanism and state policies.

While uptake is relatively slow in the near term, acceleration was assumed from the 2030s onwards as electrification expands across industrial processes.

Energy efficiency

Australia's governments have developed a range of measures to mandate or promote energy efficiency uptake across the economy. These policy-led savings are complemented by market-led savings, which are driven by factors such as technology change and consumer preferences. AEMO's energy efficiency forecasts incorporated existing and assumed future policy-led improvements as well as market-led improvements to buildings, appliances and processes, with very little change in the forecast since last year.

3.1.6 Alternative scenarios capture forecast uncertainties

AEMO forecasts multiple scenarios, to capture a range of possible future operational consumption outcomes, as shown in **Figure 17**. While the spread between scenarios remains similar to the 2025 NEM ESOO, the key sources of uncertainty considered in these scenarios have shifted further towards data centre activity and emerging industrial demand. In this context, the *Step Change* forecast in the 2026 NEM ESOO reflects an upward shift relative to the 2025 NEM ESOO, with the shift widening over the outlook period. The increase in this scenario is driven primarily by stronger growth in data centre load (see Section 3.1.5 for more detail), residential load and BMM.

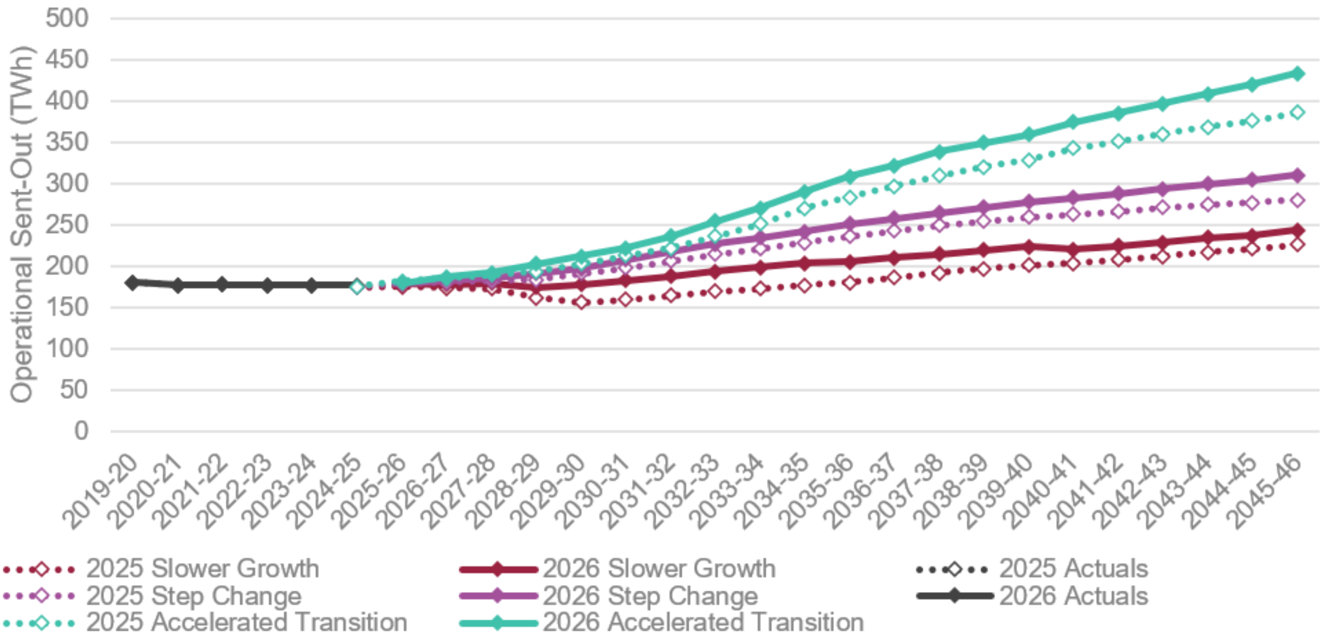
The *Slower Growth* scenario reflects downside risks including weaker economic conditions and potential industrial closures across the NEM in the short to medium term. Under this scenario, consumption increases gradually, driven primarily by business electrification and growth in residential load. Compared to the *Step Change* scenario, consumption is consistently lower, largely due to reduced data centre growth, a higher incidence of industrial load closures as supply contracts expires, and more subdued growth in general business activity and EV uptake.

The gap between the *Accelerated Transition* and *Step Change* scenarios widens with time. The higher forecast under the *Accelerated Transition* scenario reflects increased consumption driven by the assumed expansion of new industries such as data centres and green commodities, supported by strong economic conditions and greater assumed investment in onshore

[28] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf.

AI. This scenario also assumed greater population growth, stronger EV uptake, and faster growth in the broader business sector underpinned by more favourable economic conditions.

Figure 17 Actual and forecast NEM operational consumption, all ESOO scenarios and compared to 2025 ESOO, 2019-20 to 2045-46 (TWh)



Economic uncertainties due to conflicts and weather events

Recent conflict in the Middle East has introduced additional economic uncertainty that was not reflected in the economic forecasts underpinning AEMO's consumption forecasts. The scale, direction and overall impact on Australia's economy, and the flow-on effects on electricity consumption, are uncertain. For example:

- Higher fuel prices may drive accelerated industrial, business and residential electrification, and accelerated EV adoption, particularly if consumers expect the exposure to be enduring.
- Higher cost of living impacts from higher inflationary drivers may weaken business confidence, lower industrial output and weaken customers' capacity to invest in energy assets.

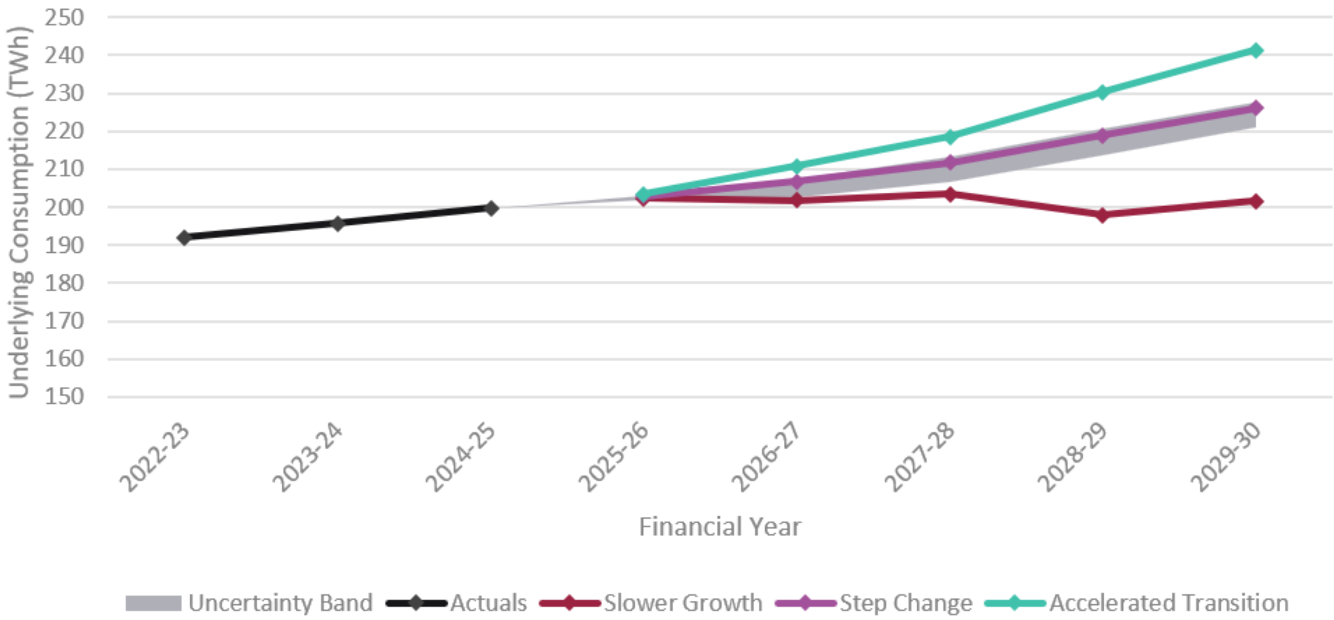
AEMO has estimated potential upside and downside risks to the near-term consumption outlook to calculate a range around the *Step Change* forecast. This range is for information purposes only and does not apply to the reliability forecast. In this estimation:

- The upper band assumed:
  - accelerated EV uptake for two years, with double the growth assumed in *Step Change* for the 2026-27 and 2027-28 financial years, equivalent to an extra 700,000 EVs on the road, adding an extra 1.2 TWh per year to NEM electricity consumption, and
  - accelerated residential and business electrification (excluding transport electrification), following the *Accelerated Transition* forecast instead of *Step Change* for the 2026-27 and 2027-28 financial years, displacing 24 petajoules (PJ) of gas consumption and adding an extra 0.4 TWh per year of electricity consumption.

- The lower band assumed:
  - one percentage point lower GDP growth for the 2026-27 and 2027-28 financial years, reducing NEM consumption by 1.8 TWh per year for these years,
  - prolonged recovery at large industrial sites where production is currently stopped or slowed, reducing consumption by up to 1.4 TWh per year, and
  - reduced spending on new appliances and pause in per-household consumption growth, reducing consumption by up to 2 TWh per year.

Figure 18 shows the estimated impact of these drivers on underlying electricity consumption in the *Step Change* scenario. The relatively low spread of the band, relative to the scenario spread, demonstrates that the uncertainties that vary across scenarios drive larger consumption impacts over the forecast horizon than the minor adjustments in this short-term estimate.

Figure 18 Actual and forecast NEM underlying consumption, with uncertainty band around the *Step Change* scenario, 2022-23 to 2029-30 (TWh)



In addition to these macroeconomic uncertainties, weather events can have a material influence on annual and seasonal electricity consumption, as well as the magnitude of seasonal peak demands. Consumption is forecast considering weather representative of typical or average weather patterns, however the natural El Niño and La Niña climate patterns can materially influence weather patterns and consumers' response to them. Climate indicators identify that an El Niño event is firmly established[29], that may impact the 2026-27 summer. This uncertainty is not explicitly captured in the scenarios, and may provide an alternative, higher uncertainty band than shown in **Figure 18** above.

The potential impact of this El Niño event will be considered as part of AEMO's summer readiness assessments and may result in procurement of additional short notice reserves if required.

[29] See https://www.bom.gov.au/climate/enso/.

3.1.7 Forecast growth in maximum operational demand

Supply scarcity risks traditionally present most when demand reaches extreme levels, typically driven by consumer responses to very high temperatures from air-conditioning loads associated with space cooling, or increasingly under low temperature conditions when heating demand is high. The exact maximum demand level that may be reached is highly uncertain, as it will be influenced by how extreme weather conditions are, the timing of such conditions, and potentially the duration of heatwave conditions. To capture this inherent uncertainty, AEMO prepares maximum operational demand forecasts as a distribution, represented by 10%, 50% and 90% probability of exceedance (POE) forecasts, rather than single-point forecasts (see Section 1.2 for definitions). The 10% POE maximum demand, for example, represents the level of instantaneous demand that would be expected to be exceeded only once in every 10 years.

The ESOO maximum operational demand forecast represents the highest level of operational demand projected within a year. Operational demand is the electricity met by wholesale NEM supply, as defined in Section 1.2. Maximum operational demand is forecast without regard to potential active interventions that may be triggered by market-driven extreme pricing events, such as Wholesale Demand Response (WDR)[30] and the demand response provided by demand-side participants; this is forecast separately as DSP.

Operational demand reflects electricity supplied from the grid and is therefore reduced by CER through self-supply

Rooftop PV reduces operational demand during daylight hours, while batteries may reduce operational demand when discharging (and increase operational demand when charging). The contribution of batteries to reducing maximum operational demand depends on whether they are available and operating during the specific intervals when system demand reaches its annual peak, and represents a relatively low impact relative to the total demand from residential, business and industrial consumers.

The maximum operational demand forecasts in this NEM ESOO account for customer-controlled battery and EV charging or discharging that is not coordinated. The forecasts presented exclude potential hydrogen loads, coordinated battery and EV charging or discharging, and scheduled loads such as PHES pumping load and large-scale batteries, as these resources are expected to behave as dynamic, flexible and price-responsive loads. If effectively coordinated, battery devices, VPPs and EVs with vehicle-to-grid (V2G) capabilities may discharge to lower operational demand during these peak periods. If, instead, these loads charge or operate at times of the system peak and do not respond flexibly, maximum operational demands may be higher than forecast, and investment needs to maintain reliability may be greater as a result.

Under the *Step Change* scenario, maximum operational demand across the NEM is forecast to continue increasing over the outlook period. Growth is driven primarily by electrification, expanding data centre development, increasing EV uptake and rising industrial electricity consumption, together with the continued influence of temperature-sensitive residential and business loads. These emerging and growing sources of demand are expected to account for an increasing share of future peak demand outcomes:

[30] See https://www.aemo.com.au/initiatives/trials-and-initiatives/past-trials-and-initiatives/wholesale-demand-response-mechanism.

- **Residential and BMM** demand continues to provide the largest contribution to maximum operational demand because of customers' high sensitivity to temperature. Heating and cooling loads represent a relatively small share of annual electricity consumption, but are a major contributor to peak demand during periods of extreme temperatures in summer and winter. As electrification of space heating increases, these loads are expected to play an increasingly important role in future peak demand outcomes, increasing exposure to winter peak conditions particularly.
- While not strongly temperature-responsive, **LILs** remain a key consumer of electricity at all times. In some regions the share of industrial load relative to residential and commercial customers is high, such as in Tasmania. Changes in industrial operations at times of system peak, and the level of demand flexibility that operators apply during extreme conditions, can materially influence peak demand outcomes.
- **Data centres** are expected to become an increasingly significant driver of electricity demand over the medium and long term, particularly in New South Wales and Victoria where the concentration of development is projected to be greatest. While data centre loads may offer opportunities for demand flexibility as operational practices, guidelines and regulatory frameworks evolve (including potential self-generation), limited flexibility has been observed to date (see Section 3.1.5).
- While **EV uptake** is forecast to increase and consume high volumes of electricity each year, vehicle charging is expected to make a relatively small contribution to maximum operational demand compared to overall energy consumption. EV owners may choose to charge their vehicles during peak demand periods for convenience, or shift charging outside peak periods in response to information, pricing signals, or other incentives, subject to the availability and accessibility of charging infrastructure. As charging infrastructure expands and consumer participation in flexible charging increases, AEMO projects that EV charging will place less upward pressure on maximum operational demand over time.
- **Battery storage devices** can reduce maximum operational demand by discharging during peak demand periods and reducing the amount of electricity supplied from the grid. Recent observations indicate that consumer batteries are already helping moderate evening peak demand, even when operated independently. While many batteries are primarily managed to optimise household outcomes, these operating patterns can still provide some system benefits during peak periods. Batteries coordinated through aggregators, retailers or VPPs are expected to deliver greater reductions in maximum operational demand by targeting discharge during periods of highest market price and system demand. As already noted, AEMO's reliability methodology treats battery coordination differently across reliability assessments, and operational demand forecasts represent only the uncoordinated component of consumer battery behaviour.
- **Rooftop PV generation** substantially reduces operational demand during daylight hours, but generally has a limited influence on maximum operational demand because peak demand events typically occur late in the afternoon and evening, when solar generation is low.

Figure 19 compares historical maximum operational demand with the 2026 NEM ESOO *Step Change* forecasts, alongside the 2025 NEM ESOO forecasts, for all NEM regions. Maximum drivers are unique for each region, as discussed in Section 6, and aggregate NEM maximum demand is not forecast. The largest change since the 2025 NEM ESOO is in Victoria where, following a record maximum demand event, the model has been re-baselined. This is primarily driven by stronger residential and BMM demand, with additional growth from LILs and data centres over the forecast horizon.

Figure 19 Actual and forecast 50% POE maximum operational demand (sent-out) for each NEM region, 2026 ESOO and 2025 ESOO, *Step Change* scenario, 2021-22 to 2035-36 (GW)

Note: actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events, and exclude DSP.

3.1.8 Minimum operational demand continues to decline, but at a slower rate

Similar to maximum demand, AEMO prepares minimum operational demand forecasts as a distribution, represented by the 10%, 50% and 90% POE forecasts, rather than single-point forecasts (see Section 1.2 for definitions). Minimum demand forecasts are important to indicate when investment or operational procedures are required to manage system security needs, at times of low load conditions.

The ESOO minimum operational demand forecast represents the lowest level of operational demand projected within a year.

Operational demand reflects electricity supplied from the grid, as defined in Section 1.2, and is therefore reduced by CER through self-supply. Rooftop PV reduces operational demand during daylight hours, while consumer batteries and EVs may increase operational demand when charging. The contribution of batteries and EVs to increasing minimum operational demand depends on whether they are charging during the relatively small number of intervals when system demand reaches its annual minimum. Minimum operational demand was forecast without regard to operational interventions, including measures to constrain PV generation, or demand-side responses that may increase operational demand during periods of excess supply. While the forecasts incorporated uncertainty in weather conditions, they did not account for these potential operational actions.

The minimum operational demand forecasts accounted for customer-controlled battery and EV charging that is not coordinated. This includes charging behaviour that may be influenced by customer preferences, retail tariffs and other incentives. The forecasts excluded potential hydrogen loads, coordinated battery and EV charging, and other flexible loads, such as PHES pumping and utility-scale battery charging that operate flexibly in response to market signals and system conditions. If effectively coordinated, these resources may increase minimum operational demand.

Under the *Step Change* scenario, minimum operational demand is forecast to continue declining across all mainland NEM regions (that is, excluding Tasmania), as growth in distributed PV systems exceeds growth in underlying electricity demand during daytime conditions. However, the rate of decline is slower than forecast in the 2025 NEM ESOO due to stronger growth in electricity consumption from data centres, industrial loads, electrification and battery charging. The impact is particularly evident in New South Wales and Victoria, where data centre development is forecast to increase underlying demand.

While distributed PV remains the dominant driver of declining minimum operational demand, growing electricity consumption and battery uptake are increasingly moderating its impact. Key influences include:

- **Distributed PV remains the primary driver** – continued growth in distributed PV systems provides increasing levels of behind-the-meter generation during daylight hours, reducing the electricity supplied from the grid and lowering minimum operational demand.
  - Over the past decade, rising distributed PV uptake has progressively shifted the timing of minimum operational demand from overnight periods, typically between 4.00 am and 6.00 am, to the middle of the day, typically between 1.00 pm and 3.00 pm, across most mainland NEM regions. South Australia was the first region to experience this transition, while New South Wales was the most recent. Tasmania remains an exception, with minimum operational demand still occurring more commonly overnight.
  - On average, each megawatt of installed distributed PV capacity reduces minimum operational demand by around 0.6 MW to 0.7 MW, although the impact varies across regions due to differences in solar irradiance and panel orientation. Distributed PV therefore remains the largest contributor to declining minimum operational demand across mainland NEM regions.
- **Growth in underlying demand moderates the decline** – population growth, electrification, industrial development, data centres and other LILs increase electricity consumption throughout the day and place upward pressure on minimum operational demand.
  - Data centres are particularly influential because they operate relatively consistently throughout the day and across seasons, similar to LILs. This stable demand profile increases electricity consumption during periods when minimum operational demand typically occurs, and is a key reason minimum operational demand forecasts are higher than those published in the 2025 NEM ESOO, particularly in New South Wales and Victoria.
  - Residential and business consumption may also increasingly coincide with periods of high solar generation as consumers respond to incentives such as the Solar Sharer Offer and other daylight-oriented tariffs. The extent to which these mechanisms moderate minimum operational demand depends on how closely electricity consumption aligns with periods of strong solar generation.
- **Consumer batteries increasingly absorb surplus solar generation** – battery storage devices, including home batteries and EVs, can moderate reductions in minimum operational demand by charging during periods of high rooftop PV output. Uptake has increased materially in recent years, supported by government programs, declining technology costs and consumer interest in maximising the value of rooftop PV generation through storage.
  - Since the commencement of the CHBP, significant volumes of consumer battery storage have been installed alongside new rooftop PV systems. These batteries increasingly absorb surplus daytime solar generation, increasing operational demand during daylight hours and moderating the decline in minimum operational demand.

- However, the impact of batteries on minimum operational demand is considerably smaller than the impact of distributed PV. On average, each megawatt of installed battery capacity increases minimum operational demand by around 0.1 MW, although the effect varies depending on battery characteristics, charging behaviour and regional factors. This is because battery charging does not necessarily coincide with the relatively small number of intervals when minimum operational demand occurs. Many batteries may already be fully charged, or partially charged, by the time minimum demand is reached.
- The impact of batteries could be greater where charging behaviour is actively coordinated to align with periods of high solar generation. However, consistent with NEM ESOO forecasting assumptions, coordinated charging behaviour was not assumed in these forecasts. Instead, battery charging was assumed to occur in a largely uncoordinated manner across daylight hours. Greater uptake of pricing structures or other mechanisms that encourage daytime charging may further moderate the decline in minimum operational demand over time.

Overall, distributed PV remains the dominant influence on minimum operational demand across mainland NEM regions. However, growing electricity consumption from electrification, data centres and industrial loads, together with increasing battery uptake, is progressively offsetting part of this effect. As a result, minimum operational demand is forecast to continue declining over the outlook period, but at a slower rate than projected in previous ESOO forecasts.

Figure 20 compares historical minimum operational demand with the 2026 NEM ESOO *Step Change* forecasts for each region and the corresponding forecasts published in the 2025 NEM ESOO.

Figure 20 Actual and forecast 50% POE minimum operational demand (sent-out) for each NEM region, 2026 ESOO and 2025 ESOO, *Step Change* scenario, 2021-22 to 2035-36 (GW)

Note: 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.

3.1.9 Demand flexibility can materially lower investments needed to maintain reliability

Flexible demand refers to demand that consumers are able to adjust when they use electricity, including shifting, reducing or increasing consumption in response to operational needs, technology controls, market incentives or other signals.

In these periods, voluntary reductions in demand from those consumers able to lower their consumption can help support power system reliability by reducing pressure on generation and network infrastructure.

DSP represents a defined subset of this flexibility used in AEMO's reliability and planning studies. To prevent double counting, DSP excludes demand and supply resources whose behaviour is already reflected in demand forecasts or in the supply that is modelled in reliability assessments[31]. Examples include, but are not limited to, scheduled controlled loads, fixed time of use tariffs, customer-controlled CER storage, pumped storage and V2G services.

DSP therefore includes only flexible demand that is not otherwise captured and is expected to respond to high prices or reliability events. These responses can be modelled as an additional reliability resource and include both market-driven and reliability-driven mechanisms, such as price-responsive programs, industrial load curtailment and network-coordinated action. As a result, while all DSP is flexible demand, not all flexible demand is classified as DSP.

For the 2026 NEM ESOO, AEMO has updated its DSP estimates to reflect:

- updated information provided by DSP participants on their current and expected level of available flexible load,
- historically observed responses during high-price and reliability events, and
- updated analysis of WDR dispatch outcomes[32].

These estimates were based on DSP participant submissions as of April 2026 and historical observations over the period 1 April 2023 to 31 March 2026. Price-responsive DSP was estimated using the median (50th percentile) of observed responses across events, noting the variability of response at similar price levels.

Under the *Step Change* scenario used for the ESOO reliability assessment, only existing and committed DSP was included. Potential or uncommitted DSP was excluded, consistent with the treatment applied to generation and transmission developments to ensure the assessment of reliability is based on levels of reliability support that AEMO can confidently rely upon to operate the future power system, as outlined in the 2025 IASR[33].

Demand-side participation outlook

The projected price-triggered DSP across the NEM for summer 2026-27, shown in **Table 6**, is higher than in the 2025 NEM ESOO. All regions except South Australia demonstrated increased price-responsiveness across all price bands. Increased responses at lower price bands indicate consumers responding to a broader range of market signals, as opposed to extreme price events only. This growth reflects a combination of increased exposure to volatile wholesale electricity prices, greater

[31] See https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultationhttps://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/forecasting-approach/2023-dsp-forecast-methodology.pdf.

WDR provides a mechanism to enable DSP to participate directly in the NEM. Unlike other price-responsive DSP, which is estimated from demand reductions relative to a calculated baseline during high price events, WDR is directly measured through market dispatch outcomes. This allows WDR participation to be assessed independently and incorporated into DSP forecasts using observed dispatch history.

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

adoption of enabling technologies, and expanded participation in DSP programs offered by governments, DNSPs, and retailers. Further information on the observed changes in DSP programs is in Appendix A3[34].

The reliability response represents the estimated response during reliability events. It comprises the estimated price-driven response at prices greater than $7,500/MWh, demand response from network event programs, and responses observed during actual LOR 2 and LOR 3 events[35]. Compared with the 2025 NEM ESOO, the projected reliability response exhibited varying levels of change across regions, with increases of 141 MW in Victoria and 110 MW in Queensland, and a decrease of 160 MW in New South Wales. These changes are partly attributed to the infrequent LOR events which limits the number of historical observations for estimating reliability responses accurately. Despite this variability, Victoria, New South Wales, and Queensland continue to provide the largest reliability responses during reliability events.

Table 6 Projected demand-side participation (MW), summer 2025-26 and 2026-27

Price trigger	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	2025-26	2026-27	2025-26	2026-27	2025-26	2026-27	2025-26	2026-27	2025-26	2026-27
$300-$500/MWh	1	21	30	120	26	10	1	9	1	37
$500-$7,500/MWh	21	52	70	151	46	20	5	17	3	94
> $7,500/MWh	108	121	144	186	46	33	5	37	189	166
Reliability response	350	190	189	299	46	35	5	37	383	524

For the *Committed and Anticipated Developments* reliability assessment, AEMO applied a flat forecast for reliability-responsive DSP, shown in **Table 6,** across the ESOO forecast horizon, consistent with the DSP Forecasting Methodology[36]. In contrast, the *Government Schemes and Actionable Developments* reliability assessment assumes reliability-responsive DSP grows moderately, increasing linearly to 4.3%[37] of forecast maximum demand under the Step Change scenario by 2050. WDR remains an emerging component of DSP, with observed dispatch volumes remaining modest relative to registered capacity. As such, forecasts are based primarily on observed dispatch behaviour rather than registered capability, and will be refined as additional operational evidence becomes available.

Potential future demand flexibility from data centres

Operational data centres currently provide little DSP, and have not been observed to provide material demand flexibility under normal operating conditions. Data centre operators are presently preferring to prioritise service uptime and reliability for their customers, rather than providing demand flexibility. While some data centres may include on-site backup generation or storage, these assets are typically reserved to improve the data centre's reliability outcomes, or smooth the load, rather than actively participation in demand response.

There is potential for data centres to provide greater demand flexibility over time. Potential sources of flexibility include load shifting and the use of on-site backup systems, although each is subject to operational and commercial constraints:

[34] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2026/2026-NEM-ESOO-Appendix-A3-Demand-Flexibility for more detail.

[35] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf for the definitions of LOR 2 and LOR 3.

[36] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/dsp-forecasting-methodology-and-dsp-information-guidelines-consultation/final-stage/2023-dsp-forecast-methodology.pdf.

[37] The long-term DSP target was informed by international assessments of demand response in the United States and Europe, as outlined in the 2025 IASR.

- **Load shifting**, such as adjusting the timing of non-urgent computing tasks to align with periods of high renewable generation or lower system demand, is technically feasible and has been demonstrated internationally. Implementing load shifting may require additional capital investment and operational changes and may have commercial impacts if customer service level agreements do not make allowances for potential service disruption. This type of flexibility is more likely to be feasible for hyperscale operators with greater control over workloads, and to be less applicable to co-location facilities hosting multiple independent customers, or where risk consequences of data latency are high.
- **On-site backup systems**, including embedded generation (typically diesel) or storage, may provide additional flexibility. However, contractual and operational constraints, as well as environmental and regulatory requirements, may limit the use of these systems to emergency situations.

Given limited observed demand response from data centres, current forecasts adopted a conservative approach consistent with observed participation. Encouraging greater use of this potential may require market arrangements, operational frameworks, and incentives that enable data centres to participate reliably and in a commercially viable way. Consistent with this, AEMC recently provided advice to the Energy and Climate Change Ministerial Council (ECMC) on regulatory pathways for data centres, including recommendations to support demand flexibility through market participation, contracting arrangements and connection frameworks[38]. These expectations may support greater participation by data centres in demand flexibility programs over time. However, the extent to which they translate into measurable demand response remains uncertain and is not reflected in current forecasts.

3.2 Supply and network outlook

A reliable power system depends on the capability to generate and securely transmit electricity to consumers. This section outlines the infrastructure that exists, or is under active development to generate, store, or transmit electricity to consumers and that was applied in the 2026 NEM ESOO reliability assessments: *Committed and Anticipated Developments*, and *Government Schemes and Actionable Developments*.

3.2.1 Generation commissioning assumptions

There is a substantial pipeline of utility-scale generation and storage projects in various stages of development in the NEM. AEMO collects information from generation and storage project proponents to assess their progression and transparently publishes this data on AEMO's Generation Information web page[39]. AEMO applies commitment criteria that consider a project's progress across land, finance, planning, contracts and construction categories[40] to determine the project list that can be relied upon with a high degree of confidence in its reliability assessments.

Table 7 shows the categorisation of the known generation pipeline in the July 2026 Generation Information publication, considering the commitment criteria.

[38] At https://www.aemc.gov.au/market-reviews-advice/data-centre-advice-ecmc.

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

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

Table 7 New generation pipeline as of July 2026 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	24,549	6,338	9,623	23,487
	Queensland	22,045	3,898	9,654	110,150
	South Australia	7,705	978	2,759	21,673
	Tasmania	3,124	0	337	12,321
	Victoria	19,581	2,602	3,922	76,109
	NEM	**77,005**	**13,816**	**26,295**	**343,738**

Reflecting development and commissioning delays

While a strong pipeline exists, delays against developer-intended commencement 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 construction and commissioning.

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. **Table 8** below sets out how project delays are incorporated into the reliability assessments.

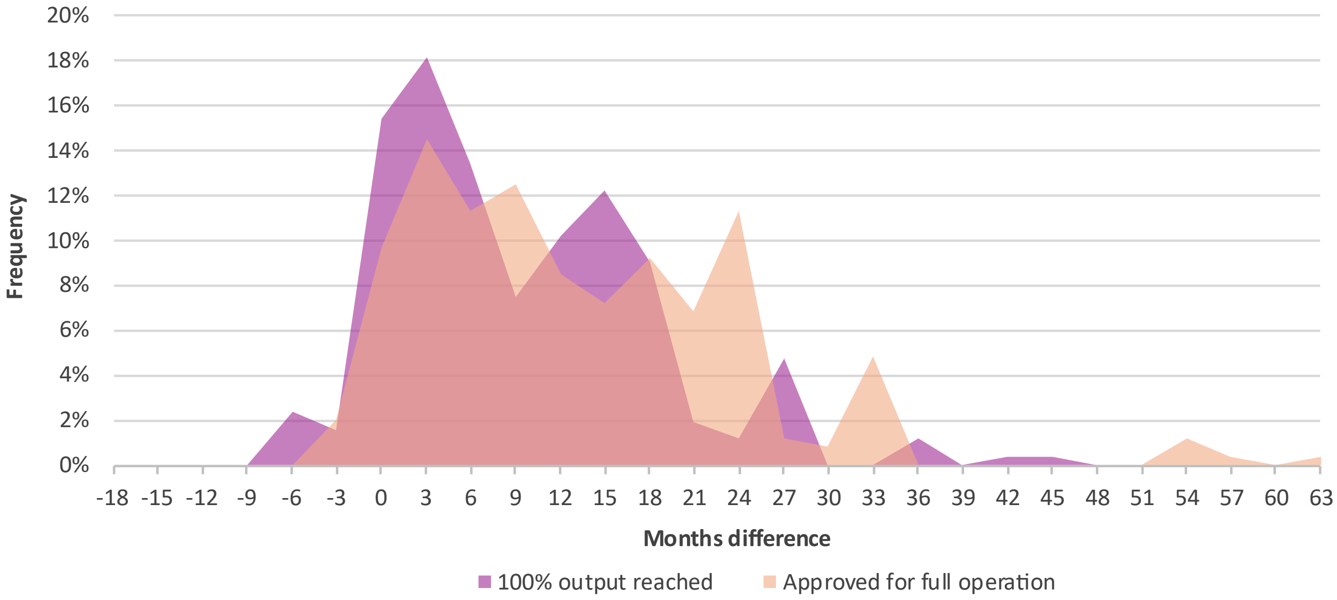
Figure 21 shows the difference between the full commercial use dates provided by developers and actual completion for developments that completed commissioning in the last 18 months.

AEMO assessed the difference for the period projects were classified by AEMO as 'committed', against two key commissioning milestones:

- **100% output reached** is 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. In the last 18 months, on average generators have experienced delays of approximately six months in reaching this milestone.
- **Approved for full operation** is 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 in its Generation Information surveys). In the last 18 months, on average generators have experienced delays of approximately 10 months delayed in reaching this milestone.

For assessing reliability, 'approved for full operation' is considered the more appropriate benchmark, as the generator may still be in testing following achievement of the '100% output reached' milestone.

Figure 21 Difference between full commercial use dates provided by developers, and actual achievement of commissioning milestones



Considering projects supported by Government schemes

Federal and state governments are implementing several programs across the NEM to support the rollout of generation and storage projects. The expanded generation pipeline that these programs support has been included in the *Government Schemes and Actionable Developments* reliability assessment. This assessment also assumed the various reasons for development delays are alleviated and projects are delivered to developers' intended schedules.

Government schemes that provide financial assistance – such as long-term revenue underwriting contracts – assist in progressing the financing category of AEMO's commitment criteria, but this does not automatically qualify a generator as 'committed', or even as 'anticipated'. Other delivery milestones still need to be achieved, and government support does not guarantee that a project will successfully complete its development. It is therefore important that both reliability assessments are examined and provided to support decision making.

Table 8 lists how AEMO applied the generation pipeline across the two reliability assessments. Where government schemes have announced development expectation or tender processes, but tenders are yet to be executed sufficiently to identify the appropriate location, timing, and technology of the developments that these schemes will support, these were not included in either reliability assessment.

