2025 Wholesale Electricity Market Electricity Statement of Opportunities

June 2025

A 10-year outlook of investment requirements to maintain reliability in the Wholesale Electricity Market in Western Australia's South West Interconnected System

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

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

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

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

Important notice

Purpose

The Australian Energy Market Operator (AEMO) publishes the Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) under clause 4.5.11 of the Electricity System and Market Rules.

This publication is generally based on information available to AEMO as at 4 June 2025 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee 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 be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1	24/6/2025	Initial release
2	1/7/2025	Replaced Figure 19, Figure 39, Figure 44, and Figure 45, corrected a small number of typographical errors.

Contents

Appendices published separately

Executive summary

The 2025 Wholesale Electricity Market (WEM) *Electricity Statement of Opportunities* (ESOO) provides forecasts for the WEM over the 10-year outlook period from 1 October 2025 to 1 October 2035. The WEM ESOO helps inform the planning and decision-making of market participants, new investors and policy-makers by advising on the additional generation, storage and network investment required to maintain reliability and security in the WEM and the South-West Interconnected System (SWIS).

The ESOO also plays an important role in the WEM's Reserve Capacity Mechanism (RCM) process by forecasting the Peak and Flexible Reserve Capacity Target (RCT) for each Capacity Year in the outlook period, and setting parameters that determine the Peak and Flexible Reserve Capacity Requirement (RCR) and type of capacity required to maintain reliability for 2027-28.

The SWIS is one of the most isolated large power systems in the world. This isolation means the SWIS is particularly sensitive to changes in technology, generation mix, weather patterns and consumption behaviours. Recent years have seen record renewable contributions, minimum demands, swings in load, and other new challenges that change the way in which the grid must be operated.

Over the last few years, the SWIS has experienced an increase in investment, particularly in large-scale battery storage. This has helped alleviate shortfalls forecast in previous WEM ESOOs and reduced operational risks associated with minimum system load. However, in the context of growing demand and a changing generation mix, new investment in energy-producing facilities will be required.

In the near term, the extent of this required investment – and the types of technology required – is highly sensitive to assumptions regarding retirement of existing plant. The ability of new facilities to connect to the SWIS to meet potential shortfalls in demand is also predicated on the timely delivery of major transmission network augmentation.

The 2025 WEM ESOO highlights the following:

- Extreme heatwave conditions over the last two summers (2023-24 and 2024-25) led to higher than anticipated cooling load response – resulting in numerous peak demand records that exceeded past WEM ESOO forecasts.
- The recent introduction of over 500 megawatts (MW)/2,000 megawatt hours (MWh) of grid-scale battery storage has helped supply these peak demand periods to date. However, with peak demand continuing to grow and extend into the night[1], additional supply that is available late into the evening will be required, particularly when these conditions coincide with multiple generator outages or low wind conditions.
  - Additional longer duration (six-hour plus) battery storage will help, but alone will be unable to meet forecast growth in these sustained peaks without complementing them with additional energy producing capacity (from solar farms, wind farms or gas generators) to sufficiently top them up.
    - Demand Side Programmes (DSP) could also play an increasingly important role in meeting this demand; however, under current rules they are not obligated to be available after 8:00 pm. Amending Rules have been drafted to address this issue in the future.

[1] Extending from 4:00 pm to 10:30 pm at night.

- In 2025-26, the SWIS requires at least 50 MW more dispatchable capacity that can be made available over a longer duration to support summer peaks. The precise requirement for, and quantity of, Supplementary Capacity to cover this next Hot Season will be informed by information available at the time of decision.
- In 2027-28, following the closure of more coal-fired generation, more capacity will need to be procured under the RCM to avert energy shortfalls that are otherwise forecast to become more prevalent. While there is substantial continued interest in battery storage to help maintain reliable supply, investment in storage alone will not suffice. At least 110 MW of new generation sources such as gas, wind and solar generation will be required. Consequently, new energy-producing investment will be prioritised in this year's Network Access Quantity process as part of the Capacity Cycle.
- Sub-regional analysis identifies capacity shortfalls in the Eastern Goldfields and North Country, and highlights the critical importance of new supply in the Goldfields region, along with the East Enhancements Project and Clean Energy Link-North (CEL-North) Project network augmentations to maintain sub-regional and system-wide reliability. Beyond these projects, continued and co-ordinated transmission investment will be needed to ensure the timely connection of new supply.
- The closure of coal- and gas-fired (thermal) generation, coupled with increasing levels of inverter-based renewable generation, is forecast to reduce fault current, dynamic reactive power support and inertia in the SWIS. Left unmanaged, this can reduce the effectiveness of power system protection systems and pose a risk to power system stability and reliability.
  - AEMO forecasts an emerging need for investment in system strength services in the Collie region (area around Shotts Terminal), Merredin Terminal in the East Country, and in the North Country, as renewable generation and battery storage replace generation historically supplied thermal generation.
  - AEMO will work with Western Power and Energy Policy WA (EPWA) to procure these services prior to the exit of thermal generation.
- As more rooftop solar is installed, minimum unscheduled demand (the lowest point of operational demand on the system) is forecast to continue falling, and load swings due to the drop-off in (and return of) rooftop solar output are forecast to become more prevalent.
  - There is currently enough flexibility in the system to manage four-hour increases in demand from the middle of the day to the evening peak, noting that faster ramping capability may be required in future.
  - The expected connection of more than 1,000 MW of battery storage by 2026-27 will provide the ability to meet fast increases and decreases in demand and also help address declining minimum demand. This battery storage could soak up excess solar output in the middle of the day, potentially avoiding the need to trigger Emergency Solar Management[2]. The stored energy could then be discharged during periods of high demand.
- Opportunities exist to maintain both reliability and system strength cost effectively through the energy transition by investing in technologies such as grid-forming batteries (rather than 'grid-following' batteries), or gas-fired generators installed with equipment (such as a clutch) to allow the plant to provide system strength even when not generating.

[2] Emergency Solar Management enables distributed PV and battery storage to be remotely turned down or switched off in emergency situations. This only applies to systems installed after 14 March 2022. For more information, see https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

Overview of key requirements

AEMO uses the Planning Criterion (the WEM's reliability standard) to set the Peak and Flexible RCT for each Capacity Year and determine any forecast peak or flexible capacity shortfall between the relevant RCT and existing and committed capacity, minus any retiring capacity.

Not all technologies are capable of satisfying all three limbs of the Planning Criterion. Given this, the question of having the appropriate capacity mix at any point in time is a critical factor in ensuring security and reliability are not compromised as the SWIS continues its energy transition.

Since the 2024 WEM ESOO, the Electricity System and Market Rules (ESM Rules) have been amended, with the aim of providing stronger targeted signals to attract the right investment at the right time. These amendments include the following:

- Changes to the mechanism used to certify battery storage capacity, leading to an increased duration requirement for new battery storage capacity, from four hours to six hours for the 2025 Reserve Capacity Cycle. This reflects the effectiveness of the recently installed battery storage at flattening the evening peak, and the need for new storage to be available for a longer duration to cover this flatter residual peak. It also has the effect of lifting the Peak RCT to account for the presence of existing battery storage with lower durations.
- The introduction of the new Flexible Capacity Planning Criterion – Limb C – reflecting the need for flexible facilities to manage the midday to evening ramp, which is forecast to increase as distributed photovoltaic (PV) generation minimises midday demand, leading to a steeper ramp into the evening peak. Flexible Capacity providers must demonstrate their ability to rapidly start, ramp up, and meet the highest forecast Four-Hour Demand Increase. Flexible Capacity providers will also have the option of applying for a 10-year price guarantee aligned with their year of entry.
- Prioritisation of new Capability Class 1 and Capability Class 3 Facilities (firm and intermittent generation capacity such as gas, wind, solar and waste-to-energy [WTE] generation) in the Network Access Quantity (NAQ) framework, if these Capability Classes are determined through the ESOO Capability Class assessment to be required to satisfy the Planning Criterion.

The WEM Planning Criterion has three limbs:

1. Limb A, which requires the WEM to have **enough reserve capacity** to meet the forecast annual peak demand and specified margins**.**
2. Limb B, which **limits expected unserved energy** (EUE) to 0.0002% of annual energy consumption.
3. Limb C, a newly introduced limb which requires the WEM to have **sufficient Flexible Capacity** to meet the largest expected four-hour increase in demand plus a reserve margin.

The following definitions of unserved energy and expected unserved energy (EUE) apply to this 2025 WEM ESOO:

- **Unserved energy** represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply) in the absence of out-of-market intervention.
- AEMO forecasts **EUE** by taking the average unserved energy over a wide range of simulated outcomes of different weather and forced outage conditions. Because the EUE is the average of many possible outcomes, a forecast over the relevant reliability standard does not guarantee that an unserved energy event is going to happen, while forecasts below the standard do not mean there are no reliability risks, although events may be less probable.

2025 Reserve Capacity Cycle key requirements determined for 2027-28	Requirement	Existing and committed
Peak Reserve Capacity	6,238 MW	5,306 MW
Minimum Capability Class 1 and 3	3,937 MW	3,827 MW
Flexible Reserve Capacity	2,527 MW	4,863 MW
Electric Storage Resource Obligation Duration	6 hours	Not applicable

NOTE: Capability Class 1 and 3 facilities may also be eligible to provide Flexible Reserve Capacity

The changing generation mix

Western Australia is transitioning towards a lower emissions energy system. Most, if not all, coal-fired generation is expected to close by 2030. Generation from intermittent, weather-dependent renewable sources (wind, large-scale solar and rooftop PV) is increasing, and now accounts for more than 40%[3] of total energy production. There is also rapid uptake of utility-scale battery storage, and DSP developments are emerging.

This WEM ESOO incorporates the following expected supply changes:

- **Closure of Synergy's Collie Power Station** (317 MW), the largest power station in the SWIS, in 2027, and Muja D (2 x 211 MW) in October 2029. Synergy's Muja C Unit 6 Power Station was retired in April 2025, having been previously made available in 'reserve outage mode' to support the 2024-25 Hot Season.
- **Assumed unavailability of Bluewaters Power Station** (2 x 217 MW) from 2027-28. The current Western Australian Government State Agreement with The Griffin Coal Mining Company Pty Ltd, which supplies the Bluewaters Power Station, is due to expire in June 2026. On 27 May 2025, the Premier of Western Australia reiterated in parliament that the subsidies for the mine ($220 million in this year's State Budget), which had previously been deemed necessary for its continued operation, will cease upon the expiry of the existing State Agreement. While AEMO understands Bluewaters has stockpiles of coal to meet capacity reserve requirements for 2026-27, due to the risk Bluewaters will not be able to establish a new coal supply arrangement past this point, AEMO considers it prudent not to assume the availability of this power station from 2027-28 onwards in the reliability assessment. Reflecting this uncertainty, sensitivity analysis was also modelled with Bluewaters continuing to be available beyond 2026-27. Importantly, the assumed unavailability of Bluewaters does not pre-empt any subsequent assessment of the power station's Certified Reserve Capacity (CRC) application and the consideration of information provided through that process.
- **Retirement of Synergy's ageing Pinjar gas turbines** between 2029-30 and 2031-32, totalling 522 MW.
- **Connection of over 1.1 gigawatts (GW) of committed supply capacity** to be online before October 2027, including 806 MW of one to four-hour battery storage, 172 MW of DSP, 106 MW of gas--fired generation, and 59 MW of WTE capacity. One of the committed battery storage projects (Merredin Battery Energy Storage System [BESS], 100 MW/400 MWh) was successful in the Capacity Investment Scheme (CIS) WEM Dispatchable Capacity Tender.

[3] Average share of renewable generation output in total SWIS generation across four quarters of 2024.

- **Growth in distributed PV and modest uptake of home batteries**, supported by the WA Residential Battery Scheme and changes to the Australian Government's Small-scale Renewable Energy Scheme (SRES), which are expected to subsidise installation of batteries in up to 100,000 homes in coming years[4].
- **Delivery of Western Power's CEL-North network expansion**, which will help alleviate network congestion and provide network access for new renewable generation. CEL-North is currently on track to be energised during the 2027-28 Hot Season, but approval processes and other external factors outside Western Power's direct control pose some risk to the delivery schedule. For the purpose of the WEM ESOO forecasts, AEMO assumed a one-year delay to reflect this risk.

In addition, AEMO is aware of 507 MW of probable projects under development but not yet sufficiently certain to be included in the base reliability assessment for this WEM ESOO. This includes projects successful through the CIS WEM Dispatchable Capacity Tender.

Peak demand forecasts reflect recent extreme weather conditions and flatter consumption forecasts

The 2025 WEM ESOO 10% probability of exceedance (POE) peak demand forecasts are higher than in the 2024 WEM ESOO until 2029-30, as shown in **Figure 1**. This is due to consideration of weather patterns that have led to extreme temperatures in the two most recent summers, and the corresponding higher than anticipated temperature sensitive load response observed.

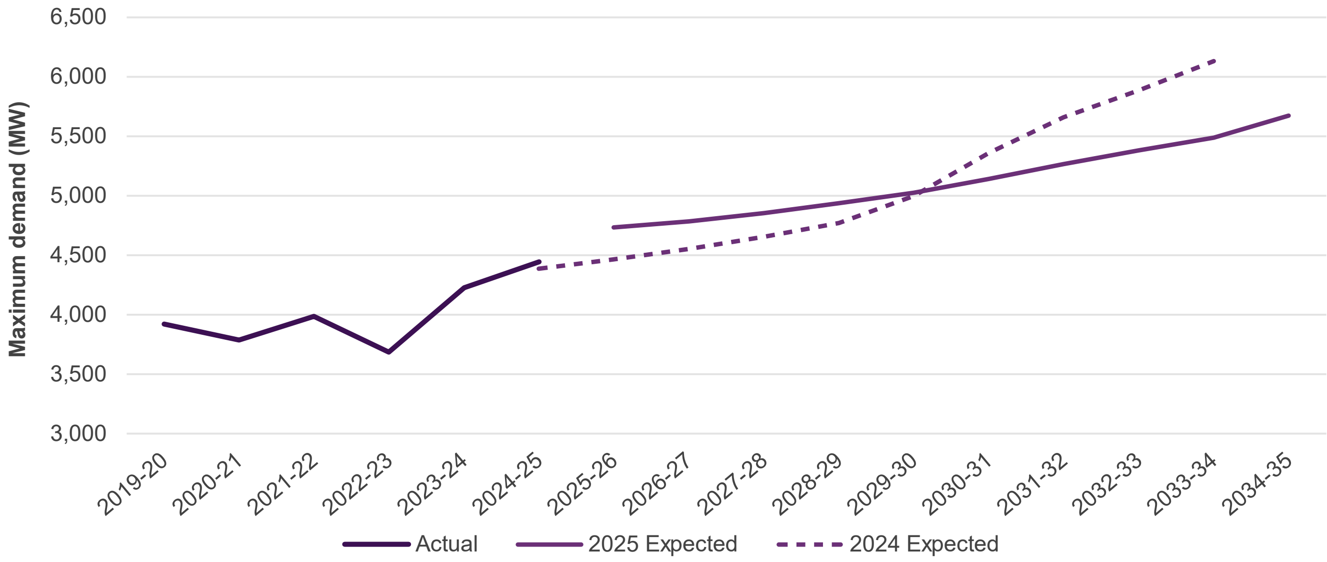
The forecast peak demand for the 2025-26 Hot Season is 4,734 MW, which is 270 MW higher than previously forecast. The forecast peak demand in 2027-28 is 4,856 MW, which is 200 MW higher than last year's forecast.

A new all-time maximum operational demand record of 4,486 MW was set at 6:30 pm on 20 January 2025. This was 253 MW higher than the previous peak demand record of 4,233 MW set on 18 February 2024. To ensure secure and reliable power supplies for consumers, AEMO activated DSP and capability procured through SC and Non-Co-optimised Essential System Services (NCESS) mechanisms totalling 126 MW. Without demand reduction from Supplementary Capacity, NCESS, and DSP, a peak demand of 4,592 MW would have been recorded[5].

[4] AEMO's 2025 WEM ESOO forecasts are based on the Western Australian residential battery scheme applied to 20,000 homes as originally announced. The scheme was subsequently expanded on 4 June 2025 to provide rebate support for up to 100,000 homes.

[5] For the 18:30 Trading Interval based on non-loss adjusted meter data, which included the 5-minute peak demand record of 4,486 MW in the 18:30 Dispatch Interval (based on non-loss adjusted SCADA data). The WEM ESOO modelling resolution is 30-minute Trading Intervals and uses verified metering data.

Figure 1 Actual peak demand and forecast 10% POE summer peak demand, Expected scenario, from 2024 and 2025 WEM ESOOs, 2019-20 to 2034-35 (MW)



Although the past summer saw extreme temperatures, AEMO's modelling indicates maximum demand could have been even higher under certain climatic conditions. Elevated humidity, extended heatwave conditions and increased cloud cover without a cooling breeze (reducing distributed PV generation) can all contribute to more extreme peak demand outcomes. Taking this into consideration, the starting point of the 10% POE maximum demand forecast for 2024-25 is set as 4,647 MW, representing a 259 MW increase relative to the forecast in the 2024 WEM ESOO.