Table 8 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 2028 (for this 2026 ESOO), or • one year after the developer advised full commissioning date.
Government scheme	***Government Schemes and Actionable Developments***	***Committed and Anticipated Developments***
Federal Government Capacity Investment Scheme (CIS) [A]	All awarded projects (included up to CIS Tender 8 announced on 24 June 2026) applied at the advised full commissioning date. Where there is no advised full commissioning date, commercial operations target date outlined by the tender was applied. All RETAs negotiated with each state and territory, that are not yet awarded, were applied in 2030-31. Further stages of the CIS, not specified in a RETA, were 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 were applied on the tender target in-service date.	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 were 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 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 were assumed to be met through other mechanisms.	Included only where committed or anticipated.
Queensland funded projects[E]	All projects with funding allocated under the Queensland Energy Roadmap budget were applied at the proponent advised full commissioning dates.	Included only where committed or anticipated.
South Australian funded projects	Firm Energy Reliability Mechanism (FERM) applied.	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://www.treasury.qld.gov.au/policies-and-programs/energy/energy-roadmap/renewables/.

Figure 22 shows the capacity outlook in each reliability assessment, with the annual utility-scale generation and storage commissioning quantities identified for the two 2026 NEM ESOO reliability assessments along with historical commissioning levels since 2021.

Both reliability assessments include a development outlook that reflects continued development and commissioning of new utility scale generation over the next five years. While a significant increase in generation development and commissioning has occurred in the last 12 months, increasing the connected capacity by 9.1 GW in 2025-26, each of the reliability assessments included continued developments that anticipate a similar or greater pace of connection of new assets to recent years:

- 12 GW per year under the *Government Schemes and Actionable Developments* assessment, and
- 7 GW per year under the *Committed and Anticipated Developments* assessment.

Figure 22 2026 NEM ESOO 10-year infrastructure development outlooks under typical summer availability assumptions with annual new utility-scale generation and storage commissioning quantities identified (GW)

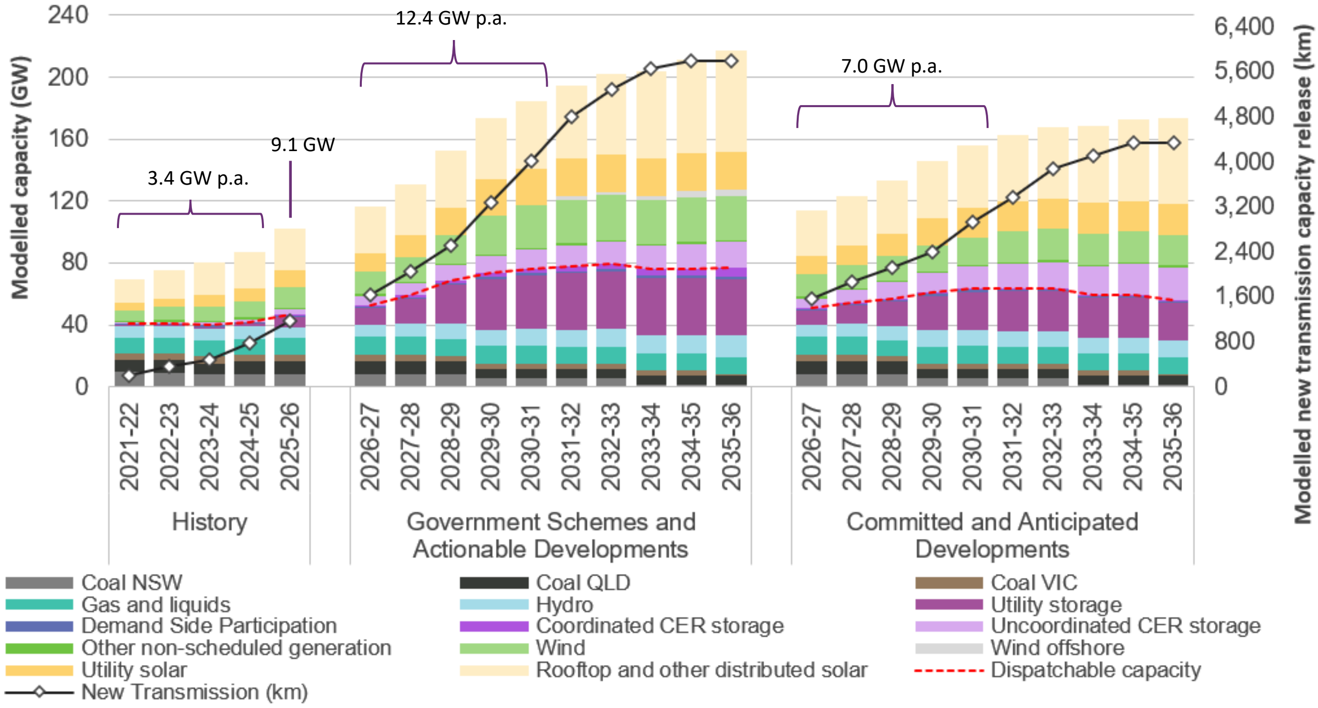
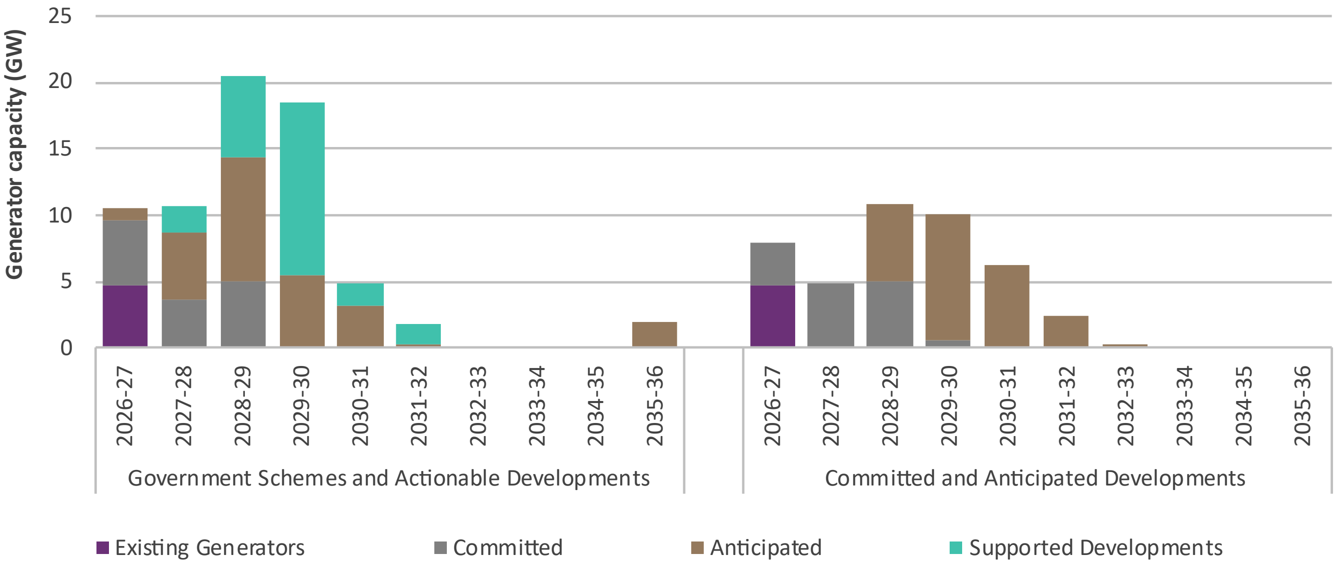


Figure 23 breaks down the assumed capacity outlook into the commissioning timeline based on commitment status for both modelled assessments.

Figure 23 2026 NEM ESOO 10-year generation pipeline based on commitment status (GW)



Note: 'Existing Generators' includes projects classified as in commissioning and in service. 'Supported Developments' includes projects classified as publicly announced.

Under the *Government Schemes and Actionable Developments* assessment:

- An average of 12 GW of new utility-scale capacity is expected to commission each year for the first five years of the horizon, which is slightly higher than the 2025-26 record development, and with the greatest increase in capacity expected in 2028-29 and 2029-30. This outlook includes:
  - a total of 30.3 GW/99.7 GWh of utility storage, 14.1 GW of utility solar and 17.3 GW of wind generation sufficiently advancing to meet criteria for inclusion over the 10-year horizon, or supported by government schemes, and
  - more than 39 GW more capacity than was considered in the equivalent reliability assessment published in the 2025 NEM ESOO.

In contrast, under the *Committed and Anticipated Developments* assessment:

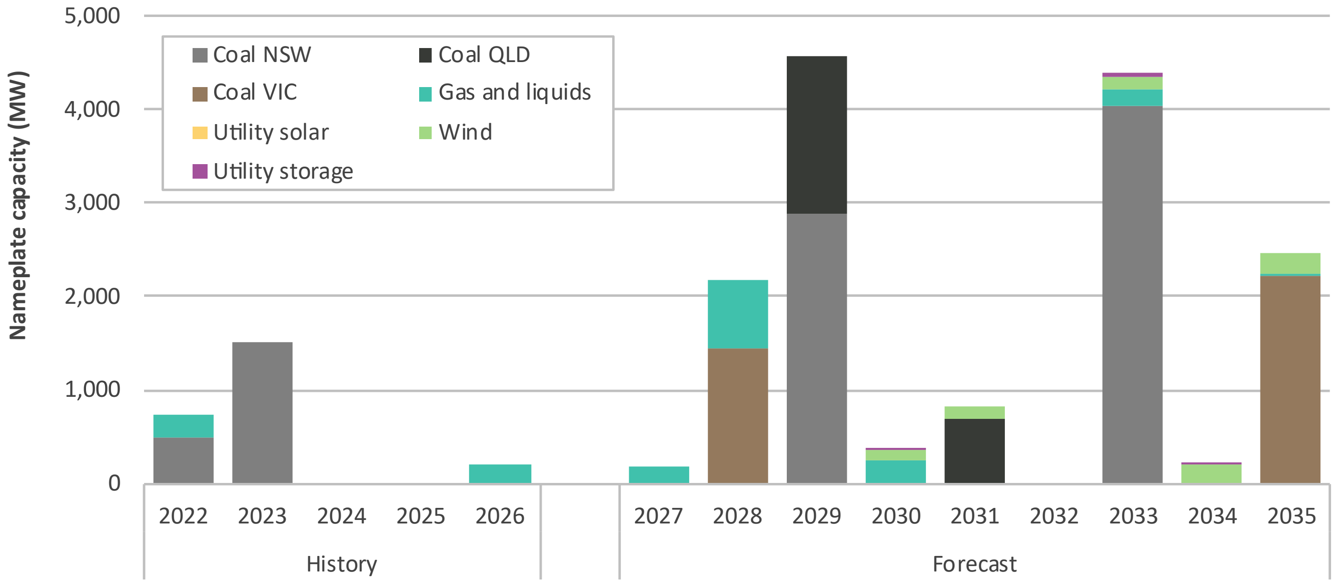
- An average of 7 GW of new utility-scale capacity is expected to commission each year for the first five years of the horizon, which applied recently observed development delays. The 10-year development outlook includes:
  - a total of 18.9 GW/50.6 GWh of utility storage, 9.1 GW of utility solar and 6.8 GW of wind generation sufficiently advancing to meet criteria for inclusion over the 10-year horizon,
  - a total of 6.1GW/16.7GWh of utility storage, 1.1 GW of utility solar and 0.8 GW of wind generation expected before July 2028 and
  - more than 24 GW of projects which have become committed or anticipated since the 2025 NEM ESOO.

In both assessments, few projects are included beyond the first five years, as there are very few projects sufficiently advanced to meet the commitment criteria to be considered committed or anticipated, and limited additional government support is sufficiently progressed to identify additional specific projects, locations and technologies that are supported by active government support.

3.2.2 Generation decommissioning assumptions

All ESOO reliability assessments assumed 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[41]. **Figure 24** shows future retirements advised by generator operators relative to generator retirements in recent years.

Figure 24 Actual and forecast retiring generation capacity, 2022 to 2035 (MW)



As advised by participants, the following retirements across the NEM have been announced over the ESOO's 10-year horizon, with more detail in **Table 9**:

- 13.0 GW of coal,
- 1.4 GW of gas and liquids,
- 0.8 GW of wind, and
- 0.1 GW/0.2 GWh of utility storage.

[41] NER 2.10.1(c1)

Table 9 Announced generator retirements across the NEM

Retirement year/date	Generator	Region	Technology Type	Capacity
31 December 2027	Osborne	SA	Gas Turbine	180 MW
1 January 2028	Port Lincoln GT (advised to remain mothballed[A] until retirement 2028)	SA	Gas Turbine	73.5 MW
	Snuggery	SA	Gas Turbine	63 MW
30 June 2028	Torrens Island B Units 2-4	SA	Gas Turbine	600 MW
1 July 2028	Yallourn W	VIC	Coal	1,450 MW
31 March 2029	Gladstone	QLD	Coal	1,680 MW
30 April 2029	Eraring	NSW	Coal	2,880 MW
2030	Cathedral Rocks	SA	Wind	62MW
	Dalrymple BESS	SA	Utility Storage	30 MW / 9 MWh
	Dry Creek GT	SA	Gas Turbine	156 MW
	Mintaro GT	SA	Gas Turbine	90 MW
	Challicum Hills	VIC	Wind	53 MW
2031	Callide B	QLD	Coal	700 MW
	Wattle Point	SA	Wind	91 MW
	Yambuk	VIC	Wind	30 MW
2033	ACT BESS	NSW	Utility Storage	10 MW / 20 MWh
	Bayswater Power Station	NSW	Coal	2,715 MW
	Vales Point B	NSW	Coal	1,320 MW
	Snowtown Wind Farm	SA	Wind	99 MW
	Starfish Hill	SA	Wind	33 MW
	Ballarat Energy Storage System	VIC	Utility storage	30 MW / 30 MWh
	Gannawarra Energy Storage System	VIC	Utility Storage	25 MW / 50 MWh
	Somerton	VIC	Gas Turbine	170 MW
2034	Lake Bonney Battery Energy Storage	SA	Utility Storage	25 MW / 52 MWh
	Waubra	VIC	Wind	192 MW
2035	Barcaldine Power Station	QLD	Gas Turbine	37 MW
	Canunda	SA	Wind	46 MW
	Hallett Stage 2 Hallett Hill	SA	Wind	71 MW
	Lake Bonney 1 Wind Farm	SA	Wind	80 MW
	Loy Yang A Power Station	VIC	Coal	2,210 MW
	Mortons Lane Wind Farm	VIC	Wind	20 MW

A. 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.

3.2.3 Generator seasonal capability

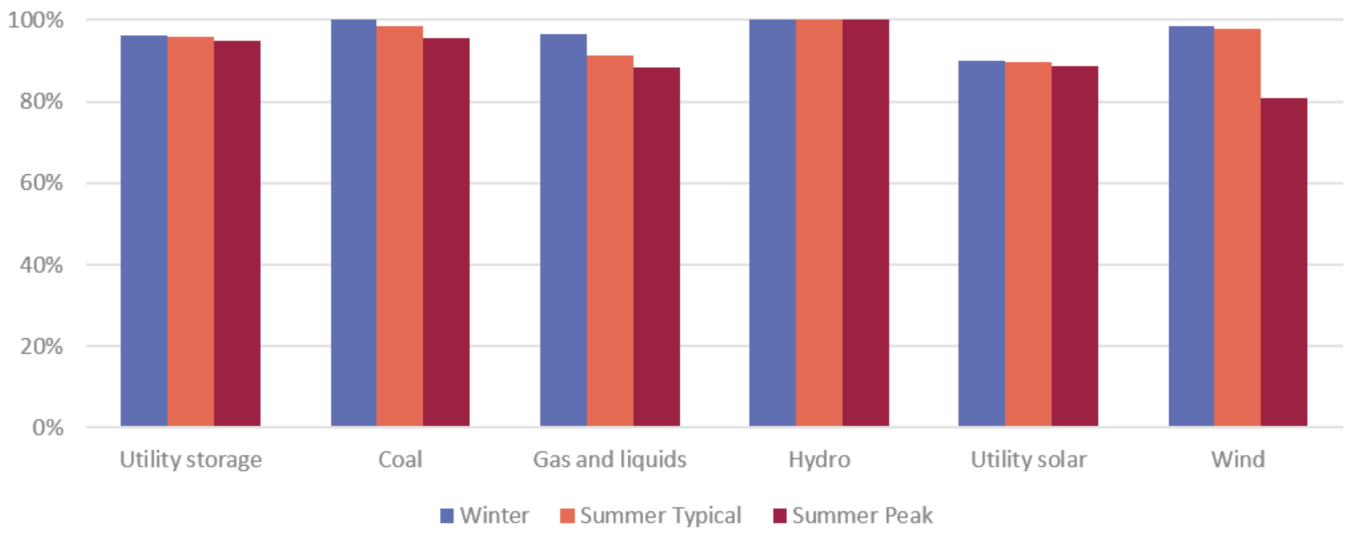
AEMO collects existing and committed scheduled and semi-scheduled generation capabilities over the next 10 years to capture seasonal generator availability. Scheduled capacity values are collected for three seasonal periods, where generator operators and proponents provide ratings consistent with the 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** is aligned with average summer temperatures and 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** is applied to all non-summer periods.

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

Figure 25 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, including up to 100% derating during summer peak temperatures. See the *ESOO and Reliability Forecast Methodology Document*[42] for more detail about generation availability.

Figure 25 Season availability for various generation technologies relative to nameplate capacity



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

3.2.4 Generator outage rates

Generator outage assumptions are a key input to the ESOO reliability assessments because they reflect the availability of scheduled generating units during periods of system stress. As the NEM transitions towards higher shares of renewable generation and storage and the existing coal fleet ages, accurately representing the availability of dispatchable generation becomes increasingly important for assessing future reliability outcomes.

Information collected and outage assumptions

AEMO conducts an annual survey of existing scheduled generating units to collect historical outage data and forward projections of outage rates. Participants provide information on the timing, duration and capacity derating of outages during the previous year. In addition, operators of coal-fired and large gas-fired generators submit forward outage projections reflecting expected changes in plant reliability.

Historical observations and participant forecasts were combined to develop outage assumptions across the 10-year outlook. Participant forecasts were applied where appropriate, including applying participant-submitted Medium Term Projected Assessment of System Adequacy (MT PASA) planned outage schedules for coal generators in the first three outlook years[43], where detailed maintenance schedules are available. Technology-level assumptions based on recent operating performance were developed for hydro, smaller gas and liquid-fuelled generators, and batteries. Detailed forecasting methodologies are published separately in the *ESOO and Reliability Forecast Methodology*[44].

Following stakeholder consultation through the 2025 *Forecast Improvement Plan*, the outage modelling framework and survey were expanded in the 2026 ESOO to include four outage categories: long-duration unplanned outages, forced outages, planned outages, and maintenance outages.

Representing planned outages and maintenance improves the realism of the reliability assessment

Previous NEM ESOOs represented only unplanned generator outages. In recent years, AEMO frequently observed planned outages, including maintenance, occurring in at-risk seasons, such as in summer. To improve the consideration of such activities and thereby improve the assessment of reliability, AEMO consulted with stakeholders on a potential adjustment to the treatment of planned outages and maintenance. Following consultation with stakeholders, for the first time, the 2026 ESOO explicitly models **planned outages and maintenance** alongside **forced and long-duration unplanned outages**.

This enhancement provides a more complete representation of generator availability by recognising both unexpected equipment failures and scheduled outages that reduce available generation. Explicitly modelling all four outage categories improves the operational realism of the reliability assessment and provides a more representative assessment of supply scarcity risks over the outlook period.

[43] Coal outages taken from MT PASA availability table on 1 July 2026.

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

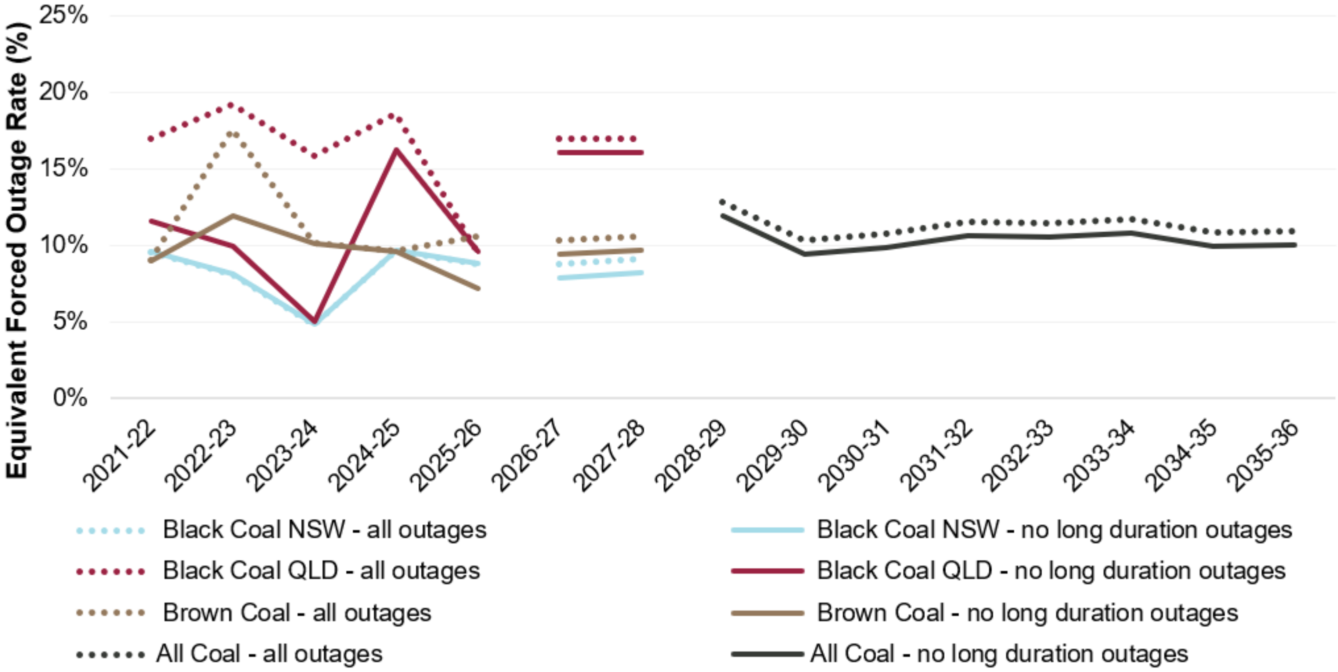
Long-duration unplanned outages and forced outages

Long-duration unplanned outages and forced outages together represent the unplanned loss of generator availability and are modelled probabilistically within the reliability assessment.

Long-duration unplanned outages represent outages lasting longer than five months and were forecast using 16 years of historical observations (2010-11 to 2025-26). Forced outage rates exclude these events and represent shorter-duration unexpected equipment failures.

Figure 26 and **Figure 27** present the projected equivalent forced outage rates[45] by technology, representing the average outage rate of combined partial and full forced outages, both excluding and including long-duration unplanned outages.

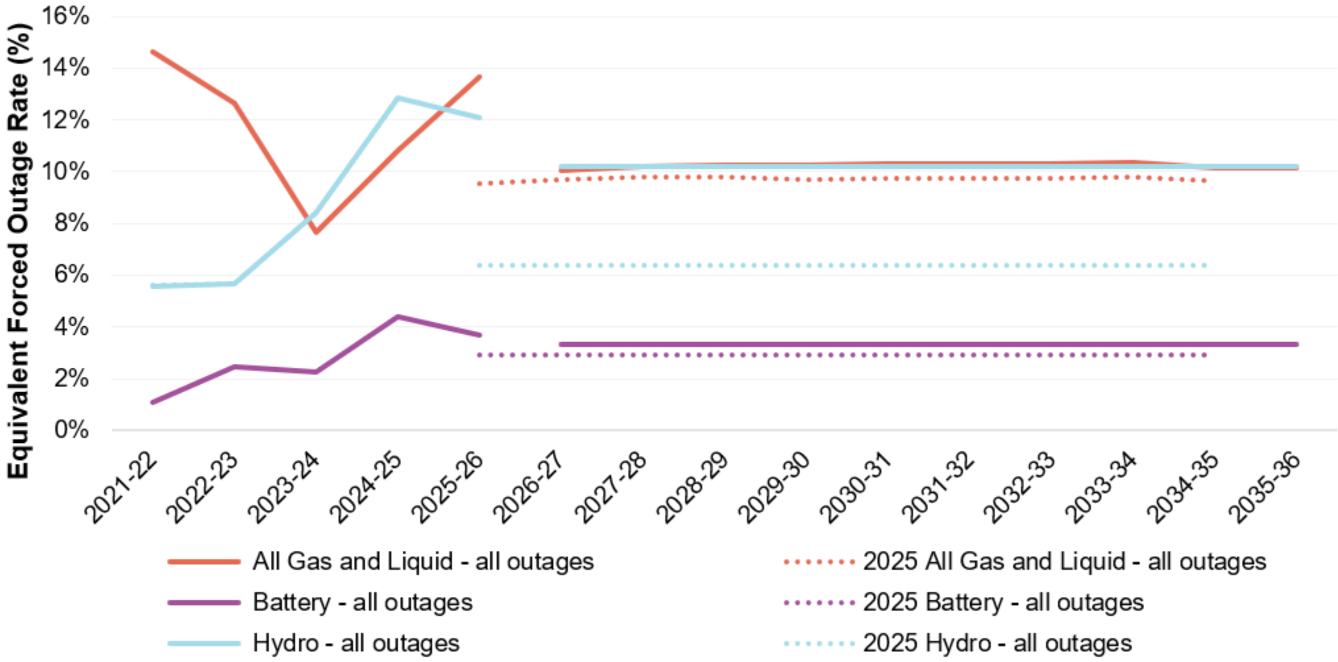
Figure 26 Actual and projected equivalent forced outage rates for coal generation technologies, 2021-22 to 2035-36



Note: 'Black Coal NSW' reported no historical long duration outages, therefore 'all outages' and 'no long duration outages' rates are the same in the historical data.

[45] Where equivalent forced outage rate = full outage rate + partial forced outage rate x average partial derating.

Figure 27 Actual and forecast equivalent forced outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2021-22 to 2035-36



Coal-fired generators continue to exhibit the highest equivalent forced outage rates of all scheduled generation technologies, reflecting the age and operating characteristics of the coal fleet. Due to improved recent operating performance and lower participant projections, forecast forced outage rates are generally lower than those applied in the 2025 NEM ESOO. Queensland black coal generators are also expected to benefit from the Queensland Government's Electricity Maintenance Guarantee Scheme[46].

Forced outage projections for gas and liquid-fuelled generators remain broadly consistent with the 2025 NEM ESOO. Hydro generators recorded a higher frequency of forced outages in recent years, leading to increased projected outage assumptions based on historical performance. Battery systems forecast outage rates are slightly higher than those used in the 2025 ESOO because they are now based on four years of operating history rather than three and the latest year's outage outcomes are relatively high compared to 2022-23 and 2023-24.

To preserve the confidentiality of participant submissions, coal outage rates are presented as an aggregated category from 2028-29 onwards, following closures in Victoria, New South Wales and Queensland.

Planned and maintenance outages

Figure 28 and **Figure 29** present projected planned outage rates and maintenance rates by technology across the outlook period. Planned outages are scheduled with sufficient lead time, allowing the outage to be scheduled in periods of low demand and system need while maintenance outages occur without long notice, either due to a plant failure that can be rectified with some flexibility in scheduling, or opportunistic maintenance undertaken by the operator.

[46] At https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf.

Figure 28 Actual and forecast equivalent planned and maintenance outage rates for coal generation technologies, 2025-26 to 2035-36

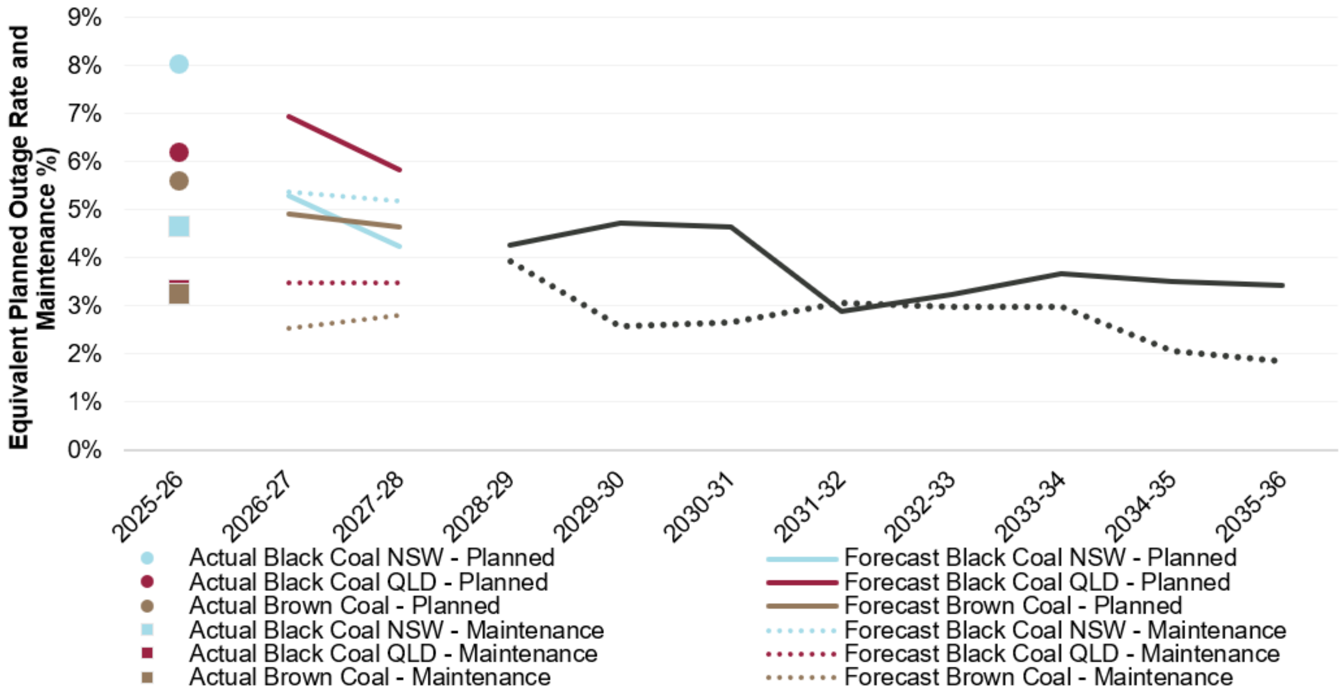
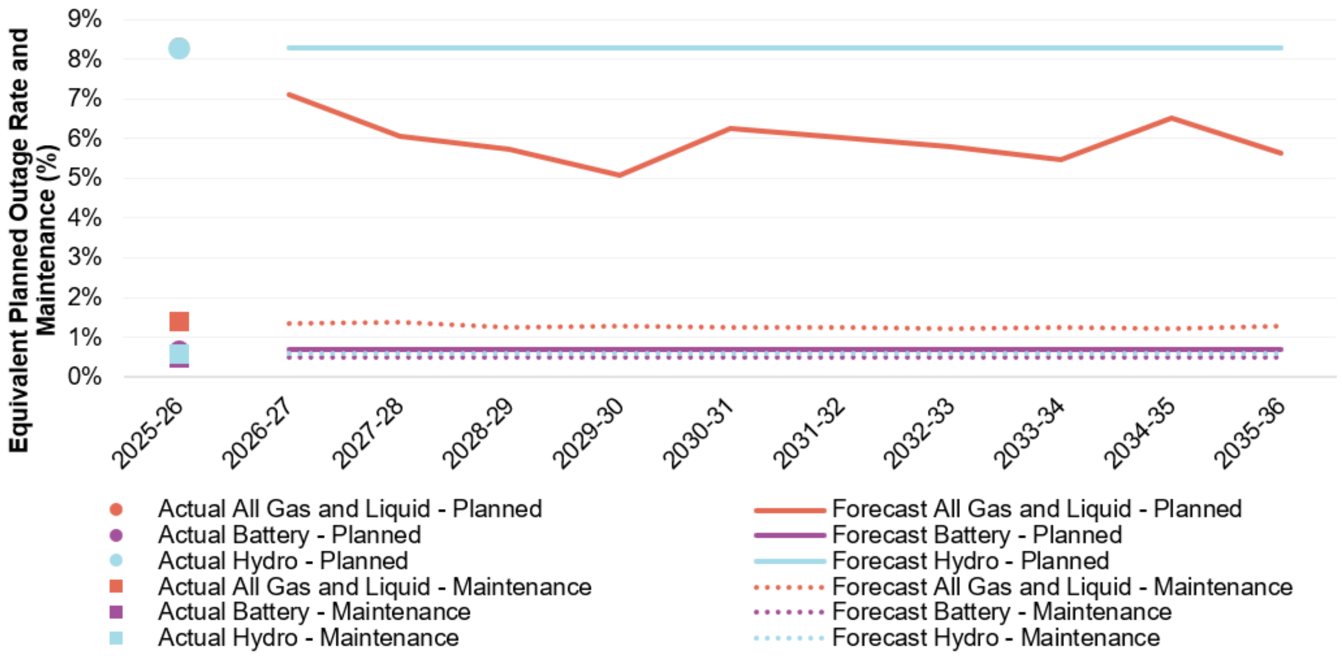


Figure 29 Actual and forecast equivalent planned and maintenance outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2025-26 to 2035-36



Coal-fired generators continue to exhibit the highest planned outage requirements. New South Wales coal generators recorded the highest planned outage rates in 2025-26, while participant submissions and MT PASA planned outage schedules indicate Queensland coal generators are projected to have the highest planned outage rates during the early years of the outlook. Planned outage rates for New South Wales and Victorian coal generators remain lower and broadly similar.

Coal maintenance outage rates generally range from approximately 3% to 5% in the near term before gradually declining over the outlook period, reflecting participant forecasts, changing maintenance requirements as generating units age, and the progressive retirement of coal-fired generators. From 2028-29 onwards, aggregated coal planned and maintenance outage assumptions were applied to preserve the confidentiality of participant submissions.