Electricity consumption is expected to grow, but more slowly than previously forecast

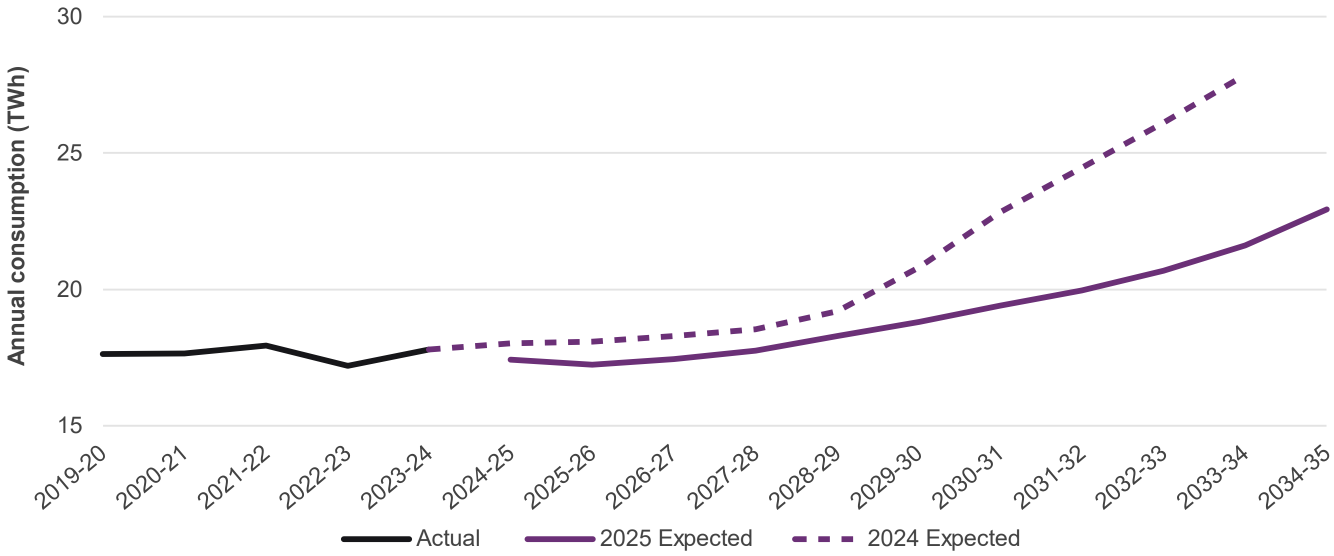
The 2025 WEM ESOO forecasts continued growth in electricity consumption, although at a noticeably slower pace than forecast under the 2024 WEM ESOO, as **Figure 2** shows.

Electricity consumption forecasts are lower than last year, primarily due to:

- reduced commercial and industrial electrification, informed by industrial customer surveys, and reflecting more challenging economic and cost of living pressures,
- lower residential forecasts, with lower anticipated 'rebound' in electricity consumption for consumers that install PV systems, and a slower rate of electrification (including from electrified transportation), and
- lower large industrial load (LIL) forecasts, due to a less favourable outlook for lithium and alumina refineries.

Partially offsetting the impact of these drivers is increased consumption in the business mass market (BMM) sector, and a reduced forecast of distributed PV uptake serving to increase operational consumption.

Figure 2 Actual and forecast operational energy consumption, Expected scenario, from 2024 and 2025 WEM ESOO, 2019-20 to 2034-35 (TWh)



The duration of battery storage availability is increasingly important to manage sustained high demand periods during heatwave conditions

Following the retirement of Muja C unit 6 Power Station, the expected total peak capacity capable of generating electricity is 4,353 MW for 2025-26 and 3,826 MW for 2027-28[6], which is less than the peak demand forecast for the corresponding Capacity Year (4,734 MW and 4,856 MW, respectively). This highlights the reliance on battery storage to support meeting peak demand, and to facilitate this, it is crucial that the battery storage has enough energy in storage for use at the right time.

During the most recent high demand days, the contribution of battery storage was largely limited to between 4:30 pm and 8:30 pm (in alignment with the Electric Storage Resource Obligation Intervals [ESROIs] determined for the summer for 2024-25). Even if fully charged prior to the peak, by 8:30 pm, battery storage was largely exhausted.

The ESM Rules for the determination of the Electric Storage Resource (ESR) Duration Requirement have been amended since the 2024 WEM ESOO. Based on analysis presented in this 2025 WEM ESOO, the ESR Duration Requirement has been determined to be 12 Trading Intervals (six hours) for 2027-28. This quantity is only applicable to any battery storage allocated Peak Capacity Credits in this 2025 Reserve Capacity Cycle. For battery storage allocated Peak Capacity Credits up to and including the 2024 Reserve Capacity Cycle, the ESR Duration Requirement is eight Trading Intervals. To provide consumers with protection for this grandfathering, and ensure reliability is maintained, an additional component of ESR Obligation Duration (ESROD) Uplift is introduced to the Limb A RCT determination.

A capacity shortfall is expected for 2025-26 Hot Season

Based on the Limb A assessment, provided all committed capacity is in service when planned, there remains sufficient reserve margin in 2025-26 to meet the maximum operational demand forecast while covering the loss of the three largest

[6] These quantities refer to peak capacity credits (not installed capacity).

generating units. Forecast Peak Capacity for the upcoming 2025-26 Hot Season[7] (including capacity procured through the NCESS framework) is 5,855 MW, leaving a residual surplus of 5 MW against a Limb A requirement of 5,850 MW.

However, the reliability assessment has identified that, even with a reserve margin equivalent to the loss of the three largest generating units, there are times when combinations of generating unit outages and low wind conditions could result in EUE exceeding 0.0002% of energy consumption in 2025-26. Under these combinations, EUE is expected to occur between 8:00 pm and 10:30 pm, with:

- DSP not required to be available after 8:00 pm under the current ESM Rules, and
- four-hour battery storage largely exhausted by 8:30 pm.

All limbs of the Planning Criterion could be satisfied by adding around 50 MW of firm capacity, capable of generating for at least 14 hours (as required by ESM Rules). If adding weather-dependent wind/solar capacity, battery storage or DSP capacity, the renewable resource-limited or duration-limited nature of this capacity[8] means that more than 50 MW installed nameplate capacity would be required to provide 50 MW firm capacity equivalent. The above could be supported by extending the DSP availability outside the current required period of 8:00 am to 8:00 pm[9]. Amending Rules have been drafted to address this issue in the future[10].

Prior to procuring any Supplementary Capacity for the 2025-26 Hot Season, AEMO will further assess the extent of any capacity shortfall, taking into account any major outages, fuel disruptions, or delays to connection of new committed capacity. In particular, AEMO is monitoring the progress of committed projects in time for the 2025-26 Hot Season, specifically Synergy's Collie BESS (2 x 250 MW/2 x 1,000 MWh), Neoen's Collie battery storage Stage 2 (300 MW/1,200 MWh) and Alinta's Wagerup battery storage (50 MW/200 MWh). AEMO encourages proponents to take early action to mitigate any potential delays[11].

Further investment is required to maintain energy adequacy from 2027-28 onwards

Table 1 and **Table 2** provide an overview of the Limb A assessment for 2025-26 to 2034-35 under the Expected scenario. Only existing and committed capacity is included. For each Facility, the capacity counted is equivalent to the amount of Capacity Credits awarded in 2026-27, inclusive of any discount due to NAQ constraints.

AEMO has calculated the reserve margin as equivalent to the loss of the largest three units in the power system. AEMO analysed outage records during the previous five Hot Seasons (2020-21 to 2024-25) and identified that the largest power system security risk relates to the coincident forced outage of multiple generating units. All five Hot Seasons experienced instances where the total capacity on forced outage exceeded the magnitude of the two largest generating units.

The addition of the ESROD Uplift from 2027-28 adds a further 256 MW to the Limb A requirement.

[7] Covering the period from December 2025 to March 2026.

[8] Energy storage is limited by the size and state of charge of its energy reservoir, as well as the ability to charge the reservoir for later discharge in high-demand periods. Demand-side response capacity is limited by running hours between 8.00 am and 8.00 pm (as per clause 4.10.1(f)(vi) of the ESM Rules).

[9] As stipulated under clause 4.10.1(f)(vi) of the ESM Rules.

[10] See Electricity System and Market Amendment (Tranche 8) Rules 2025, Schedule 9 which (once gazetted) will amend clause 4.10.1(f)(vi) of the ESM Rules to specify that the periods when the Facility can be dispatched must include 'for a Reserve Capacity Cycle from the 2026 Reserve Capacity Cycle onwards, the periods between 6:00 AM and 10:00 AM and 2:00 PM and 10:00 PM on all Business Days'.

[11] Synergy's Collie battery storage is anticipated to be in service by 1 December 2025. Neoen's Collie battery storage Stage 2 is currently being energised and is on track for approval to operate in June 2025. Alinta's Wagerup battery storage was originally scheduled for commissioning during the second half of 2024.

Table 1 Components of the Limb A requirement for the Expected scenario (MW)

Capacity Year[A]	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
10% POE Peak Demand	4,734	4,783	4,856	4,938	5,027	5,142	5,265	5,384	5,489	5,674
Intermittent Loads	7	7	7	7	7	7	7	7	7	7
Reserve Margin	976	976	958[B]	958	958	958	958	958	958	958
Frequency Regulation Raise	133	144	161	170	179	187	195	202	209	216
ESROD Uplift	-	-	256	256	256	256	256	256	256	256
Limb A requirement	**5,850**	**5,910**	**6,238**	**6,329**	**6,427**	**6,550**	**6,681**	**6,807**	**6,919**	**7,111**

A. For 2025-26 and 2026-27, Capacity Credits have been assigned. For 2027-28, the Capacity Credits assignment is expected to occur over the next months. For 2028-29 onwards, the Reserve Capacity Cycles have not commenced.
B. Reserve margin reduces slightly in this year due to the retirement of the Collie Power Station. The next largest unit is Neoen's 300 MW battery storage Stage 2.

Table 2 Limb A assessment for the Expected scenario (MW)

Capacity Year[A]	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Limb A requirement	5,850	5,910	6,238	6,329	6,427	6,550	6,681	6,807	6,919	7,111
Reserve Capacity from Existing Facilities	4,854	4,904	4,147	4,142	3,537	3,531	3,526	3,176	3,171	3,166
Reserve Capacity from Committed Facilities	1,001	1,144	1,158	1,151	1,143	1,136	1,129	1,122	1,115	1,108
Total Reserve Capacity	5,855	6,048	5,306	5,293	4,680	4,668	4,655	4,298	4,286	4,275
Capacity shortfall (-) /surplus (+)	**5**	**138**	**-932**	**-1,036**	**-1,747**	**-1,882**	**-2,026**	**-2,509**	**-2,633**	**-2,836**
Reserve Capacity from probable Facilities	0	0	507	501	496	490	485	480	475	470
Capacity shortfall (-) /surplus (+) including probable projects	**5**	**138**	**-425**	**-536**	**-1,252**	**-1,393**	**-1,541**	**-2,028**	**-2,157**	**-2,367**

A. For 2025-26 and 2026-27, Capacity Credits have been assigned. For 2027-28, the Capacity Credits assignment is expected to occur over the next months. For 2028-29 onwards, the Reserve Capacity Cycles have not commenced.

Based on the Limb A assessment, the capacity outlook remains largely balanced until 2027-28, assuming timely delivery of committed projects. There is a need for further investment from 2027-28 to satisfy Limb A as existing supply decreases, with a forecast capacity shortfall of 425 MW, assuming all probable projects are commissioned by October 2027. This capacity shortfall would be removed completely until 2029-30 if Bluewaters is able to establish new coal supply arrangements beyond the expiry of the Griffin Coal Mining Company Pty Ltd's State Agreement in mid-2026. Conversely, without the probable projects or Bluewaters, the capacity shortfall in 2027-28 is 932 MW.

Results of the Limb B assessment indicate that, except in 2026-27, the modelled EUE exceeds the 0.0002% reliability standard throughout the outlook period. This is the case even assuming all probable projects are commissioned by October 2027. In the short term, this EUE outcome is driven by insufficient storage depth to cover both the magnitude and duration of the higher forecast demand peaks. From 2027-28 onwards, EUE increases due to the retirements and assumed unavailability of coal capacity, which is predominantly replaced by non-energy producing capacity such as battery storage and DSP.

Table 3 Limb B assessment for the Expected scenario, 2025-26 to 2029-30

Capacity Year	Unit	2025-26	2026-27	2027-28	2028-29	2029-30
EUE – Expected scenario, existing and committed plant only	**MWh**	53	13	1,335	1,939	68,478
EUE – Expected scenario, existing and committed plant only[A]	**% of annual consumption**	0.0003%	0.0001%	0.0075%	0.0106%	0.3640%
Additional firm capacity required to satisfy both Limb A and Limb B of the Planning Criterion	**MW**	**50**	**N/A**	**932**	**1,036**	**1,747**
EUE – Bluewaters sensitivity[B]	**% of annual consumption**	0.0003%	0.0001%	0.0003%	0.0006%	0.0285%
EUE - Expected scenario, including probable projects	**% of annual consumption**	0.0003%	0.0001%	0.0008%	0.0016%	0.1469%

A. Expected scenario assumed Bluewaters is not available from 2027-28.
B. Bluewaters sensitivity assumed that both Bluewaters generating units retire on 1 October 2030, as opposed to 1 October 2027 assumed for the Expected scenario. This sensitivity was modelled to illustrate the impact of Bluewaters retirement date on EUE.

If Bluewaters can establish a coal supply solution for 2027-28, then EUE improves in that year from 0.0075% to 0.0003%, and would be below the 0.0002% threshold if all probable projects were also available.

Expressions of interest (EOIs) received at the commencement of this 2025 Reserve Capacity Cycle demonstrated that investment interest in the WEM remains strong, with over 2.3 GW of nameplate capacity that is not yet under construction or completed, submitting eligible EOIs[12]. The majority of these are battery storage, and many are only in the early stages of project development either with no network Access Proposal or incomplete Environmental Approvals.

More energy-producing capacity is needed to replace anticipated reductions in existing thermal generation capacity

Nearly 1.7 GW of thermal generation is expected to retire in the SWIS over the next decade. This capacity (Capability Class 1) can be dispatched up to its Peak Certified Reserve Capacity for all Trading Intervals, allowing for outages.

The retiring existing capacity is forecast to be partially replaced with committed capacity, of which approximately 1 GW (82%) is comprised of non-energy producing, duration-limited capacity such as battery storage and DSP (Capability Class 2). Only 0.2 GW (18%) committed capacity is energy-producing (Capability Class 1 and Capability Class 3).

Probable capacity – which does not meet all criteria to be considered committed by AEMO, and as such represents greater uncertainty of delivery in time for 2027-28 – could add a further 0.5 GW. This probable capacity is primarily comprised of CIS -announced[13] battery storage facilities (Boddington, Muchea and Waroona) totalling over 0.4 GW[14], with the remaining capacity comprised of natural gas and solar facilities.

Figure 3 shows the supply capacity outlook for the 2025 WEM ESOO by Capability Class.

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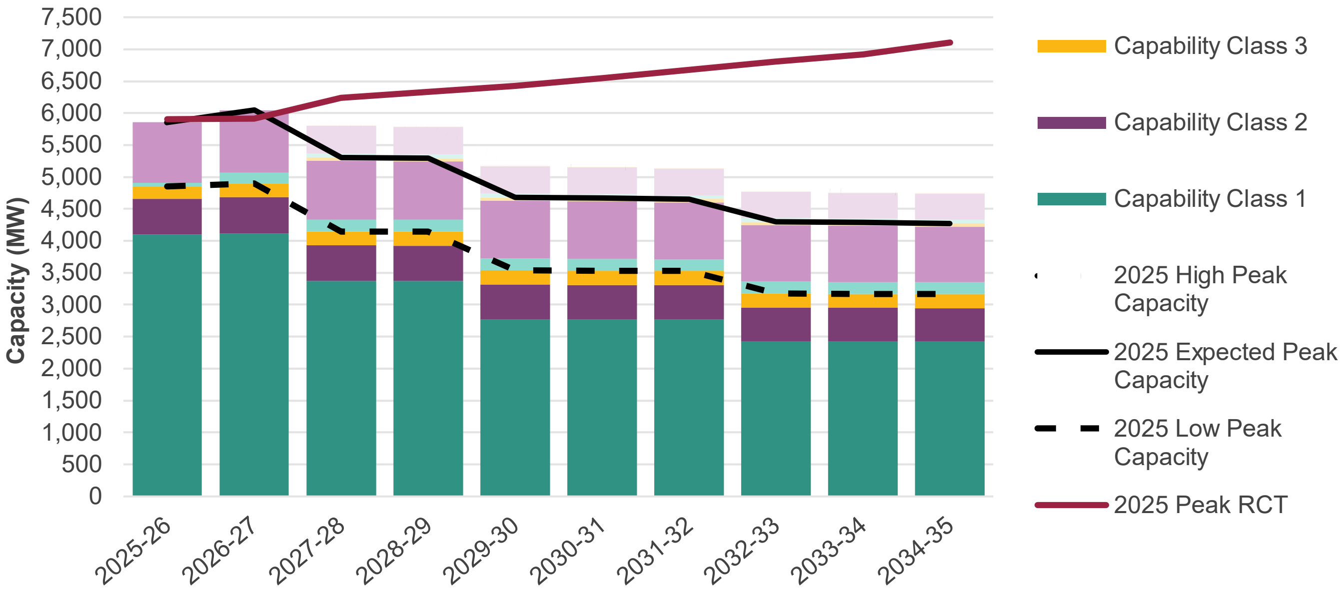
[12] See 2025-expression-of-interest-summary-report.pdf.

[13] See www.dcceew.gov.au/about/news/capacity-investment-scheme-supports-four-new-projects-wa. Note that the Merredin BESS is classified as committed in this WEM ESOO.

[14] The Boddington, Muchea and Waroona projects are four-hour duration ESR. Since the ESR Duration Requirement has increased from four hours to six hours, their potential contribution to the Reserve Capacity Target reduces from 665 MW to 439 MW.

Figure 3 Forecast Peak Capacity by Capability Class and status against RCT, Expected scenario (MW)



Note: black lines indicate three groups of capacity by status: existing (below the dashed line), committed (between solid and dashed), and probable (between dotted and solid). Colour coding represents Capability Classes (with fading colours representing decreasing certainty).

The modelled absence of investment in energy-producing plant such as wind, solar and gas-fired generation contributes to the levels of EUE, particularly in the next three to five years. The Capability Class assessment for 2027-28 indicates the need for a minimum of 110 MW of capacity from new generation facilities (Capability Class 1 or 3) to keep EUE below 0.0002%. The optimal mix of firm capacity that is not energy limited (Capability Class 1) and non-firm capacity such as wind or solar (Capability Class 3) will depend on factors outside the Capability Class assessment including location, developer interest and lead times, access to the network, and investment cost.

There is adequate Flexible Capacity for the entire outlook period with narrowing of the surplus throughout the outlook period

AEMO forecasts adequate Flexible Capacity for the entire outlook period, with the surplus more than 2,000 MW for 2025-26 and gradually narrowing to about 1,000 MW by 2034-35 as some thermal generators are expected to close. This assumes that all technology types that can apply for 2025 CRC, will apply.

The need for Flexible Capacity that can start, stop, ramp up and ramp down quickly is driven by the magnitude, slope, and duration of the ramp up from minimum demand to the evening peak required. The current requirement is for facilities to provide electricity quickly and flexibly within a four-hour period. Future analysis may highlight the need for faster ramping durations, such as that observed on 13 March 2025 where volatility in operational demand was caused by sudden changes in cloud cover and associated distributed PV output.