Planned and maintenance outage assumptions for gas, hydro and battery technologies remain relatively stable throughout the outlook. Hydro generators continue to exhibit substantially higher planned outage rates than maintenance outage rates, reflecting longer scheduled overhaul activities, while planned and maintenance outage rates for batteries remain low, indicating that unexpected equipment failures remain the dominant source of battery unavailability (though it may be premature in this technology's maturity stage to reflect normal long-term levels of each outage category).

Together, the four outage categories provide a relatively complete representation of generator availability across the outlook period, improving AEMO's assessment of energy adequacy and supply scarcity risks.

3.2.5 Generator energy limits

As part of the reliability forecasting improvements introduced under the 2025 Forecast Improvement Plan, AEMO collected station-level operational energy limits for scheduled generating units (excluding batteries[47]) for the 2026 NEM ESOO and incorporated them into the reliability assessments. Participants submitted energy limits at various time resolutions, including daily, weekly, monthly, quarterly and yearly intervals. These limits represent operational constraints on the amount of energy generating units produce over different time horizons, excluding market or commercial considerations.

Unlike previous ESOOs, the 2026 NEM ESOO explicitly incorporated these participant-submitted energy limits in the reliability assessment. This reflects the growing importance of energy availability as the generation mix transitions towards higher shares of renewable generation and storage. The 2025 ESOO *Generator Maintenance* sensitivity demonstrated that reducing generator energy availability can materially increase expected USE outcomes in most regions.

The 2026 *Gas Statement of Opportunities* (GSOO) identified gas shortfall risks particularly during extreme peak day conditions during winter from 2029 in southern regions[48], and the need for additional gas supply from 2030. As the 2026 ESOO does not include market-level limits, such as the impacts of the whole-of-gas-system limits, emphasis in this ESOO has been placed on the relevance and impact of operational station-level constraints provided by participants which may not account for whole system limits and may assume that additional gas supply is developed to be able to meet whole-of-gas-system demands. In other words, the 2026 NEM ESOO assumed the structural supply gap identified in the 2026 GSOO is addressed by the gas industry.

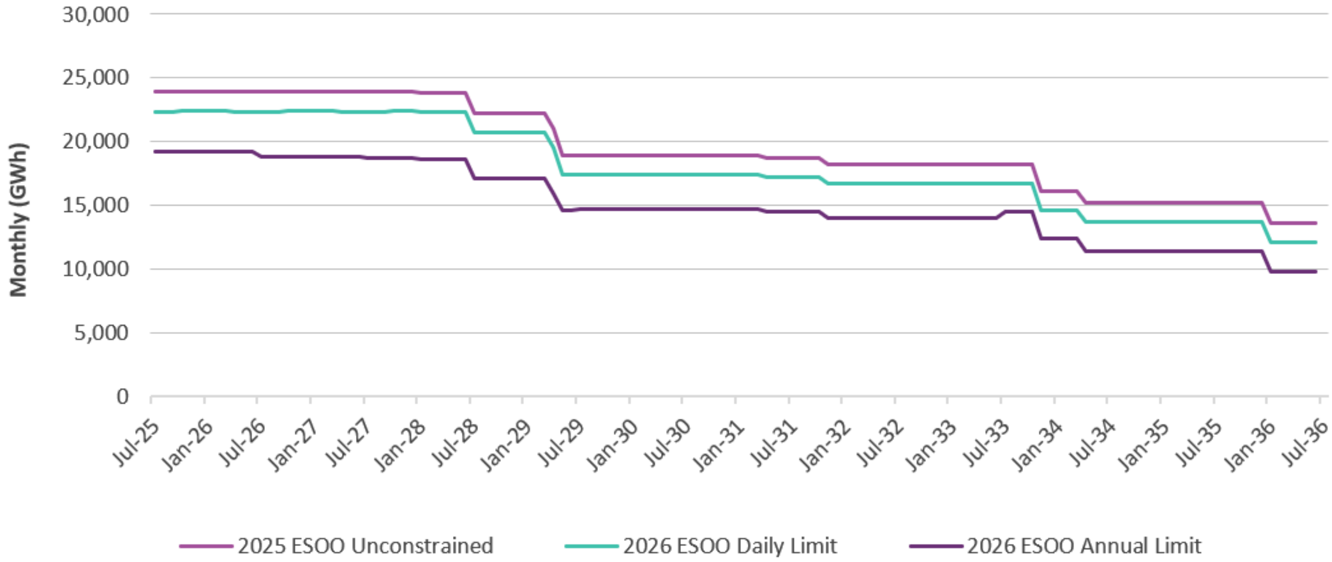
Figure 30 compares the aggregated daily and annual energy limit values for the 2026 ESOO compared to unconstrained limits for the 2025 NEM ESOO for coal, gas and liquid fuel generators. To illustrate this, participant-submitted daily and annual limits have been converted to monthly energy limits across the 10-year modelling horizon. Interactions between the limits that have been supplied by participants at different time resolutions were considered in developing forecasts.

[47] The ESOO reliability forecasts assumed a default annual limit of 365 equivalent cycles, unless a different annual cycling limit was provided by participants.

[48] Southern regions include New South Wales, South Australia, Tasmania, and Victoria. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf.

Although converted to a similar metric on the chart, daily limits can restrict duration of model outcome of generation; that is, a generator operating at its daily limit for multiple days in succession may not be able to meet its monthly or annual limits. The submissions indicate energy is more constrained than was assumed in the 2025 NEM ESOO, where energy limits for coal, gas and liquid fuel generators were not considered. Annual energy limits are reduced relative to the 2025 NEM ESOO, which did not apply energy limits. Further detail on the treatment and implementation of generator energy limits is in the *NEM ESOO Reliability Forecast Methodology*.

Figure 30 Comparison of aggregated daily and annual energy limits assumptions of coal, gas, and liquid fuel generators applied in the 2025 and 2026 NEM ESOOs (GWh)



3.2.6 Transmission capability and commissioning assumptions

The ESOO reliability assessments applied a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain[49] dispatch in the NEM, as well as potential future constraints with consideration of committed, anticipated and actionable network investments (depending on the treatment of these investments in each reliability assessment as discussed below). 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[50]. To determine if a transmission project is committed or anticipated, AEMO applied commitment criteria consistent with the *ISP Methodology*[51] and the AER's *Cost Benefit Analysis Guidelines* (and the Regulatory Investment Test for Transmission [RIT-T][52]).

[49] Since modelling for the 2026 NEM ESOO was completed, AusNet has advised that some network elements are likely to be derated, which may reduce the transmission capability between Melbourne and parts of regional Victoria. AEMO will work with AusNet, and where relevant the jurisdictional planning body, to understand the impact of the reduced transmission capability and explore options available to reduce any risks associated with the network derating.

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

[51] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

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

Consistent with AEMO's *ESOO and Reliability Forecast Methodology Document*[53], **Table 10** shows the timing applied to the assumed commissioning of transmission infrastructure in both development outlooks.

Table 10 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.	Applied consistent with operational advice.
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[A].
Anticipated	Applied by the full capacity release date as 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 2026 ISP, or other actionable frameworks	Applied by the full capacity release date as advised by the developer.	Not applied.

A. A six-month delay was applied to large transmission projects with an advised in-service timing after August 2027. The delay is consistent with delays observed for recently commissioned projects, and consistent with the assumption applied in the 2025 ESOO.

Figure 31 shows the committed, anticipated and actionable transmission construction assumed over the 10-year horizon in the two 2026 NEM 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 444,000 km of existing transmission lines and cables that provides the interconnected backbone of the NEM. The *Committed and Anticipated Developments* assessment included over 3,000 km of new transmission developments, while the *Government Schemes and Actionable Developments* assessment considered approximately 5,000 km of new developments, including the actionable VNI West and Marinus Link Stage 2 interconnectors, with most other augmentations in New South Wales and Queensland.

Figure 31 Cumulative new transmission capacity release assumed over the 10-year ESOO horizon (km)

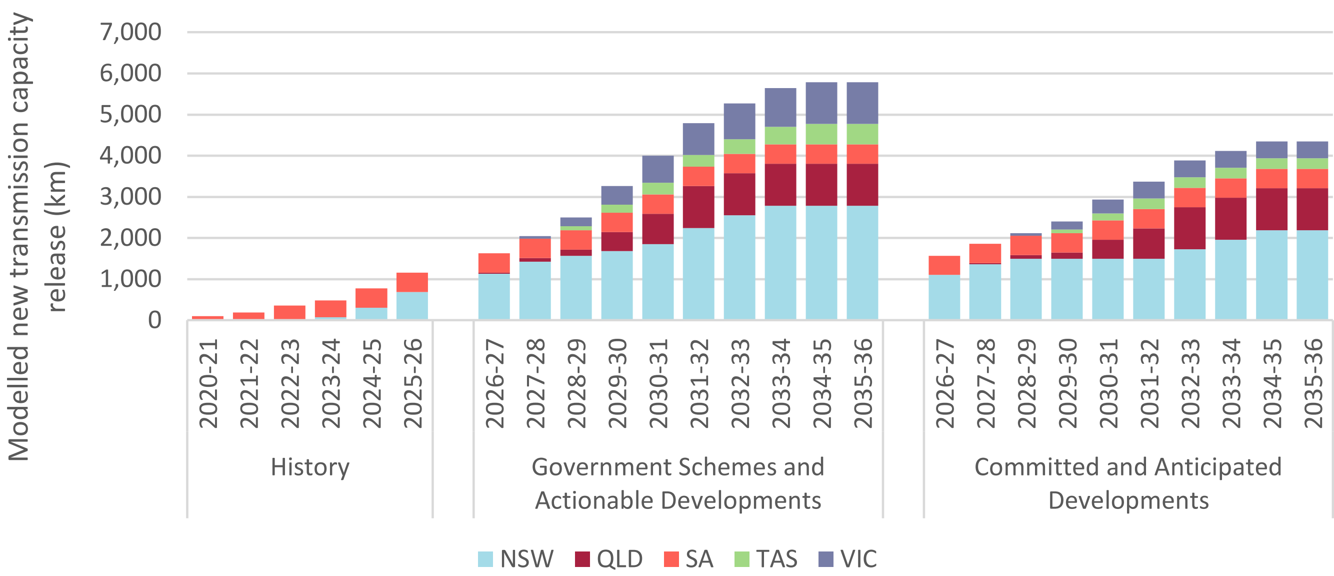
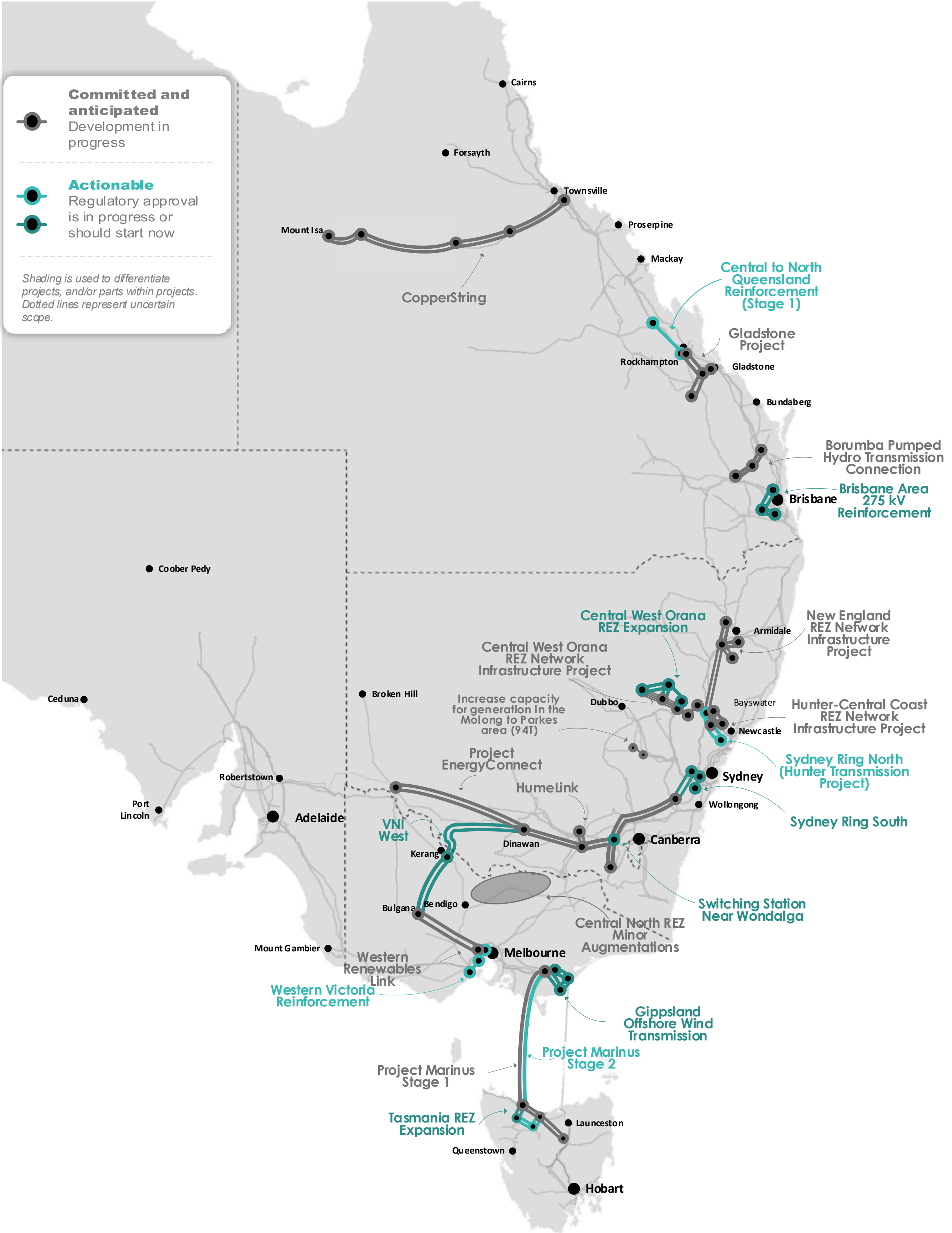


Figure 32 shows all committed, anticipated and actionable projects on a map. A list of all relevant projects, including project timing, is outlined in **Table 11** and provided in more detail in the 2026 *ESOO Results Workbook*.

[53] See Section 3.5, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf?rev=3ceb7e7280fa46d8b7da3f8c7c138d18&sc_lang=en.

Figure 32 Map of network investments considered by status



† Grey bubbles indicate anticipated and committed REZ augmentation projects that may include non-network augmentations.

Table 11 Overview of transmission projects considered in the assessments

Project	Location	Approximate increase in network capacity [A]	Expected operation date	
			Government Schemes and Actionable Developments	*Committed and Anticipated Developments*
Project EnergyConnect (Stage 2)	New South Wales, South Australia	650 MW increase between New South Wales and South Australia in both directions.	December 2027 [B]	December 2027 [B]
HumeLink	New South Wales	Increase in capacity between Southern New South Wales and Central Network South Wales of 2,200 MW in both directions.	December 2027	June 2028
Hunter-Central Coast REZ Network Infrastructure project	New South Wales	Increase in transfer capacity of 400 MW through Muswellbrook BSP and 600 MW through Newcastle BSP.	July 2028	January 2029
Central-West Orana REZ Network Infrastructure Project	New South Wales	4,500 MW [C]	December 2028	June 2029
Gladstone Project	Queensland	Central Queensland to Gladstone Grid: 2,600 MW, Gladstone Grid to Central Queensland: 500 MW.	March 2029 (Critical new transmission) Balance of the project by mid-2030	March 2030 (Critical new transmission) Balance of the project by mid-2031
Western Victoria Reinforcement Project	Victoria	WNV to MEL: 800 MW	June 2029	-
Western Renewables Link	Victoria	WNV-MEL: 695 MW (both directions) V2: 310 MW	November 2029	November 2030
Hunter Transmission Project	New South Wales	5,000 MW increased in network capacity between Central New South Wales and Sydney, Newcastle & Wollongong	November 2029	-
Sydney Ring South Power Flow Control Option	New South Wales	Improves power sharing.	July 2030	-
Project Marinus (Stage 1)	Tasmania, Victoria	750 MW increase in flow between Victoria and Tasmania in both directions.	December 2030	December 2031
Tasmania REZ Expansion	Tasmania	800 MW	December 2030	-
Switching Station near Wondalga	New South Wales	450 MW increase in transfer between Southern New South Wales and Central New South Wales in both directions.	April 2031	-
Central to North Queensland Reinforcement	Queensland	Central Queensland to North Queensland: Forward: 350 MW Reverse: 500 MW	July 2031	-
Gippsland Offshore Transmission Project	Victoria	V8 REZ increase in capacity: Option 1 – 2,000 MW Option 2 – 2,000 MW	July 2031 (Option 1) July 2033 (Option 2)	-
VNI West	New South Wales, Victoria	Increase in transfer between Victoria to New South Wales of 1,885 MW and New South Wales to Victoria of 1,669 MW.	Stage 1: August 2029 Stage 2: November 2031	-
CopperString	Queensland	1,400 MW [D]	June 2032	June 2033
Brisbane Area Reinforcement	Queensland	685 MW	June 2032	-
Central-West Orana REZ Expansion	New South Wales	1,500 MW	March 2033	-

Project	Location	Approximate increase in network capacity [A]	Expected operation date	
			Government Schemes and Actionable Developments	*Committed and Anticipated Developments*
Sydney Ring South – 500 kV option	New South Wales	Central New South Wales to Sydney Newcastle Wollongong: Stage 1 – 1,300 MW Stage 2 – 2,300 MW	July 2033	-
New England REZ Infrastructure Project	New South Wales	6,000 MW	January 2034	January 2035
Project Marinus (Stage 2)	Tasmania, Victoria	750 MW increase in flow between Victoria and Tasmania in both directions.	December 2034	-

A. The increase in network capacity is approximate. For the purpose of reliability assessments, AEMO models the increase in network capacity through the network constraint equations.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
C. Hunter Transmission Project is required to address network constraints between Central New South Wales and Sydney, Newcastle and Wollongong to enable the increase from 3,000 MW to 4,500 MW.
D. This network capacity is limited by the capability of the 330 kV network between Hughenden and Townsville. Flows from CopperString will compete with generation in Far North Queensland for the 275 kV capacity south of NQ 275 kV substation.

3.2.7 Transmission reliability assumptions

In forecasting the reliability of the NEM in this ESOO, AEMO applied transmission unplanned outage rates 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 materially contribute to inter-regional energy transfer. For more information on the modelling of transmission outages, see the *ESOO and Reliability Forecasting Methodology*[54].

Table 12 presents the outage rates used in the 2026 NEM ESOO. Most flow paths show slightly lower rates than those applied in the 2025 NEM ESOO, except for the Liddell – Bulli Creek flow path, which has a marginal increase in unplanned outage rates due to reclassification events. 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 EnergyConnect Stage 2 is modelled to release full capacity in December 2027, as the impact of a single circuit outage is less impactful when there are more circuits interconnecting South Australia to other NEM regions.

Table 12 Projected unplanned outage rates for inter-regional transmission flow paths

Flow path	2026 ESOO transmission UOR (%)	2026 ESOO Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.27	21.1	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.79	3.8	Annual static
Murraylink – Credible Contingency	1.26	56.6	Annual static
Basslink – Credible Contingency	4.22	159.6	Annual static
Mortlake – South East (VSA) Credible Contingency	0.03	2.1	Annual, set to 0% post commissioning of Project EnergyConnect Stage 2
Mortlake – South East (VSA) Reclassification	0.01	4.7	Annual, set to 0% post commissioning of Project EnergyConnect Stage 2 in December 2027

54 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.

3.2.8 Key supply changes since 2025 ESOO October Update

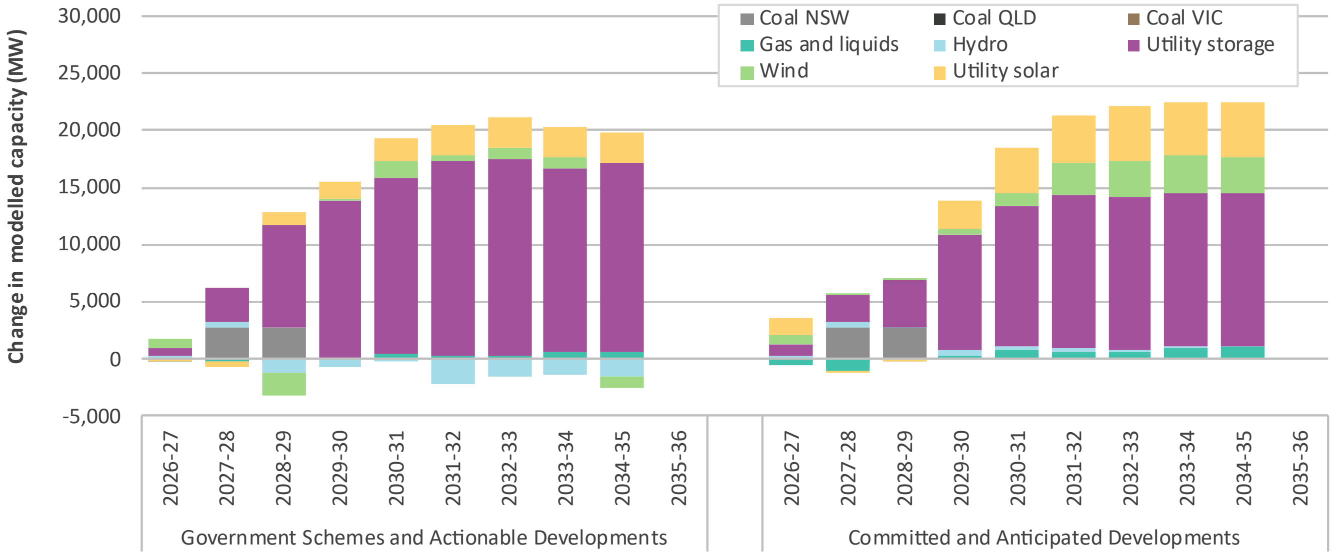
Compared to the *October 2025 Update to the 2025 Electricity Statement of Opportunities* (2025 NEM ESOO October Update), the 2026 reliability assessments included significantly more generation and storage developments over the 10-year horizon, as a record number of projects have progressed sufficiently 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.

Table 13 lists all changes since 2025 NEM ESOO October Update for considerations of the government schemes and actionable development projects. **Figure 33** shows the capacity change between 2025 NEM ESOO October Update and 2026 NEM ESOO in both development scenarios.

Table 13 *Government Schemes and Actionable Developments* changes from 2025 NEM ESOO October Update to 2026 NEM ESOO

Change category	2025 NEM ESOO October Update consideration	2026 NEM ESOO consideration	2026 NEM ESOO total scheme capacity considered
Capacity Investment Scheme	CIS tender 1 awarded projects, as well as all remaining RETAs targets, by building any capacity required but not yet awarded. Targets negotiated with each state and territory, that are not yet awarded.	All NEM awarded projects up to CIS tender 8, as well as all remaining RETAs targets negotiated with each state and territory, that are not yet awarded.	38.8 GW
New South Wales Infrastructure Investment Objectives (IIO) Report	Included awarded projects, firming targets and long duration targets.	Included previously identified awarded projects, firming targets and long duration targets some of which are expanded.	7.6 GW
Victorian offshore wind	No change, included Victorian offshore wind targets (2 GW by 2032 and 4 GW by 2035).	No change, included Victorian offshore wind targets (2 GW by 2032 and 4 GW by 2035).	4.0 GW
Queensland Renewable Energy and Hydrogen Jobs Fund	Projects included as listed in the 2025 Queensland budget.	Included projects listed in the 2025 Queensland budget with the following changes: • addition of Capricornia Energy Hub (CEH) PHES (750 MW/12,000 MWh), • removal of Mt Rawdon pumped hydro (2,040 MW/20,000 MWh) which has been discontinued, and • exclusion of Cressbrook Pumped Hydro Project (400 MW/4,000 MWh) which now falls outside the 10 year horizon.	3.4 GW
South Australia's FERM	Not considered.	Awarded long-duration storage projects included (517 MW of committed output capacity with eight or more hours storage), with additional capacity required but not yet awarded also included (700 MW by the end of 2031).	1.1 GW

Figure 33 Change in capacity considered in each outlook relative to the 2025 ESOO October Update



For the *Committed and Anticipated Developments* reliability assessment, more than 24 GW of developments have progressed sufficiently to be considered committed or anticipated since the 2025 ESOO October Update. Several projects that were included in the 2025 ESOO October Update are no longer classified as committed or anticipated, and therefore were not included in this assessment. This is due to these projects having been classified by project proponents as discontinued, or have been reassessed by AEMO given updated participant information as no longer meeting the relevant commitment criteria due to changes to the project proposal, resulting in a less advanced commitment categorisation:

- Aldoga BESS (400 MW/400 MWh) in Queensland,
- Riverina Solar Farm (32 MW) in New South Wales,
- Ravenswood BESS (20 MW/ 40 MWh) in Victoria, and
- Richmond Valley BESS (275 MW/2,200 MWh) in New South Wales.

Given the unprecedented scale of development now anticipated, and recognising that many anticipated projects remain at an earlier stage of development and have yet to achieve key milestones, AEMO has undertaken a sensitivity to assess supply scarcity risks if only committed projects are delivered. Further details are in Section 4.

For the *Government Schemes and Actionable Developments* reliability assessment, more than 39 GW of additional capacity was assumed to develop over the 10-year horizon, relative to the 2025 NEM ESOO October Update. Key changes and insights are:

- Between 2027-28 and 2028-29, more New South Wales coal capacity was assumed due to the extended operation of Eraring Power Station, relative to the expected closure applied in the 2025 ESOO October Update.
- Significant solar and wind developments have progressed since the 2025 ESOO October Update, though even more projects are developing with support from government schemes and are yet to reach committed or anticipated development milestones. As previously mentioned, financial support does not meet the full commitment criteria in isolation, nor does it guarantee on-time delivery, and it is important for developers to progress these projects to commitment and deployment to maintain reliability.

4 Assessing future reliability and resource adequacy

Maintaining reliability through the energy transition depends on balancing growing demand, ageing thermal retirements, and the timely delivery of new generation, storage, transmission and CER. This section presents two complementary reliability assessments, supported by targeted sensitivities, to examine future resource adequacy under different assumptions. Together, they show the NEM has a credible pathway to maintaining reliability if the current investment pipeline is delivered on time, while highlighting the need for continued investment as demand grows and thermal generation retires.

4.1 On-time project delivery and continued investment alongside consumer investments are critical to maintaining reliability

The 2026 NEM ESOO presents two complementary reliability assessments that provide different future supply outlooks (see Section 2.2 for a detailed description of each assessment and **Table 4** in that section for the key assumptions applied):

- ***Government Schemes and Actionable Developments*** – assessed reliability outcomes with on-time delivery of committed and anticipated developments, alongside additional generation and dispatchable storage that are supported through government programs, as well as actionable transmission developments, coordinated CER and flexible demand resources (including DSP, VPP and V2G projections) in addition to existing and committed DSP, VPP and V2G developments.
- ***Committed and Anticipated Developments*** – forms AEMO's reliability and indicative reliability forecasts under the NER. The assessment included only existing resources and projects classified as committed or anticipated, and recognised potential project delivery delays given observed commissioning timeframes that have impacted recent developments.

The 2026 NEM ESOO incorporated several important enhancements to the reliability assessment. Building on the 2025 NEM ESOO *Generator Maintenance* sensitivity[55] and as consulted on as a key improvement for AEMO's reliability modelling[56], both assessments explicitly incorporated planned and maintenance outages across the outlook period, together with station-level energy limitations advised by market participants for coal, gas and other energy-constrained generation. These enhancements provide a more comprehensive representation of generator operational availability during extended periods of system stress and increasingly reflect the operational characteristics of the transitioning power system.

Across both assessments:

[55] See Section 5.3 of the 2025 NEM ESOO.

[56] As introduced as part of the 2025 *Forecast Improvement Plan*. See https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-forecast-improvement-plan-consultation.

- **Across the first half of the outlook,** supply scarcity risks have lowered relative to the 2025 ESOO October Update, including reliability outcomes within the IRM for the upcoming 2026-27 summer in all NEM regions. The improved outlook is primarily driven by additional committed generation and storage developments, the extension of Eraring Power Station to April 2029, the high penetration of customer batteries stimulated by the CHBP, and other continued investment across the NEM. Supply scarcity may still occur in some circumstances such as extreme weather events, or multiple concurrent unplanned outages, but there is now more capacity to reduce the impacts and severity if these risks were to materialise.
- **Beyond the first half of the outlook,** supply scarcity risks materially increase, including relative to the 2025 NEM ESOO October Update, as electricity demand continues to grow and around 13 GW of coal-fired generation – including Yallourn, Eraring, Gladstone, Callide B, Bayswater, Vales Point and Loy Yang A – progressively retires. This reflects the combined effects of continued demand growth, particularly from higher data centre developments, and the inclusion of planned and maintenance outages and station-level energy limitations. Relative to the *Generator Maintenance* sensitivity from the 2025 NEM ESOO, the higher supply scarcity risks in most regions reflect the higher consumption that is now forecast across the regions, demonstrating the need for continued investment in energy-producing plant such as wind, solar and new gas.

Generation and storage investments support reliability in response to generation retirements

A number of coal-fired generators have provided notice of their intent to cease operations across the NEM. This includes Yallourn (Victoria, announced closure date of July 2028), Eraring (New South Wales, announced closure date of April 2029), and Gladstone (Queensland, announced closure date of March 2029).

The rules that require generators to provide 3.5 years minimum notice of closure enables AEMO, and the industry, to assess the ongoing reliability of the power system, and enable sufficient time to replace that lost capacity. For some generators that provide firming support, such as peaking gas generators, replacing the retired capacity may need only an alternative form of firming, such as a battery.

For retiring coal generators, the retirements also lead to a reduction in electricity generation potential across the year. For example, over the past four years, Yallourn, Eraring and Gladstone each generated 8.4 TWh, 14.7 TWh and 6.2 TWh of energy respectively on average. Across those years, the aggregate NEM generation has been between 187.1 TWh and 191.5 TWh; these generators therefore have effectively supplied approximately 15% of the NEM's annual sent-out electricity supplied from the grid.

The 2022 NEM ESOO was the first to be prepared after Yallourn announced the closure date of July 2028. Since the publication of the 2022 ESOO, 18.9 GW of generation and storage has commissioned and is now operating across the NEM, with total output from all newly operating generators since 2022 equal to approximately 27.8 TWh as of 2025-26.

Additionally, in the NEM there are 6.4 GW of wind projects either committed or anticipated, where timely delivery will support reliability outcomes. Ensuring that these projects can reach financial close and subsequently enter construction on anticipated timeframes will drive whether these projects can meet their proposed timings in the pipeline. Financial close timings are driven by a range of factors including project economics, contracting arrangements, transmission access, approvals, community acceptance and connection requirements.

Over the same period, the growth in CER has also been significant, adding 9 GWh of distributed PV generation to service customer needs. Finally, over the same time period, underlying electricity consumption across the NEM has increased from 177 TWh to 204.2 TWh in 2025-26. Therefore, while there have been significant additions to the energy generation potential in the NEM, not all electricity production capacity is as firm as coal generation has historically been, and much of the new generation capability has been to meet rising demand, rather than to replace retiring generation.

In support of the energy transition, investments in complementary technologies are needed to maintain reliability. Unlike the coal generation that is exiting the system, future investments of different technologies and types play different roles, including those that increase bulk energy supply such as CER and VRE, and others that firm and shape other technologies, such as storages and flexible gas generation. Delays in the investment in any of the elements can lead to increased reliance on other technologies or resources.

Maintaining reliability to 2030

Despite the volume of retirements of large coal generators in the near term, expected USE remains within the reliability standard immediately following these closures. There is an additional 2.3 GW of anticipated and committed generation expected to be operational prior to the closure of Yallourn W (1.6 GW) in Victoria, 6.3 GW in New South Wales prior to the closure of Eraring (2.9 GW), and a further 3.8 GW in Queensland prior to the closure of Gladstone (1.7 GW). Much of this is VRE generation that will offset the loss of energy generation from the coal generators that have supplied much of the NEM's electricity over their operating lives. With these new generation resources, supplemented by storage solutions, reliability gaps do not emerge within the T-3 horizon of the RRO (2029-30).

Additional investment is progressively required from 2030

There is also a strong pipeline of recently commissioned (9.1 GW in 2025-26) and committed or anticipated projects that are scheduled to start producing before 2030 (31.9 GW).

While this is potentially sufficient to replace these retiring major coal power stations, additional growth in consumption, and additional retirements beyond 2030, require further investment to maintain supply-demand balance and meet the reliability standard. Without this investment, energy shortfalls will emerge, as forecast in the second half of the ESOO outlook period, and described in more detail in Section 5.1. In such circumstances, greater reliance will be placed on energy-limited plant and associated fuel supplies.

Figure 34 shows the results of the *Government Schemes and Actionable Developments* reliability assessment across the NEM. Under this assessment, expected USE remains below the reliability standard until 2032-33 in New South Wales, Victoria and South Australia, until 2033-34 in Tasmania, and throughout the outlook period in Queensland.

To provide the full level of detail not visible at **Figure 34**'s scale, **Table 14** shows the expected USE in each region in 2035-36 in this assessment.

These outcomes demonstrate that, if government-supported generation, storage and transmission are delivered broadly in line with developer expectations, alongside the effective coordination of CER and demand flexibility, the existing investment pipeline is sufficient to maintain reliability through much of the transition within the outlook period. However, more investments are needed to replace the retiring dispatchable capacity and particularly their energy generation potential towards the end of the outlook period – specifically, the 700 MW of coal retiring in Queensland in 2031-32, the 4.3 GW of coal retiring in New South Wales in 2033-34, and the 2.2 GW of coal retiring in Victoria in 2035-36.