Transmission projects are a key enabler for the connection of future capacity

Sub-regional modelling highlights the criticality of network investment to both support regional reliability outcomes, remove constraints on existing Facilities and unlock future generation projects to alleviate system-wide capacity shortfalls.

The CEL-North Project unlocks network transfer capacity in the northern region of the SWIS and is a key enabler for future generation to be connected along the 330 kilovolts (kV) infrastructure in the Mid-West. After this transmission project is built, generation projects connecting into the northern region of the SWIS (at or south of Three Springs Terminal along the 330 kV line) are expected to help reduce unserved energy both locally and system-wide.

The East Enhancements Project (EEP)[15] is another key transmission project that is expected to improve regional EUE outcomes and improve reliability in the East region of the network. Line uprates associated with the EEP and the introduction of dynamic line ratings along the 132 kV infrastructure are forecast to improve the power transfer capability into the region, reducing the forecast capacity shortfall in the East region compared to the 2024 WEM ESOO. However, further investment is likely to be required. Western Power's Transmission System Plan[16] provides further detail on network constraints and opportunities for investment. Western Power is currently evaluating NCESS proposals to improve reliability during islanding events in the next five years.

Beyond these two planned network projects, further investment may also be needed within specific sub-regions of the SWIS due to forecast demand growth, particularly on the networks that are around key metropolitan terminal sites. These regions have limited local supply options due to minimal land availability and network solutions may be subject to delivery challenges associated with highly built-up areas. These areas may benefit from co-ordinated aggregation of distributed energy resources (DER) and/or demand flexibility services.

Maintaining power system security is crucial, as the capacity mix changes

The power system requires sufficient security and reliability services to ensure it remains stable and resilient. The energy transition will result in a need for new assets to provide fault current, frequency management, voltage stability, voltage control, fast ramping capability, and system restart services. To help assess these needs and monitor real-life performance, more detailed network models and connection of enhanced high-speed data recorder Phasor Measurement Units (PMUs) will be needed.

The timing and magnitude of emerging requirements are influenced by the following:

- **Retiring thermal generation** – historically, coal- and gas-fired generation has been relied on to maintain system security in the SWIS and is utilised for voltage control and passively providing stability to the system. These thermal generators are spinning machines (synchronous generators) that help form, support and anchor the voltage waveform. Replacement services will be needed to fill the system security and reliability requirements as these units withdraw.
- **Increases in inverter-based resources (IBR)** – adequate system strength, voltage control, voltage stability, and fast ramping capability will be needed to ensure that future levels of IBR (such as wind and solar generation) can operate stably.
- **Major network augmentations** – network upgrades can help improve network resilience by enabling more transmission system pathways and allowing better sharing of existing services across multiple locations. They can also reduce the likelihood of SWIS regions becoming islanded and the impact of credible network events, putting downward pressure on security needs.

[15] The East Enhancements Project (EEP) was previously known as the East Region Energy Project (EREP).

[16] See Western Power's transmission system plan and network opportunity map, at https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/transmission-system-plan--network-opportunity-map/.

In this WEM ESOO, AEMO has identified network locations where system strength issues may occur due to new generation technology composition and fringe areas of network. The consequences of low levels of system strength can lead to voltage instability, the disconnection of sensitive equipment and the potential maloperation of protection equipment. AEMO has also identified some preliminary network locations where the system may be strong enough to accommodate additional IBR.

System strength is defined in the ESM Rules as 'a measure of how resilient the voltage waveform is to disturbances such as those caused by a sudden change in Load or an Energy Producing System, the switching of a Network element, tapping of transformers and other types of faults'.

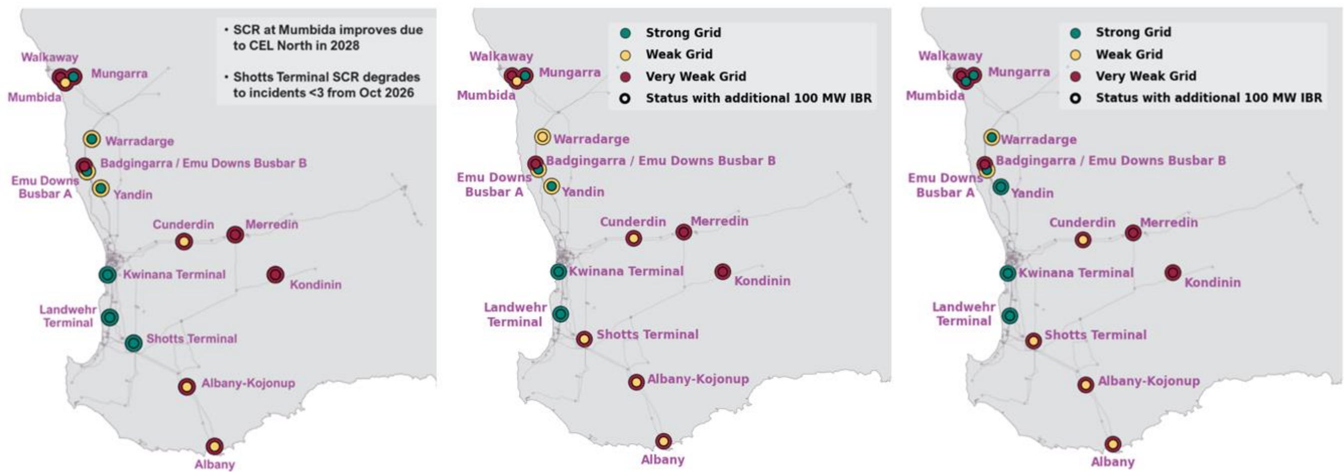
Figure 4 shows the strength of the system in various parts of the network and projected changes by 2031, based on a high-level assessment of short-circuit ratios at the node. This figure also shows how system strength is expected to change if 100 MW of additional IBR was developed at each location, above what is currently committed.

Areas with potentially low levels of system strength include the Collie region (area around Shotts Terminal), Merredin Terminal in East Country, and areas of the North Country including Walkaway and the Badgingarra/Emu Downs Busbar B location.

Solutions will be required following the next coal retirement and connection of more IBR, to manage system strength at several locations in the SWIS. These solutions may include:

- new sources that can supply higher fault levels (new synchronous generation such as gas generation, or synchronous condensers),
- modifications to protection settings for safe network operation,
- grid-forming IBR, and
- operational management, including review of network configuration, curtailment of IBR, and operational unit commitment of thermal generation (such as coal- or gas-fired generation).

Figure 4 System strength assessment outcomes – October 2024 (left), October 2027 (middle) and October 2031 (right)



AEMO supports EPWA's work to establish a system strength framework in the SWIS as soon as possible, as it would allow Facilities contributing to system strength services to be recognised and rewarded through appropriate mechanisms, and ultimately facilitate the development of more renewable generation. In the meantime, procurement of system strength services may be necessary through the existing NCESS framework to address system strength concerns at Shotts and Merredin substations and support the continued connection of IBR. System strength remediation is also likely to be required in North Country to accommodate the scale of connection interest from wind farm proponents in the area.

In the Collie region (area around Shotts Terminal), there is an operational requirement to ensure a minimum number of synchronous generations are kept online to support system security and voltage stability during low load periods. In addition, inertia requirements are managed via dispatch. The Bluewaters Power Station has been a reliable source of both voltage support and inertia. In the event of Bluewaters Power Station's unavailability, alternative options to support voltage and maintain a sufficient level of inertia would be required. Although connecting new IBR in the Muja area has the potential to negatively impact fault current level, where the IBR are designed to be grid-forming, they could help support system strength, address existing voltage constraints, and contribute to the future need for inertia after coal retirements. If the new IBR are designed to use grid-following technology, further investment in synchronous condensers or gas-powered generation will likely be required.

AEMO will work collaboratively with Western Power in undertaking further power system studies to establish what solutions will be necessary to resolve the emerging issues identified. This will require assessment of minimum fault level requirements for the correct operation of protection systems.

1 Introduction

The WEM ESOO provides an outlook for the next 10 Capacity Years to inform decisions by market participants, investors and policy-makers in the WEM and determines key parameters for the third Capacity Year, as required, for the Reserve Capacity Cycle. Its primary purpose is to help identify the investment required in local generation capacity, storage, and demand side capacity to ensure a secure and reliable electricity supply over the next decade.

The WEM ESOO informs planning and decision-making by WEM participants, investors and policy-makers, by providing information on and projections of:

- electricity consumption and demand across a range of weather and growth scenarios,
- electricity supply from generation, storage, and DSP,
- power system reliability and supply-demand balance,
- the Peak RCT, used to identify the capacity needed to meet the Planning Criterion[17],
- the Flexible RCT, to set the requirement to meet the largest expected Four-Hour Demand Increase,
- ESR[18] and DSP requirements, including the ESR Duration Requirement,
- the minimum Capability Class 1 and Class 3 requirement (that is, the minimum quantity of additional capacity capable of generating electricity), and
- locations where investment to maintain system strength may be required to support the transition from coal to renewable generation.

1.1 Purpose and scope

The WEM ESOO presents the outcomes of AEMO's annual Long Term Projected Assessment of System Adequacy (PASA) study for the SWIS. The study provides a 10-year view of capacity requirements and is a vital input to the RCM. The primary aim of the RCM is to provide investment signals to encourage capacity to be connected and be available to maintain secure and reliable electricity supply in the SWIS[19]. This 2025 WEM ESOO:

- forecasts the amount of electricity consumption across each Capacity Year in the 10-year horizon, and at times of peak demand conditions, that must be serviced by sufficient generation resources to meet the Planning Criterion,
- forecasts regional and sub-regional EUE under various demand and supply scenarios,
- determines the Peak and Flexible RCTs that will satisfy the Planning Criterion for each Capacity Year in the outlook period,
- assesses the extent to which existing and committed capacity can satisfy the limbs of the Planning Criterion, and identifies any capacity shortfalls,

[17] As defined in clause 4.5.9 of the ESM Rules.

[18] Electric Storage Resources (ESR) is the term used under the ESM Rules to describe utility-scale battery storage.

[19] For more information on the RCM and how it works, see https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism.

- identifies any potential capacity supply, storage, demand response or transmission augmentation options that would alleviate any forecast shortfalls,
- sets the Peak and Flexible RCR, which is the amount of capacity to be procured through the RCM for the 2025 Reserve Capacity Cycle, including minimum capacity levels to be provided by Capability Class 1 and Capability Class 3 – the Capacity Year associated with the 2025 Reserve Capacity Cycle is 2027-28,
- determines ESR and DSP availability requirements for the 2025 Reserve Capacity Cycle, and
- forecasts reductions in system strength at various locations across the SWIS and identifies actions needed to remedy any potential shortfall.

1.2 Structure of this document

- Chapter 1 summarises key definitions of demand consumption, the forecasting scenarios, methodologies and the scope of the reliability assessment.
- Chapter 2 presents electricity consumption and demand projections.
- Chapter 3 covers the battery storage and demand side response requirements.
- Chapter 4 covers the supply outlook.
- Chapter 5 presents Long Term PASA results, including projections of EUE, RCTs and the regional capacity shortfall assessment.
- Chapter 6 presents the system strength forecasts.
- Chapter 7 identifies investment opportunities for maintaining system reliability and security.

1.3 Regulatory changes since the 2024 WEM ESOO

There have been several relevant changes to the Western Australia energy rules and regulation framework since the 2024 WEM ESOO was published. **Table 4** summarises the key changes and impacts on this year's WEM ESOO.

Table 4 Summary of relevant key regulatory and rule changes since last year's WEM ESOO

Regulatory/rule change	Summary	Impact on the 2025 WEM ESOO
State Electricity Objective (SEO)	Commenced on 6 February 2025. The SEO replaces the Wholesale Market objectives, Pilbara electricity objectives and the Code objective (of the *Electricity Networks Access Code 2024*) and empowers statutory decision-makers and regulators[A] to consider the environment (including greenhouse gas emissions) in addition to reliability and price when seeking to promote the long-term interests of WA's energy consumers[B]. It is a deliberate feature that the three limbs of '*quality, safety, security and reliability*'; '*price*' and '*the environment and greenhouse gas emissions reduction*' exist in tension, giving decision-makers the ability to weigh each as appropriate to the decision[C].	AEMO understands that EPWA has consulted broadly around the development of the State Electricity Objective. The rule changes outlined below, that are implemented in this ESOO, are aimed to support all three limbs of the SEO.
Transition to the Electricity System and Market (ESM) Rules	The new ESM Rules will, via a transition process, consolidate the following specified instruments: • Wholesale Electricity Market Rules,	The 2025 WEM ESOO and subsequent reports will refer to 'ESM Rules' in place of the WEM Rules.

Regulatory/rule change	Summary	Impact on the 2025 WEM ESOO
	• *Electricity Networks Access Code 2004*, • *Electricity Industry (Metering) Code 2012*, • *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, and • Western Power Technical Rules. At the time of publication of the 2025 WEM ESOO, only the WEM Rules are able to be incorporated into the ESM Rules as part of the amendments to the *Electricity Industry Act 2004* commencing on 6 February 2025. The remaining instruments will be incorporated on proclamation by the Minister for Energy (at a date no later than 31 December 2028).	
Integration of new technologies (distributed energy resources) into the ESM Rules	The ESM Rules will cover a broader scope of matters than those covered by the specified instruments that will be incorporated. New content for the ESM Rules includes matters relating to distributed energy resources and power system security and reliability. The development of this new content will occur in parallel with, and as part of, the transition process.	No impact to the 2025 WEM ESOO.
Availability Duration Gap and storage requirements	This requirement covers the Peak and Flexible DSP dispatch requirements, ESROD Uplift, and ESR Duration Requirement. Rule changes that commenced on 7 October 2024[D] and were amended under the ESM (Tranche 8) Amending Rules require AEMO to determine the Availability Duration Gap (ADG) and the ESR Duration Requirement for the third Capacity Year of the Long Term PASA Study Horizon.	The 2025 WEM ESOO reflects these requirements.
Minimum Capability Class 1 & 3 requirement	Clause 4.5.12(i) of the ESM Rules requires the reliability assessment to determine the minimum capacity required for Capability Class 1 and Capability Class 3. The assessment must identify an appropriate mix of additional Capability Class 1 and Capability Class 3 capacity if any shortfall is identified for the third Capacity year of the Long Term PASA Study Horizon under the 10% POE Expected demand scenario. As part of the ESM (Tranche 8) Amending Rules, a new clause 4.5.12A was added so that when AEMO determines that additional Capability Class 1 and Capability Class 3 capacity would be required to satisfy Limb B, then any Capability Class 1 and Capability Class 3 Facility that has not been assigned a Network Access Quantity in any previous Reserve Capacity Cycle is to be deemed to be a Network Augmentation Funding Facility.	The 2025 WEM ESOO reflects these requirements. It presents a determination of the minimum Capability Class 1 and Capability Class 3 capacity required in 2027-28.
Flexible Capacity product	Rule changes that commenced on 15 January 2025[E] include arrangements for a Flexible Capacity product that can start, ramp and stop quickly, which is a key RCM review outcome[F]. AEMO is now required to determine the Flexible RCT for each Capacity Year of the Long Term PASA Study Horizon, determine the minimum eligibility requirements for Facilities receiving Flexible Certified Reserve Capacity, and determine, review and record the Flexible ESROI.	The 2025 WEM ESOO reflects these requirements. An assessment of Flexible Capacity is undertaken in the Reliability chapter.

A. Statutory decision-makers and regulators are those directly empowered by legislation and include the Minister for Energy, the Economic Regulation Authority (ERA), the Co-ordinator and the Electricity Review Board. Note AEMO is not a decision-maker in this context.
B. See https://www.wa.gov.au/government/media-statements/Cook-Labor-Government/Legislation-to-modernise-electricity-sector-rules-passes-Parliament-20240229.
C. Parliament of Western Australia (2023), *Electricity Industry Amendment (Distributed Energy Resources) Bill 2023, Explanatory Memorandum*, pp.13-14. See https://www.parliament.wa.gov.au/Parliament/Bills.nsf/E35776BF096674C348258A1A001F9711/$File/EM%2B127-1.002.pdf.
D. Changes via the *Wholesale Electricity Market Amendment (Miscellaneous Amendments No 3) Rules 2024, Schedule 1*, which commenced on 7 October 2024.
E. Changes via the *Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025, Schedule 1,* which commenced on 15 January 2025.
F. See https://www.wa.gov.au/system/files/2023-05/epwa_reserve_capacity_mechanism_review_information_and_consultation_paper.pdf.

1.4 Forecasting demand and consumption

The approaches used to forecast operational demand and consumption are aligned with the methodologies outlined in AEMO's *Forecasting Approach – Electricity Demand Forecasting Methodology* paper (Methodology Paper), published on August 2024[20]. Where appropriate, AEMO has aligned forecasting methods for both the WEM and the National Electricity Market (NEM); however. there remain important distinctions that are outlined in the Methodology Paper. These distinctions are typically made for compliance or market design reasons (for example, the use of Capacity Years in the

[20] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf.

WEM) or due to differences in data availability. As the market develops and new trends emerge, AEMO will continue to evolve and refine its forecasting methodology in consultation with stakeholders. A summary of changes to this year's forecasting approach is provided in Section 1.4.2.

1.4.1 Key definitions of consumption and demand

The key definitions of electricity consumption and demand are as follows:

- Electricity **consumption** represents the amount of power used over a period of time, measured in megawatt hours (MWh), gigawatt hours (GWh), or terawatt hours (TWh), and reported as an annual figure.
- **Demand** is used to refer to the amount of power consumed at a particular point in time, measured in megawatts (MW) or gigawatts (GW), and reported as an average over a 30-minute period. In this report, demand is typically reported at times of maximum and minimum demand.

Consumption and demand can be measured at different locations in the electricity system, to communicate power system needs in different ways. Commonly used consumption and demand definitions are as follows:

- **Underlying consumption** – the total amount of electricity used by consumers at their power points. This electricity can be sourced from the grid, or from behind-the-meter DER such as distributed PV and ESR. Underlying consumption includes business and residential consumption.
  - Business underlying consumption comprises LIL and BMM, commercial electric vehicle (EV) charging, electricity for hydrogen production, electrification[21], and energy efficiency measures[22].
  - Residential underlying consumption considers population growth, dwellings and connections growth[23], appliance uptake, PV rebound effect, EV uptake, electrification[24] and energy efficiency measures.
- **Delivered consumption** – the electricity supplied to customers from the grid, which excludes the portion of their consumption that is met by behind-the-meter (typically distributed PV) generation.
- **Operational consumption/operational demand** – sent-out generation supplied by all market-registered energy producing systems, which includes both distribution and transmission losses. Annual unscheduled operational consumption forecasts include delivered consumption for all consumer sectors, plus transmission and distribution losses.
- **Unscheduled operational demand** – operational demand that excludes any demand associated with scheduled loads (such as large-scale ESR charging).
- **Operational maximum (peak) and minimum demand**[25] – the highest and lowest level of electricity drawn from the grid, measured as an average over a 30-minute period in either summer (December to March), winter (June to August), or shoulder months (April, May, September to November).

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[21] Business electrification includes any process that involves fuel-switching to electricity (excluding fuel-switching in transportation), such as replacing an industrial gas hot water system with a heat pump, electrified heating, and cooling of air.

[22] Energy efficiency measures reduce the energy required to perform a given task; for example, building insulation reduces the energy required for heating or cooling.

[23] Residential base forecasts capture the growth in consumption with respect to new connection points, reflecting population increase.

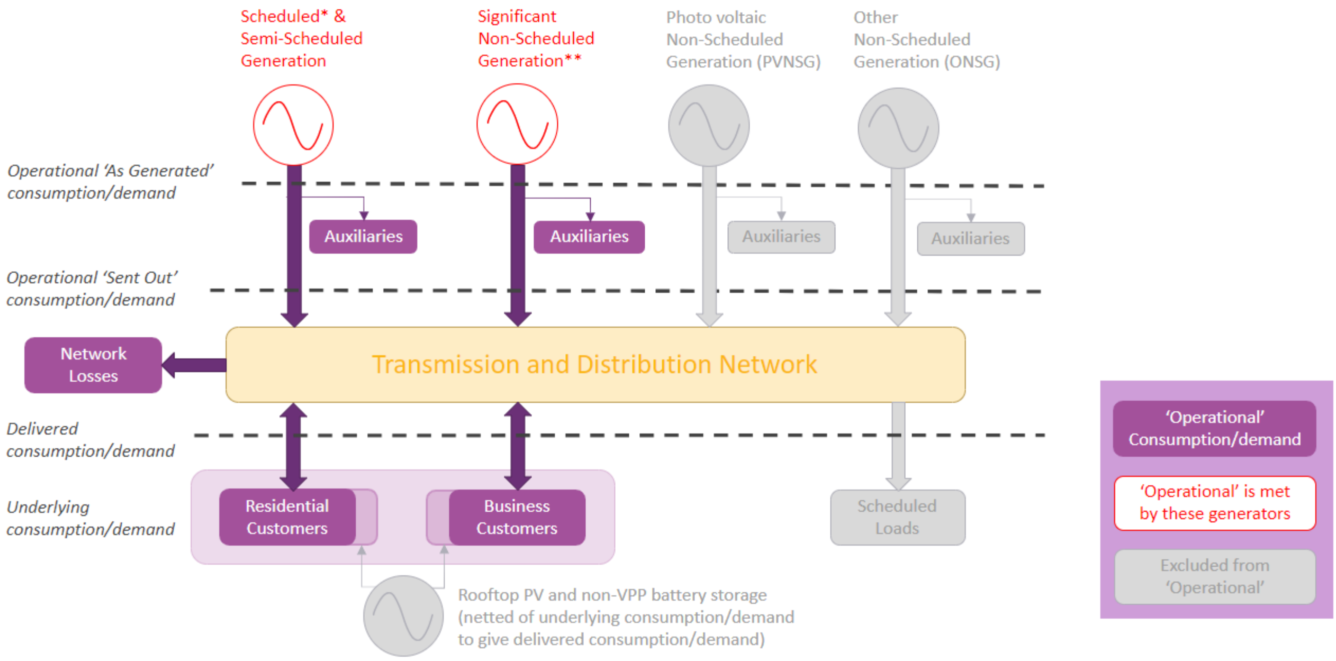
[24] Residential electrification includes any process that involves fuel-switching to electricity (excluding fuel-switching in transportation), such as replacing a residential gas stovetop with electric stovetop, gas hot water system with a heat pump, electrified heating, and cooling of air.

[25] Peak and minimum demand refers to unscheduled operational demand, unless otherwise specified.

- **Unscheduled operational maximum (peak) and minimum demand** – the operational peak and minimum demand forecasts that exclude the impact of scheduled load operations (such as large-scale ESR charging). Unscheduled operational peak forecasts are expected to match the operational peak forecasts, because scheduled loads such as utility scale batteries, are unlikely to charge from the grid during peak periods.

Figure 5 elaborates consumption and demand definitions used in this WEM ESOO.

Figure 5 Relationship between the components of consumption and demand



Note: 'As generated' consumption/demand is not forecast in this WEM ESOO. It refers to sent-out generation plus generators' auxiliary loads (the electricity used by a generator), which represents the gross electricity generation on site.

The WEM ESOO reports unscheduled operational consumption and demand. This is different from Operational Demand as defined in the ESM Rules, which is an instantaneous, end of Dispatch Interval measurement used for dispatch purposes.

Peak underlying and operational demand forecasts are prepared as a probability distribution, from which the 10%, 50% and 90% POE forecasts for three seasons (summer, shoulder and winter) are taken.

Unscheduled operational peak and minimum unscheduled operation demand forecasts are presented with:

- A **50% POE**[26], meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions (also called one-in-two-year).
- A **10% POE** (for maximum demand) or **90% POE** (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called one-in-10-year).
- 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.

[26] POE is the likelihood a peak or minimum demand forecast will be met or exceeded.

1.4.2 Changes to the demand forecasting approach since the 2024 WEM ESOO

The forecasting approach for this 2025 WEM ESOO remains broadly consistent with the 2024 methodology, however, there are some notable changes following consultation[27] with stakeholders in 2024 and 2025:

- **Demand forecasting data improvements** – peak demand forecasts generated with statistical models have been trained with the past eight years of actual demand, to March 2025. This includes the 2023-24 and 2024-25 summer periods, which experienced higher recorded demand than previous years. The historical demand includes adjustments to add back the reduction in load associated with NCESS and Supplementary Capacity.
- **Accommodating the solar PV rebound effect** – the solar PV rebound effect[28] is a widely observed phenomenon where underlying household consumption increases after rooftop PV systems are installed, and resulting lower bills change consumption behaviour or trigger investments in equipment that use more electricity. In the 2025 WEM ESOO, and based on stakeholder feedback, the solar PV rebound is proportional to historical consumption rather than installed PV system generation. As such, the size of the PV system no longer affects the magnitude of the rebound effect in the methodology. Further details about this change can be found in the 2024 Electricity Demand Forecasting Methodology Consultation paper[29].
- **WA Household Battery Scheme** – the 2025 forecasts incorporated consideration of the forthcoming residential battery rebate, which launches on 1 July 2025[30]. The WA Household Battery Scheme is an initiative by the Western Australian Government to encourage the adoption of residential battery storage systems[31], supplemented by recently announced changes to the Australian Government's Small-scale Renewable Energy Scheme. This scheme is explored further in Appendix A2.3.2.
- **Demand trace development** – the demand traces developed for the 2025 forecasts now target 10% POE underlying demand rather than operational demand. This ensures the peaks in operational demand across weather reference years better represent the 10% POE, which is subject to rooftop PV variability in each weather year.

In addition to these changes, all supporting forecasts (such as economic outlook, energy efficiency and multi-sectoral modelling) have been updated to reflect contemporary data.

Refer to Appendix A1 for detailed information on all modelling assumptions and methods.

1.4.3 Scenarios

The ESM Rules require AEMO to prepare three demand growth scenarios: Low, Expected, and High. These three scenarios are based on different levels of economic growth, and incorporate different rates of decarbonisation, fuel-switching, carbon

[27] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

[28] PV rebound effect refers to the phenomenon where electricity customers who install rooftop PV systems increase their overall electricity consumption, even after accounting for the PV generation they produce. This happens because the savings from PV generation can lead to increased appliance use, or a delay in energy efficiency upgrades.

[29] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

[30] AEMO's 2025 WEM ESOO forecasts are based on the Western Australian residential battery scheme applied to 20,000 homes as originally announced. The scheme was subsequently expanded on 4 June 2025 to provide rebate support for up to 100,000 homes. See Appendix A2.3.2.

[31] See https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme.

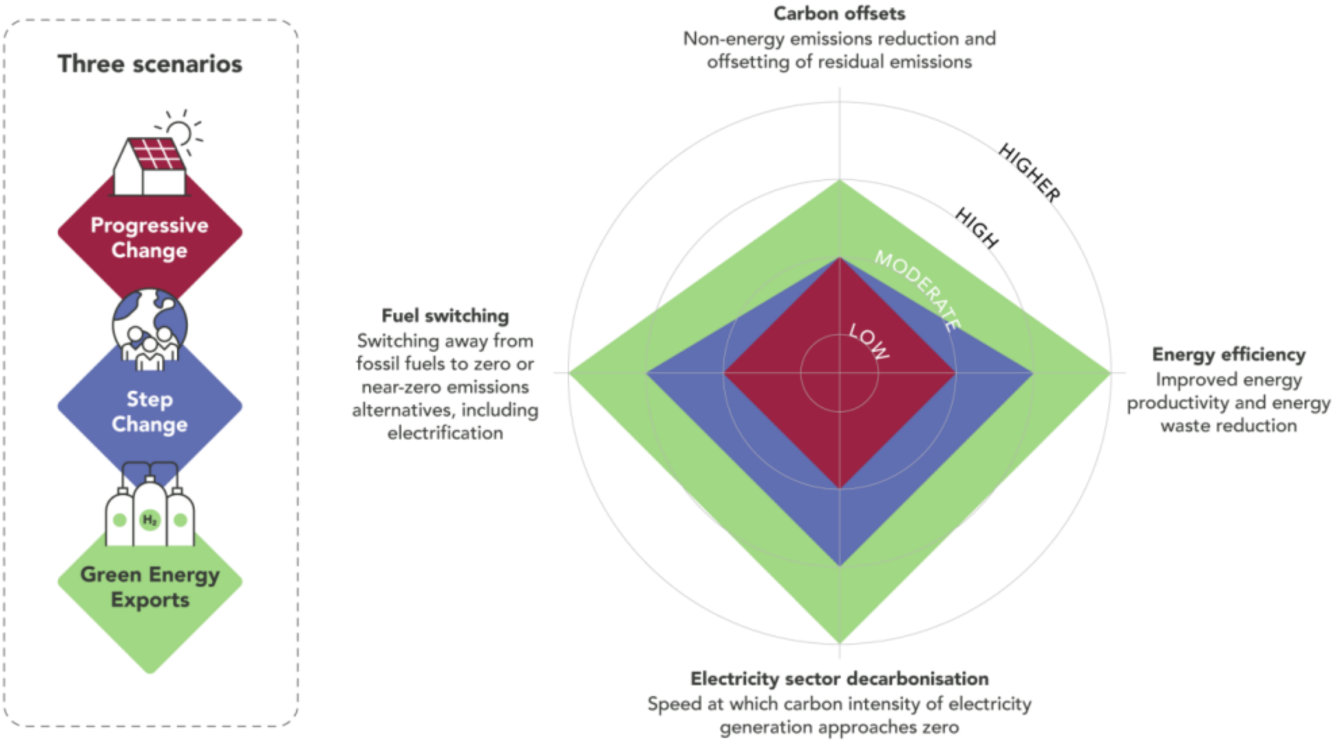
offsets, and energy efficiency in the WEM. For the 2023 and 2024 WEM ESOOs, AEMO adopted the three scenarios used in its Draft 2023 *Inputs, Assumptions and Scenarios Report* (IASR)[32].

For this 2025 report, AEMO adopted the equivalent scenarios in the Draft 2025 IASR[33]. The three scenarios are:

- *Progressive Change* (Low scenario),
- *Step Change* (Expected scenario), and
- *Green Energy Exports* (High scenario).

As **Figure 6** shows, the three scenarios are based on different rates of carbon offsets, energy efficiency, fuel-switching, and electricity sector decarbonisation in the WEM. For more details of the IASR scenarios, see Appendix A1.

Figure 6 Draft 2025 IASR scenarios



1.5 Assessing supply and reliability

1.5.1 The Planning Criterion

Reliability standards are used in power systems to mitigate the risk of supply shortfalls. They prescribe strict parameters on factors such as available capacity or unserved energy, with the aim of ensuring the power system has the capability to meet

[32] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/draft-2023-inputs-assumptions-and-scenarios-report.pdf.

[33] See https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-inputs-assumptions-and-scenarios-report-stage-1.pdf. The 2025 IASR scenarios are generally the same as the 2023 scenarios, with modifications to reflect the latest assumptions and trends.

demand at all times within the prescribed tolerance level. Standards between power systems vary depending on the risk appetite and characteristics[34] of that system.

The reliability standard in the WEM is referred to as the 'Planning Criterion'[35]. The Planning Criterion, defined in clause 4.5.9 of the ESM Rules, sets out the criteria AEMO uses to determine its 10-year Long Term PASA. The Planning Criterion has three limbs, designed to:

- ensure there is sufficient capacity to meet the forecast 10% POE peak demand forecasts plus allowances for Intermittent Loads, Regulation Raise, a reserve margin[36], and the ESROD Uplift (Limb A),
- limit EUE to less than 0.0002% of the annual forecast operational consumption (Limb B), and
- ensure there is sufficient supply flexibility to meet the highest forecast Four-Hour Demand Increase plus a reserve margin (Limb C).

Explaining expected unserved energy (EUE)

Unserved energy 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. For example, unserved energy could be caused by:

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

AEMO forecasts EUE by calculating the average unserved energy over a wide range of simulated outcomes of range of different weather and forced outage conditions.

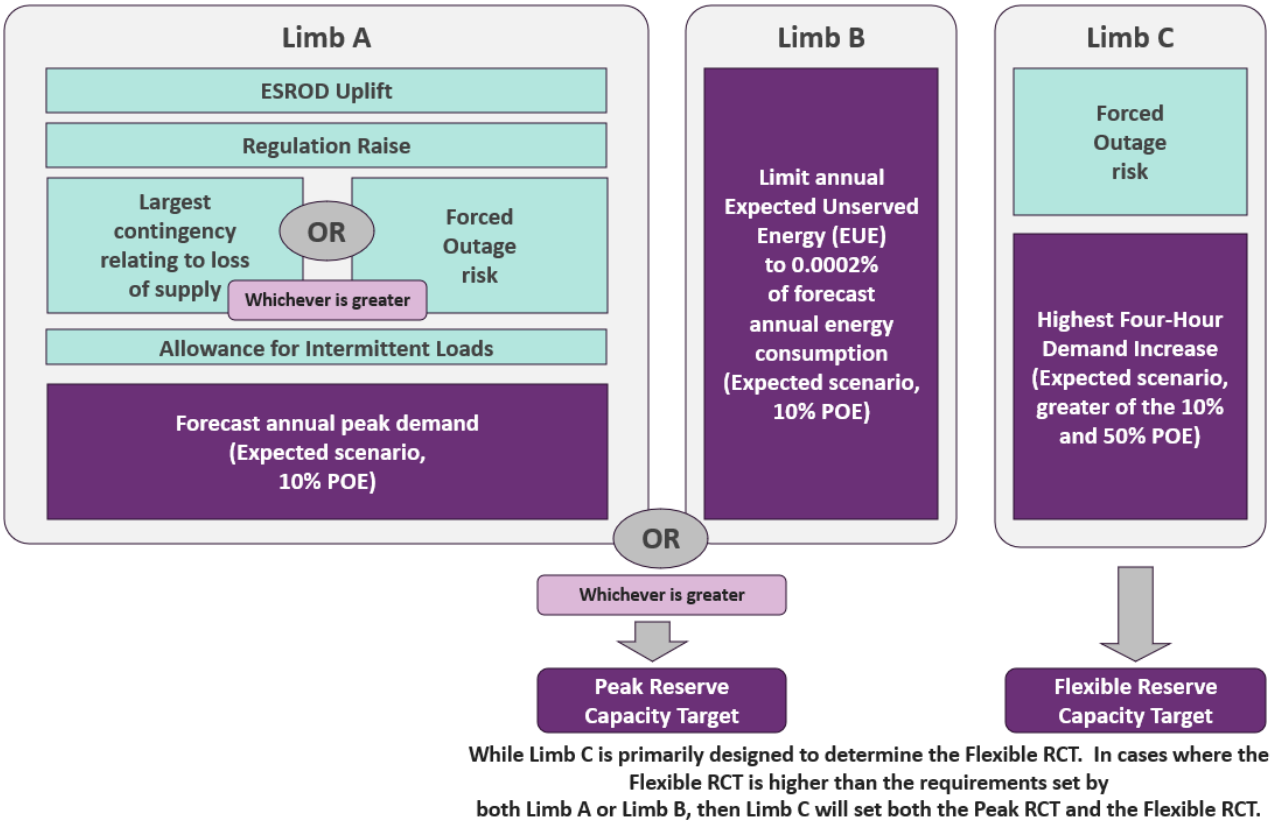
Figure 7 shows the three limbs of the Planning Criterion. The assessments against Limb A and B are typically what drive the Peak RCT, with the greater of the two limbs setting the target. Limb C sets the Flexible RCT, and its purpose is to ensure that there is sufficient capacity that can ramp fast enough to meet the change in demand over a four-hour period, known as 'Flexible Capacity'. If the Flexible RCT is higher than Limbs A and B, then it will also set the Peak RCT.

[34] For example, risk is determined by the power system's size, demand profiles, generator characteristics and outages, and level of interconnection.

[35] Defined in clause 4.5.9 of the ESM Rules.

[36] The reserve margin is the greater of: (i) the size of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand, and (ii) the forecast peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages.