Figure 34 Expected USE outcomes for the *Government Schemes and Actionable Developments* assessment, 2026-27 to 2035-36 (% USE)

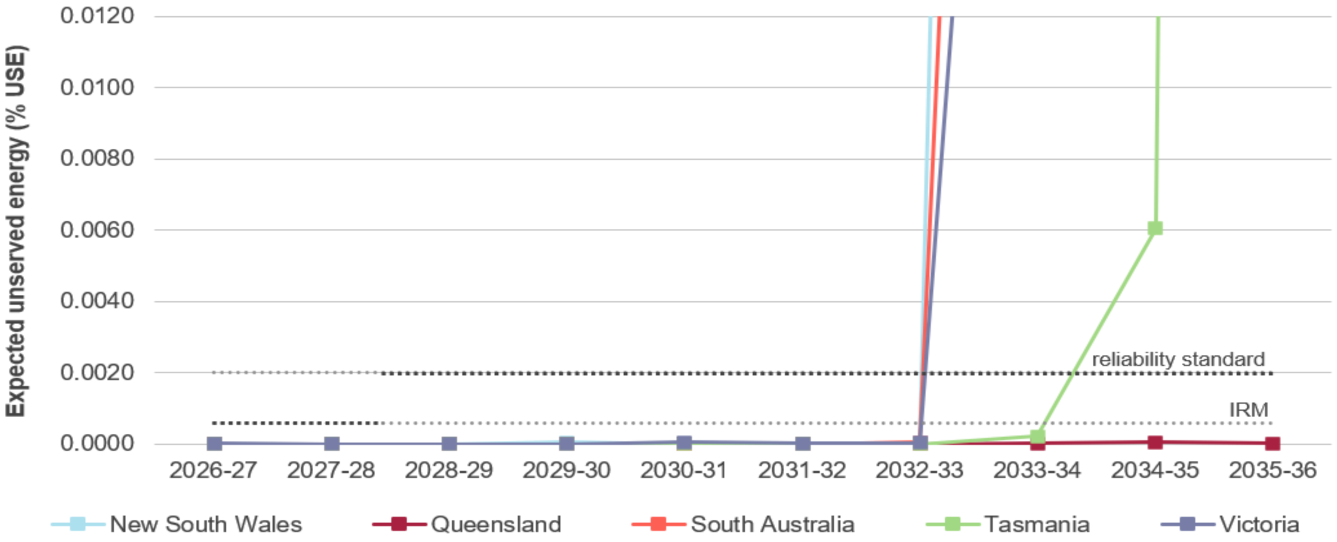


Table 14 Expected USE in 2035-36 under the *Government Schemes and Actionable Developments* reliability assessment

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Expected USE in 2035-36 (%)	2.2367	0.0000	0.8102	0.3120	1.8164

Table 15 shows the additional firm equivalent capacity that is estimated to be needed to reduce expected USE below the reliability standard and the IRM for the *Government Schemes and Actionable Developments* reliability assessment. This estimate considered each region separately, without any allowance for the ability for additional capacity to offset reliability gaps across regions. The values reflect the firm, continuously available, and fully unconstrained capacity required, noting that many generation, storage and demand-side options in different locations can contribute to meeting this requirement with varied efficacy.

Table 15 Additional firm equivalent capacity to meet the reliability standards under the *Government Schemes and Actionable Developments* reliability assessment (MW)[A]

Standard	Region	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
IRM of 0.0006% USE	New South Wales	0	0	IRM does not apply from 2028-29							
	Queensland	0	0								
	South Australia	0	0								
	Tasmania	0	0								
	Victoria	0	0								
Reliability standard of 0.002% USE	New South Wales			0	0	0	0	0	5,635	6,655	7,270
	Queensland			0	0	0	0	0	0	0	0
	South Australia			0	0	0	0	0	1,320	1,460	1,565
	Tasmania			0	0	0	0	0	0	260	1,215
	Victoria			0	0	0	0	0	2,610	3,170	3,675

A. Cells coloured in red reflect the relevant reliability standard applicable for that year.

Figure 35 shows the results of the *Committed and Anticipated Developments* reliability assessment across the NEM. Under this assessment, supply scarcity risks above the relevant reliability standard emerge earlier, with expected USE exceeding the reliability standard from 2030-31 in New South Wales and Victoria, 2031-32 in South Australia, 2032-33 in Queensland, and 2033-34 in Tasmania. This relies on anticipated projects progressing to commitment and being delivered broadly in line with currently advised commissioning schedules, and demonstrates the importance of continued investment beyond the current committed and anticipated development pipeline. To provide the full level of detail not visible in **Figure 35**, **Table 16** shows the expected USE in each region in 2035-36 in this assessment.

Figure 35 Expected USE outcomes for the *Committed and Anticipated Developments* assessment, 2026-27 to 2035-36 (% USE)

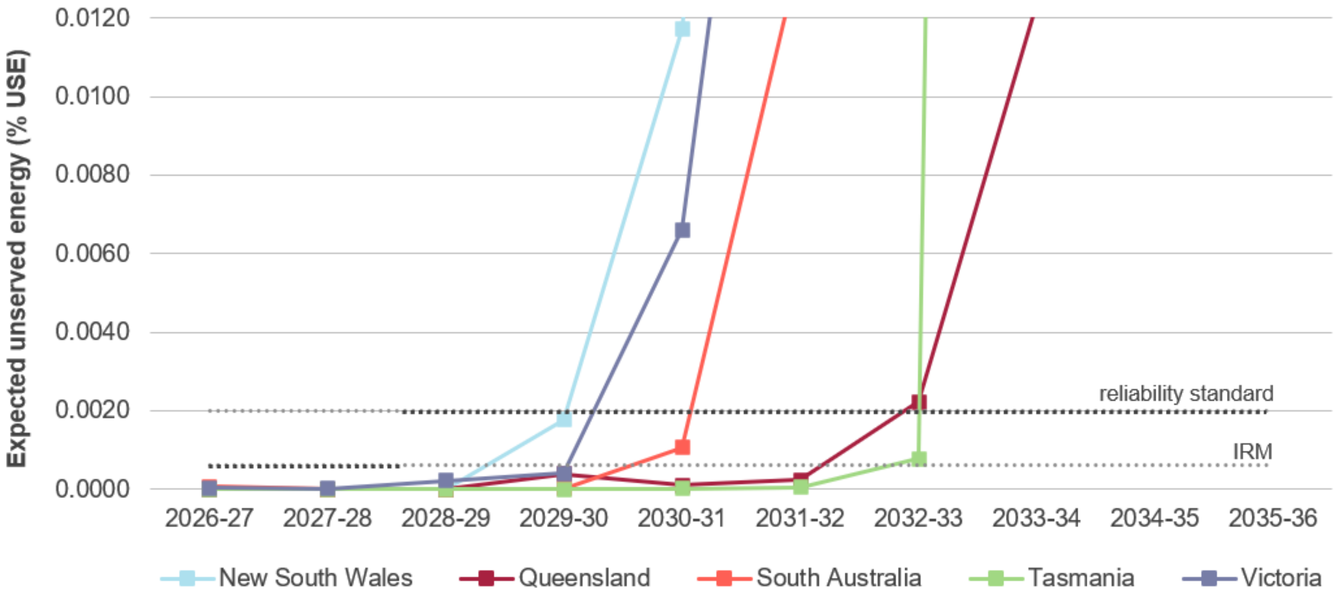


Table 16 Expected USE in 2035-36 under the *Committed and Anticipated Developments* reliability assessment

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Expected USE in 2035-36 (%)	15.1298	0.1229	4.5525	2.2096	9.0444

Table 17 shows the additional firm equivalent 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 considered each region separately, without any allowance for the ability for additional capacity or actionable transmission projects to offset reliability gaps across regions. The values reflect the firm, dispatchable, continuously available, and fully unconstrained capacity required, noting that many generation, storage and demand-side options in different locations can contribute to meeting this requirement with varied efficacy.

Table 17 Additional firm equivalent capacity to meet the reliability standards under the *Committed and Anticipated Developments* reliability assessment (MW)[A]

Standard	Region	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
IRM of 0.0006% USE	New South Wales	0	0	IRM does not apply from 2028-29							
	Queensland	0	0								
	South Australia	0	0								
	Tasmania	0	0								
	Victoria	0	0								
Reliability standard of 0.002% USE	New South Wales			0	0	1,815	3,280	4,950	6,270	6,260	6,280
	Queensland			0	0	0	0	35	770	1,435	1,880
	South Australia			0	0	0	840	1,380	1,695	1,835	1,905
	Tasmania			0	0	0	0	0	685	860	1,550
	Victoria			0	0	920	2,160	3,005	3,790	4,075	4,630

A. Cells coloured in red reflect the relevant reliability standard applicable for that year.

Compared with the *Government Schemes and Actionable Developments* assessment, additional firm capacity is required earlier under the *Committed and Anticipated Developments* assessment. The government-supported development outlook delays this need by around three years in New South Wales and Victoria, two years in South Australia, and one year in Tasmania, while no additional firm equivalent capacity is identified for Queensland within the outlook under the *Government Schemes and Actionable Developments* assessment. This demonstrates the reliability benefit of the broader development pipeline. The differences in firm equivalent capacity should not be interpreted as the direct capacity contribution of those additional developments, as the two assessments include different generation, transmission, CER and demand flexibility resource availability assumptions that interact across regions and years.

Critically, consumers have a key role in the transition through decisions and investments that reduce operational demand, including CER investments and the potential coordination of these resources. Further reliability improvements may be available from the demand side, through greater demand flexibility and DSP, or if new load developments support further supply investments. For example, the AEMC's recent Data Centre advice to the ECMC[57] recommended that data centres contract sufficient new renewable energy to offset their electricity consumption, and demonstrate their load is covered by firmed capacity, either through financial contracts or investment in storage or demand flexibility.

These 2026 NEM ESOO reliability assessments demonstrate that the NEM has a credible pathway to maintaining reliability until the early 2030s provided the current market-led and government-supported development pipeline is delivered to schedule. Beyond this period, continued demand growth and thermal generation retirements mean further investment will be required to maintain resource adequacy. The characteristics of these emerging reliability gaps are discussed in Section 5.

4.2 Factors shaping the reliability outlook

The differences between the near-term and later-year outcomes in both reliability assessments reflect how the generation mix, electricity demand and operational characteristics of the power system are projected to evolve over the outlook period. Importantly, however, they reflect that most generation developments in the medium to longer term are unable to

[57] See https://www.aemc.gov.au/market-reviews-advice/data-centre-advice-ecmc.

demonstrate sufficient progression against AEMO's commitment criteria to be included in the reliability forecast, though a significant pipeline of developments has been announced.

While the timing and magnitude of supply scarcity risks vary between the two assessments and across regions (see Section 6), underlying factors that shape reliability outcomes are common across the NEM. Key drivers include:

- **Electricity demand is forecast to increase**. Growth in residential, commercial and industrial electrification, together with increasing electricity consumption from large industrial developments and data centres, increases both peak demand and the amount of energy that must be supplied throughout the year despite growth in CER and other demand-side factors such as energy efficiency savings.
- **Retiring thermal generation must be replaced.** As coal-fired generation progressively retires, maintaining reliability increasingly depends on timely and effective replacement. This includes replacement for both the peak output that is lost, and critically the energy output that particularly coal generators have provided. As identified in the 2026 ISP, replacements are likely to require a mix of generation, storage, transmission, CER and flexible demand entering service in sufficient quantities and at the required pace.
- **Reliability increasingly depends on both resource adequacy and operational availability.** The explicit modelling of planned and maintenance outages, together with station-level energy limitations, shows that installed capacity alone is no longer a sufficient indicator of reliability. Maintaining reliability increasingly depends on the availability of dispatchable energy during extended periods of system stress.
- **Consumer investments are important, and more flexible demand can improve reliability outcomes further.** Continued investment in CER is forecast to improve reliability outcomes, and consumer choices – such as the time for charging EVs, or the behaviours to respond to extreme temperatures – will have a key impact on the scale of additional grid-scale investment needed. As identified in the 2026 ISP's demand side factors statement[58], significant system cost savings can be achieved with more energy efficiency, and CER coordination. Large new loads, including data centres and electrified industrial processes, could also provide valuable demand flexibility, with greater opportunities available where flexibility is incorporated into project design from the outset.
- **Weather and resource-sharing become increasingly important.** As renewable generation supplies a larger share of energy, reliability outcomes become more dependent on weather conditions, the availability of dispatchable resources during renewable lulls, and the ability to share resources across the interconnected NEM.

Together, these factors change the nature of supply scarcity risk over the outlook period. Earlier in the outlook, supply scarcity risks remain largely associated with periods of high demand. In the later years in this NEM ESOO, reliability increasingly depends on maintaining sufficient energy production, supported by appropriate demand flexibility and dispatchable reserves.

These changing conditions are examined in more detail in Section 5.1.

[58] See https://www.aemo.com.au/-/media/files/major-publications/isp/2026/appendices/a9-demand-side-factors-statement.pdf.

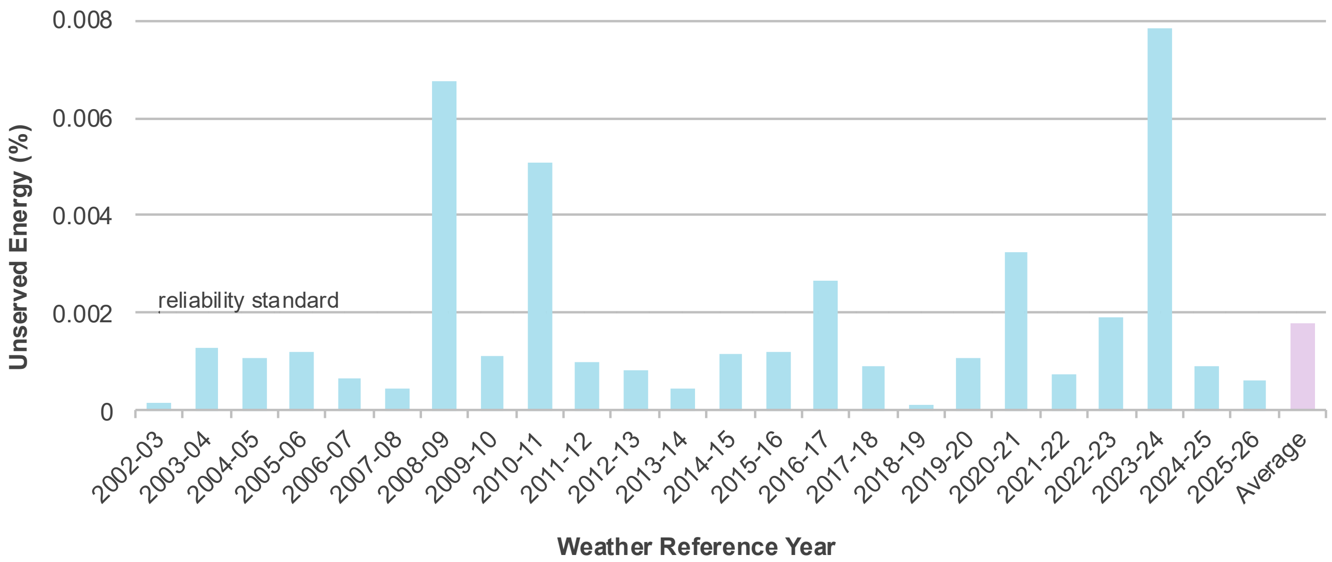
4.3 Supply scarcity risks are not uniform, and the distribution of risks varies significantly

The 2026 NEM ESOO assessed reliability using thousands of Monte Carlo simulations that captured uncertainty in the magnitude of peak demands, the prevalence of generator outages and the outcome of weather conditions. For each financial year in the outlook period, the reliability assessment combines 24 historical weather reference years[59] with 25 random outage combinations and the forecast maximum demand levels, producing a large distribution of possible operating outcomes. Expected USE was calculated across these outcomes using the applicable demand probability weightings[60]. It should be interpreted as the average level of supply scarcity risk across the modelled distribution, rather than the most likely individual outcome.

Figure 36 illustrates this distribution of expected USE outcomes for New South Wales in 2029-30 across weather reference years under the *Committed and Anticipated Developments* assessment. It shows that while the average outcome remains below the reliability standard, approximately 20% of weather reference years containing expected USE that exceeds the reliability standard.

Energy shortfalls are forecast to emerge in New South Wales from 2029-30 and are more pronounced in some weather reference years. In years with lower renewable energy output, greater reliance is placed on hydro, gas and remaining coal resources to meet energy requirements. Where these resources are already approaching their daily or annual energy limits, their ability to compensate for reduced renewable output becomes constrained, increasing the risk of breaching the reliability standard.

Figure 36 Distribution of expected USE across simulated weather reference years in New South Wales, *Committed and Anticipated Developments*, 2029-30 (%)



59 The 2026 NEM ESOO reliability modelling was based on 24 historical weather reference years, covering measured conditions observed from 2002-03 to 2025-26.

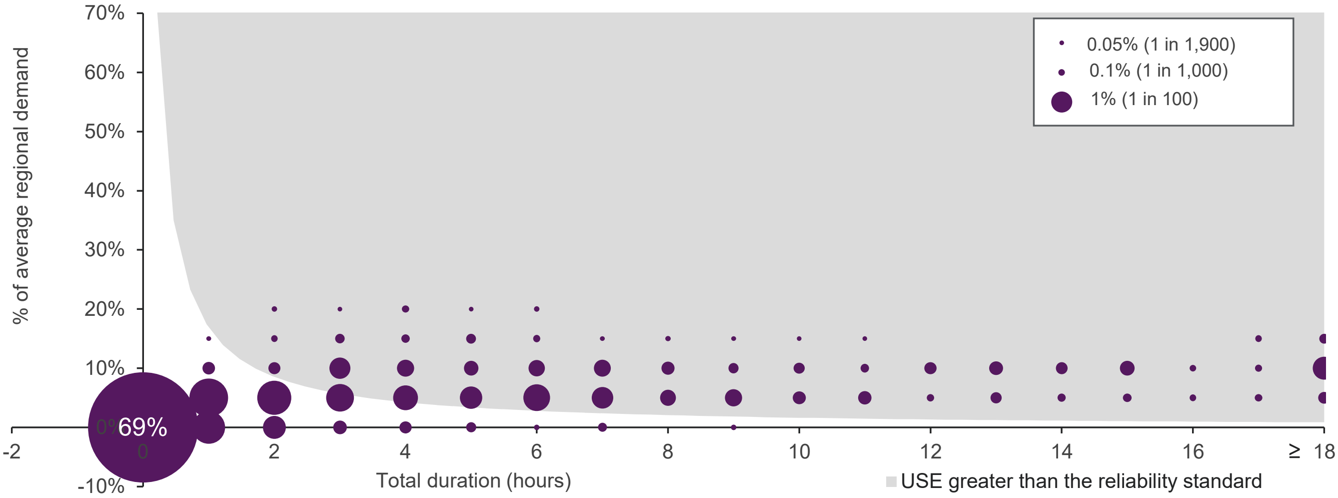
60 AEMO calculates expected USE using 10% POE, 50% POE, and 90% POE maximum demand outcomes. 10% POE and 50% POE outcomes are weighted at 30.4% and 39.2% respectively, with the remaining 30.4% weighting assigned to 90% POE outcomes with zero USE assumed.

The distribution of simulation outcomes provides additional insight into the likelihood and severity of reliability events. In this same 2029-30 year in New South Wales, across the forecast conditions, the most likely outcome (being the outcome that is most frequently observed across the distribution of simulations) is no USE, with almost 70% of simulations showing sufficient supply to meet demand throughout the year, as seen in **Figure 37**. Despite this, more severe outcomes are possible, with 25% of simulations individually exceeding the reliability standard.

These results indicate that while the overall average risk is low, more severe 'tail risk' outcomes are possible under various weather conditions and outage patterns. Investment in more energy-producing generation such as wind or solar, and/or longer duration storage to reduce renewable energy spill in times of surplus for use during times of supply scarcity, would help reduce this risk (see Section 5.1.2).

Guidance on interpreting these charts is in Appendix A4.5.3. Results for 2029-30, presented as an illustrative year for all regions, are available in the 2026 *ESOO Results Workbook*.

Figure 37 Forecast USE duration and depth in New South Wales, *Committed and Anticipated Developments* assessment, 2029-30



This probabilistic behaviour is observed across all regions. A forecast within the reliability standard does not mean USE cannot occur, only that its likelihood and expected magnitude is relatively low. Conversely, forecasts exceeding the reliability standard do not imply that USE will occur in all conditions, but rather a higher average level of supply scarcity risk exists across a broad range of plausible operating conditions.

Actual consumer outcomes may also be influenced by factors not considered within the ESOO's reliability assessment framework, including abnormal transmission system conditions, fuel availability that differs from participant expectations, and operational interventions such as the RERT. These factors are addressed through AEMO's operational planning and preparedness activities considering both average risk and the potential for low-probability, high-impact events.

4.4 Testing the reliability outlook under key uncertainties

In addition to the two core reliability assessments, the 2026 NEM ESOO includes two targeted reliability sensitivities (described in Section 2.2.2) that explored key uncertainties influencing future resource adequacy. Rather than providing alternative forecasts, these sensitivities tested the reliability implications of different assumptions relating to electricity demand growth driven by data centre loads, as well as the impact of anticipated project delivery. Together, they complement the core reliability assessments by providing additional insight into the resilience of the reliability outlook and where future investment may be required.

4.4.1 Data centre growth creates opportunities for additional investment

Growing investment in data centres is expected to support Australia's expanding digital economy and become an increasingly important driver of electricity consumption, particularly in New South Wales, Victoria and South Australia. As outlined in Section 3.1, strong growth in data centre electricity consumption is a key driver in this 2026 NEM ESOO's *Step Change* demand forecast, with annual data centre electricity consumption forecast to increase from around 5 TWh (2.8% of NEM operational consumption) in 2025-26 to around 34 TWh (13% of forecast NEM operational consumption) by 2035-36[61].

Given the uncertainty in the scale, timing and location of future developments, the 2026 NEM ESOO assessed the reliability implications of even stronger data centre growth through a *High Data Centre Growth* sensitivity. This sensitivity helps identify additional investment needs if electricity demand from data centres grows more rapidly than the central outlook. In this sensitivity, the growth applied was consistent with the *Accelerated Transition* scenario's data centre growth, while all other inputs and assumptions remained consistent with the *Step Change* scenario. The sensitivity assessed whether the generation, storage and transmission investments included in the *Government Schemes and Actionable Developments* assessment are sufficient to maintain resource adequacy under a higher growth trajectory, applying all supply assumptions consistently with that reliability assessment.

As **Figure 38** shows, the sensitivity explored increasing data centre load, particularly from the early 2030s, with annual data centre electricity consumption reaching around 52 TWh by 2035-36 – approximately 18 TWh (56%) higher than under the *Step Change* forecast. The reliability outcomes for the *High Data Centre Growth* sensitivity were assessed for 2030-31 to 2035-36, reflecting the period when forecast data centre consumption under the *Accelerated Transition* scenario begins to materially diverge from the *Step Change* scenario.

Figure 39 compares expected USE under the *High Data Centre Growth* sensitivity with the *Government Schemes and Actionable Developments* assessment, illustrating how stronger growth in electricity demand from data centres influences future investment requirements while all supply-side assumptions remain unchanged. **Table 18** shows the expected USE in each region in 2035-36 in this assessment, as full detail is not supported by the figure's scale.

[61] See Section 3.1.5 of this 2026 NEM ESOO.

Figure 38 Actual and forecast NEM data centre consumption, all ESOO scenarios, 2019-20 to 2035-36 (TWh)

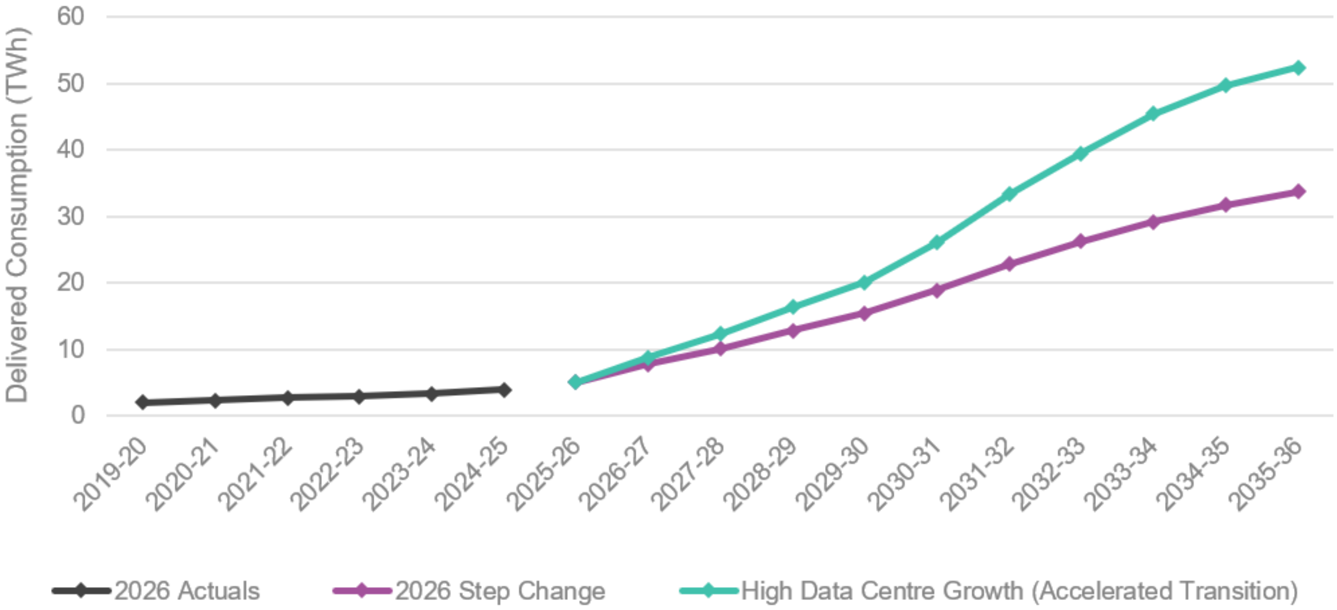


Figure 39 Expected USE for the *Government Schemes and Actionable Developments* assessment, *High Data Centre Growth* sensitivity, 2030-31 to 2035-36 (% USE)

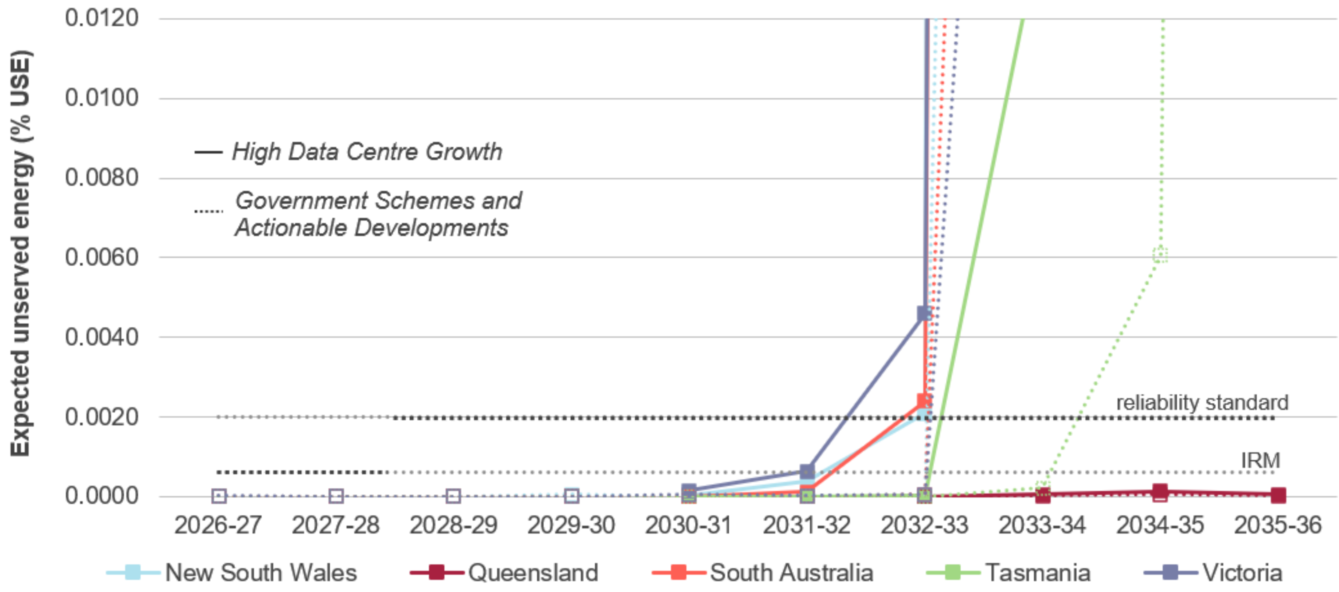


Table 18 Expected USE in 2035-36 under the for the *Government Schemes and Actionable Developments* assessment and *High Data Centre Growth* sensitivity

Expected USE in 2035-36 (%)	New South Wales	Queensland	South Australia	Tasmania	Victoria
***Government Schemes and Actionable Developments* Assessment**	2.2367	0.0000	0.8102	0.3120	1.8164
***High Data Centre Growth* sensitivity**	5.5816	0.0000	2.0993	1.7054	3.9508

The sensitivity indicates that reliability can be maintained even if the level of data centre growth assumed for 2035-36 in the *Step Change* scenario is realised four years earlier, in 2031-32, provided the *Government Schemes and Actionable*

Developments projects are delivered on time and no coal exits ahead of schedule. However, further development would be required from 2032-33 onwards to mitigate supply scarcity risks, particularly in New South Wales, Victoria and South Australia where most of the increased demand is assumed to occur:

- In **New South Wales**, **Victoria**, and **South Australia**, expected USE exceeds the reliability standard one year earlier from 2032-33, indicating that earlier and additional investment in generation, storage and supporting transmission would be required to maintain comparable reliability outcomes under stronger demand growth.
- **Tasmania** exceeds the reliability standard one year earlier, from 2033-34. While growth in Tasmania's own data centre demand is relatively modest, the sensitivity shows the importance of maintaining resource adequacy across the interconnected NEM, with stronger demand growth in mainland regions also resulting in earlier reliability gaps in Tasmania.
- In **Queensland**, expected USE remains largely unchanged, as data centres is still forecast to contribute relatively little to demand growth in this sensitivity. Since these forecasts were produced, AEMO has greater visibility of data centre projects in Queensland, suggesting that growth opportunities exist for this region, and such growth would likewise lead to potential supply solutions to support it.

This sensitivity highlights the importance of increasing visibility of data centre load in the NEM to support development of accurate demand forecasts, and coordinating the growth of large electricity loads with timely investment in electricity infrastructure, including resources that can contribute both annual electricity production and peak supply. Greater demand flexibility (to lower consumption during periods of supply scarcity) can also materially lower investment needs. Data centres may provide greater load flexibility than has been historically observed across existing facilities.

AEMO notes that the Federal Government has recently announced proposals for connection requirements for future large data centres[62], including the requirement for new large data centres to underwrite their own power supply. This proposed framework will introduce Australian Standards for AI that could influence how future generation, storage, firming capacity and demand flexibility are delivered to support data centre growth.

In addition, in July 2026 the AEMC provided advice to the ECMC on regulatory pathways to require data centres to offset their demand through investment[63]. The AEMC made four main policy recommendations:

- drive new renewables through the Renewable Electricity Guarantee of Origin scheme,
- introduce a data centre contract obligation,
- introduce market registration requirements, and
- support demand flexibility and co-location with generation through connection agreements.

The 2026 NEM ESOO did not explicitly model this emerging requirement for data centres to contract supply to meet their demand, as it is not possible to identify the specific supply projects that data centre proponents would contract with. The forecasts demonstrate that investment in generation and storage will be required to support the potential impact of demand increases during the energy transition.

[62] See: Prime Minister of Australia: AI in Australia's interests, 15 July 2026, at https://www.pm.gov.au/media/ai-australias-interests.

[63] See https://www.aemc.gov.au/market-reviews-advice/data-centre-advice-ecmc.

The sensitivity should therefore be interpreted as an exploration of the additional investment that may be required to maintain resource adequacy under stronger data centre growth, based on current supply assumptions; if the framework is implemented as proposed, the increased development opportunities may be naturally delivered by the data centre developers, lowering supply scarcity risks to other electricity consumers.

4.4.2 While the project pipeline has expanded, it is essential to deliver anticipated and other supported energy assets

Anticipated generation and storage projects account for approximately 26 GW, or more than 60% of the current NEM committed and anticipated development pipeline. While these projects are actively progressing through development stages, they also have not yet satisfied the commitment criteria associated with the 'committed' status and therefore retain some delivery uncertainty.

The development and commissioning timing of anticipated projects is an important input to the reliability assessments. After applying observed recent commissioning delays as per the current reliability forecast methodology for the *Committed and Anticipated Developments* assessment, no anticipated projects were assumed to enter service before July 2028, with most forecast to commission between 2028-29 and 2031-32 (see **Figure 23** in Section 3.2.1). This commissioning period overlaps with several major coal-fired generator retirements across the NEM, making the timely delivery of anticipated projects a key element that is needed to maintain a reliable outlook.

To demonstrate the important contribution that anticipated projects provide to reliability outcomes, AEMO developed a *Committed Only* sensitivity covering 2028-29 to 2031-32, which reflects the assumed development period of these projects.

Relative to the *Committed and Anticipated Developments* assessment, this sensitivity excluded all 'anticipated' classified generation and storage projects. All other modelling assumptions remained as per the *Committed and Anticipated* assessment; this sensitivity did not remove or delay anticipated transmission developments[64].

Figure 40 compares the expected USE of the *Committed Only* sensitivity with the corresponding *Committed and Anticipated Developments* reliability assessment. **Table 19** shows the expected USE in each region in 2031-32 in this assessment as full detail is not supported by the figure's scale.

This sensitivity shows the importance of anticipated projects in maintaining reliability as major thermal generator retires. Without anticipated projects, reliability gaps emerge earlier in New South Wales[65] and Queensland[66] following the following Eraring and Gladstone power station closures in 2029-30, and increase in South Australia[67] following the Dry Creek and Mintaro closures in 2030-31. These results underline the importance of progressing replacement generation, storage and other anticipated developments in advance of these retirements.