Figure 7 The limbs of the Planning Criterion



1.5.2 Key definitions of supply

The supply forecasting approach for this 2025 WEM ESOO remained broadly consistent with the 2024 methodology, however, there are some notable changes in capacity category following an update in the ESM Rules:

- **Capability Class 1, 2, and 3** – Capability Class 1 is firm capacity that is not energy-limited, such as gas-fired generation, that meets the 14-hour fuel availability requirements. Capability Class 2 is firm capacity with energy or availability limitations that includes both DSP and ESR technologies. Capability Class 3 is non-firm capacity such as wind and solar with no associated firming capacity.
- **Peak Capacity** – refers to the Peak Reserve Capacity, equal to the Capacity Credits assigned to Facilities following trade declarations and the determination of Network Access Quantities through the 2024 Reserve Capacity Cycle. Forecast Peak Capacity also includes capacity procured through the 2024-26 and 2025-27 Peak Demand NCESS depending on the scenario considerations as described in Chapter 4.
- **Flexible Capacity** – refers to the Flexible Reserve Capacity, a new component of the RCM in the WEM, introduced from the 2025 Reserve Capacity Cycle and onwards. Forecast Flexible Capacity includes all technology types that are potentially eligible for assignment of Flexible Capacity, with different minimum eligibility requirements for each technology type (based on the maximum output the Facility can achieve within four hours from a cold state with the quantity of Flexible Capacity capped at the level of assigned Peak Capacity Credits), and any capacity procured through the 2024-26 and 2025-27 Peak Demand NCESS depending on the scenario considerations as described in Chapter 4.

- **Maximum capacity** – refers to the maximum dispatchable capacity of a Facility to meet Limb B of the Planning Criterion, either stemming from the Facility's nameplate capacity or the contracted quantity procured through the 2024-26 and 2025-27 Peak Demand NCESS or forecast Peak Capacity.

In addition to these changes in capacity category, the modelling assumptions and methods for supply forecast and reliability modelling reflect changes in the ESM Rules that are discussed in Appendices A3, A4, and A5.

1.5.3 Changes to the scope of the Long Term PASA

The WEM ESOO considers power system reliability in the SWIS using the Long Term PASA, otherwise referred to as the reliability assessment, as defined in section 4.5 of the ESM Rules.

As summarised in Table 4 above, there have been several relevant recent rule changes that have been factored into this year's Long Term PASA and reliability assessment, namely:

- **introduction of a Flexible Capacity product**, requiring AEMO to determine forecast Flexible Capacity, Flexible RCT and Flexible ESROI,
- **implementation of a new method for calculation of the Availability Duration Gap (ADG)**, used to determine the ESR Duration Requirement,
- **introduction of ESROD Uplift**, a new component to the Limb A RCT determination, which increases the Peak RCT to account for the need for additional Reserve Capacity arising as a result of the ESR Duration Requirement protection provisions for ESR previously certified on the basis of a shorter ESR Duration Requirement, and
- **extension of the requirement of minimum capacity assessment for Capability Class 1 and Capability Class 3 capacity** to include the determination of the appropriate mix of Capability Class 1 and Capability Class 3 capacity to make up shortfall.

1.6 System strength

This ESOO introduces a new chapter summarising AEMO's assessment of system strength in the SWIS.

In August 2024, AEMO published a SWIS Engineering Roadmap providing a view of the technical, engineering and operational actions required to prepare the WEM to securely and reliably operate at times of high renewables contributions[37].

[37] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/swis-engineering-roadmap.pdf?la=en&hash=A65DB858E3058106C3FB1989C1FB77D4.

System strength is a major component for maintaining the secure technical operating envelope of the power system under increasing levels of renewable contribution and large-scale IBR.

The SWIS requires sufficient capability to maintain system strength to meet stability requirements; this is critical for Western Australia's safe, secure and reliable transition towards a low emissions energy system.

The system strength assessment was undertaken in consultation with Western Power and in parallel to EPWA's Power System Security and Reliability Review program of work, which includes the development of a new system strength framework. The purpose of the assessment is to provide decision-makers and investors with an early indication of the location, magnitude and timing of any system strength uplift required, and of the types of remediation that may be necessary to address shortfalls.

In the context of the RCM, the assessment outcomes inform potential market entrants of the locations and timings at which system strength is likely to remain sufficient, or may require remediation to enable connection or more renewable generation. Furthermore, assessment outcomes signal locations at which new projects, if designed appropriately, could efficiently contribute to both maintaining reliability and system security.

System strength is defined in the ESM Rules as 'a measure of how resilient the voltage waveform is to disturbances such as those caused by a sudden change in Load or an Energy Producing System, the switching of a Network element, tapping of transformers and other types of faults'.

1.7 Additional information in the 2025 WEM ESOO

The following information should be considered part of the 2025 WEM ESOO:

- The 2025 WEM ESOO report and the 2025 WEM ESOO appendices.
- Supplementary information published on the 2025 WEM ESOO page, including the 2025 Reserve Capacity Information Pack, the 2025 WEM ESOO Data Register, the 2025 WEM ESOO Demand Traces, the 2025 WEM ESOO Visual overview and EY's 2025 WEM ESOO Reliability Assessment Methodology Report.
- The demand forecasting data portal[38].
- The 2025 Draft IASR[39], accompanying assumptions workbooks and supplementary material.

[38] See https://aemo.com.au/energy-systems/data-dashboards/electricity-and-gas-forecasting/.

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

1.8 Notes for reading this report

- This WEM ESOO uses many terms that have meanings defined in the Electricity System and Market Rules (ESM Rules)[40]. Terms which are defined in the ESM Rules are capitalised. Other terms are defined throughout the report and in the Glossary.
- HH:MM Trading Interval means Trading Interval commencing at HH:MM.
- The WEM ESOO modelling resolution is 30-minute Trading Intervals.
- All data in this WEM ESOO is based on Capacity Years unless otherwise specified. A Capacity Year commences in the 08:00 Trading Interval on 1 October and ends in the 07:30 Trading Interval on 1 October of the following calendar year.
- All references to a single year (as 20xx) present a calendar year.
- Consumption/demand is operational consumption/demand unless otherwise specified in this WEM ESOO.
- Key definitions of operational consumption and demand, as well as reliability assessment related terminology, can be found in Chapter 1 and in the Glossary.
- The three seasons reported in this WEM ESOO are the Hot Season/summer (covering a period from December to March), winter (covering a period from June to August), and shoulder (covering April, May, and September to November) Trading Months.
- This WEM ESOO provides low, expected, and high demand growth scenarios based on different levels of economic growth as defined in clause 4.5.10 of the ESM Rules. Unless otherwise indicated, demand forecasts are based on the expected demand growth scenario.
- All temperature data is reported at a half-hourly resolution and is based on the maximum temperature recorded in that Trading Interval.
- This WEM ESOO provides forecasts for the 2025 Long Term PASA Study Horizon, which covers the 2025-26 to 2034-35 Capacity Years, also referred to as the 10-year outlook period in this WEM ESOO. The first half of the outlook period refers to the period 2025-26 to 2029-30, and the second half refers to the period 2030-31 to 2034-35.
- The compound annual growth rate was used to calculate the average annual growth rate. AEMO uses the first outlook year (year 1) minus one year (year 0) as the base year instead of year 1 to calculate the 10-year average annual growth rate. AEMO used 2024-25 and 2029-30 as year 0 to calculate the five-year average annual growth rates for the first half and second half of the outlook period, respectively.

[40] On 6 February 2025, changes to the *Electricity Industry Act 2004* were made by the commencement of parts of the *Electricity Industry Amendment (Distributed Energy Resources) Act 2024*. These changes introduced the ESM Rules, consolidating the Wholesale Electricity Market Rules with other electricity laws and regulations.

2 Consumption and demand forecasts

This chapter presents forecasts of energy consumption and demand across the 10-year outlook period. These forecasts are a key input to the Long Term PASA. The Expected scenario shows:

- Annual electricity consumption is expected to grow, but more slowly than previously forecast primarily due to slower electrification across the industrial, residential and commercial sectors. Industrial electrification has been limited by the rate of technological development. In addition to this lower level of electrification, the forecast reflects slower population growth and weaker economic activity.
- Electricity consumption grows more strongly over the second half of the outlook period than the first, as electrification investments progress over time.
- Summer peak demand is higher in the initial years of the forecast compared to the 2024 WEM ESOO, reflecting recent record peak demand events in 2024 and 2025.
- In a change from last year's forecasts, winter peak demand is not expected to exceed the summer peak during the next 10 years.
- The introduction of ESR through NCESS has successfully supported secure and reliable SWIS operation under minimum demand conditions. While unscheduled minimum demand is projected to continue falling, AEMO expects the entry of over 1,000 MW of storage by 2025-26 to keep scheduled demand at levels that enable secure and reliable SWIS operations.

2.1 Consumption and demand drivers

The main drivers of the energy consumption and demand forecasts considered in this 2025 WEM ESOO are:

- economic and population growth, including new household connections,
- electrification of homes and businesses,
- LIL activities,
- DER uptake, including EVs, distributed PV and distributed energy storage systems,
- energy efficiency measures, and
- potential hydrogen production development.

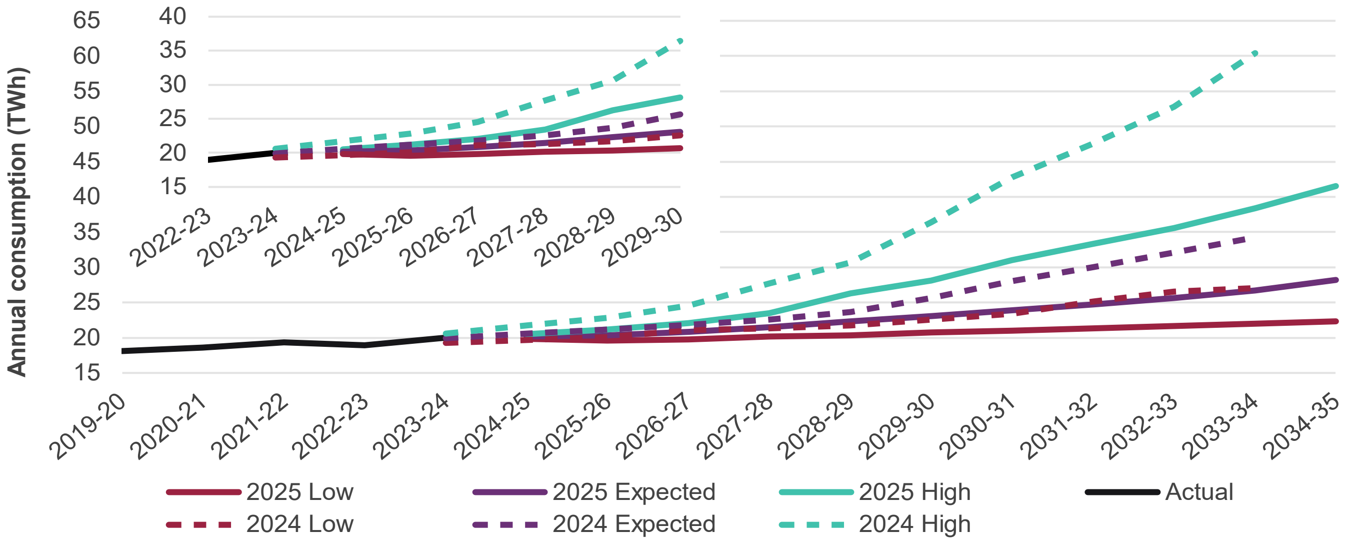
A summary of the forecasts resulting from these drivers is discussed in the following sections. More detailed analysis is provided in Appendix A2.

2.2 Energy consumption forecasts

Energy consumption is projected to grow across all scenarios, although at a slower rate than in the 2024 WEM ESOO. For the Expected scenario, growth in underlying annual consumption is forecast to increase from approximately 20 TWh at the beginning of the outlook period to 28 TWh by 2035. Growth is driven by electrification in the business and residential sectors, partially tempered by improving energy efficiency of households and businesses. Commodity processing and hydrogen production (primarily for export) also contribute to rising consumption, especially in the High scenario. However, hydrogen production projections are significantly lower than those assumed in the 2024 WEM ESOO.

Figure 8 shows forecast underlying consumption for the outlook period in comparison to the 2024 WEM ESOO forecasts.

Figure 8 Actual and forecast underlying consumption under three scenarios from 2024 and 2025 WEM ESOOs, 2019-20 to 2034-35 (TWh)



All three scenarios exhibit a flatter growth trajectory in the 2025 WEM ESOO forecasts for both underlying and operational consumption than in last year's WEM ESOO. This is due to:

- reduced commercial and industrial electrification, reflecting lower level of committed and anticipated industrial investment and slower forecast investment to support decarbonisation, informed by *Multi Sectoral Modelling*[41] and progression of actual investments,
- lower residential forecasts, with reduced 'rebound'[42] in electricity consumption for households that install PV systems, and a slower rate of electrification (including from electrified transportation),
- marginally lower consumption for LILs due to a less favourable outlook for lithium and alumina refineries, and
- uncertainty in the potential commencement of a hydrogen industry in the SWIS, in part resulting from increased hydrogen costs and little momentum in financial decisions to commence hydrogen projects.

This reduced consumption is partially offset by increased consumption from updated business mass market forecasts[43] and a lower forecast of distributed PV.

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

[42] See Section 1.4.2.

[43] Updated BMM forecasts reflect the 2025 CSIRO multi-sectoral modelling consultancy (footnote 36) and draft 2025 IASR: https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/draft-2025-inputs-assumptions-and-scenarios-report-stage-2.pdf?la=en.

Table 5 summarises the key inputs that support the consumption and demand forecasts in the 2025 WEM ESOO, and how these differ from last year's WEM ESOO.

Table 5 Summary of changes to input assumptions

Input	Changes from previous WEM ESOO
Economy	• Forecast state economic growth is weaker than the forecast national average due to relatively weak population growth associated with an expected slowdown in the mining industry; this is despite more resilient household consumption, with respect to inflationary and interest rate pressures. • In the near term, public spending is expected to make a larger contribution to economic growth, with moderating commodity prices weighing on exports, partly offset by slower growth in imports. • Over the outlook period slightly slower population growth is forecast, due to ageing population and decreased migration. Projected population growth declined from an average annual rate of 1.2%-1.8% across the scenarios in the 2024 WEM ESOO to 0.9%-1.3% in this 2025 WEM ESOO. • In the longer term, the mining industry is forecast to decline as a share of the state's economy.
Distributed PV forecasts	• Scenarios are closely aligned in the short term, recognising that new PV system costs have not shifted materially in the updated projection in CSIRO's *GenCost* report[44]. • Long term forecasts lowered across scenarios due to lower revised average system size assumption, which was deemed too high relative to recent market trends and experts' view of its upper limit. • Updated forecasting methodology relating to PV rebound compared to previous WEM ESOOs[45].
EV forecasts	• Lower population growth assumptions are expected to reduce the pace of EV uptake[46]. • Electricity consumption from EVs is lower due to the slower uptake and improved efficiency of mid-size EVs.
Distributed energy storage systems	• The Western Australian Government battery subsidy is forecast to bring forward the installation of batteries at residential properties. The impact is forecast to accelerate ~47 MW of battery uptake by 2027-28.
LIL	• All scenarios: ~300 GWh less LIL in the 2025 ESOO due to softened lithium market conditions. • Some business customers have grown large enough to now be considered LILs (mining/ manufacturing/ transport) – these were reallocated from the BMM. • High: prospective loads start two years later than in the 2024 ESOO mainly caused by delays to a major mining project.
Electrification	• Electrification is projected to be lower for households, industrial and commercial sectors. • Rate of electrification is based on draft 2024 multi-sectoral modelling forecast[47], which featured improved detailed and explicit modelling of LIL processes. • Assumes lower residential electrification, mainly due to slower fuel-switching from natural gas to electricity for water heating and cooking end use types.
Green hydrogen	• Hydrogen production forecasts have been significantly reduced (by up to 75%) in the High scenario by 2035. This is due to lower demand assumptions for exports, commodity processing, and lower domestic volume due to high hydrogen costs. A lower proportion of hydrogen is forecast to be produced within the SWIS. • The combined hydrogen volumes for export and commodity processing have been reduced, following stakeholder feedback from the 2023 IASR. • The assumed proportion of green commodities produced in the SWIS has reduced from 30% to approximately 20% by 2035. • The average on grid proportion of electrolysers has reduced slightly.

2.2.1 Underlying consumption forecast to grow modestly

Figure 9 shows historical underlying consumption and a sectoral component breakdown of the Expected scenario forecast over the outlook period. The black dashed line is the WEM ESOO operational consumption forecast (consumption via the

[44] See https://www.csiro.au/-/media/Energy/GenCost/GenCost2024-25ConsultDraft_20241205.pdf.

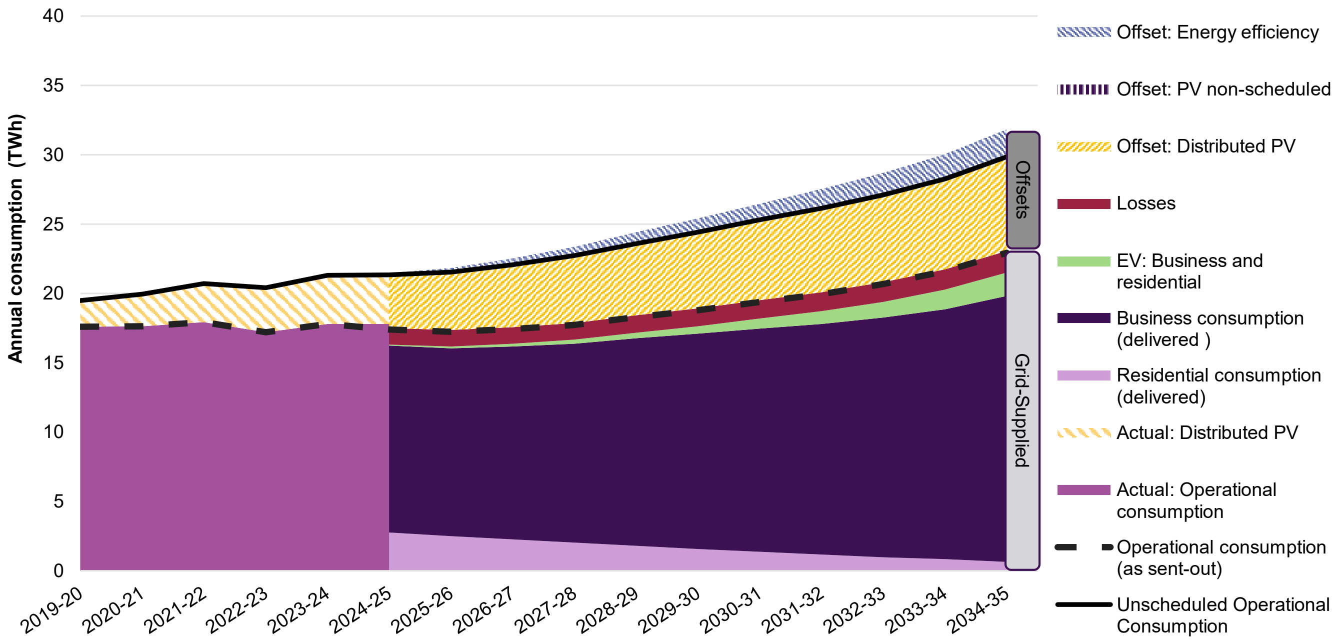
[45] For previous ESOOs, the PV rebound was linked to installed PV system size. This led to unreasonably large increases in forecasts for underlying consumption. The new method links PV rebound to household consumption regardless of installed system size.

[46] See https://aemo.com.au/-/media/files/major-publications/isp/2025/deloitte-access-economics-2024-economic-forecast.pdf?la=en.

[47] The draft 2024 multi-sectoral modelling forecast is identical to the final multi-sectoral modelling forecast for the Expected and Low scenarios.

grid). The segments below the black dashed line show the component growth or decline to operational consumption over the outlook period. The segments above the black dashed line show the factors that offset underlying consumption to arrive at operational consumption, such as distributed PV and energy efficiency measures.

Figure 9 Actual and forecast underlying electricity consumption by component, Expected scenario, 2019-20 to 2034-35 (TWh)



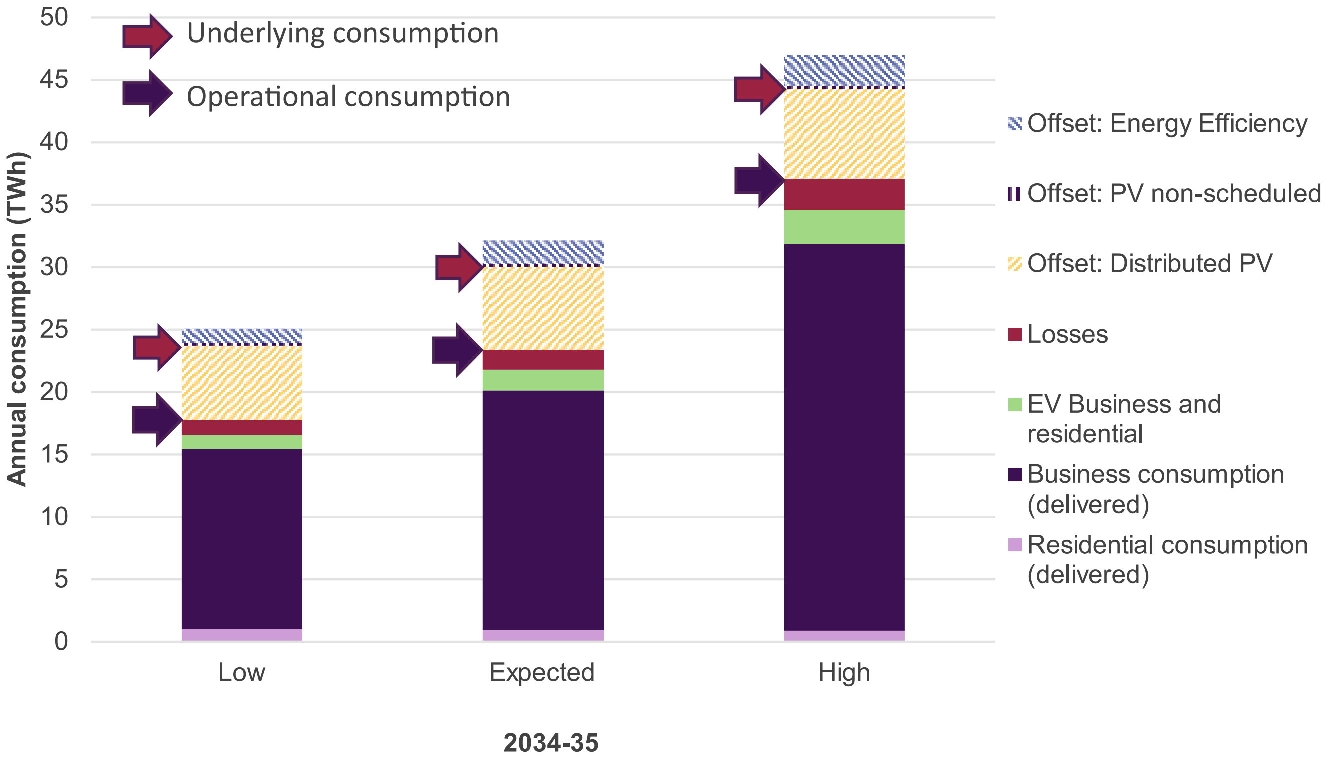
Notes:

- Impacts of distributed battery storage systems are negligible compared to other components and are therefore not shown separately.
- Transmission and distribution losses are included within the total forecast in Figure 9 to reflect forecast methodology and are not shown separately here.

Underlying consumption grows throughout the outlook period, adding 8 TWh between 2024-25 and 2034-35. This forecast consumption growth is more modest than in last year's ESOO, which projected a 14 TWh uplift. Distributed PV generation and energy efficiency measures in the Expected scenario offset nearly 17% of underlying consumption in 2025 and approximately 30% by 2035.

Figure 10 compares the three forecast scenarios. Each stack represents the impact of each sectoral component on underlying consumption at the end of the outlook period (in 2034-35), with the level of operational consumption indicated with an arrow.

Figure 10 Forecast underlying consumption by component, under three scenarios, 2034-35 (TWh)



Note: sectoral components that contribute to operational consumption are drawn in solid colours while those reducing operational consumption are drawn in shaded patterns.

The following sections describe forecast trends in underlying consumption at the residential and business level, presenting the Expected scenario[48] only.

2.2.2 Underlying residential consumption growth is marginal, with distributed PV generation growing substantially.

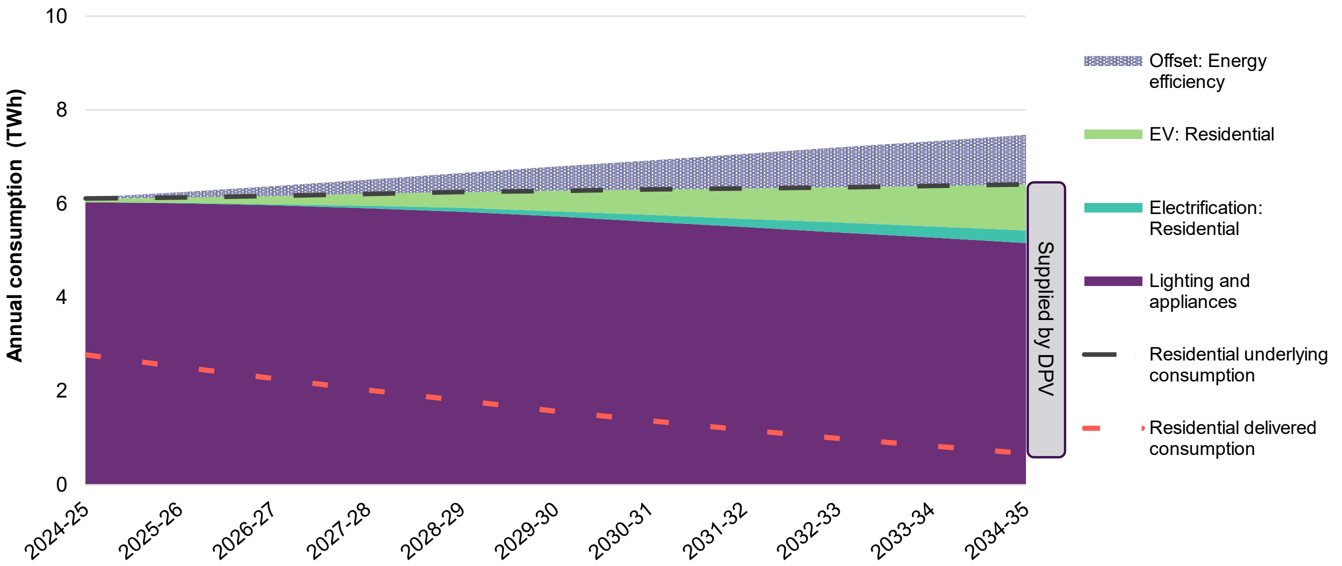
Figure 11 shows forecast underlying residential consumption. The chart highlights that by 2035, distributed PV generation from residential installations is forecast to provide an equivalent[49] to 90% of underlying residential consumption.

Underlying residential consumption for "conventional uses" such as lighting and appliances is forecast to decline due to increases in energy efficiency. This is forecast to be offset by an increase in EV charging, resulting in a marginal increase in underlying demand by the end of the decade. This growth is slower than in the 2024 WEM ESOO, which projected faster growth in fuel-switching from gas to electricity for water and space heating, cooking, and EVs, and a higher anticipated 'rebound' in electricity consumption for households that install PV systems. Households are still expected to electrify, and the uptake of EVs to grow, but at a slower pace than previously forecast.

[48] Other scenarios are downloadable via AEMO's Forecasting data portal. See https://aemo.com.au/energy-systems/data-dashboards/electricity-and-gas-forecasting/.

[49] Distributed PV generation exceeding residential needs is made available to all consumers via the grid (instantaneously) at the time of generation.

Figure 11 Forecast underlying residential consumption by component, Expected scenario, 2024-25 to 2034-35 (TWh)



Notes:

- Residential delivered consumption presented here excludes battery storage to reflect the forecast methodology.
- Transmission and distribution losses are included within the total forecast in Figure 11 to reflect forecast methodology and are not shown separately here.

2.2.3 Business consumption underlying consumption expected to increase moderately, reflecting slower electrification and large industrial load growth

Figure 12 shows forecast underlying consumption by business customers, including the largest consumers (LILs), and all other traditional industrial and commercial consumers (BMM). The forecast also includes business EVs, and grid connected hydrogen producers, highlighting consumption delivered via the grid.

While underlying consumption is projected to grow, it does so at a more modest pace than forecast in the 2024 WEM ESOO. Underlying BMM consumption, which comprises industrial and commercial consumers below the LIL threshold definition[50], is higher than in the 2024 WEM ESOO throughout the outlook period, despite some BMM consumers now being classified as LILs[51]. This growth is a result of updates to WEM manufacturing electricity consumption from the multi-sectoral modelling undertaken by CSIRO[52] (excluding electrification).

Delivered consumption is forecast to grow modestly over the outlook period. Electrification, which includes electrification of minerals processing such as alumina and the uptake of commercial EVs, causes overall business consumption to increase by the end of the outlook period. However, compared to last year's forecasts, the projected growth in electrification and hydrogen production is considerably muted, as market developments show more moderate progress for electrification investments than previously forecast and slower progress (or project withdrawals) for hydrogen.

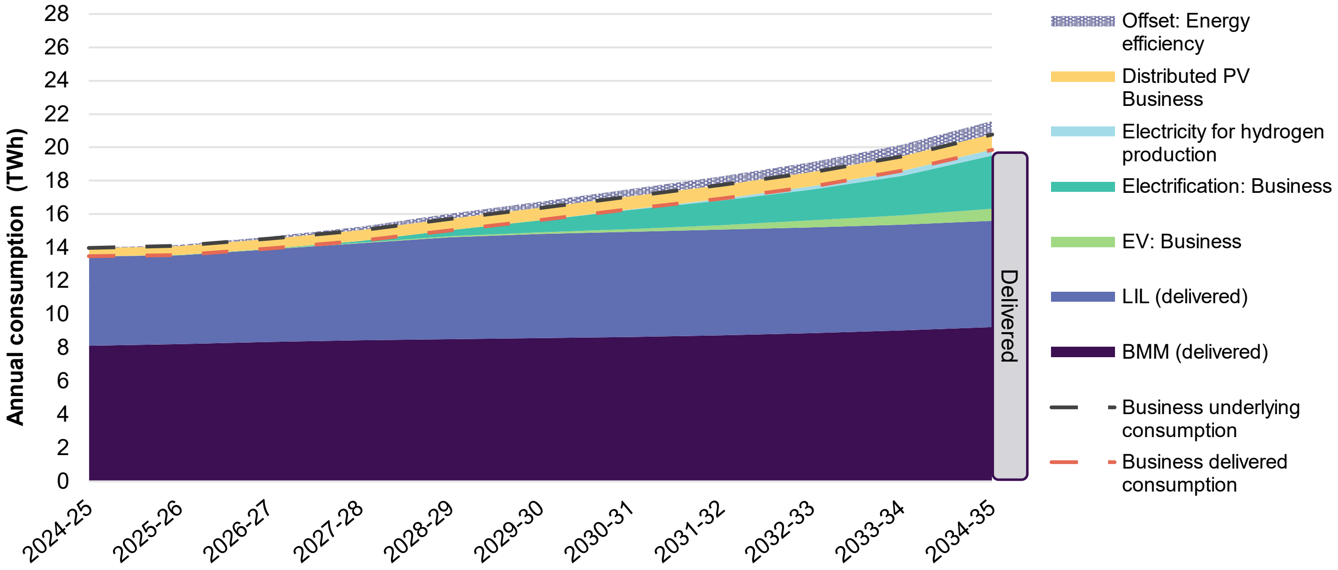
[50] For the LIL threshold definition, refer to Appendix A2.4.

[51] This reclassification has resulted in a reduction of base year BMM sector underlying consumption of approximately 0.2 TWh, with a corresponding increase to the LIL sector.

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

The amount of business consumption offset by business distributed PV generation[53] and energy efficiency activities is also forecast to increase, but at a more modest rate than previously forecast.

Figure 12 Forecast underlying business consumption by component, Expected scenario, 2024-25 to 2034-35 (TWh)



Notes:

- Components of business delivered consumption are presented here excluding round trip battery losses, and losses are aggregated in the calculation of total operational consumption.
- Transmission and distribution losses are included in the total forecasts to reflect forecast methodology and are not shown separately here.

2.3 Demand forecasts

The 2025 WEM ESOO demand forecasts take into account the 2024-25 summer and 2023-24 winter weather and peak demand records, as well as reflecting recent load behaviours. These factors contribute to an increase in the summer and winter peak demand forecast in the base year compared to the 2024 WEM ESOO base year.

Peak demand is typically driven by extreme weather conditions such as high temperature and heatwaves. The 2024-25 summer saw four of the top 10 highest demand days on record. This included the current all-time maximum operational demand record of 4,486 MW[54], set on 20 January 2025 at 6:30 pm.

Figure 13 shows the actual demand profile for the period 18 January 2025 to 25 January 2025.

Demand in this period was driven by prolonged heatwave conditions and concurrent development of Tropical Cyclone Sean between 20 January and 23 January with temperatures exceeding 40°C and overnight minimums not dropping below 25°C.

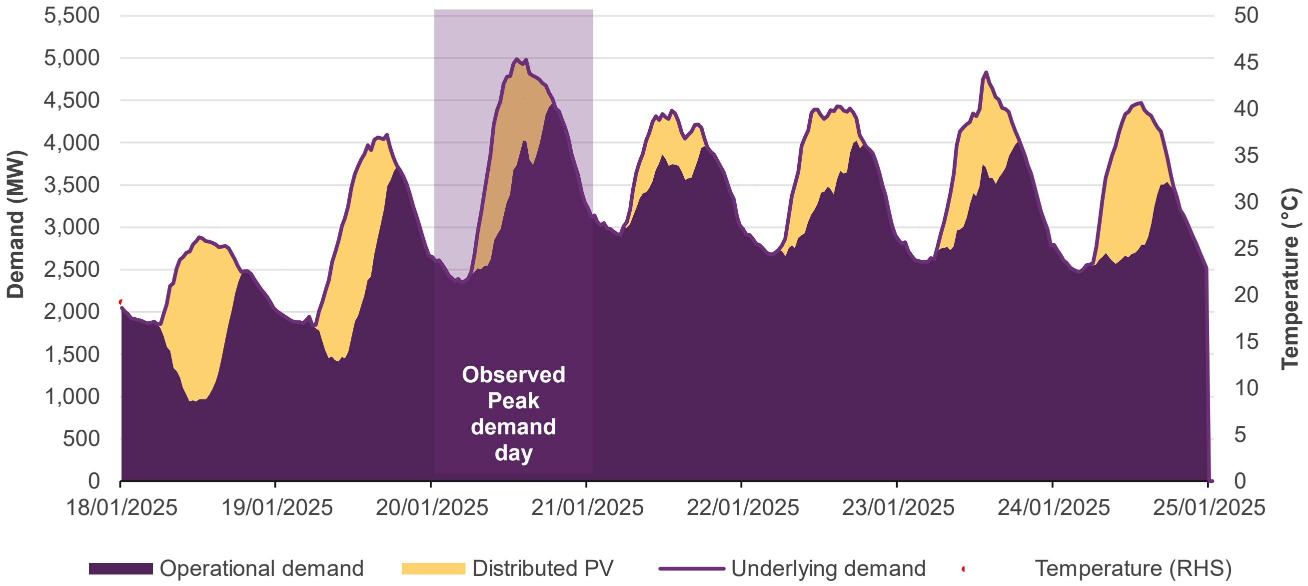
A peak temperature of 43.6°C was recorded at the time of the peak operational demand record, and was coupled with cloud cover, resulting in low distributed PV generation of only 118.5 MW. The supply mix during this peak event was

[53] Distributed PV generation exceeding business needs is made available to all consumers via the grid (instantaneously) at the time of generation.

[54] For the 18:30 Trading Interval based on non-loss adjusted meter data, which included the five-minute peak demand record of 4,486 MW in the 18:30 Dispatch Interval (based on non-loss adjusted SCADA data). The WEM ESOO modelling resolution is 30-minute Trading Intervals and uses verified metering data. In this context, the five-minute peak of 4,486 MW contributed to a 30-minute Trading Interval operational demand used in this WEM ESOO of 4,468 MW. This record was also published in AEMO's *Quarterly Energy Dynamics* Q1 2025; see https://aemo.com.au/-/media/files/major-publications/qed/2025/qed-q1-2025.pdf?la=en&hash=B77CD787D2D2FB67E4B74FA8BC9B6973.

primarily comprised of gas and coal (56.5% and 29.8%, respectively) and to a lesser extent battery and wind (6.6% and 4.2%, respectively). High demand conditions extended into the evening of 20 January with demand only falling below 4,000 MW after 9.00 pm. Dense cloud cover on the following day increased the likelihood that daily demand could occur in the middle of the day rather than early evening.

Figure 13 Demand (MW) and temperature (°C) profiles covering the observed peak demand day



Note: chart data in 30-minute Trading Intervals.