Excluding anticipated projects results in higher expected USE across most mainland regions over the assessment period, with reliability gaps emerging earlier than in the *Committed and Anticipated Developments* assessment. Compared to that

[64] See **Table 4** Key assumptions of each reliability assessment and targeted sensitivity in Section 2.2.2.

[65] For example, anticipated projects in New South Wales include Coppabella Hybrid Generator (290 MW wind), assumed to be commissioned in July 2028 and Tomago BESS (501 MW/ 2,000 MWh), assumed to be commissioned in in October 2028.

[66] For example, anticipated projects in Queensland include Punch and Creek Renewable Energy (399 MW/1,600 MWh), assumed to be commissioned in July 2028 and Tomago BESS (501 MW/2,000 MWh), assumed to be commissioned in in October 2028.

[67] For example, anticipated projects in South Australia include Solar River Solar and BESS Project (256 MW/ 650 MWh and 256 MW solar), assumed to be commissioned in November 2028 and Emeroo BESS (281 MW/1,114 MWh), assumed to be commissioned in in September 2029.

assessment, this sensitivity shows that expected USE was forecast to remain below the reliability standard in 2028-29 in all regions. Beyond 2028-29:

- In **New South Wales**, expected USE exceeds the reliability standard in 2029-30, one year earlier, following the retirement of Eraring Power Station (2,880 MW).
- In **Queensland**, expected USE exceeds the reliability standard from 2029-30, two years earlier, following the retirement of Gladstone Power Station (1,680 MW). The commissioning of the Gladstone Project (a network project designed to address the anticipated retirement of Gladstone Power Station and support the area's industry) improves reliability outcomes in 2030-31, though the retirement of Callide B Power Station (700 MW) in 2031-32 leads to increased supply scarcity risks.
- In **South Australia**, expected USE exceeds the reliability standard from 2030-31, one year earlier, reflecting the retirement of the Dry Creek and Mintaro gas turbines (246 MW in aggregate).
- In **Victoria**, expected USE exceeds the reliability standard from 2030-31, consistent with the *Committed and Anticipated Developments* assessment, but at materially higher levels.
- In **Tasmania**, expected USE increases more modestly and remains below the reliability standard.

Overall, the sensitivity demonstrates the key role that anticipated developments provide to replace the retiring capacity, and their energy generation potential.

Figure 40 Expected USE outcomes for the *Committed Only* sensitivity assessment compared to the *Committed and Anticipated Developments* assessment, 2028-29 to 2031-32 (% USE)

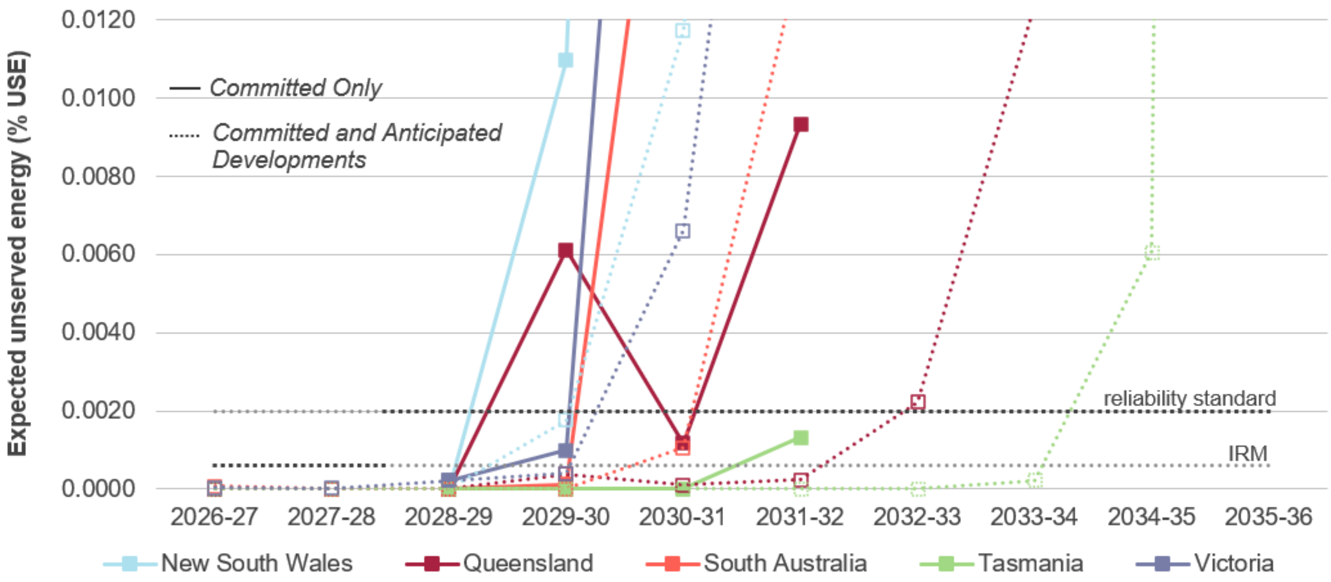


Table 19 Expected USE in 2031-32 under the *for the Committed and Anticipated Developments assessment and Committed Only* sensitivity

Expected USE in 2031-32 (%)	New South Wales	Queensland	South Australia	Tasmania	Victoria
***Committed and Anticipated Developments* Assessment**	0.0389	0.0002	0.0137	0.0001	0.0295
***Committed Only* sensitivity**	0.6679	0.0093	0.2264	0.0013	0.3370

5 Maintaining a reliable and secure power system

This section summarises observable drivers of supply scarcity risks, supporting appropriate investment to mitigate them.

Supply scarcity risks can be met through a combination of new generation, storage and network, as well as increased investments of demand-side solutions that reduce operational demand or increase demand flexibility.

While there is a need to invest in replacement infrastructure to offset the lost electricity production from retiring generators, the location and type of new infrastructure is a key investment consideration, as must be able to provide energy where and when needed to meet demand. This section sets out to discuss:

- how the nature of risks to reliability are changing as the energy market evolves (Section 5.1),
- the importance of maintaining a pipeline of diverse investments to support reliable supply (Section 5.2), and
- the importance of maintaining system security alongside the changes to support reliability (Section 5.3).

5.1 Conditions driving supply scarcity risks are changing

The factors influencing reliability are changing as coal generators retire and the NEM transitions towards a more diverse mix of supply and demand-side resources, with increasing shares of renewable generation, storage, and CER. These changes are altering when supply scarcity risks emerge and what resources are needed to manage them. As the generation mix continues to diversify, understanding these emerging risks is critical to maintaining system reliability and supporting a secure and affordable energy transition.

Historically, supply scarcity risks have been driven by summer peak demand events coinciding with generator outages, when available capacity may be insufficient to meet short periods of extreme demand. As coal-fired generators retire and demand grows, the historical surplus of dispatchable energy is expected to reduce. Supply scarcity risks are therefore projected to emerge not only during peak demand periods, but also during extended periods of low renewable generation, particularly in winter when solar output is lower. During these periods, dispatchable generators may need to sustain higher output for longer to meet demand, while also enabling pumped hydro and batteries to recharge ahead of subsequent high-demand periods.

The changing nature of reliability over the outlook period is explored through two key themes in this section:

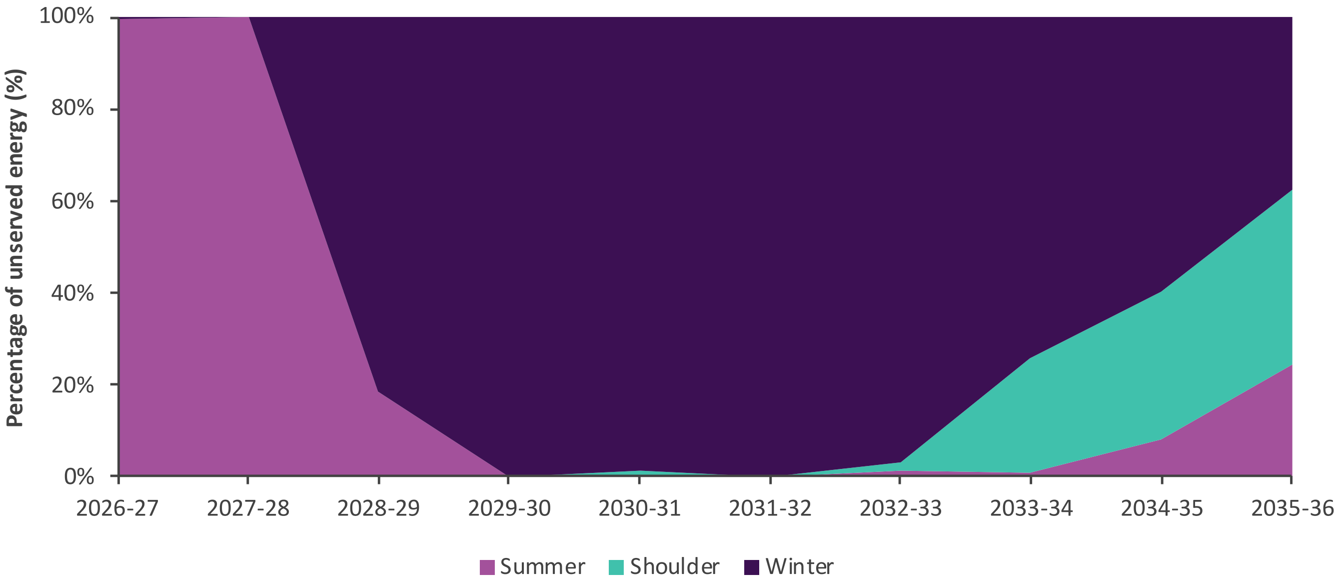
- the increasing influence of weather conditions as renewable generation supplies a growing share of electricity (Section 5.1.1), and
- the changing timing and duration of forecast USE events over the outlook period (Section 5.1.2).

5.1.1 As renewable energy penetration increases, reliability outcomes are more influenced by weather conditions

As renewable generation supplies a larger share of electricity, the conditions that require firming and flexibility are changing. Variations in wind and solar output can be managed through storage, hydro generation, flexible gas generation, demand-side participation and resource sharing across regions. In that context, system needs are increasingly shaped by how long supply must be sustained, and by how effectively resources can recharge, operate and share energy across the NEM.

Figure 41 shows the distribution of forecast expected USE by season across the horizon in Victoria under the *Government Schemes and Actionable Developments* reliability assessment. Victoria is shown as an example to illustrate the evolution of supply scarcity risk across the outlook period, in a region with relatively high exposure to electrification of gas heating loads. Equivalent figures for all other NEM regions are available in the 2026 *ESOO Results Workbook* and in Section 6.

Figure 41 Evolution of the seasonal distribution of USE across the outlook period, Victoria, *Government Schemes and Actionable Developments* assessment



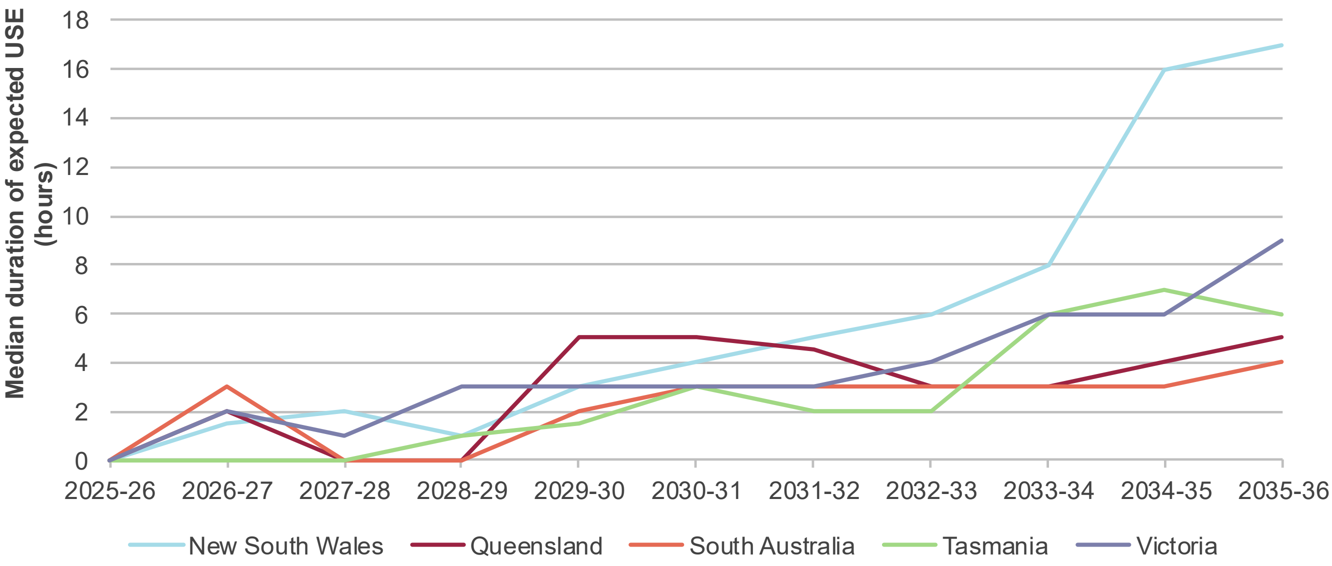
The analysis shows that:

- Early in the outlook period, USE is most typically forecast during high summer demand on hot days, when operational demand peaks in the evening as solar generation declines. While CER help reduce the operational peak demand, their limited storage duration may not sustain output during longer periods of high demand events. Coincident generator outages can further increase supply scarcity risks.
- Towards the middle of the outlook period, USE events are more frequently observed during winter relative to other seasons, particularly as retiring coal generators reduce the energy availability from the generation mix, compounding supply scarcity risks during this season with lower solar output and diminished opportunity for storages to recharge.
- Towards the end of the outlook period, supply scarcity risks in this assessment are more evenly distributed across seasons, as limited replacement capacity exists in this assessment to compensate for further retirements. This indicates emerging energy shortfalls and emphasises the need to invest in more generation (or demand-side options that reduce

consumption throughout the year) to support customer needs, rather than just investing in dispatchable capacity to support peak demand events.

Figure 42 shows that simulated USE events are generally short in the early years of the outlook but increase in duration in several regions later in the period. This is most pronounced in New South Wales, where the median duration rises materially from the early 2030s, and in Victoria, where simulated USE events also lengthen towards the end of the outlook. South Australia, Queensland and Tasmania show more moderate increases.

Figure 42 Median duration of expected USE events for the Committed and Anticipated Developments assessment



These results show that supply scarcity risks are increasingly shaped by both capacity adequacy and energy adequacy. Firm capacity remains essential to meet high-demand periods, including emerging winter peaks as electrification increases heating load. However, maintaining reliability will also require sufficient energy availability through extended periods of lower renewable output, when storage recharge opportunities may be limited and energy-limited resources may need to operate for longer.

Historically, sufficient capacity to meet peak demand often implied sufficient energy availability, because dispatchable generators could sustain output across the year. As the power system changes, maintaining reliability will increasingly depend on a diverse mix of technologies which, together, provide enough capacity in both peak seasons and enough energy available to sustain supply over longer periods of system stress.

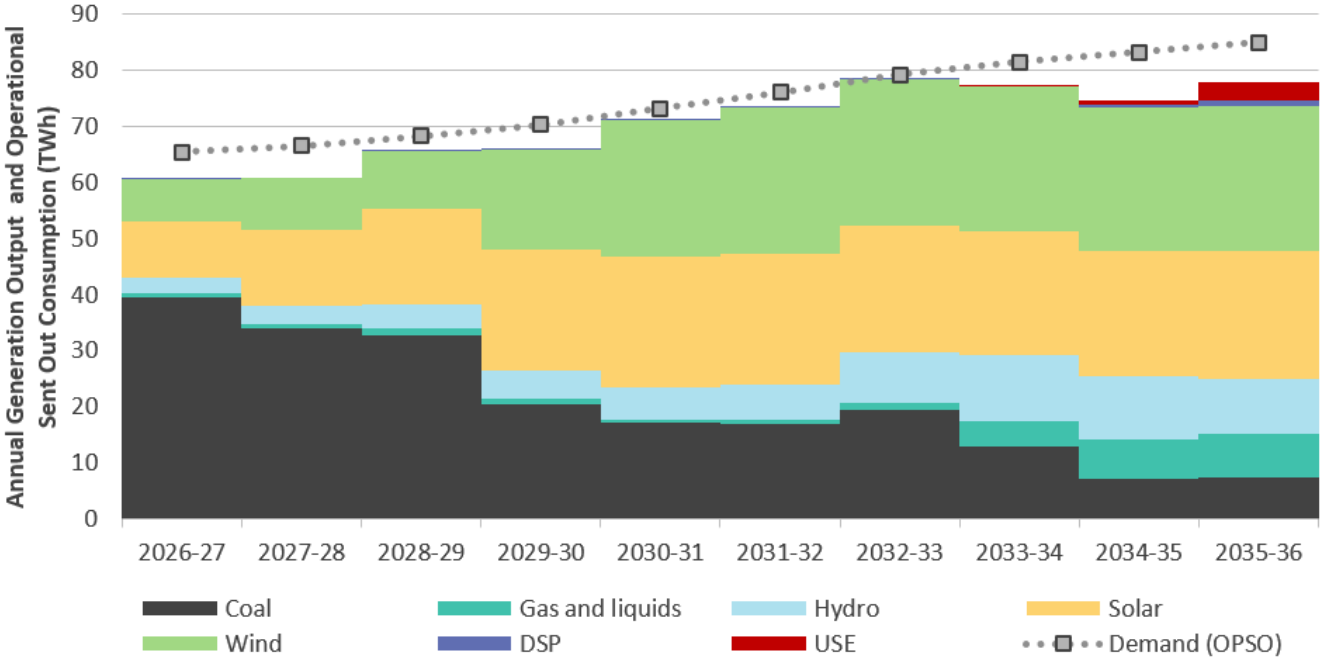
5.1.2 Energy adequacy is increasingly important for power system reliability as generators retire

The 2026 NEM ESOO incorporates participant-submitted generator outages and station-level energy limits. Energy limits, including fuel supply limits, represent operational constraints on a generator's ability to sustain electricity production over time. Together, outages and energy limits reduce the amount of energy generators can provide and are increasingly associated with the reliability gaps identified in this ESOO.

Figure 43 shows total utility scale generation output by generation type for New South Wales under the *Government Schemes and Actionable Developments* assessment.

Over the later years of the horizon, New South Wales generation output does not fully meet forecast consumption which, when unable to be met by interconnector inflows, leads to USE.

Figure 43 New South Wales generation output and operational sent out consumption (TWh and average annual GWh, *Government Schemes and Actionable Developments* assessment)



Note:' Demand (OPSO)' refers to operational sent out demand. When this exceeds the generation profile each financial year indicates that remaining demand is met by imports from neighbouring regions, though this is still insufficient in later years when USE occurs. Also note that the demand met in the model also includes things like hydro pumping, charging of large-scale BESS and co-ordinated VPP, auxiliaries and other variables.

The figure demonstrates that investment opportunities remain, particularly later in the horizon, to replace retiring coal-fired generators in New South Wales (and across other NEM regions). Without further investments, other generation technologies are required to increase production to meet demand, often operating up to their energy limits. Gas and liquid-fuelled generation shows the largest increase in output across the horizon, though these may require broader gas system investment to ensure sufficient gas supply is available to these generators (as energy limits submitted by their operators may not reflect market-level supply constraints that may occur as outlined in the 2026 GSOO and highlighted in Section 3.2.5).

In this reliability assessment, expected USE is forecast during periods when coal, gas, liquid-fuelled and hydro generators have exhausted their available energy production capability. While aggregate gas generation output continues to rise in future years, the increase will be driven by individual generators that have not yet reached their energy production limits. From 2033-34, a larger supply gap emerges, requiring both additional generation capacity and additional energy production.

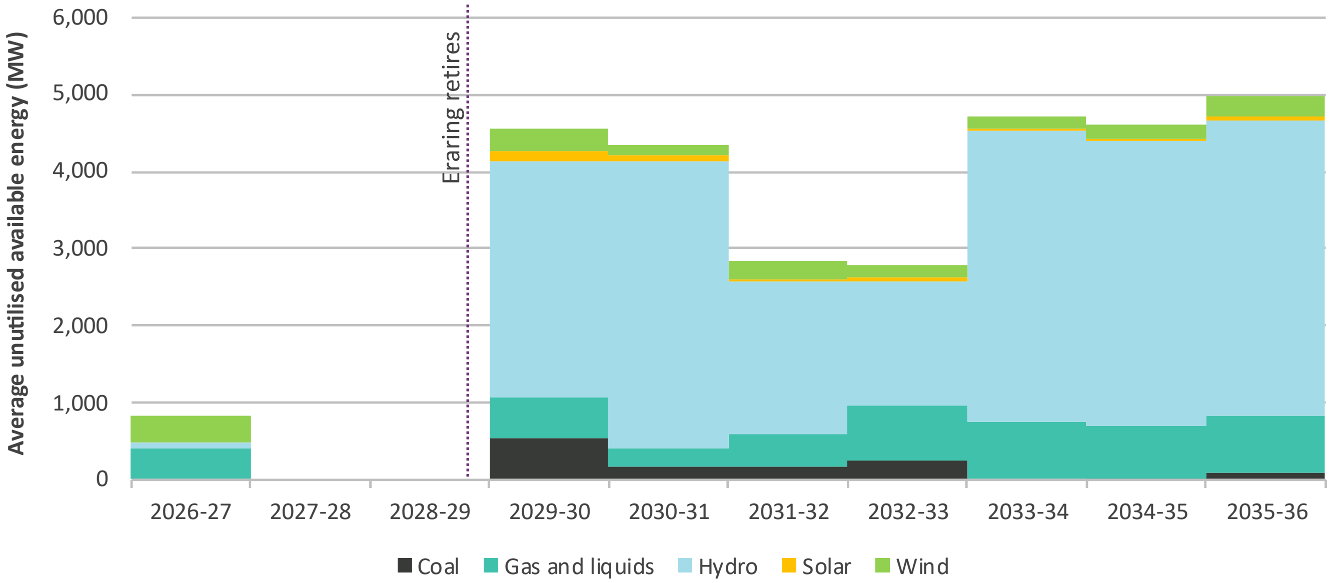
To help explain this outlook, **Figure 44** shows average unutilised generator availability during forecast USE periods for coal, gas and liquid-fuelled generators, and hydro generators in New South Wales.

In this analysis, unutilised generator availability is generation capacity that is available but not producing electricity. It is measured as the difference between a generator's available capacity and its forecast generation output during USE periods. During periods of forecast USE, unutilised generator availability can occur due to one of two possible causes:

- the generator is subject to a transmission limitation and is unable to dispatch, or
- the generator has fully utilised its fuel or energy limit, suggesting it is subject to fuel unavailability (be it water, gas, coal or diesel fuel) or other operational limits.

In **Figure 44**, after Eraring retires, much of the unutilised generation from coal, hydro, gas and liquid-fuelled generation during USE events is due to energy limitations, where fuel or water availability constrains operation below maximum dispatch capacity. For renewable generators, unutilised generation during USE events is typically driven by network limitations.

Figure 44 New South Wales average annual unutilised generator availability of thermal and hydro generators during USE periods, *Government Schemes and Actionable Developments* assessment (MW)



Observations of unutilised availability for coal, gas and liquid-fuelled generators highlight the growing importance of fuel and energy adequacy. Without further transmission, wind, solar or medium-duration storage development, production from these generators will need to increase to replace energy previously produced by coal generation, and their ability to contribute is increasingly constrained by fuel availability and other energy limitations.

The 2026 GSOO[68] for Australia's east coast gas system and market identified a risk of winter gas shortfalls following Eraring's retirement, and the broader need for additional gas supply investment in subsequent years. This assessment further highlights the importance of investment in gas production and transport infrastructure to support generator access to fuel. Similarly, the 2026 ISP operability assessments[69] emphasise that strategic operation of hydro reservoirs and deep storage resources will also become increasingly important in preserving energy for periods when supply is most needed.

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

[69] See https://www.aemo.com.au/-/media/files/major-publications/isp/2026/appendices/a4-system-operability.pdf?rev=bdf7b0d6a2f94c07a6b05938ad94a518&sc_lang=en.

5.2 Maintaining reliability through coordinated investment across a diverse portfolio of resources

As generators retire and electricity demand grows, continuing to meet the reliability standard will increasingly depend on the timely delivery, effective location and operational availability of new resources. Firm capacity and peak demand flexibility remain important, but supply scarcity risks are increasingly shaped by the ability to sustain supply, or reduce demand, over extended periods of system stress, particularly when renewable output is lower for multiple hours or days. The right combination will depend on the nature of the supply scarcity risk, including whether it is driven by peak demand, prolonged periods of low renewable output, network constraints, or a combination of factors. Location and coordination are also critical, with transmission enabling capacity and energy to be shared across regions and reducing the risk that available resources cannot reach consumers when needed.

The *Government Schemes and Actionable Developments* reliability assessment demonstrates that coordinated investment across government-supported generation and storage, CER coordination, and actionable transmission developments can materially reduce forecast supply scarcity risks throughout much of the outlook period. While supply scarcity risks increase later in the outlook as electricity demand is forecast to grow and coal-fired generators retire, the assessment shows that coordinated investment significantly delays the emergence of reliability gaps by maintaining access to diverse sources of energy and firm capacity across the NEM.

Compared with the *Government Schemes and Actionable Developments* assessment, expected USE above the reliability standard is forecast earlier in most jurisdictions in the *Committed and Anticipated Developments* assessment because fewer replacement generation, storage and transmission projects were assumed to proceed particularly over the second half of the outlook period. This impact is even more pronounced in the *Committed Only* sensitivity. This highlights the importance of anticipated projects and other projects still in the development pipeline progressing and being delivered in-time for and ahead of coal-fired generation retirements, and expansions in electricity demand.

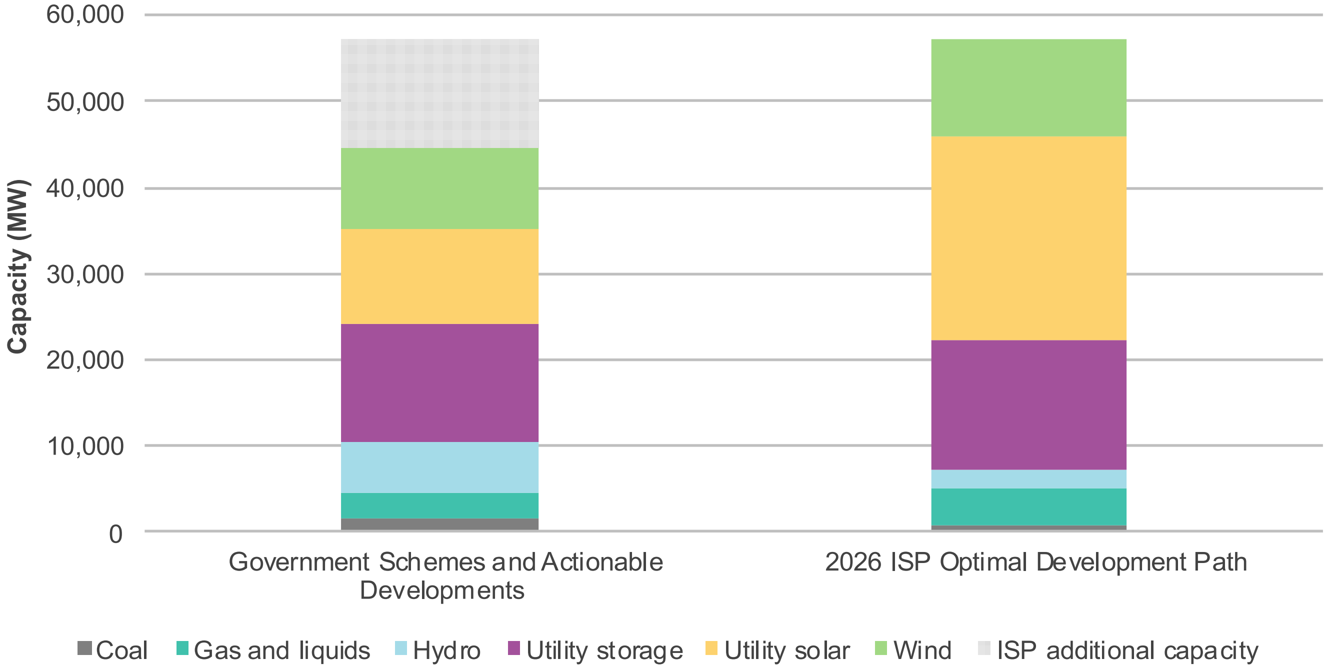
The forecast reliability gap sizes presented in **Table 15** and **Table 17** in Section 4.1 illustrate the scale of additional firm equivalent capability associated with maintaining the relevant reliability standards throughout the next decade under the two reliability assessments.

These values represent equivalent firm, continuously available and unconstrained capacity, and should be interpreted as planning indicators rather than prescribed investment targets. In practice, a range of technology combinations including generation, storage, transmission, CER and flexible demand will be needed to provide for a reliable NEM.

Figure 45 compares projected New South Wales capacity in 2035-36 under the *Government Schemes and Actionable Developments* assessment with the 2026 ISP optimal development path (*Step Change* scenario). The *Government Schemes and Actionable Developments* assessment includes committed, anticipated, government-supported and actionable developments identified for the ESOO reliability assessment. By 2035-36, the *Government Schemes and Actionable Developments* assessment includes around 45 GW of capacity in New South Wales, compared with around 57 GW in the 2026 ISP optimal development path. The hatched area shows the additional capacity identified in the ISP beyond the government and industry pipeline currently included in the ESOO assessment[70]. In addition to maintaining reliability, this additional capacity supported achievement of government policies at least cost for consumers.

[70] As outlined in 0 in Section 3.2.1, there remains a reasonable level of tender processes that are yet to sufficiently advance to adequately identify the appropriate developments to be included in the ESOO.

Figure 45 Comparison of New South Wales capacity under the *Government Schemes and Actionable Developments* assessment and the 2026 ISP optimal development path, 2035-36 (MW)



Note: comparisons of hydro and utility storage capacity should be interpreted with care, as some pumped hydro assets are classified differently between the ESOO assessment and the 2026 ISP optimal development path. Regardless of classification, these assets provide valuable flexible capacity that supports reliability.

This comparison highlights that further government-supported and market-led developments are still needed to align with the broader least-cost pathway identified in the ISP and to provide sufficient replacements for the coal fleet's replacement. Critically, that includes more renewable energy supply, with reasonable similarity between the level of battery developments. This reinforces the need for additional energy-producing investments to be developed to replace retiring coal generation, and to support load growth.

Demand-side solutions – including CER coordination, energy efficiency investments and flexible demand – can contribute to maintaining reliability by reducing or shifting electricity consumption during periods of higher demand, complementing investments in generation, storage and transmission. While not quantified in the same manner, investments that reduce consumption, particularly at times of system stress, can be an effective means of reducing supply scarcity risks for other consumers. AEMO is developing the *Demand Side Statement of Opportunities* (DSOO) which will provide greater visibility of these opportunities and their potential contribution to future reliability needs[71].

Lastly, the location of new generators and the strength of their network access to customers is also critical to their capacity to support reliability. Generation and storage solutions must be able to operate effectively during periods of supply scarcity risk without being significantly constrained from reaching consumers.

AEMO's 2025 *Enhanced Locational Information* report[72] (also in the 2025 NEM ESOO) reinforces the importance of locating new assets in locations with strong network connection to the customers the firming resources endeavour to support. AEMO's 2026 *Enhanced Locational Information* publication, expected to be released in Q4 2026, will provide further insights into how project location and transmission capability influence the contribution of generation and storage to reliability.

[71] See https://www.aemo.com.au/newsroom/speeches-and-presentations/aemo-ceo-speech-at-australian-energy-week-2026.

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

5.3 Maintaining system security is critical to power system operations

This 2026 NEM ESOO projects 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, but that without more wind or solar development, greater reliance will be place on energy-limited plant and associated fuel supplies. However, the ongoing reliability of the power system also relies on the ability to maintain the system in a secure operating state, at all times.

A secure power system is one operated safely within defined technical limits, with the ability to withstand credible disturbances, return to secure operation, and restart following a widespread outage. While reliability requires sufficient generation and network capacity to meet customer demand, the requirements for system security are more technical, and include system strength, frequency and inertia, voltage control, transient and oscillatory stability, operability, and system restoration.

The fundamentals of power system security are enduring, but how they are being provided is changing. The next 10 years are important as renewable and inverter-based generation increases and demand and market participation evolve to replace coal generators that are increasingly withdrawing from the power system, either commercially for hours, days or months, operationally for planned or unplanned maintenance, or completely due to retirement.

Currently, large-scale synchronous units are essential for delivering system security services such as system strength, inertia, voltage control, and ramping. These units need to operate within the technical limits – above their safe operating minimums, and up to their maximum ratings.

A range of operational system security needs and capabilities are being planned and delivered across the NEM over the coming five to 10 years. Declining minimum operational demand, reduced operation of synchronous generators, and rapid uptake of VRE resources have combined to create an increased need for essential power system services.

Periods of low operational demand can occur when demand is largely met by distributed generation, significantly reducing demand on the transmission system. In all mainland NEM regions, there is a risk of operational demand falling below the thresholds needed to dispatch sufficient synchronous units to maintain system security. AEMO's Minimum System Load (MSL) framework[73] describes the actions that may be taken to manage system security in such conditions. They include recalling outages, directing participants, and instructing NSPs to maintain demand above the secure threshold, which may include active management of CER only if and when required.

AEMO's annual *Transition Plan for System Security* evaluates how the power system can continue to operate securely and reliably as the energy transition continues at pace. The 2025 *Transition Plan for System Security*[74] presents the system strength, inertia and network support control ancillary service (NSCAS) considerations for the next five to 10 years, and contains recommended actions to manage minimum system load conditions into the future. While mainland regional forecasts suggest a continuing decline in minimum demand, the impact of this on MSL conditions is expected to be offset to some extent by increasing large-scale storage charging. The 2026 *Transition Plan for System Security* will provide an update to the MSL Outlook considering these forecasts.