In response to the extreme conditions on 20 January, AEMO activated DSP and capacity procured through Supplementary Capacity and NCESS mechanisms totalling 126 MW[55].

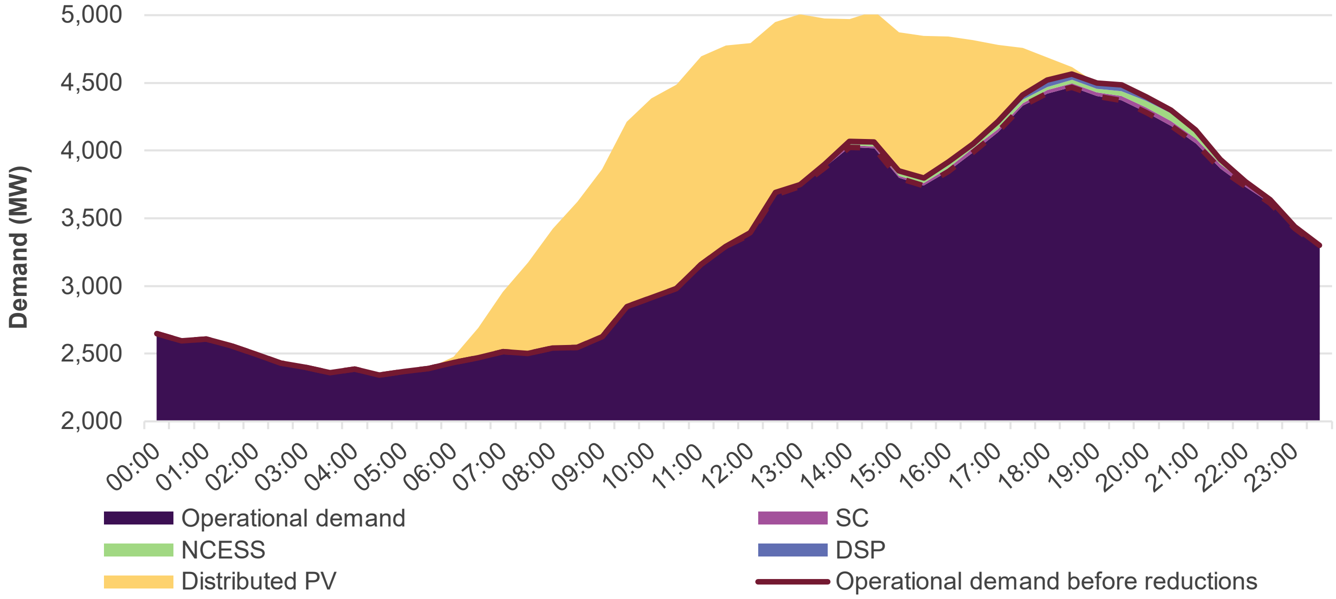
Figure 14 shows the demand profile, which would have peaked at a maximum operational demand of 4,594 MW if AEMO had not activated these demand reductions, which included 20 MW of DSP, 11.5 MW of Supplementary Capacity, and 94.5 MW of NCESS[56].

Although the past summer saw extreme temperatures, AEMO's modelling indicates maximum demand could have been even higher under certain climatic conditions. Elevated humidity, extended heatwave conditions and increased cloud cover without a cooling breeze (reducing distributed PV generation) can all contribute to more extreme peak demand outcomes. Taking this into consideration, the starting point of the 10% POE maximum demand forecast for 2024-25 is set as 4,647 MW, representing a 259 MW increase relative to the forecast in the 2024 WEM ESOO.

[55] Activated demand reduction is not equivalent to delivered, or actual, demand reduction. Actual demand reduction is measured on a trading interval (30-minute) basis and as such has not been estimated for the peak dispatch interval (five-minute).

[56] See https://aemo.com.au/-/media/files/major-publications/qed/2025/qed-q1-2025.pdf?la=en.

Figure 14 Demand profile for 20 January 2025 including activated demand side response (MW)

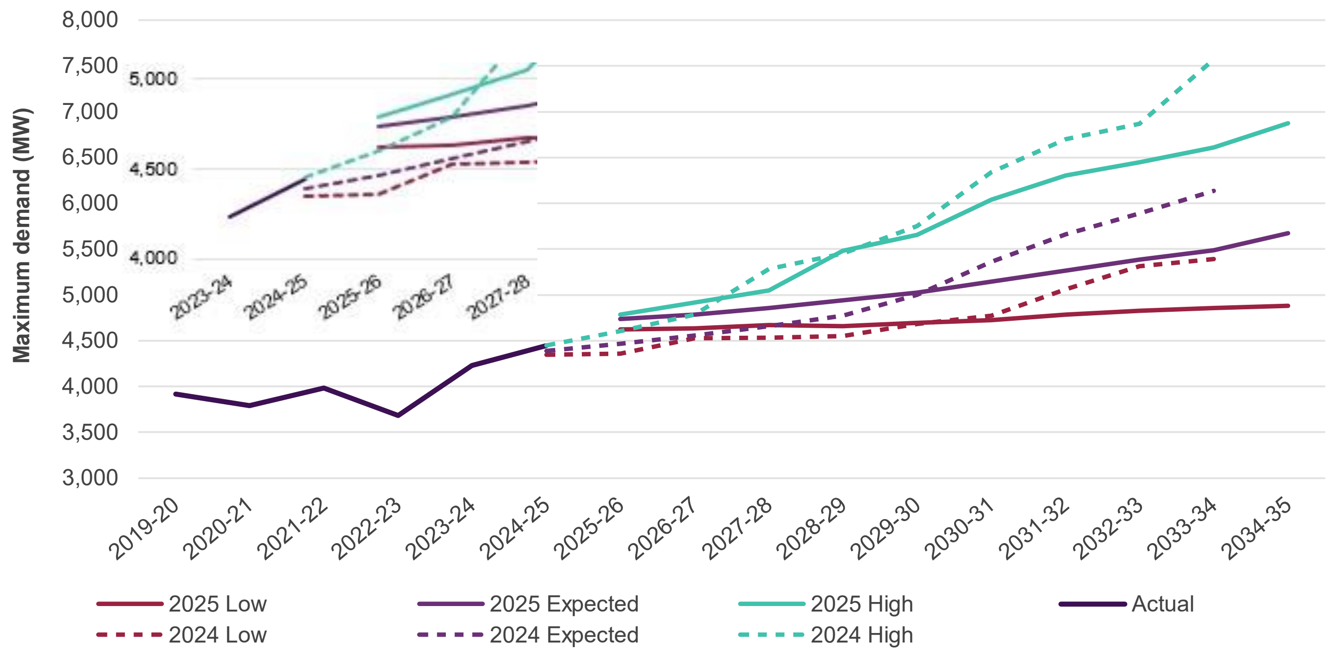


Note: chart data in 30-minute Trading Intervals.

Summer peak demand expected to increase due to rise in cooling load and electrification

Figure 15 shows the 10% POE peak demand forecasts under the three scenarios for the 2025 WEM ESOO. Peak demand forecasts are higher than the 2024 WEM ESOO until 2029-30, due to consideration of weather patterns that have led to extreme temperatures in the two most recent summers, and the corresponding higher than anticipated temperature sensitive load response observed.

Figure 15 Actual peak demand and forecast 10% POE summer peak demand under three scenarios, from 2024 and 2025 WEM ESOOs, 2019-20 to 2034-35 (MW)



Note: the actuals displayed reflect observed demand under the prevailing weather conditions and include load reduction activation actuals.

The forecast peak demand for the 2025-26 Hot Season is 4,734 MW, which is 271 MW higher than previously forecast. The forecast peak demand in 2027-28 is 4,856 MW, which is 199 MW higher than last year's forecast.

In training the demand forecasting model, AEMO added back the impact of load reductions that were activated through NCESS, Supplementary Capacity and DSP mechanisms. Load reductions driven by Individual Reserve Capacity Requirements (IRCR) were not added back due to the ongoing commercial incentive for electricity consumers to reduce their demand in peak events. Forecasts assume similar trends in IRCR driven load reductions, but do not make any assumptions regarding NCESS, Supplementary Capacity and DSP as these activations are options used, if required, to help meet a forecast peak demand. Demand forecasts also assume 90% curtailment of hydrogen load during peak demand.

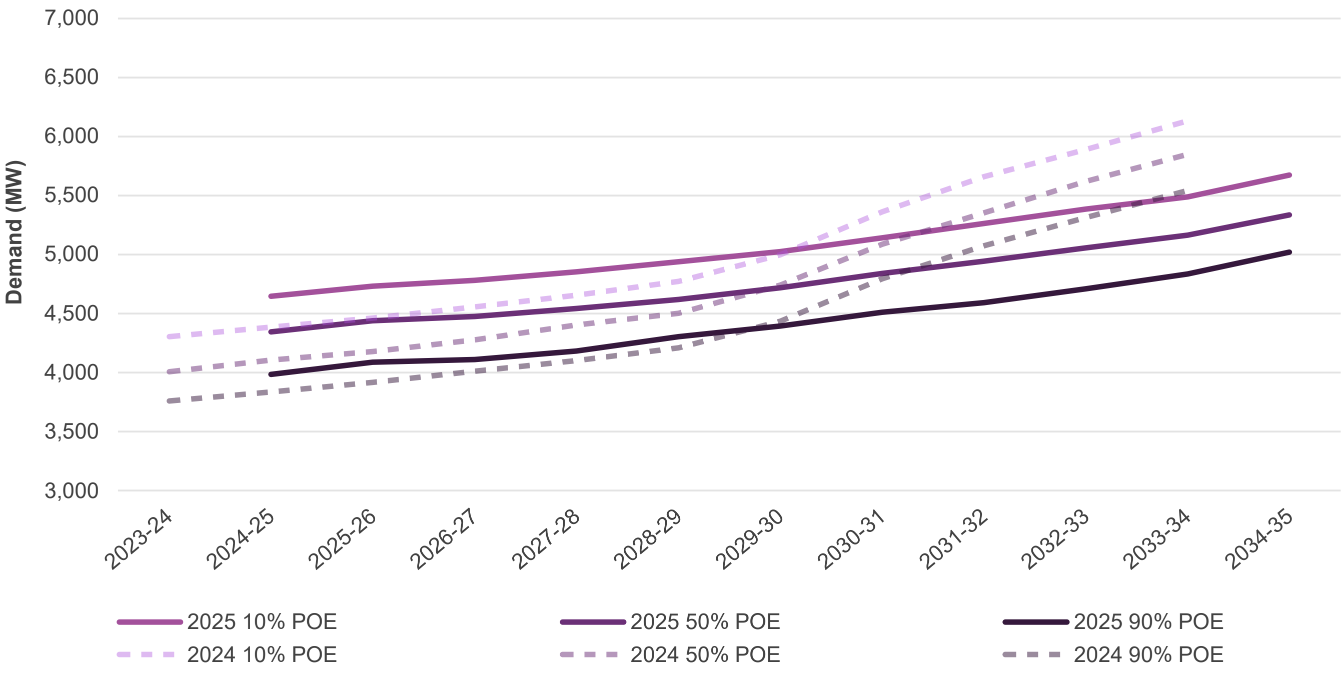
Table 6 summarises the summer peak demand growth rates and key growth drivers. Across all three scenarios, forecast growth for 10% POE summer peak demand is steady across the outlook period.

Table 6 Summer peak demand change rates and assumptions, by scenario

	Low	Expected	High
Average annual growth rate			
Whole period	0.9%	2.5%	4.5%
First half	1.1%	2.5%	4.9%
Second half	0.8%	2.5%	4.0%
Forecast growth drivers relative to the 2024 WEM ESOO	Comparatively flatter trajectory due to lower electrification and residential underlying consumption growth offset partially by less residential PV generation towards end of decade.	Comparatively flatter trajectory due to lower electrification and residential underlying consumption growth offset partially by less residential PV generation towards end of decade.	The lower 'High scenario' is due to lower forecast hydrogen production and delays to a major mining project.

Figure 16 shows peak demand forecasts under the Expected scenario relative to the 2024 WEM ESOO forecast. The spread between the 10%, 50%, and 90% POE peak demand forecasts remains consistent throughout the outlook period. The growth in demand is broadly consistent with forecast energy consumption growth, but with less offset from distributed PV as operational peak demand is typically in the early evening when solar generation is minimal.

Figure 16 10%, 50%, and 90% POE summer peak demand forecasts, from 2024 and 2025 WEM ESOOs, Expected scenario (MW)



Winter peak demand outlook is more moderate, driven by slower electrification and reduced outlook for large industrial loads

The winter peak is expected to increase steadily over the outlook period and in the Expected scenario, growth is projected to accelerate in the second half of the decade, yet remain lower than the summer peak. This is a change from the 2024 WEM ESOO forecasts, which anticipated faster electrification growth would increase winter heating peak demands above summer peak demands for 50% POE by 2029-30 in the Expected scenario.

The 2025 forecasts include more moderate rates of electrification, with fewer residential properties switching from natural gas for water and space heating. The softer economic outlook for the mineral and resources sector also suggests slower growth in LILs, which leads to a lower winter peak than previously forecast.

Figure 17 shows the 10% POE winter peak demand forecasts under all three modelled scenarios from the 2024 and 2025 WEM ESOOs, with actuals from 2019-20 to 2023-24. The lower actual in 2023-24 reflects the impact of milder winter conditions, consistent with the El Niño climate cycle.

The 10% POE forecast represents demand under a one-in-10-year cold winter event, drawn from approximately 3,000 simulations using 13 historical weather reference years. This probabilistic approach enables the forecast to reflect plausible peak conditions, while smoothing out short-term variability such as the mild 2024 winter. As a result, a gap between the 2023-24 actual and the 2024-25 10% POE forecast is expected and consistent with the forecasting methodology[57].

[57] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf?la=en.

Figure 17 Actual and forecast 10% POE winter peak demand under three scenarios, from 2024 and 2025 WEM ESOOs, 2019-20 to 2034-35 (MW)

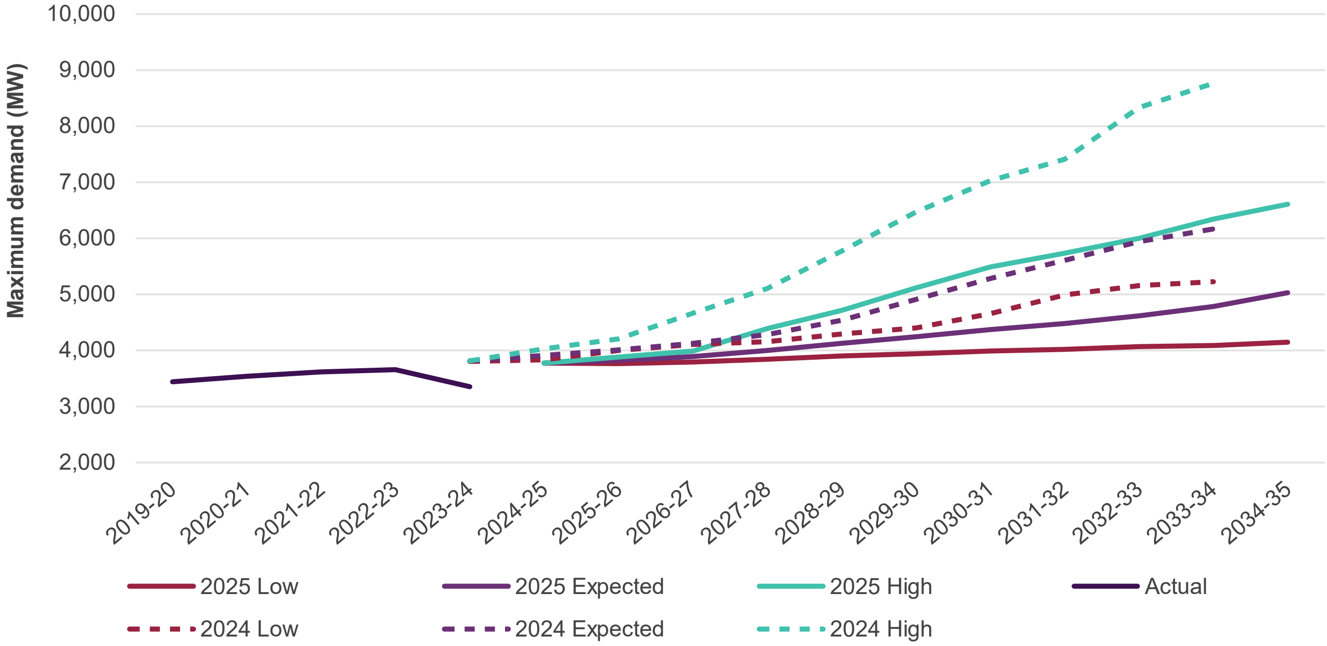


Table 7 summarises the winter peak demand growth rates and key drivers across the scenarios. While slower than the 2024 WEM ESOO forecasts, winter peak demand is projected to grow faster than summer peak demand.

Table 7 Winter peak demand change rates and assumptions, by scenario

	Low	Expected	High
Average annual growth rate			
Whole period	1.0%	2.9%	5.8%
First half	0.8%	2.4%	6.3%
Second half	1.1%	3.5%	5.3%
Forecast growth drivers relative to the 2024 WEM ESOO	Slower growth in electrification and slower growth in demand from LILs.	Slower growth in electrification and slower growth in demand from LILs.	Considerably reduced load in the hydrogen sector. Secondary drivers are heating load, electrification, and EV uptake.