[73] At https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/managing-minimum-system-load.

[74] See https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-tpss-appendix-a2-network-requirements.pdf.

Table 20 summarises the 2025 *Transition Plan for System Security* requirements for TNSPs, from the report's detailed assessments of system strength, inertia, and ancillary service shortfalls. These requirements will be reviewed and updated in the 2026 *Transition Plan for System Security*, reflecting updated forecasts in this NEM ESOO.

Table 20 Summary of network requirements, to be addressed by transmission network service providers, as calculated for, and presented in, the 2025 *Transition Plan for System Security*

Region	TNSP requirements as at December 2025
New South Wales (Transgrid) 	**System strength deficits across New South Wales were confirmed from 2027-28 based on the Eraring Power Station retirement date, as announced at the time*.** In response, Transgrid is expediting the procurement of synchronous condensers with support from the New South Wales government. Following the subsequent delay of Eraring's retirement to 2029, the 2026 *Integrated System Plan*[75] assessed that Transgrid's first phase of synchronous condensers is expected to be commissioned ahead of closure – improving the system security outlook to 2030, although some risks remain. Deficits were projected in 2031-32 under a delayed delivery scenario for the second phase of synchronous condensers. No deficits were projected from 2036-37 onwards, following major network augmentations and delivery of the preferred option in Transgrid's system strength RIT-T. The impacts of Eraring's revised retirement date will be further assessed in the 2026 Transition Plan for System Security. **Inertia deficits were also forecast from 2027-28**, underscoring the need for action by Transgrid to ensure sufficient inertia is available from 2 December 2027. The synchronous condensers being procured will include flywheels to deliver inertia, although deficits are currently forecast until those assets are installed. **No gaps related to thermal loading or voltage control have been identified** under current demand scenarios. Nonetheless, several emerging network risks remain for electricity supply around Sydney during periods of peak demand, particularly if expected generation and network developments, including actionable projects, do not proceed as planned.
Queensland (Powerlink) 	**There are emerging system strength needs in Queensland from 2027-28, with solutions underway.** These needs are expected to be fully addressed by Powerlink's planned system strength solutions. **Two emerging inertia needs have been identified, with remedial measures underway.** These will be fully met through the installation of synchronous condensers, the existing clutch solution at Townsville Power Station, and expected contributions from existing grid-forming inverters. **The successful delivery of the Gladstone Project transmission augmentation is essential** for managing emerging thermal and voltage risks following the retirement of Gladstone power station. Powerlink has already commenced work on this project.
South Australia (ElectraNet) 	**No system strength deficits have been identified.** **No inertia deficits have been identified.** **The previously declared voltage control gap is actively being addressed**. ElectraNet is resolving this issue through the installation of new switched reactors in the Adelaide and South East regions. Three of the six reactors have already been installed, with the remaining three scheduled to be operational by October 2027.
Tasmania (TasNetworks) 	**AEMO has confirmed projected system strength deficits across Tasmania.** TasNetworks is exploring several options to manage these requirements. **Inertia deficits have also been identified.** Options are being explored alongside system strength remediation. **No gaps have been identified in relation to thermal loading or voltage control at this time.**
Victoria (VicGrid) 	**Emerging system strength needs are anticipated from 2028-29, primarily associated with the planned closure of Yallourn Power Station.** VicGrid is actively progressing solutions to address these needs, including the installation of synchronous condensers and potentially contracting with generation capable of operating in synchronous condenser mode. **An inertia deficit has also been confirmed from 2027-28.** While the synchronous condensers scheduled for installation will partially mitigate this need, VicGrid may need to take additional measures to ensure that sufficient inertia is available in Victoria from 2 December 2027. **AEMO confirmed the existing voltage control and thermal loading risks at Deer Park.** Control schemes are currently in place to manage these operational challenges until network augmentations can be delivered. Overloading risks were also identified for supply into Melbourne following the Yallourn retirement. To address these issues, VicGrid is investigating solutions.

* Since the publication of the 2025 *Transition Plan for System Security*, the Eraring Power Station's announcement retirement date has been delayed. The impact of this change will be assessed in the 2026 *Transition Plan for System Security*, scheduled to be published by 1 December 2026.

[75] See https://www.aemo.com.au/-/media/files/major-publications/isp/2026/appendices/a7-system-security.pdf

6 Regional outlook

This section summarises the reliability outcomes for each region, and their primary demand and supply drivers.

The regional outlook provides state/territory outcomes including:

- the overall reliability forecasts across the core assessments and each sensitivity (a national overview of the reliability outcomes in Section 4),
- the state/territory forecast of energy demand and key drivers, including annual consumption, maximum and minimum demand (see Section 3.1 for a national overview),
- the state/territory trends for generation investment (see Section 3.2 for a national overview),
- the state/territory distribution of residual demand, and unserved energy as a function of residual demand, and
- the state/territory trends for the seasonal distribution of simulated reliability incidents.

In this NEM ESOO, residual demand refers to the sent-out operational demand less generation from grid-scale VRE. It represents the operational demand remaining after considering the supply available from grid-scale VRE generation, which must be provided by other resources, including dispatchable generation and storage, interconnector imports, or reductions through DSP. Being ‘operational demand’, it is also net of the generation from CER and does not include auxiliary, pumping or charging load that would also need to be met.

Appendix A4 provides additional guidance on how to interpret the reliability assessment charts presented in this section.

6.1 Regional insights for New South Wales (including the Australian Capital Territory)

Key risks for New South Wales, including the Australian Capital Territory

Expected USE is forecast to increase above the reliability standard in New South Wales by 2033-34 with developments supported by government schemes, but three years earlier considering only committed and anticipated developments. Ongoing investment in infrastructure (or demand-side actions to lower forecast demand) are needed beyond this period to support projected data centre growth, electrification and replace coal fired generation.

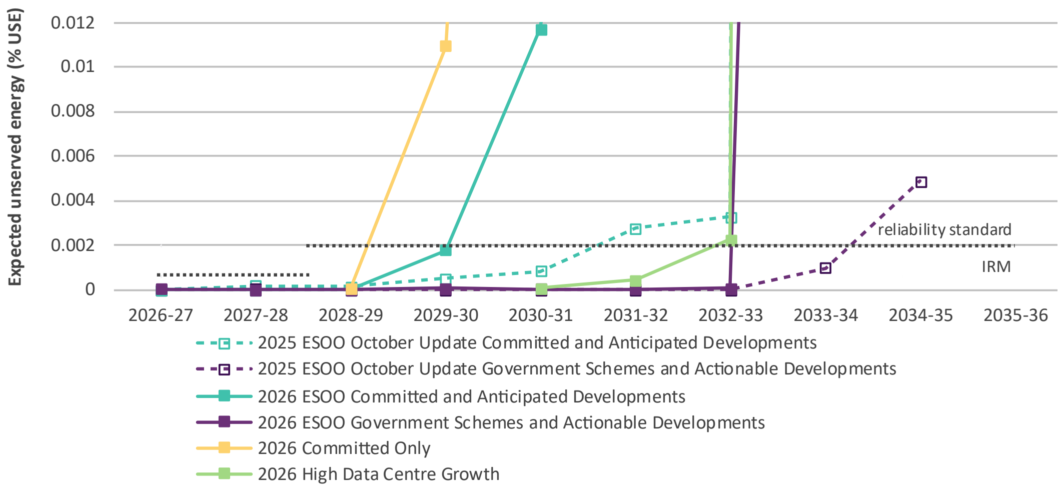
Prior to the retirement of the 2.9 GW Eraring Power Station in April 2029, 6.3 GW of committed and anticipated capacity is expected to be commissioned, with a further 9.6 GW of committed and anticipated capacity in the development pipeline for delivery thereafter. Growing energy shortfalls are projected over the horizon that will require more investment due to the total retirement of 6.9 GW of capacity in New South Wales (including Eraring, Bayswater and Vales Point), which has historically provided an average generation of 36 TWh per year over the last four years. Further insights are available in the *2026 NEM ESOO Results Workbook*.

New South Wales (including the Australian Capital Territory)	Summer readiness	T-1 (2027-28)	T-3 (2029-30)	Above the reliability standard
Government Schemes and Actionable Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	2033-34
Committed and Anticipated Developments				2030-31

Resource adequacy

If projects supported by government schemes proceed to schedule, expected USE is forecast within the relevant reliability standards until 2032-33. Additional investment is needed to replace retiring coal capacity and the generation it has provided and meet growing demand.

If only projects that meet AEMO's criteria for committed and anticipated projects proceed, sufficient capacity is projected to maintain the reliability standard to 2029-30. Additional actionable ISP network projects, and generation and storage supported by government schemes, together with assumed CER orchestration, will reduce supply scarcity risks by increasing dispatchable capacity and energy generation potential. Continued investments to replace further retirements and rising demand are needed in the longer term.

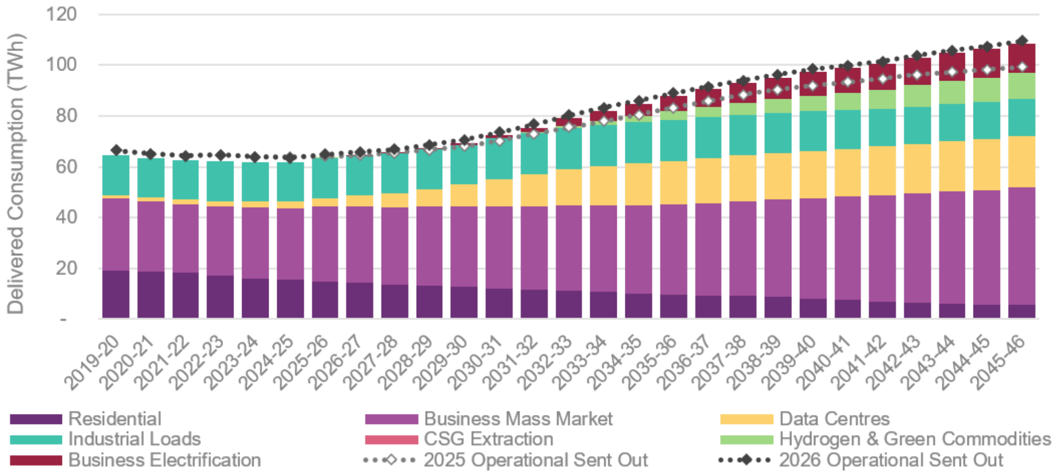


Electricity consumption trends

Sydney is projected to remain Australia's primary data centre hub, and data centre usage is projected to drive a material level of growth in the region.

Growth in the business sector is a key source of overall consumption, and other key drivers beyond data centre developments include growth from BMM and business electrification, as well as potential hydrogen and green commodities. Existing industrial load is forecast to remain broadly flat. Business electrification is forecast to progress at a relatively modest pace to 2030, before decarbonisation actions are projected to accelerate to support the economy's net-zero transition.

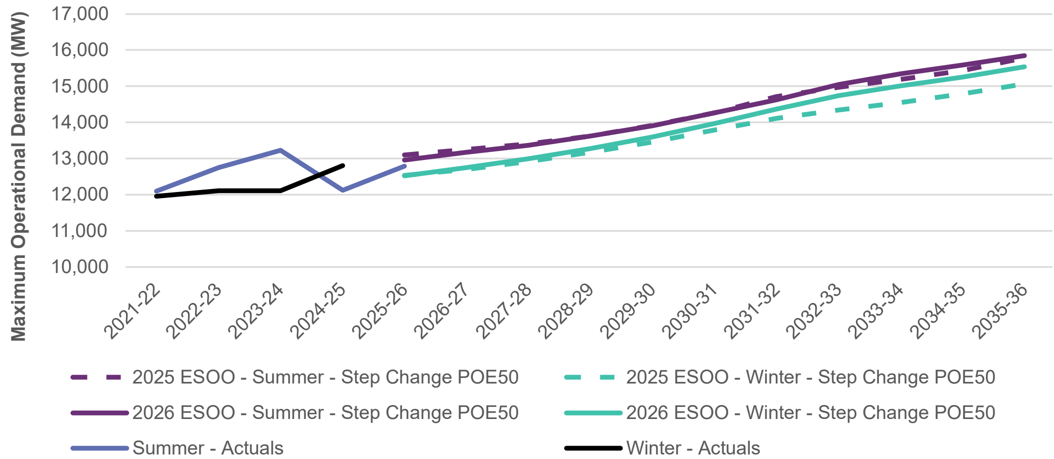
While residential loads also increase (due to rising populations, increased transport electrification and other fuel switching from gas to electric appliances), distributed PV developments offset this growth and result in a lowering of wholesale-delivered electricity to support the residential sector.



Maximum demand forecast

Maximum demand is forecast to continue to increase, driven by factors that align with the overall consumption trends. Expanding data centre demand, increasing electrification and EV uptake, and broader BMM demand provide a growing demand that is not highly temperature sensitive. While delivered residential consumption is reducing, distributed PV does not reduce maximum demands materially, and customer-controlled battery developments have only a modest contribution to lowering the most extreme peaks, as discharge is more spread across evening and overnight periods.

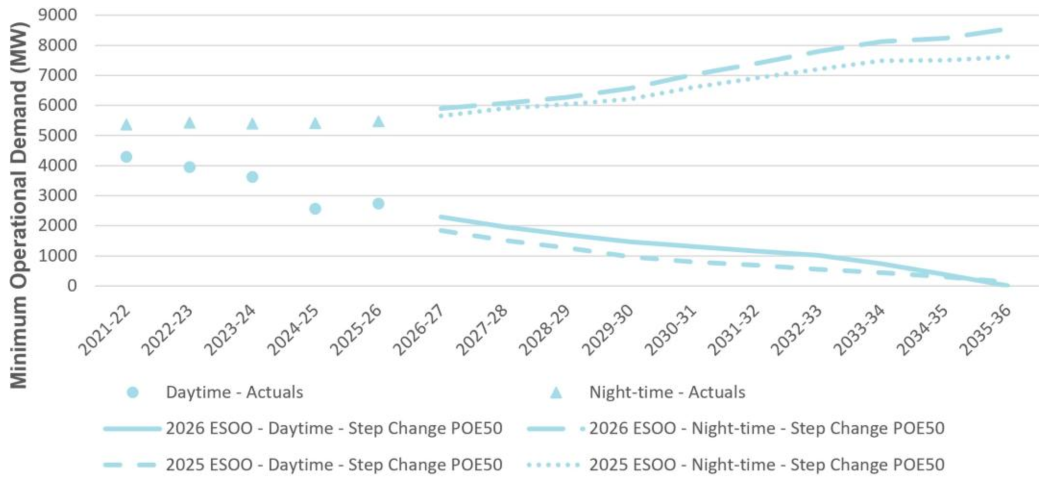
Summer peak demand remains higher than winter peak demand, reflecting the continued influence of hot weather and air-conditioning loads. However, winter maximum demand is forecast to grow slightly faster as electrification increases space heating loads, gradually narrowing the seasonal gap.



Minimum demand forecast

Minimum demand is forecast to continue to decline, driven by increasing uptake of distributed PV. Increasing electricity consumption partially offsets this decline, with LILs and data centres providing key daytime loads. Daytime minimum demand continues to occur during summer, typically in the early afternoon when distributed PV generation is at or near its highest level. Battery and EV charging offsets some of this generation.

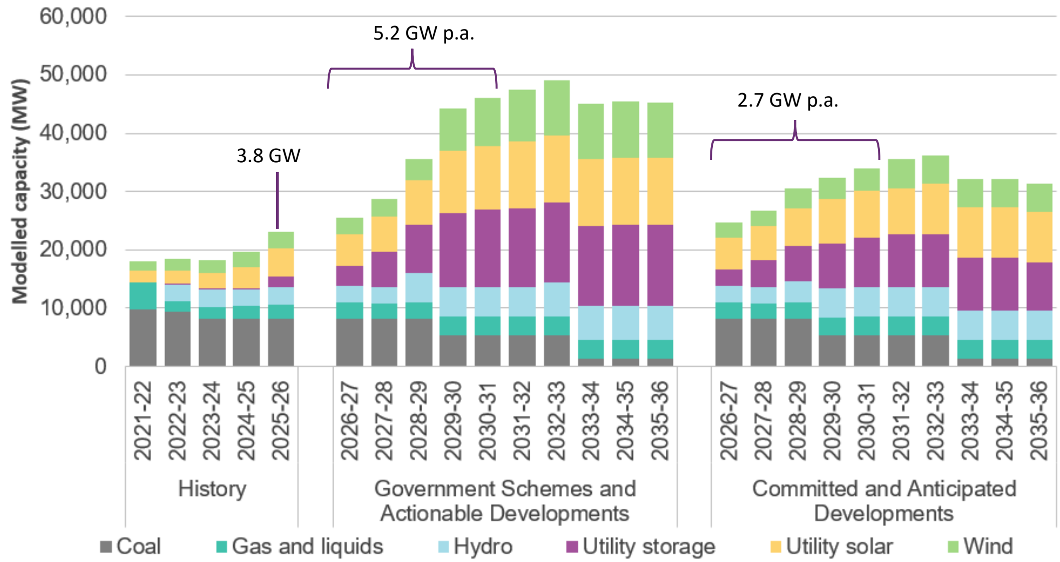
Daytime minimum loads are the primary driver of the overall minimums, with overnight minimum demands forecast to rise, driven by underlying residential and business demand, including data centre operation. Night-time minimum demand typically occurs during the shoulder seasons in the early morning, when electricity consumption is generally at its lowest.



Generation and storage developments

There is a substantial pipeline progressing as either committed or anticipated projects, or that have explicit government support through various tenders and schemes. In the next five years, 14.1 GW of new projects in New South Wales are committed and anticipated. A further 12.8 GW of government supported projects have been identified, helping to replace 6.9 GW of retirements before 2035-36.

However, the development pipeline generally plateaus from 2030-31 as projects cannot be identified as sufficiently advanced to be classified committed and anticipated over the longer horizon. Strong growth in batteries increases dispatchable capacity, but new energy production capabilities from solar and wind generators (or gas) will be needed to replace coal generation. Few projects can demonstrate sufficient advancement beyond the next five years to be considered, demonstrating that further investments are needed in the medium to long term to maintain reliability.

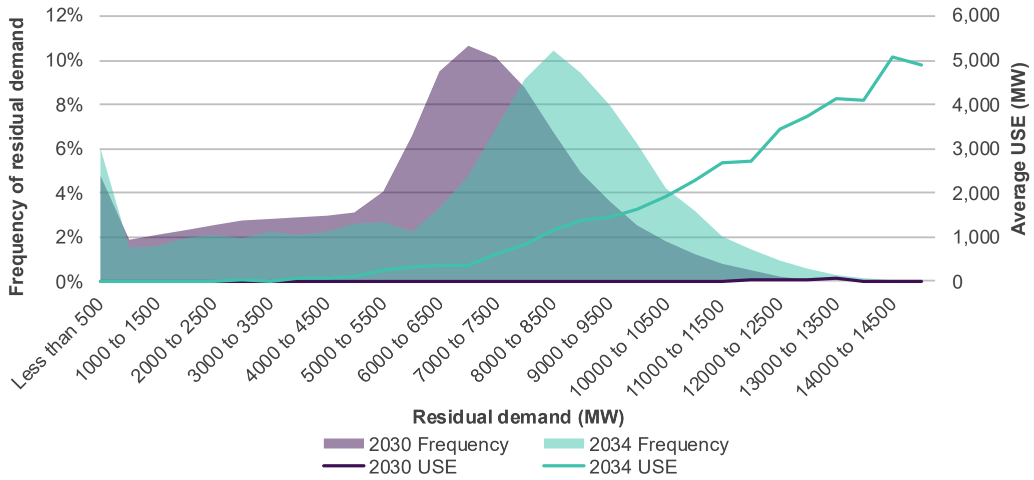


Supply scarcity risks

The risks are forecast to vary depending on conditions that drive higher demand as well as lower renewable resource availability. They are highest when high demand and low VRE conditions occur simultaneously, particularly if these conditions endure for long periods and reduce the availability of energy-limited reserves such as hydro and battery storages.

The figure shows forecast average expected USE at different levels of residual demand in 2029-30 and 2033-34 for the *Committed and Anticipated Developments* assessment highlighting that USE is observed in simulations where residual demand is highest.

As the horizon moves forward, the frequency distribution of **residual demand changes**. This is partly a function of demand growth but also demonstrates the challenge weather-dependent resources have towards the later years, as dispatchable capacity is required to try and maintain system reliability.

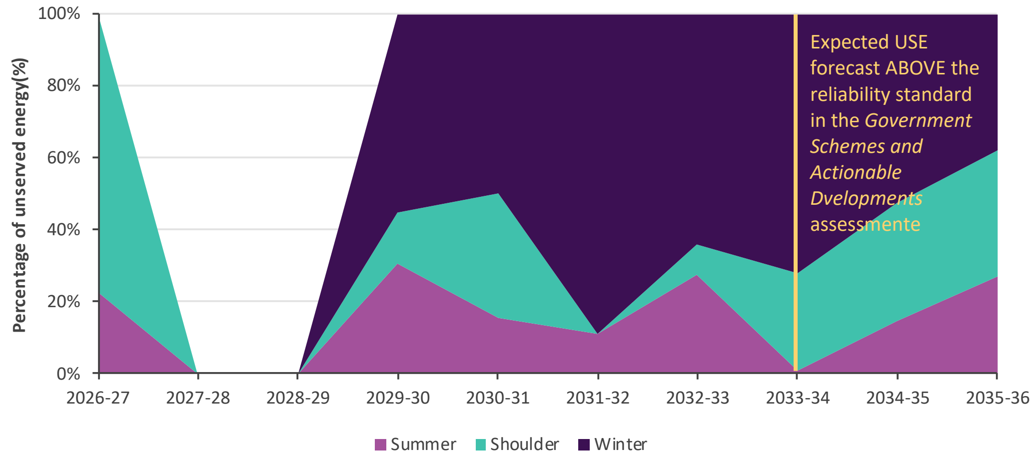


Supply scarcity risks increase, primarily in winter, as coal retires and available energy production therefore reduces. The winter season also typically has lower renewable energy resources from shorter days impacting solar production.

Coal retirements are occurring at the same time as heating loads are forecast to electrify. New business loads, such as industrial electrification and data centres, are also increasing the load that is less temperature sensitive.

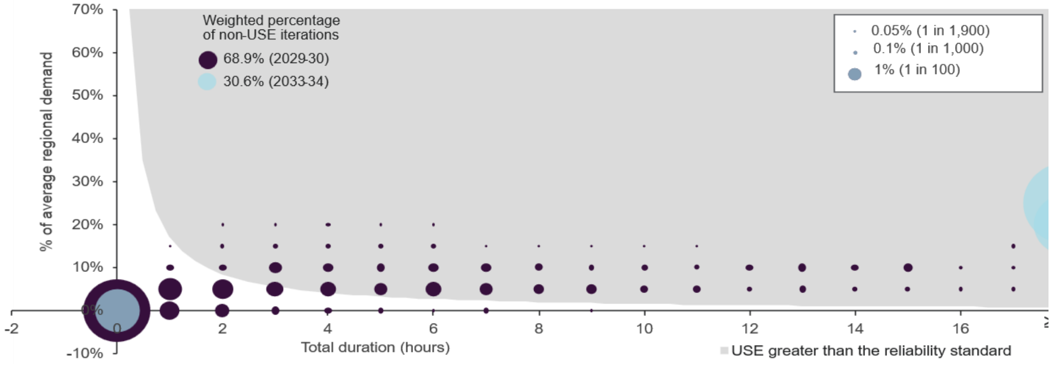
As coal-fired generators retire and demand grows, the surplus of energy production potential reduces, and without additional investments supply scarcity risks are increasingly likely to emerge across all conditions, rather than during extreme heat or cold events in summer and winter. To mitigate these forecast risks, new sources of firmed energy supply will be needed. Greater energy supply will also lower reliance on energy-limited resources, such as hydro, gas and battery storages.

This figure reflects the changing seasonal risk profile in the *Government Schemes and Actionable Developments* assessment.



The distribution of USE changes across the forecast horizon. While the forecast duration of USE events and the simulated amount of USE in the *Committed and Anticipated Developments* simulations is relatively dispersed in 2029-30, multiple components of this change towards 2033-34 and beyond.

Notably, the number of all forecast USE events increases in total by almost 40%, but importantly the USE outcomes are no longer as distributed – instead being more concentrated and severe for longer periods of time, often lasting more than 18 hours due to increasing tightening of supply and demand.



6.2 Regional insights for Queensland

Key risks for Queensland

Forecast USE is observed to increase above the reliability standard in Queensland by 2032-33 considering only committed and anticipated developments. No exceedance of the reliability standard is expected with consideration of developments supported by government schemes, indicating that infrastructure investment is needed to support electrification and replace coal fired generation.

Prior to the retirement of 1.7 GW Gladstone power station in March 2029, 3.8 GW of committed and anticipated capacity is expected to be commissioned, with a further 7.8 GW of committed and anticipated capacity in the development pipeline for delivery thereafter. Growing energy shortfalls are projected under the *Committed and Anticipated Developments* reliability assessment. This will require more investment due to the overall retirement of 2.4 GW of capacity, which has historically provided an average of 10 TWh per year over the last four years.

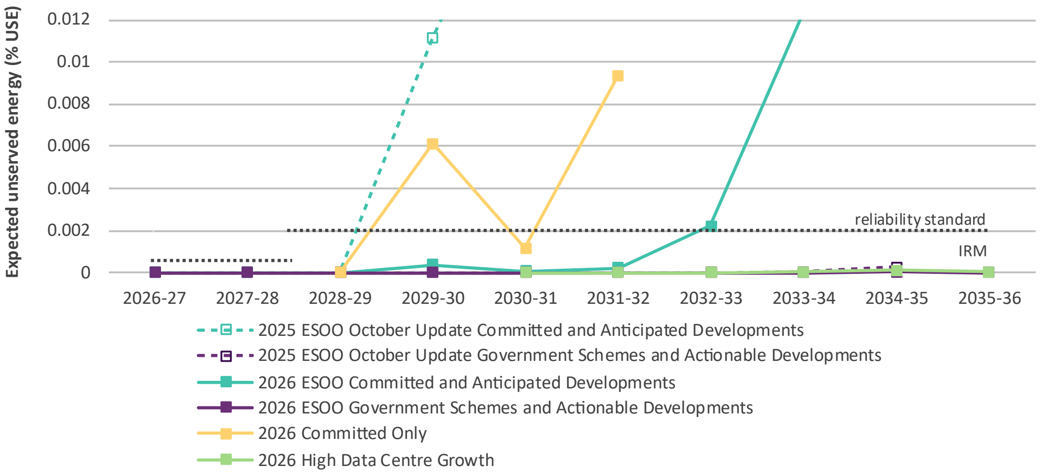
Further insights are available in the 2026 NEM ESOO Results Workbook.

Queensland	Summer readiness	T-1 (2027-28)	T-3 (2029-30)	Above the reliability standard
Government Schemes and Actionable Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	-
Committed and Anticipated Developments				2032-33

Resource adequacy

If projects supported by government schemes proceed to schedule, expected USE is forecast within the relevant reliability standards over the whole horizon.

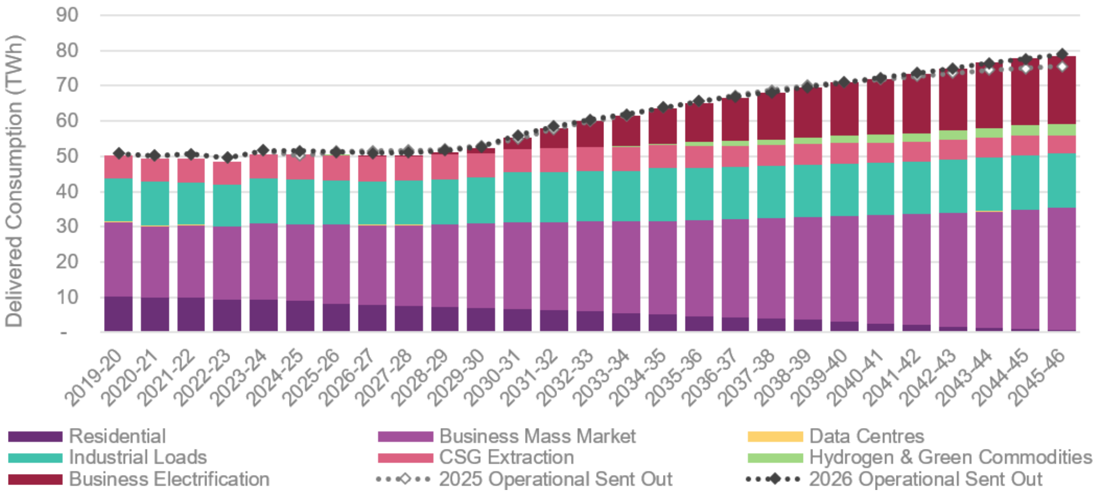
If only projects that meet AEMO's commitment criteria for committed and anticipated projects proceed, sufficient capacity is projected to maintain the reliability standard to 2031-32. Additional generation, storage and network supported by government schemes will improve supply scarcity risks by increasing dispatchable capacity and energy generation potential, which – alongside assumed CER orchestration – improves supply scarcity risks. Continued investments to replace further retirements and rising demand are needed in the longer term.



Electricity consumption trends

In 2025-26, Queensland accounts for nearly 30% of LIL across the NEM, the majority of which is based in the Gladstone area and is projected to grow steadily. The current prospective industrial load pipeline is dominated by mining and minerals processing.

Growth in underlying residential consumption in Queensland is stronger in the short to medium term than the NEM average. This growth is primarily driven by projected EV uptake, strong customer connection growth, and the upward trend in observed consumer behaviour changes (higher electricity consumption for comfort).



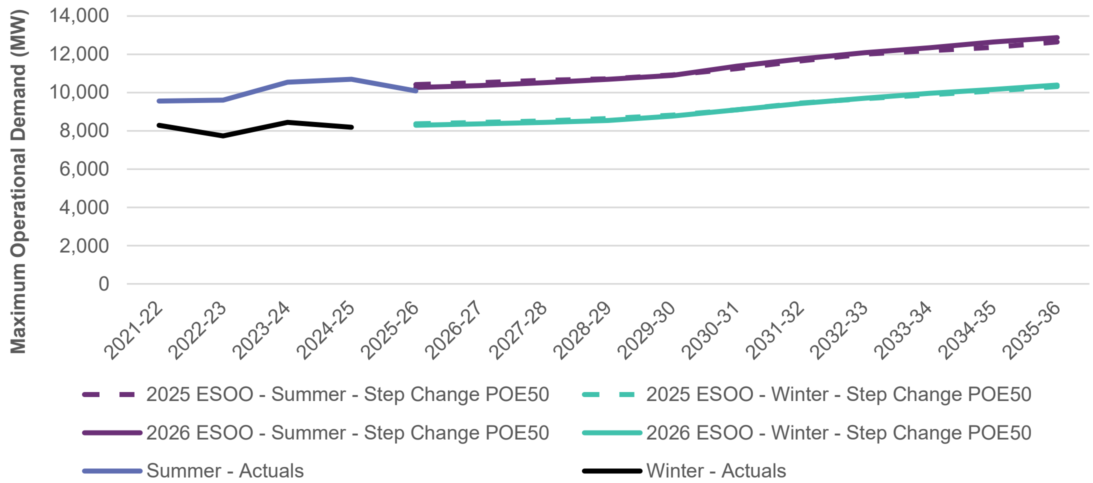
Maximum demand forecast

Maximum demand is forecast to continue increasing, driven by factors that align with the overall consumption trends. Increasing electrification and EV uptake and continued growth in business demand are the primary drivers of growth, while LILs continue to make a significant contribution to peak demand outcomes.

In contrast to New South Wales and Victoria, data centre developments are projected to contribute relatively little to maximum demand growth in Queensland.

Although delivered residential consumption is reducing, distributed PV does not materially reduce maximum demand, and customer-controlled battery developments make only a modest contribution to reducing the most extreme peaks, as battery discharge is generally spread across evening and overnight periods.

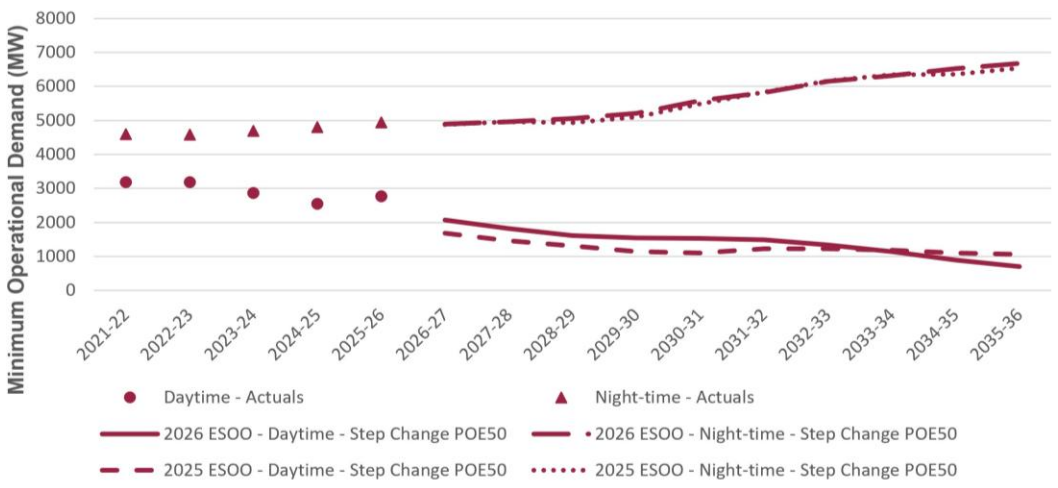
Summer peak demand remains materially higher than winter peak demand, reflecting the continued influence of hot weather and air-conditioning loads.



Minimum demand forecast

Minimum demand is forecast to continue to decline, driven by increasing uptake of distributed PV. Increasing electrification and consumer battery charging partially offset this decline by increasing underlying daytime electricity demand. Daytime minimum demand continues to occur during the shoulder or winter seasons, typically around midday when distributed PV generation is at its highest level.

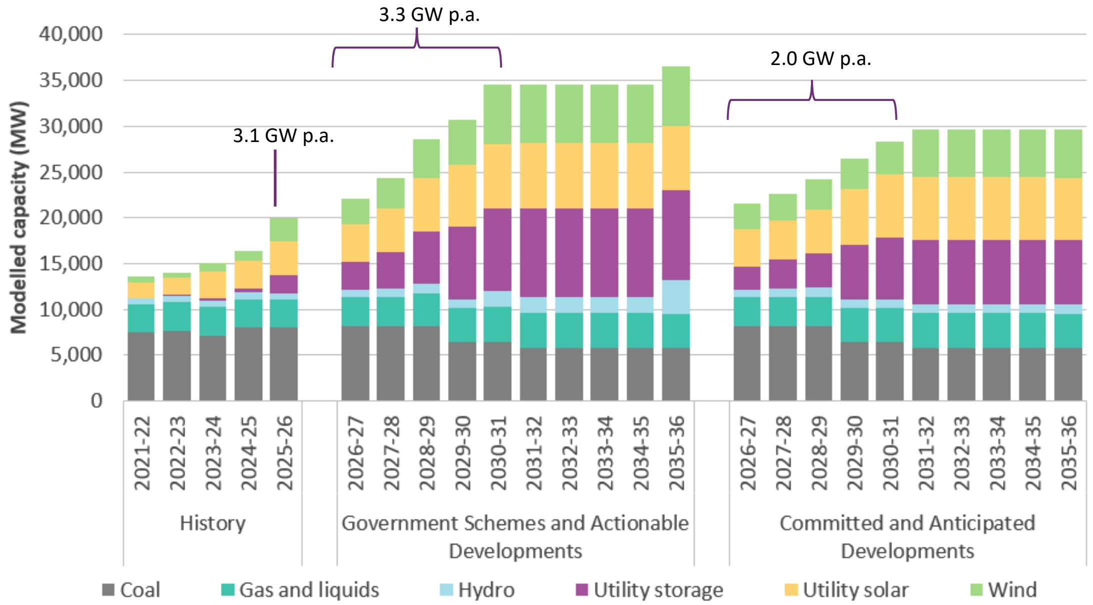
Daytime minimum loads are the primary driver of the overall minimums, with night-time minimum demands tending to rise, driven primarily by growth in LILs and continued growth in underlying residential and business demand. Night-time minimum demand typically occurs during the shoulder seasons in the early morning, when electricity consumption is generally at its lowest.



Generation and storage developments

There is a substantial pipeline progressing as either committed or anticipated projects, or that have explicit government support through various tenders and schemes. In the next five years, 10.5 GW of new projects in Queensland are committed and anticipated. A further 5.1 GW of additional government-supported projects have been identified within the modelling horizon, helping to replace 2.4 GW of coal-fired generator retirements before 2035-36. However, the development pipeline generally plateaus from 2031-32 as projects cannot be identified as sufficiently advanced to be classified committed and anticipated over the longer horizon.

Strong growth in batteries increases dispatchable capacity, but new energy production capabilities from solar and wind generators (or gas) will be needed to replace coal generation. Few projects can demonstrate sufficient advancement beyond the next five years to be considered, demonstrating that further investments are needed in the medium to long term to maintain reliability.

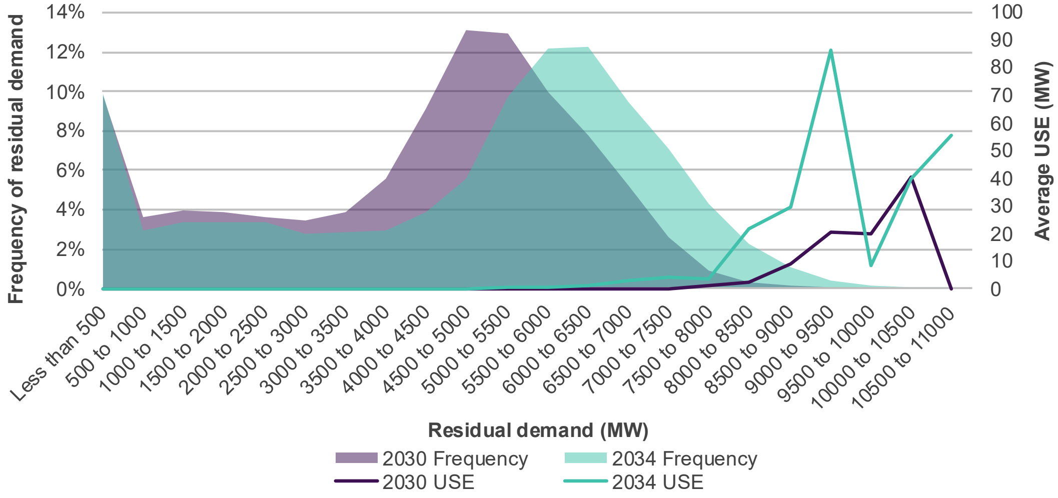


Supply scarcity risks

The risks are forecast to vary depending on weather conditions. Supply scarcity risks are highest when high demand and low VRE conditions occur simultaneously, particularly if these conditions endure for long periods and reduce the availability of energy-limited reserves such as hydro and battery storages.

The figure shows forecast average expected USE at different levels of residual demand in 2029-30 and 2033-34 for the *Committed and Anticipated Developments* assessment, highlighting that USE is forecast where residual demand is highest.

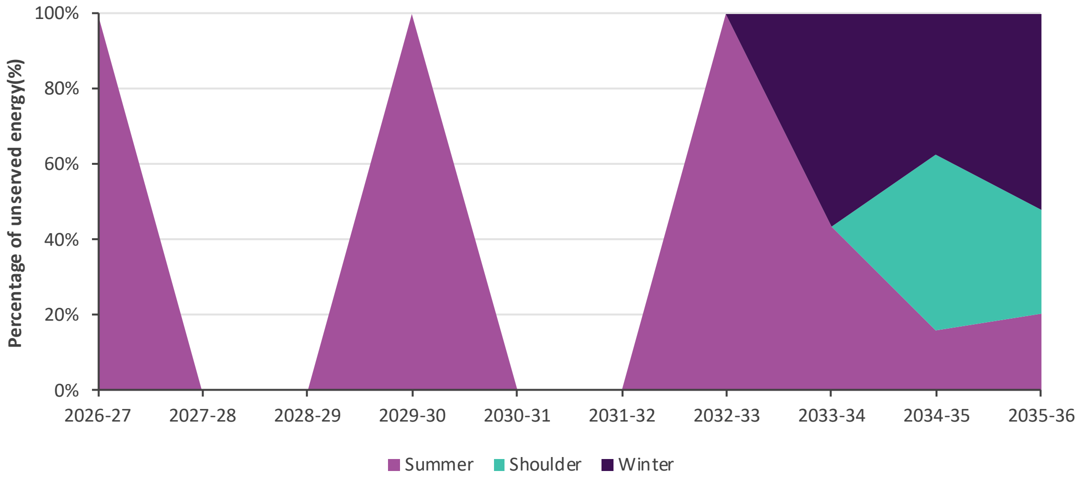
As time progresses, the frequency distribution of **residual demand changes** in Queensland, indicating a strong reliance on dispatchable capacity to meet reliability standards as demand grows and supply tightens.



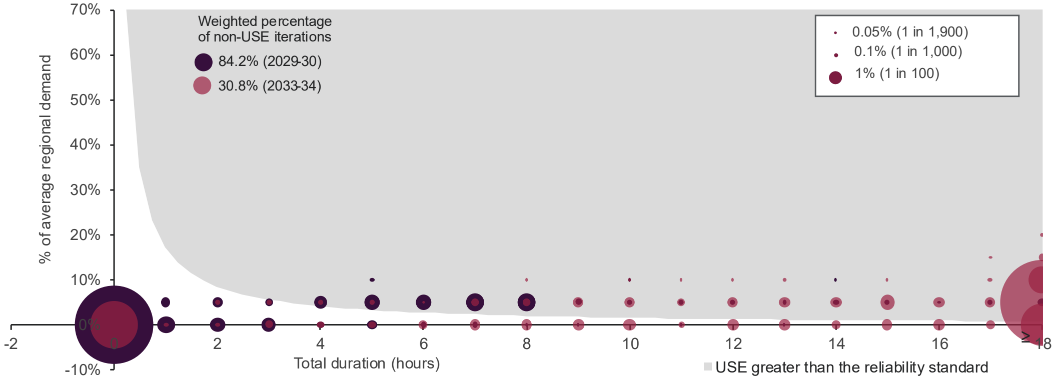
As coal-fired generators retire and demand grows, the surplus of dispatchable energy production potential is expected to reduce.

Supply will have greater exposure to weather variation in winter months, when solar generation is lower, though Queensland has lower demand growth drivers in winter given its warmer climate. As such, summer remains the most at-risk season until broader energy shortfall risks eventuate.

This figure reflects the changing seasonal risk profile in the *Government Schemes and Actionable Developments* assessment.



The distribution of USE changes across the forecast horizon. For Queensland, however, the intensity of USE outcomes remains relatively consistent across years 2029-30 to 2033-34 in the *Committed and Anticipated Developments* assessment, with many short, low intensity events gradually shifting to increasingly longer events. While the number of simulations that experience some level of USE does increase substantially from 16% to almost 70% across this period, the severity of USE events remains more evenly distributed. Nonetheless, the number of USE events lasting longer than 18 hours substantially increase, reflective of the changes in USE as part of the reliability assessment.



6.3 Regional insights for South Australia

Key risks for South Australia

Expected USE for South Australia increases above the reliability standard by 2033-34, with developments supported by government schemes, but two years earlier considering only committed and anticipated developments. More supply investment or demand-side solutions will be needed to support projected demand growth, including industrial activity, data centre growth, and broader electrification.

Prior to the retirement of Torrens Island B in June 2028 (providing 0.6 GW of gas capacity), 0.7 GW of new developments are committed and anticipated to be operational, supported by growing interconnection due to the implementation of Project EnergyConnect that is assumed to be in service before the closure. A further 3.0 GW of committed and anticipated capacity in the development pipeline is assumed to come online following the retirement of Torrens Island B.

Growing energy shortfalls are projected that will require more investment due to the overall retirement of 1.7 GW of capacity, including 1.2 GW of gas capacity, which has historically provided 2 TWh on average of generation over the last four years.

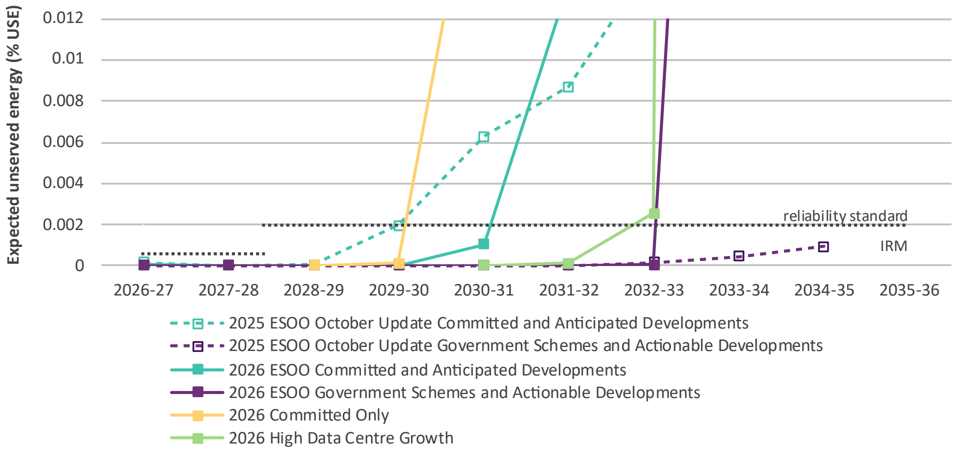
Further insights are available in the 2026 NEM ESOO Results Workbook.

South Australia	Summer readiness	T-1 (2027-28)	T-3 (2029-30)	Above the reliability standard
Government Schemes and Actionable Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	2033-34
Committed and Anticipated Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	2031-32

Resource adequacy

If projects supported by government schemes proceed to schedule, expected USE is forecast within the relevant reliability standards until 2032-33. Additional investment is needed to replace retiring local gas capacity, and the generation provided by coal capacity in neighbouring regions.

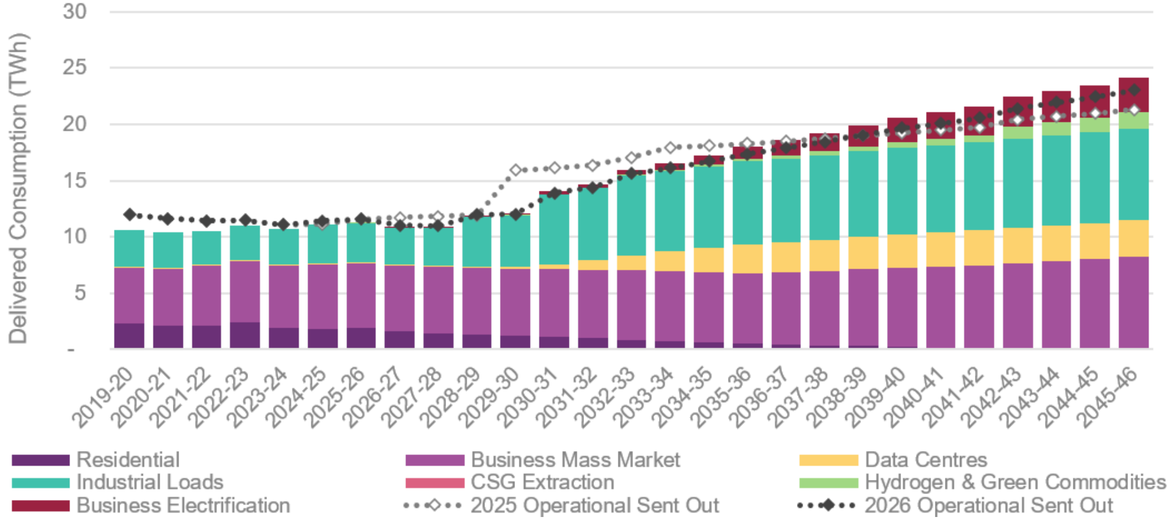
If only projects that meet AEMO's commitment criteria for committed and anticipated projects proceed, sufficient capacity is projected to maintain the reliability standard to 2030-31. Additional generation, storage and network supported by government schemes will improve supply scarcity risks by increasing dispatchable capacity and energy generation potential, which alongside assumed CER orchestration, reduce supply scarcity risks. Continued investments to replace further retirements and rising demand are needed in the longer term.



Electricity consumption trends

Large industrial consumption in South Australia is forecast to more than double by 2035-36, as a high number of prospective industrial projects are anticipated to develop over the outlook period. These opportunities are predominantly associated with mining, smelting and data centres.

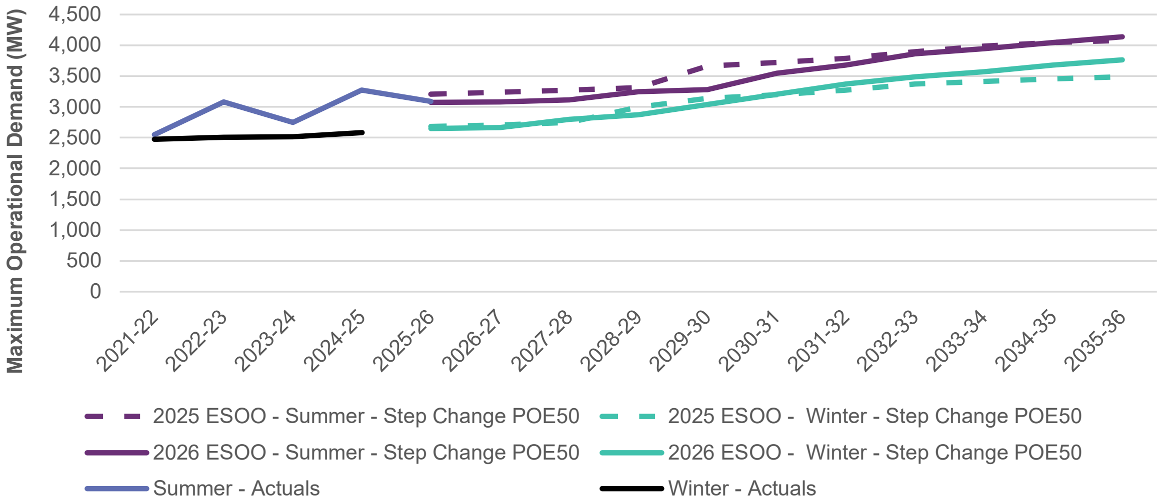
Underlying residential consumption increases gradually across the forecast horizon, with growth in customer connections, consumer behaviour impact, electrification and EV uptake partially offset by energy efficiency measures. Due to the continued uptake of rooftop PV, net delivered residential consumption is forecast to become negative from 2035-36 in *Step Change*, with households feeding more into the grid than what they withdraw over the year.



Maximum demand forecast

Maximum demand is forecast to continue increasing over the outlook period, driven primarily by growth in large industrial loads associated with mining, metallurgy and related infrastructure developments, together with expanding data centre demand. Residential and business demand continues to be the largest contributor to maximum demand, while industrial developments contribute an increasing share of future growth.

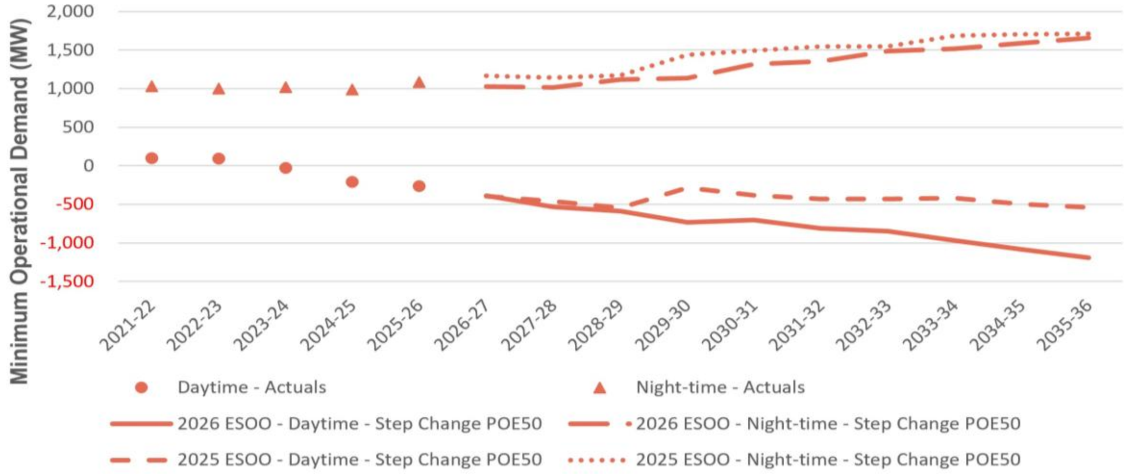
Summer peak demand remains higher than winter peak demand, reflecting the continued influence of hot weather and air-conditioning loads. However, increasing industrial activity is expected to support demand growth across both seasons.



Minimum demand forecast

Minimum demand is forecast to continue to decline over the outlook period, driven by increasing uptake of rooftop PV and PV non-scheduled generation (PVNSG). Growth in residential demand and large industrial loads partially offsets this decline, although PV generation remains the dominant influence on daytime minimum demand. Daytime minimum demand continues to occur during summer, typically in the early afternoon when rooftop PV generation is at or near its highest level.

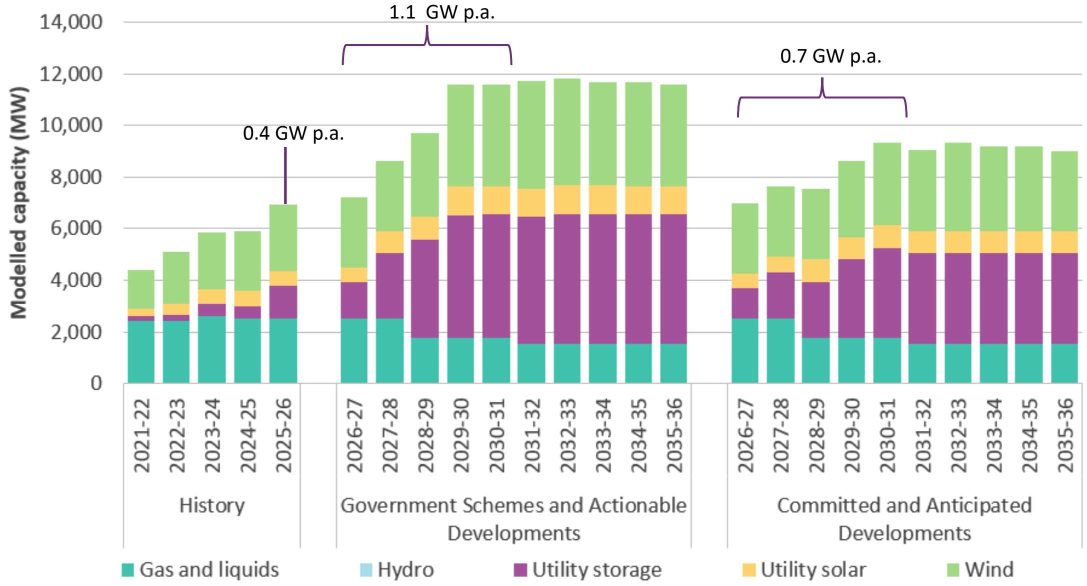
Daytime minimum loads are the primary driver of overall minimum demand outcomes. Night-time minimum demand is forecast to increase over the outlook period, driven primarily by growth in large industrial loads associated with mining and metallurgy, with additional contributions from data centre demand. Night-time minimum demand typically occurs during the shoulder seasons in the early morning, around 5 am, when electricity consumption is generally at its lowest.



Generation and storage developments

There is a substantial pipeline of that are progressing as either committed or anticipated projects, or that have explicit government support through various tenders and schemes. In the next five years, 3.4 GW of new projects in South Australia are committed and anticipated. A further 2.3 GW of additional government-supported projects have been identified helping to replace 1.7 GW of retirements before 2035-36. However, the development pipeline generally plateaus from 2031-32 as projects cannot be identified as sufficiently advanced to be classified committed and anticipated over the longer horizon.

Few projects can demonstrate sufficient advancement beyond the next five years to be considered, demonstrating that further investments are needed in the medium to long term to maintain reliability.

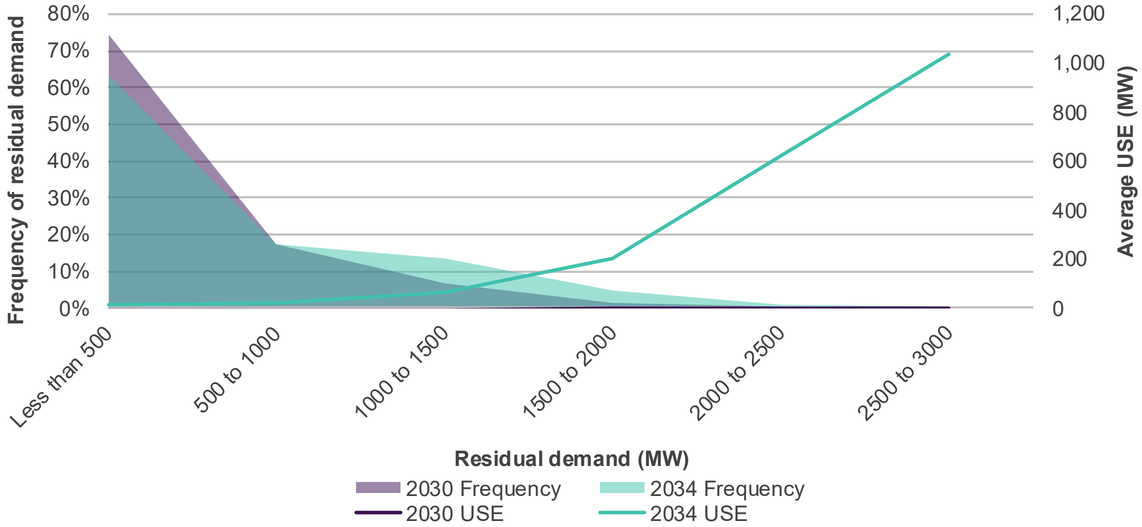


Supply scarcity risks

Risks are forecast to vary depending on weather conditions, with supply scarcity risks highest when high demand and low VRE conditions occur simultaneously, particularly if these conditions endure for long periods and reduce the availability of energy-limited reserves such as hydro and battery storages.

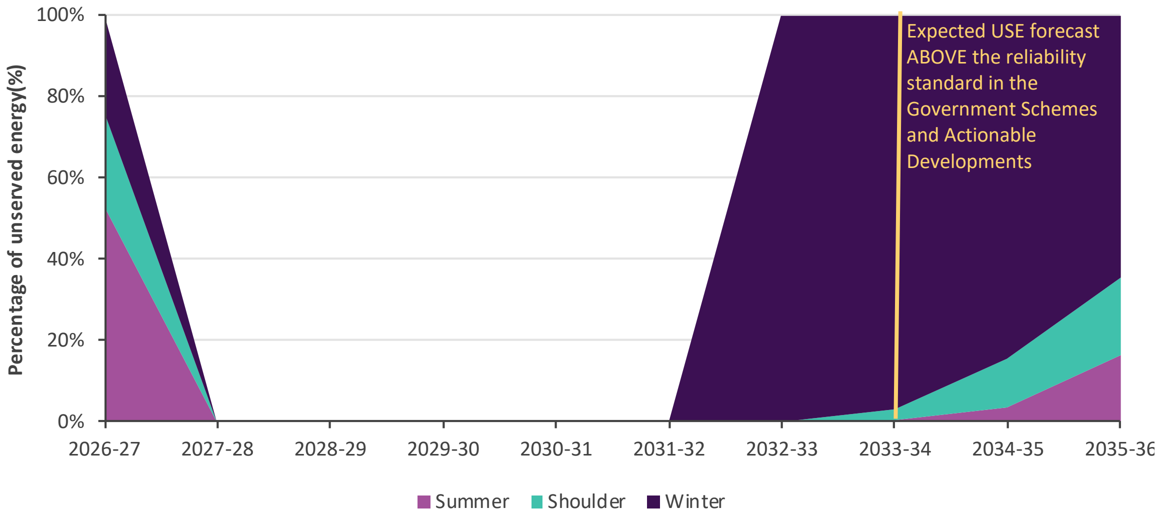
The figure shows forecast average expected USE at different levels of residual demand in 2029-30 and 2033-34 for the *Committed and Anticipated Developments* assessment highlighting that USE is forecast where residual demand is highest.

As time progresses, the frequency distribution of **residual demand changes minimally** in South Australia, demonstrating the high frequency of periods where renewable generation can supply most of South Australia's load.

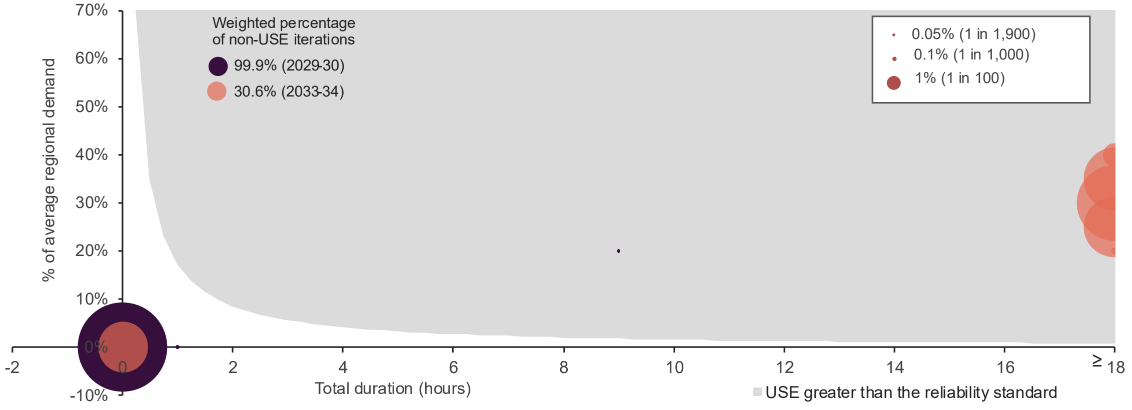


Supply scarcity risks increase primarily in winter during high demand periods on cold days later in the forecast. The winter months typically also observe lower renewable energy output, particularly from solar generators. This compounds supply scarcity risks during this season with lower solar output and diminished opportunity for storages to recharge.

This figure reflects the changing seasonal risk profile in the *Government Schemes and Actionable Developments* assessment. Note that this a relative profile between seasons, so total percentage sums to 100 per cent regardless of level of USE.



The distribution of USE events significantly changes in South Australia between 2029-30 and 2033-34 in the *Committed and Anticipated Developments* assessment. Many scattered USE events are projected in the simulations, with a rising proportion of long duration and larger magnitude events as energy shortfalls emerge over the horizon.



6.4 Regional insights for Tasmania

Key risks in Tasmania

Expected USE is observed to increase above the reliability standard in Tasmania by 2034-35 with developments supported by government schemes, and one year earlier with committed and anticipated developments. In Tasmania, the forecast USE is being driven by the potential for energy shortfalls as at times of high exports.

0.3 GW of committed and anticipated capacity is expected to be commissioned over the horizon, with no local capacity scheduled to retire in Tasmania.

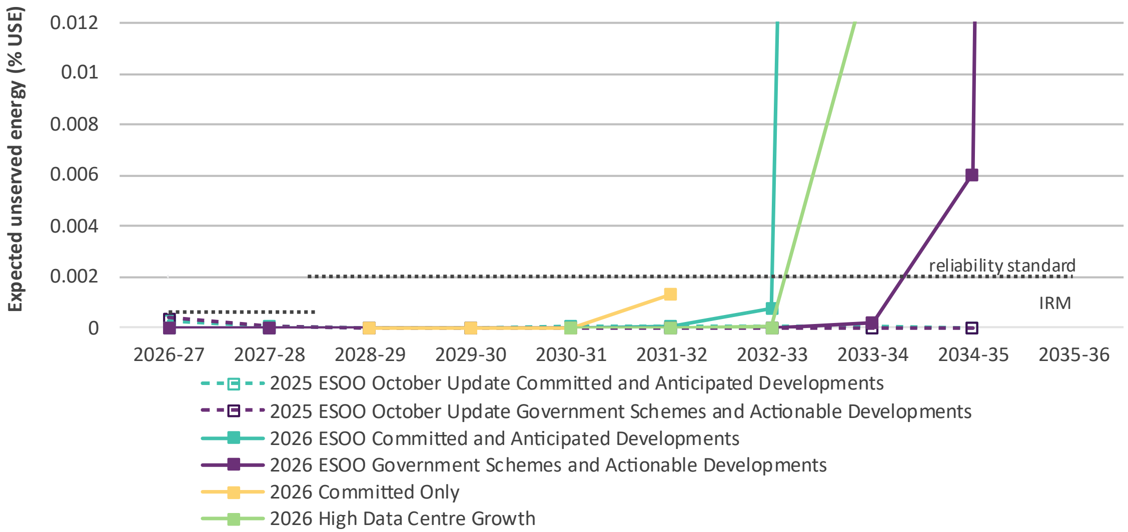
Further insights are available in the 2026 NEM ESOO Results Workbook.

Tasmania	Summer readiness	T-1 (2027-28)	T-3 (2029-30)	Above the reliability standard
Government Schemes and Actionable Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	2034-35
Committed and Anticipated Developments				2033-34

Resource adequacy

If projects supported by government schemes proceed to schedule, expected USE is forecast within the relevant reliability standards until 2033-34. These developments, including additional generation and transmission, together with assumed CER coordination, provide additional energy supply and energy-sharing capability and reduce resource adequacy risks. If only projects that meet AEMO's commitment criteria for committed and anticipated projects proceed, sufficient capacity is projected to maintain the reliability standard to 2032-33. In the later years, growing demand increasingly tightens Tasmania's energy balance. Tasmania has extensive hydro generation capacity and increasing interconnection with Victoria, but hydro energy availability varies with weather-dependent inflows and water availability. Victoria can provide additional energy when available, however, support may be limited or not available during periods when supply is tight in both regions.

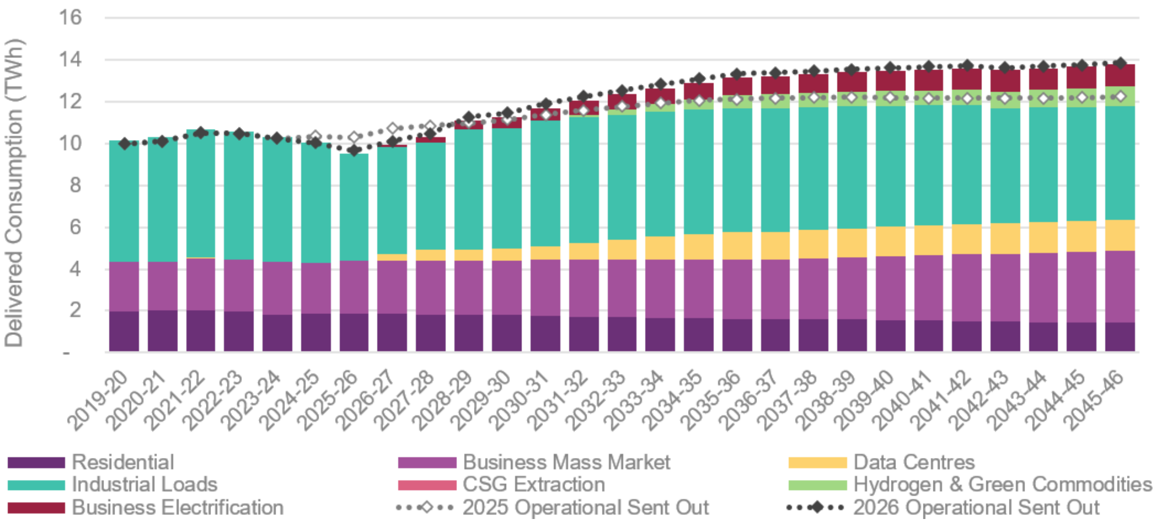
With a relatively limited pipeline of additional projects in Tasmania later in the outlook, reliability becomes increasingly dependent on the availability of energy within Tasmania and across the interconnected NEM during periods of scarcity. Further investment in energy supply, alongside flexible demand and CER coordination, in Tasmania or elsewhere in the interconnected NEM, could therefore reduce these reliability risks as demand continues to grow.



Electricity consumption trends

Large industry in Tasmania accounts for over half of operational consumption. While consumption dips in the early years of the forecasts, reflecting reduced consumption at a few industrial sites, operations are projected to resume and consumption to recover by 2029.

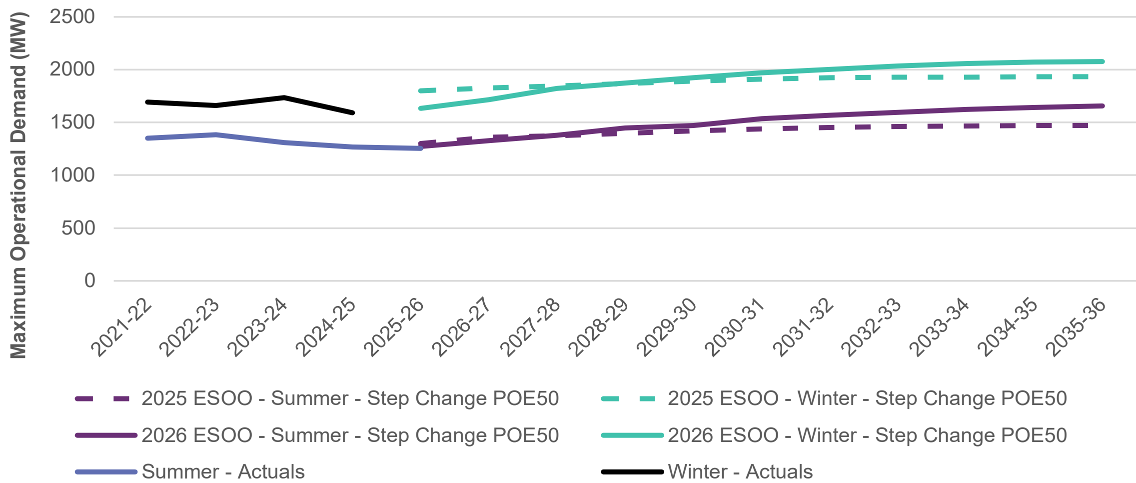
Some small electrification projects and mining restarts make modest additions to industrial consumption, but the most growth comes from new industries of data centres and assumed hydrogen developments.



Maximum demand forecast

Maximum demand is forecast to increase modestly over the outlook period, driven by factors that align with the overall consumption forecast. Growth is supported primarily by industrial activity including electrification and expanding data centre developments.

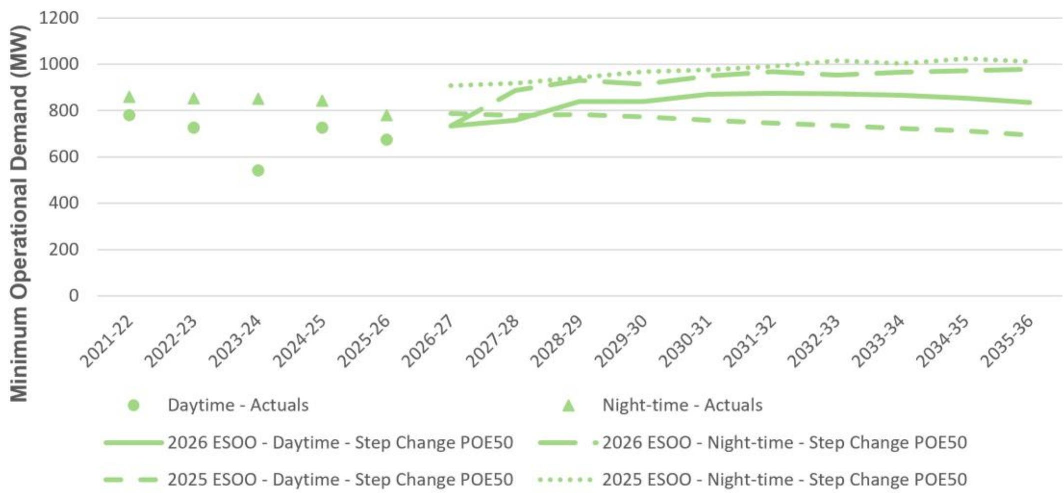
Unlike the mainland NEM regions, Tasmania remains strongly winter peaking, due to cold-weather heating and hot-water demand together with elevated industrial electricity consumption during winter mornings.



Minimum demand forecast

Minimum demand is forecast to initially increase over the outlook period, driven by LILs, data centres and emerging industries. Lower relative uptake of rooftop PV limits its offsetting influence. From around 2030, stronger growth in rooftop PV and PVNSG drives daytime minimum demand lower. Daytime minimum demand typically occurs during summer and the shoulder seasons in the early afternoon, when rooftop PV generation is at or near its highest level.

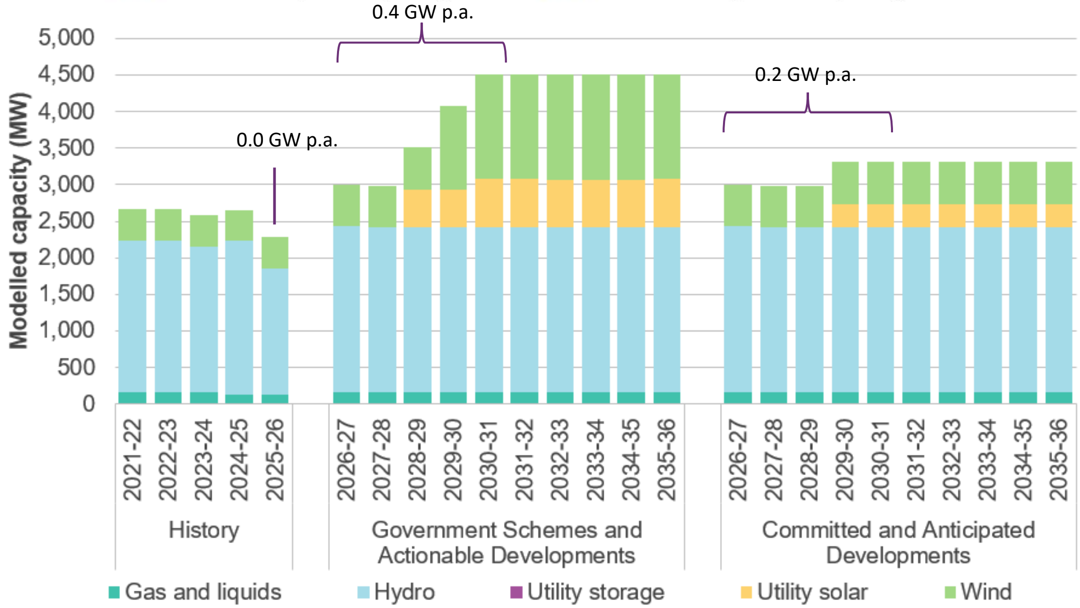
Daytime minimum loads remain the primary driver of overall minimum demand outcomes. Night-time minimum demand remains broadly steady over the outlook period, with changes in large industrial consumption offset by recovering industrial activity and growth in data centre demand. Night-time minimum demand typically occurs during summer in the early morning, around 3.00 am to 4.00 am, when electricity consumption is generally at its lowest.



Generation and storage developments

Relative to other regions, there is a more limited pipeline progressing as either committed or anticipated projects, or that have explicit government support through various tenders and schemes in Tasmania. In the next five years, 0.3 GW of new projects in Tasmania are committed and anticipated. A further 0.8 GW of additional government supported projects have been identified over the modelling horizon.

Few projects can demonstrate sufficient advancement beyond the next five years to be considered, demonstrating that further investments are needed in the medium to long term to maintain reliability.

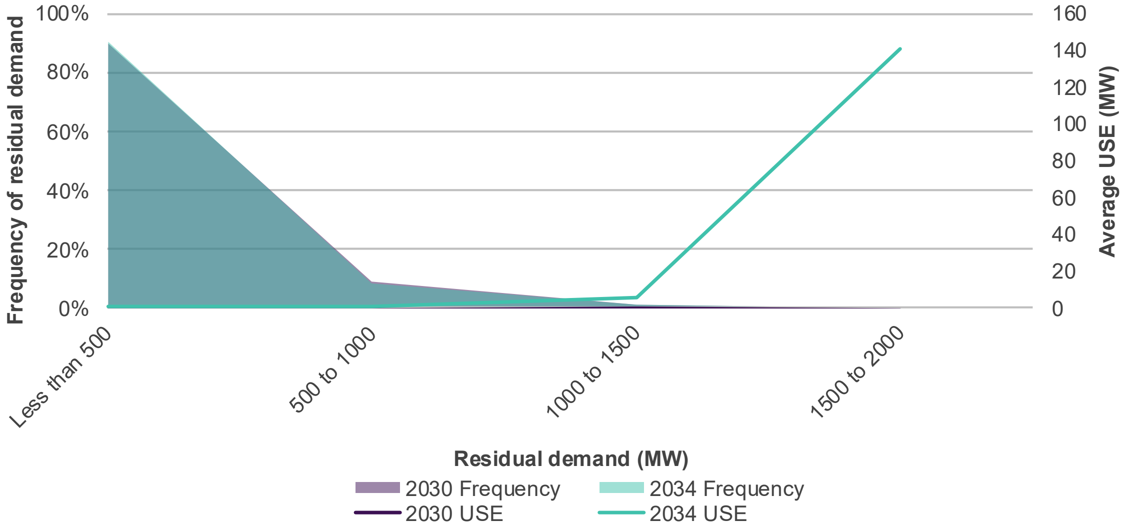


Supply scarcity risks

The risks are forecast to vary depending on weather conditions, with supply scarcity risks increasing when high demand and low VRE conditions occur.

The figure shows forecast average USE at different levels of residual demand in 2029-30 and 2033-34 for the *Committed and Anticipated Developments* assessment highlighting that USE is observed where residual demand is highest.

The distribution of residual demand doesn't change significantly for Tasmania, with majority of the generation source consisting of dispatchable generation.

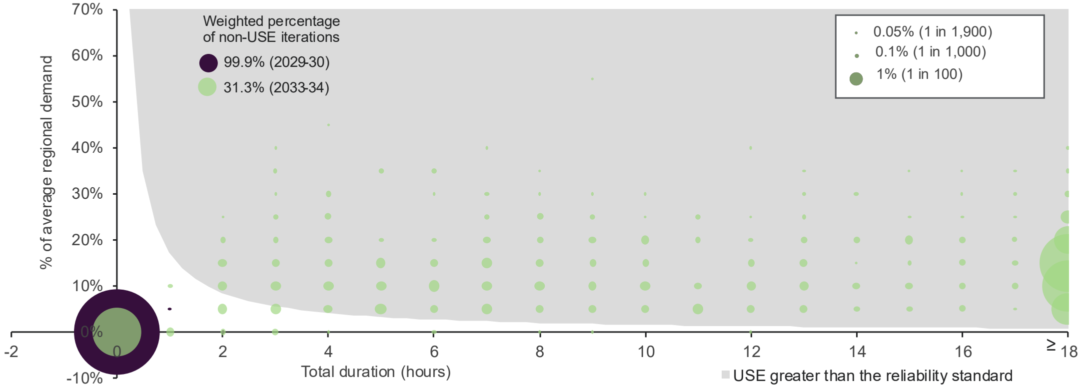


Supply scarcity risks increase in winter during high demands on cold days during the early outlook periods.

Supply scarcity risks will have greatest likelihood in winter months. As Tasmania's demand is forecast to grow, the risk emerges over time, compounded by reduced energy supplies in neighbouring regions

This figure reflects the changing seasonal risk profile in the *Government Schemes and Actionable Developments*. Note that this a relative profile between seasons, so total percentage sums to 100 per cent regardless of level of USE.

Initially, USE risks are minor, and events tend to be small in Tasmania in the *Committed and Anticipated Developments* assessment. As the forecast moves through 2029-30 to 2033-34, a diverse range of USE event outcomes can occur as system-wide challenges emerge, and Tasmania demand continues to grow. Similar to other regions, many USE events are concentrated in lasting longer than 18 hours, but these remain lower in intensity.



6.5 Regional insights for Victoria

Key risks in Victoria

Expected USE is forecast to increase above the reliability standard in Victoria by 2033-34 with developments supported by government schemes, but three years earlier considering only committed and anticipated developments. Ongoing investment in infrastructure will be needed beyond this period to support projected data centre growth, electrification and replace coal-fired generation.

Prior to the retirement of 1.5 GW of Yallourn W in 2028, 2.3 GW of committed and anticipated capacity is expected to be commissioned, with a further 4.2 GW of committed and anticipated capacity in the development pipeline for delivery thereafter. Growing energy shortfalls in the longer term are projected that will require more investment due to the overall retirement of 4.2 GW of capacity, which has historically provided 23 TWh on average of generation over the last four years.

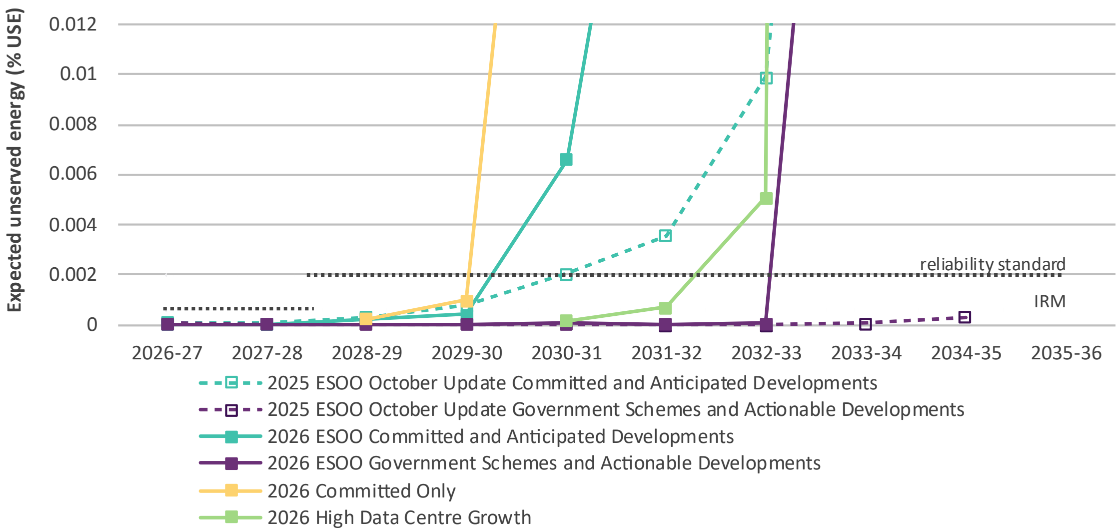
Further insights are available in the 2026 NEM ESOO Results Workbook.

Victoria	Summer readiness	T-1 (2027-28)	T-3 (2029-30)	Above the reliability standard
Government Schemes and Actionable Developments	Within the IRM and reliability standard	Within the IRM and reliability standard	Within the reliability standard	2033-34
Committed and Anticipated Developments				2030-31

Resource adequacy

If projects supported by government schemes proceed to schedule, expected USE is forecast to be maintained within the relevant reliability standards until 2032-33, but additional investment is needed to replace retiring coal capacity and the generation it has provided and meet growing demand.

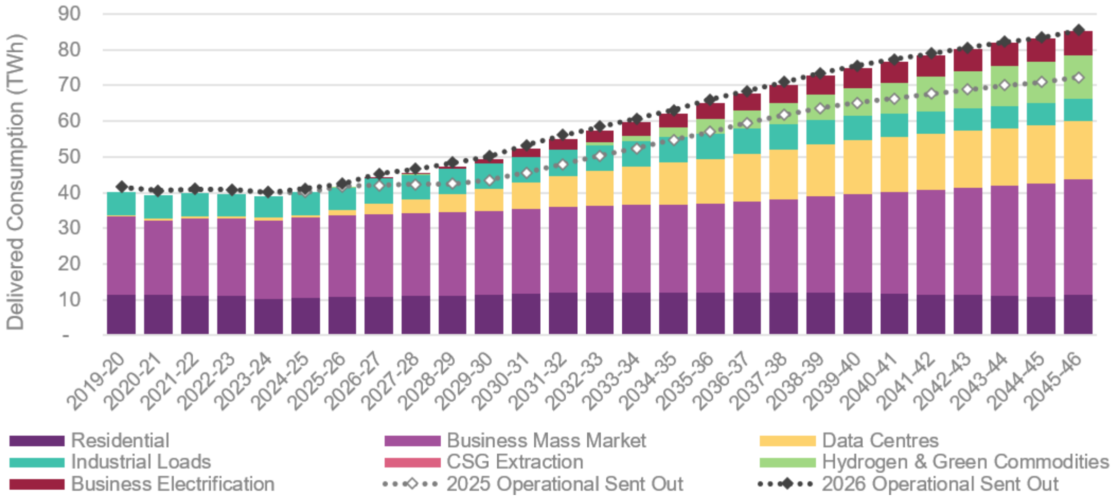
If only projects that meet AEMO's commitment criteria for committed and anticipated projects proceed, sufficient capacity and energy production is projected to maintain the reliability standard to 2029-30. Additional generation, storage and network supported by government schemes will improve supply scarcity risks by increasing dispatchable capacity and energy generation potential, which alongside assumed CER orchestration, reduce supply scarcity risks. Continued investments to replace further retirements and rising demand are needed in the longer term.



Electricity consumption trends

Melbourne is Australia's second largest data centre hub, and data centre usage is projected to drive a material level of growth in the region.

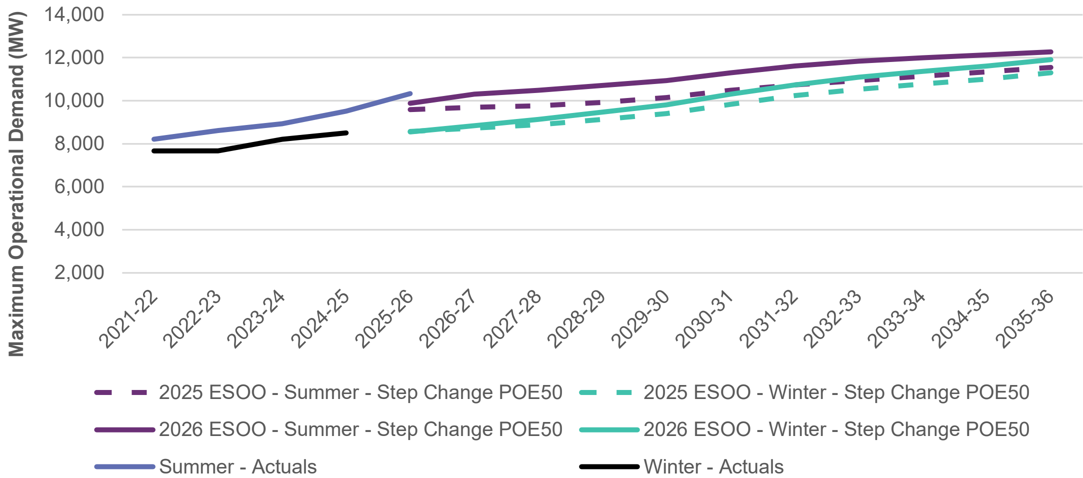
Other key drivers include electrification of households, businesses and transport, while the region also exhibits greater temperature sensitivity than other regions. Energy efficiency investments moderate these growth drivers, and strong continued growth in CER reduces the delivered electricity supply needed from the grid.



Maximum demand forecast

Maximum demand is forecast to continue increasing, driven by factors that align with the overall consumption trends. Expanding data centre demand, increasing electrification and EV uptake, and strong growth in residential and business demand contribute to higher maximum demand over the outlook period. The increase in residential demand reflects updated analysis of underlying consumer behaviour, including stronger base, heating and cooling loads.

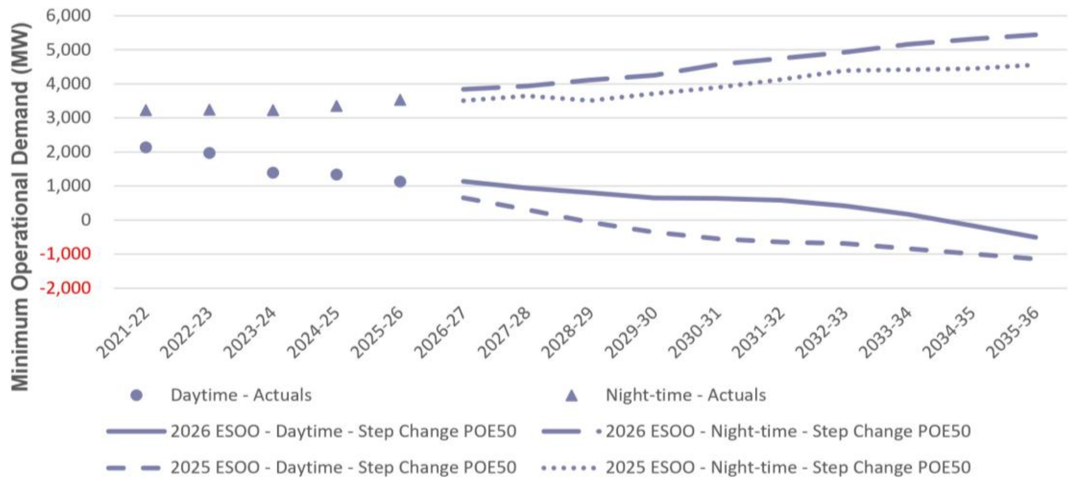
Summer peak demand remains higher than winter peak demand, reflecting the continued influence of hot weather and air-conditioning loads. However, winter maximum demand is forecast to grow more rapidly as electrification increases space heating loads, gradually narrowing the seasonal gap. Compared with the 2025 NEM ESOO, the maximum demand outlook for Victoria is higher across the forecast horizon, primarily reflecting stronger residential demand growth, more electricity use to increase comfort in temperature extremes, and with additional contributions from business demand and rapid growth in data centre consumption.



Minimum demand forecast

Minimum demand is forecast to continue to decline over the outlook period, driven by increasing uptake of rooftop PV and PVNSG. Stronger underlying residential and business demand, expanding data centre loads and battery charging partially offset this decline. Daytime minimum demand continues to occur during summer, typically in the early afternoon when rooftop PV generation is at or near its highest level.

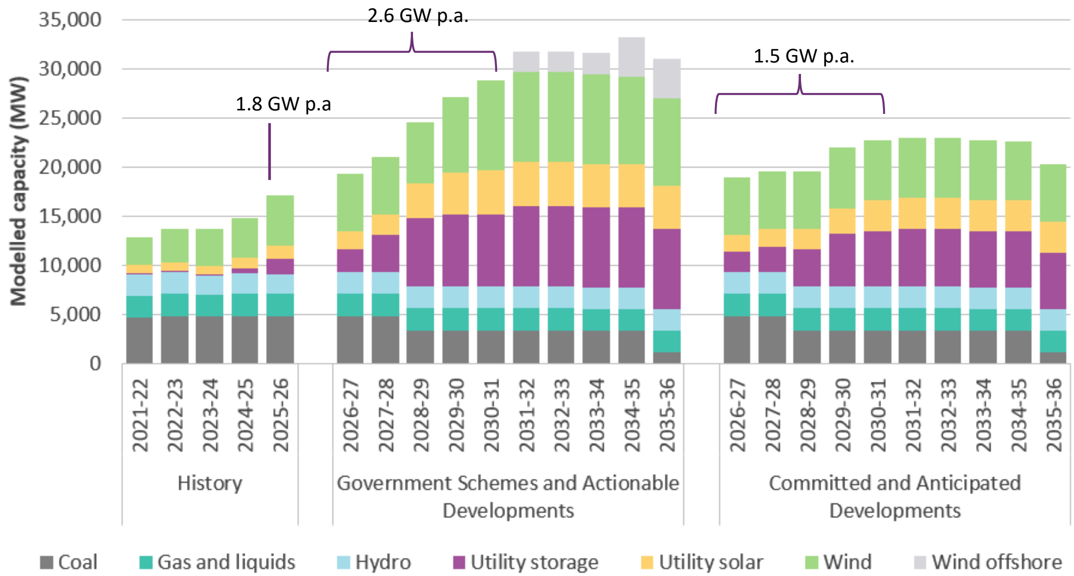
Daytime minimum loads are the primary driver of overall minimum demand outcomes. Night-time minimum demand is forecast to continue increasing over the outlook period, driven primarily by expanding data centre demand and continued growth in underlying residential and business demand. Night-time minimum demand typically occurs during summer in the early morning, around 2:00 am, when electricity consumption is generally at its lowest.



Generation and storage developments

There is a substantial pipeline progressing as either committed or anticipated projects, or that have explicit government support through various tenders and schemes. In the next five years, 6.5 GW of new projects in Victoria are committed and anticipated. A further 5.0 GW of additional government supported projects have been identified helping to replace 4.2 GW of retirements by 2035-36. However, the development pipeline generally plateaus from 2030-31 as projects cannot be identified as sufficiently advanced to be classified committed and anticipated over the longer horizon.

Strong growth in batteries increases dispatchable capacity, but new energy production capabilities from solar and wind generators (or gas) will be needed to replace coal generation. Few projects can demonstrate sufficient advancement beyond the next five years to be considered, demonstrating that further investments are needed in the medium to long term to maintain reliability.

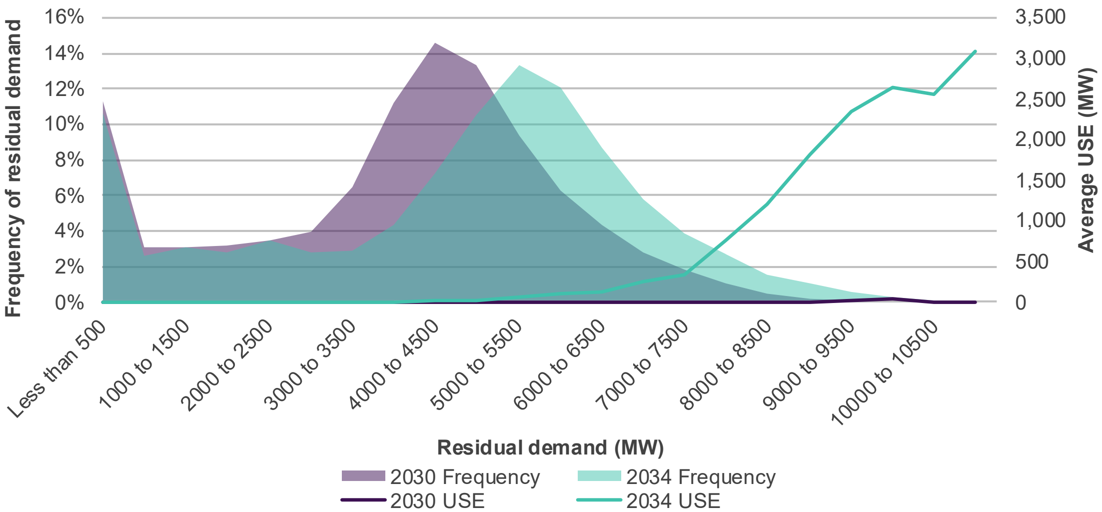


Supply scarcity risks

The risks are forecast to vary depending on weather conditions, with supply scarcity risks increasing when high demand and low VRE conditions occur.

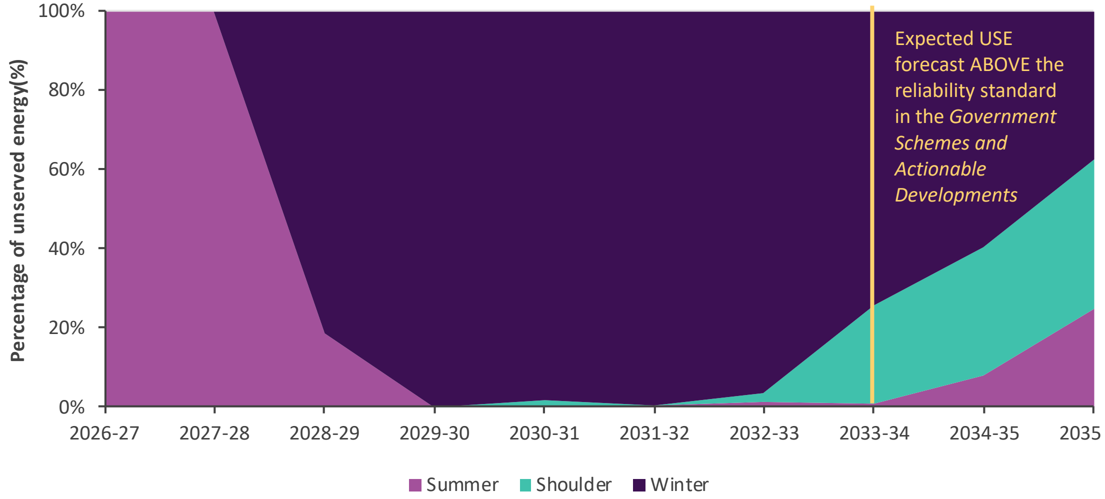
The figure shows average USE at different levels of residual demand in 2029-30 and 2033-24 for the *Committed and Anticipated Developments* assessment. When weather drives high demand and low VRE conditions average, USE increases.

As time progresses, the frequency distribution of **residual demand changes** in Victoria, indicating material growth in demand that is increasing the frequency of higher levels of demand.

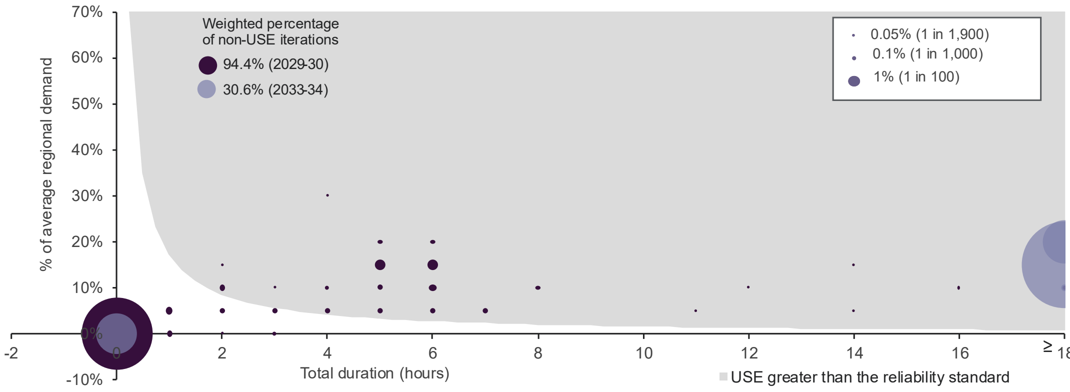


Supply scarcity risks increase in winter as heating loads are forecast to electrify. As coal-fired generators retire and demand grows, the surplus of dispatchable energy is expected to reduce. Supply scarcity risks are therefore increasingly likely to emerge during the shoulder season. In addition, supply will have greater exposure to weather variation in winter months, when solar generation is lower.

This figure reflects the changing seasonal risk profile in the *Government Schemes and Actionable Developments*. Note that this a relative profile between seasons, so total percentage sums to 100 per cent regardless of level of USE.



The distribution of USE events significantly changes in Victoria between 2029-30 and 2033-34 in the *Committed and Anticipated Developments* assessment. Many scattered USE events are projected in the simulations, with a rising proportion of long duration, and larger magnitude events as energy shortfalls emerge over the horizon.



List of tables and figures

Tables

Figures

Abbreviations

Abbreviation	Term
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AI	artificial intelligence
ARENA	Australian Renewable Energy Agency
BESS	battery energy storage system
BEV	battery electric vehicle
BMM	Business Mass Market
BSP	Bulk Supply Point
CEH	Capricornia Energy Hub
CER	consumer energy resources
CHBP	Cheaper Home Batteries Program
CIS	Capacity Investment Scheme
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DNSP	distribution network service provider
DSOO	*Demand Side Statement of Opportunities*
DSP	demand-side participation
EAAP	Energy Adequacy Assessment Projection
ECMC	Energy and Climate Change Ministerial Council
EMMS	Electricity Market Management System
ESEM	Electricity Services Entry Mechanism
ESOO	*Electricity Statement of Opportunities*
EV	electric vehicle
FAR	*Forecast Accuracy Report*
FERM	Firm Energy Reliability Mechanism
GDP	Gross Domestic Product
GSOO	*Gas Statement of Opportunities*
GW	gigawatt/s
GWh	gigawatt hour/s
IASR	*Inputs, Assumptions and Scenarios Report*
ICE	internal combustion engine
IEA	International Energy Agency
IIO	Infrastructure Investment Objectives
IRM	Interim Reliability Measure
ISP	*Integrated System Plan*
LIL	large industrial load

Abbreviation	Term
LNG	liquefied natural gas
LOR	lack of reserve
MSL	minimum system load
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	megawatt/s
MWh	megawatt hour/s
NEM	National Electricity Market
NER	National Electricity Rules
NSCAS	network support and control ancillary services
NSP	network service provider
OCGT	open cycle gas turbine
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicle
PJ	petajoule/s
POE	probability of exceedance
PV	photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland – New South Wales Interconnector
RAP	Reconciliation Action Plan
RERT	Reliability and Emergency Reserve Trader
RETA	Renewable Energy Transformation Agreement
REZ	renewable energy zone
RIT-T	regulatory investment test for transmission
RRO	Retailer Reliability Obligation
SEC	State Electricity Commission (Victoria)
TNSP	transmission network service provider
USE	unserved energy
V2G	vehicle-to-grid
VNI West	Victoria – New South Wales Interconnector West
VPP	virtual power plant
VRE	variable renewable energy
WDR	wholesale demand response