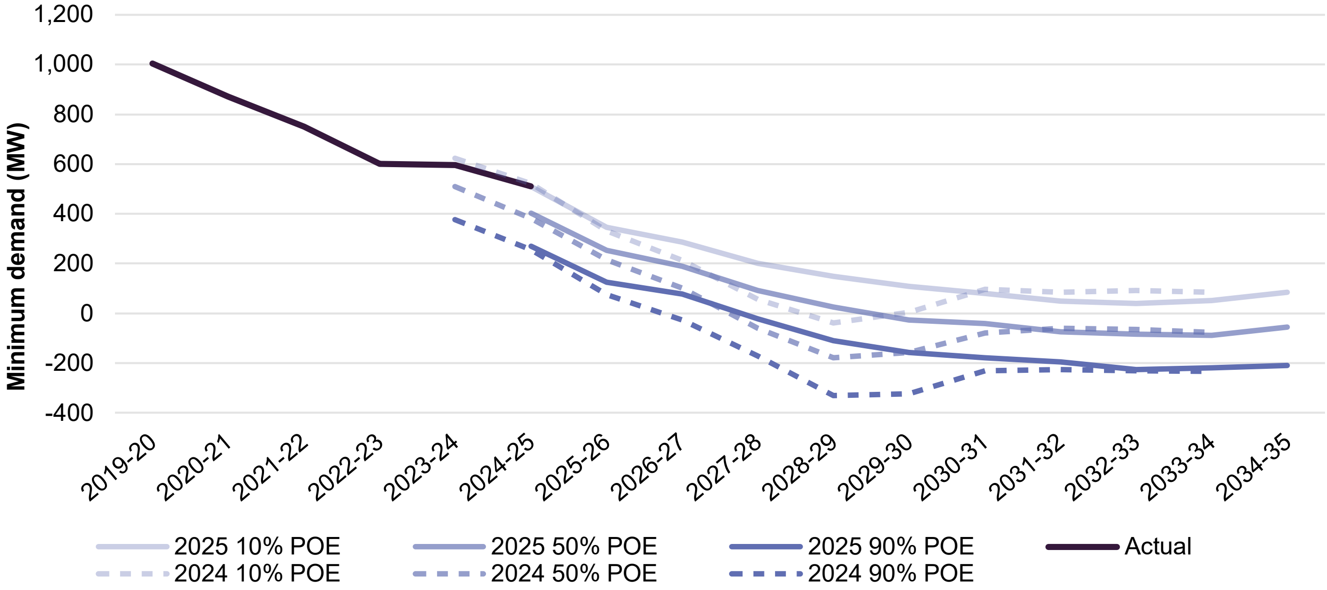
Demonstrated system security management will continue to play an important role as minimum unscheduled operational demand declines with PV uptake growth

The introduction of battery storage through NCESS has successfully supported secure and reliable SWIS operation under minimum demand conditions. With falling minimum demand, AEMO expects the entry of over 1,000 MW of storage by 2025-26 to complement existing NCESS to continue to support secure and reliable SWIS operations.

Minimum demand in the SWIS continues to fall as distributed PV uptake grows. The current minimum operational demand record of 511 MW was set on Sunday 10 November 2024. The minimum unscheduled operational demand record was also broken on the same day, reaching 474 MW. Unscheduled operational demand excludes the impact of scheduled load operations, such as ESR charging.

Figure 18 shows the 2025 forecasts for 10%, 50%, and 90% POE minimum operational demand under the Expected scenario, compared with the 2024 forecasts. It also shows actual minimum demand since 2019-20 (as of April 2025).

Figure 18 Actual and 10%, 50%, and 90% minimum demand forecasts, Expected scenario from 2024 and 2025 WEM ESOOs, 2019-20 to 2034-35 (MW)



Notes:

- The starting point is lower than actual, mainly due to higher PV forecast in 2025 compared to actual 2024.
- The actuals displayed reflect observed demand under the prevailing weather conditions.

AEMO forecasts minimum operational demand to continue to decrease across the forecasting horizon for 10%, 50%, and 90% POE, driven by continued growth in distributed PV installation and slower electrification. The 50% POE forecast declines rapidly from 402 MW in 2024-25 to 25 MW in 2028-29, then to below zero from 2029-30. This conceptually negative quantity of unscheduled operational demand represents potential PV generation available for storage.

AEMO has identified the Minimum Demand Threshold (MDT) of 300 MW[58] of operational demand to maintain system security, including local region (both South and North) reactive power management requirements. As a result, managing power system security and reliability during periods of low operational demand will play an increasingly important role.

Prior to reaching the MDT, Power System Security is managed through either increasing operational demand through charging of ESR, or through actions such as the Emergency Solar Management framework. The Emergency Solar Management framework provides for distributed PV to be turned down or switched off in low operational demand situations if insufficient ESR is available and charging to maintain scheduled load above a Minimum Demand Threshold[59].

[58] 'Western Power Limit Advice 27 - Generator Reactive Reserve Requirements' sets a lower limit to ensure that operational demand does not fall below 300 MW and that the minimum number of synchronous units in both the south and north regions are online for the minimum megavolt-amperes reactive (MVAr) requirements. Battery storage withdrawing power helps to increase operational demand and allow the synchronous generation to stay online during these minimum demand periods. In the operational timeframe MDT is dynamic and calculated based on fleet availability.

[59] To maintain the stability of the electricity system and support the continued installation of rooftop solar, the WA State Government introduced ESM. ESM works to stabilise the network when there is a high amount of solar energy being generated from rooftop solar systems, and not enough demand in the network. ESM provides the capability to remotely turn off (and on again) all new and upgraded rooftop solar systems. See https://www.synergy.net.au/Your-home/Solar-and-battery/Emergency-Solar-Management.

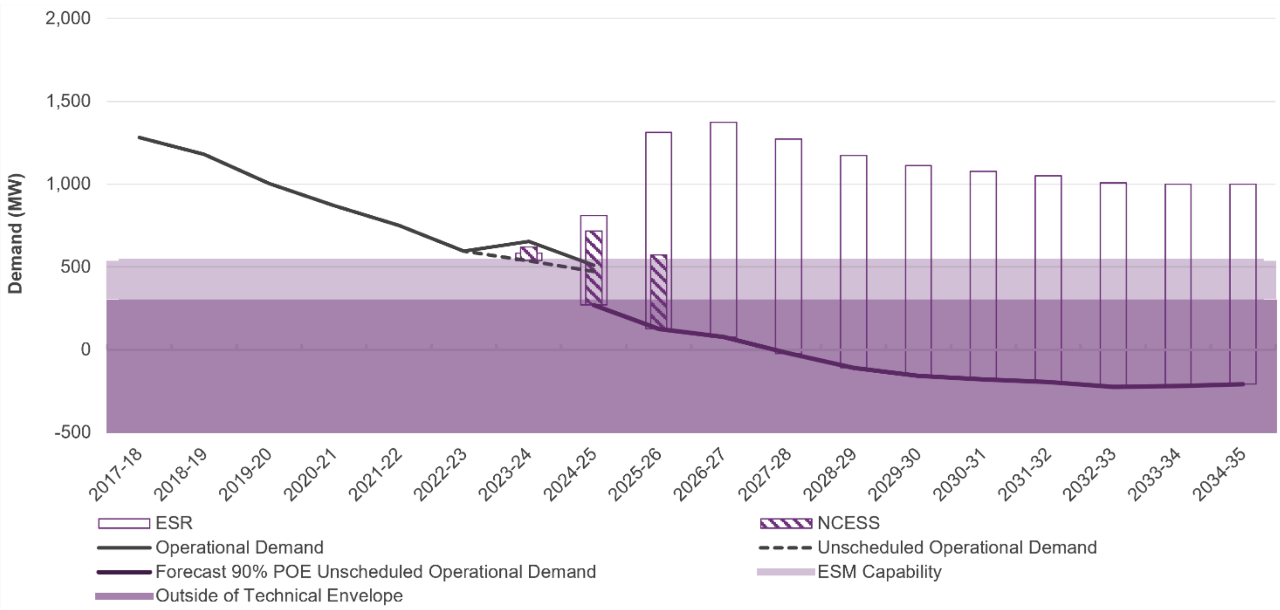
Over 1,000 MW of committed ESR projects expected to raise minimum demand to stable levels

AEMO expects the existing and committed entry of over 1,000 MW of storage by 2026-27 to play a key role in soaking up excess solar and discharging it during periods of high demand.

For 2024-25 and 2025-26, AEMO has procured 446 MW of minimum demand NCESS[60] from storage providers to support system security during periods of low operational demand (see **Figure 19**). Ongoing management of these services will include monitoring for ESR outages and state of charge.

As distributed PV growth continues and operational demands reduce, AEMO will continue to monitor any emerging capability to manage power system security and reliability. Over the longer term, greater orchestration of distributed PV and distributed batteries, enabled through foundational capability currently being developed as part of the DER Roadmap[61], may provide further opportunities to maximise the value of these consumer assets and contribute to a secure and reliable power supply for all consumers.

Figure 19 Minimum demand forecast and committed ESR entry, 90% POE Expected scenario, 2017-18 to 2034-35 (MW)



Notes:

- The difference between 2024-25 actuals and forecast arises due to the comparison of actuals to a 90% POE forecast.
- NCESS is higher than ESR in 2023-24 due to inclusion of ESM in the NCESS total.
- Actual minimum demand for 2024-25 is a year-to-date value, based on data until end May 2025.

[60] See https://aemo.com.au/consultations/tenders/tenders-and-expressions-of-interest-for-ncess-reliability-services-wa.

[61] For detail see https://aemo.com.au/initiatives/major-programs/wa-der-program/project-jupiter.

3 Battery storage and DSP requirements

This chapter presents requirements for ESR and DSP for the 2025 Reserve Capacity Cycle, determined in accordance with new clauses of the ESM Rules introduced or amended as part of Tranche 8 Amending Rules in June 2025. These clauses are intended to ensure new storage investment and DSPs meet the evolving needs of the power system during ramping and peak periods, mainly through an increase in their duration. In turn, these changes also result in changes to the Peak RCT.

3.1 Battery storage parameters

The ESR requirements for Peak Capacity include the ESR Duration Requirement – setting the duration requirement for new ESR in the 2025 Reserve Capacity Cycle – and the Mid Peak ESROI, to be reviewed for 2025-26 and 2026-27 and determined for 2027-28. The Flexible ESROI are also to be determined for 2027-28. The meaning and relationship between the ESR Duration Requirement, Mid Peak ESROI and Peak ESROD are discussed in **Table 8**, and conceptually presented in **Figure 20**.

In addition, the determination of the ESROD Uplift is a new requirement for the 2025 WEM ESOO. ESROD accounts for the need for additional Reserve Capacity arising as a result of an increase to the ESR Duration Requirement. It also accounts for the existing 'protection' provided under the ESM Rules for ESR previously certified on the basis of a shorter ESR Duration Requirement. Due to this protection (by which ESR continue to receive CRC for 10 Years, based on the shorter ESR Duration Requirement applying to the Reserve Capacity Cycle in which it was first certified), there will be a gap between the actual capacity available to meet the Peak RCT and the peak capacity which is assigned Capacity Credits. To correct this, the ESR Duration Requirement Uplift is added to the capacity target required to satisfy Limb A of the Planning Criterion.

Table 8 The relationship between ESR Duration Requirement, ADG, Mid Peak ESROI, and Peak ESROD

Season	Expressed as	Meaning
ESR Duration Requirement	Number of consecutive Trading Intervals	The number of contiguous Trading Intervals in each Trading Day in the applicable Capacity Year to be designated as Peak ESROIs for ESR first allocated Peak Capacity Credits in the Reserve Capacity Cycle. For Reserve Capacity Cycles up to and including the 2024 Reserve Capacity Cycle, the ESR Duration Requirement is eight Trading Intervals. For Reserve Capacity Cycles after 2024, the ESR Duration Requirement is the value determined by AEMO under clause 4.5.12(d) for the third Capacity Year of the Long Term PASA Study Horizon in the relevant Reserve Capacity Cycle. The ESR Duration Requirement was determined for the first time in the 2024 WEM ESOO (illustrative) but not applied in the 2024 Reserve Capacity Cycle. In the 2025 WEM ESOO, the ESR Duration Requirement will apply to new ESR in the 2025 Reserve Capacity Cycle.
Availability Duration Gap (ADG)	Number of consecutive Trading Intervals	The ADG is added to the 2026-27 ESR Duration Requirement to set the ESR Duration Requirement for 2027-28. This has the effect of increasing the ESR Duration Requirement.
Mid Peak Electric Storage Resource Obligation Intervals (ESROI)	Timestamp	The reference Trading Interval for all ESR used to determine the Peak ESROD. The Mid Peak ESROI is determined based on the Mid Peak and Flexible ESROI WEM Procedure[A]. Mid Peak ESROI is the middle of the Peak ESROD if it has an odd number of Trading Intervals, otherwise the last Trading Interval of the first half of the Peak ESROD.
Peak Energy Storage Resource Obligation Duration (ESROD)	Timestamp from – timestamp to	Represents the consecutive Trading Intervals (with a specified starting timestamp and ending timestamp) over which ESR is required to be available. Each of the consecutive Trading Intervals

Season	Expressed as	Meaning
		are referred to as an ESR Obligation Interval (ESROI). The number of ESROIs making up Peak ESROD is equal to the ESR Duration Requirement.

A. https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures

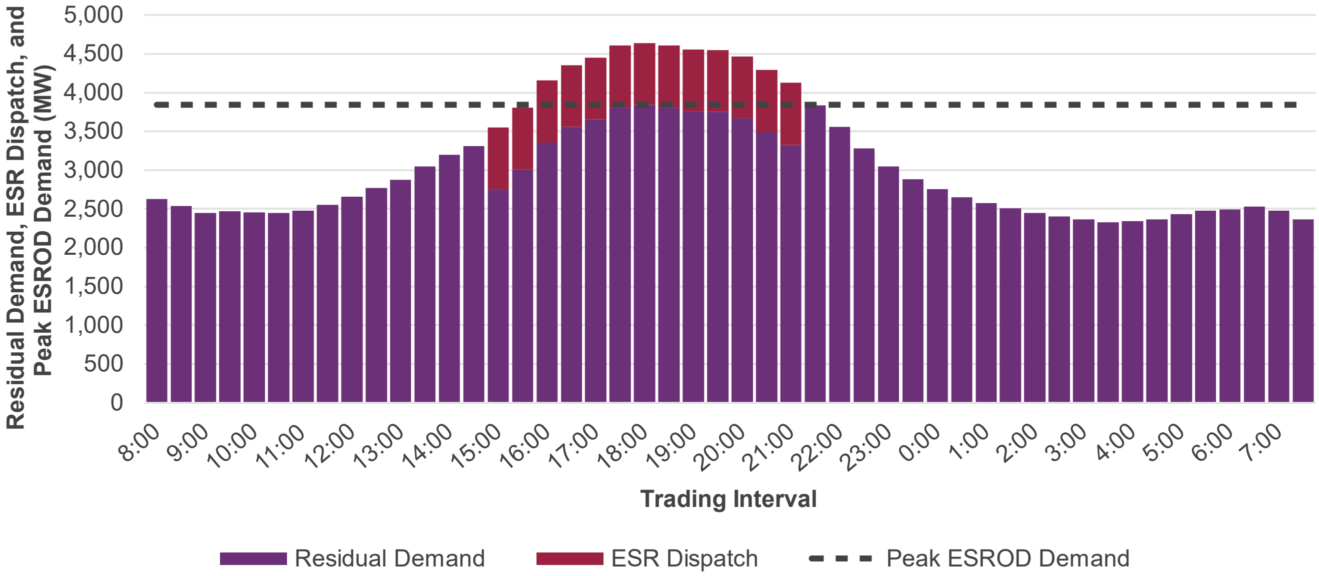
Figure 20 Illustration of the relationship between Mid Peak ESROI, ESR Duration Requirement, and Peak ESROD

3.1.1 ESR Duration Requirement for 2027-28

AEMO has determined the ESR Duration Requirement for each year of the outlook period, using demand traces developed for the Limb B assessment. The assessment was performed for the peak demand day of each of the 14 weather reference years developed for this WEM ESOO.

An example assessment is presented in **Figure 21,** which seeks to find the optimal duration for a given demand day to minimise peak demand. The assessment seeks to find the optimal duration (using de-rated capacity) where ESR minimises demand, without leaving higher demand in intervals outside of intervals in which ESR is dispatched. This assessment assumes that all ESR assigned Capacity Credits in the most recent Reserve Capacity Cycle are dispatched at derated capacity, where derated capacity is calculated as total ESR MWh capacity divided by assessed duration (which is iteratively extended until the optimal Reference ESROD is found).

Figure 21 Residual Demand, ESR Dispatch, and Peak ESROD Demand at each Trading Interval for illustration of ESR Duration Requirement assessment for a single peak demand day in a single weather reference year (MW)



The average assessed duration across all weather reference years is determined to be the ESR Duration Requirement for 2027-28. Indicative durations are provided for each year of the outlook period. The assessed duration, for each weather reference year across the outlook period, is presented in **Table 9**. A duration of 6-6.5 hours is observed across the outlook period across most weather reference years, with some weather reference years showing a declining trend to 5.5 hours.

Table 9 Reference_ESROD_QTY in hours for each weather reference year across the outlook period

Weather reference year	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
2010	4.0	6.5	6.5	6.0	6.0	6.0	6.5	6.5	6.5	6.5
2011	4.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
2012	4.0	6.5	6.5	6.0	6.0	6.0	6.0	6.0	6.5	6.5
2013	4.0	6.0	6.0	6.0	6.0	5.5	5.5	5.5	5.5	5.5
2014	4.0	6.0	6.0	6.0	5.5	5.5	5.5	5.5	5.5	5.5
2015	4.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
2016	4.0	6.0	6.0	5.5	5.5	5.5	5.5	6.0	6.0	6.0
2017	4.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
2018	4.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.5
2019	4.0	6.0	6.0	6.0	6.0	6.0	5.5	5.5	5.5	5.5
2020	4.0	6.5	6.5	6.0	6.0	6.0	6.0	6.5	6.5	6.5
2021	4.0	6.5	6.0	6.5	6.0	6.0	6.0	6.0	6.0	6.0
2022	4.0	6.0	6.5	6.0	6.0	6.0	6.0	6.0	6.0	6.0
2023	4.0	7.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Median	**4.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**

AEMO has determined an Availability Duration Gap of four Trading Intervals (two hours), which is added to the 2026-27 ESR Duration Requirement of eight Trading Intervals (four hours) to set the ESR Duration Requirement for 2027-28 as 12 Trading Intervals (six hours).

To consider the impacts of probable new entrants, AEMO conducted the same assessment with an assumption all probable new entrants are assigned Capacity Credits. These results are presented in **Table 10** and show an increase of ESR Duration Requirement to seven hours once these projects are operational, and for the remaining years of the outlook period (noting no degradation of Capacity Credits has been assumed).

Table 10 Reference_ESROD_QTY in hours for each weather reference year across the outlook period, inclusive of probable facilities

Weather reference year	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
2010	4.0	6.5	7.0	7.0	7.0	7.0	7.5	7.5	7.5	7.5
2011	4.0	6.0	7.0	7.5	7.0	7.0	7.0	7.0	7.0	7.0
2012	4.0	6.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.5
2013	4.0	6.0	6.5	7.0	6.5	6.5	6.5	6.5	6.5	7.0
2014	4.0	6.0	6.5	7.0	6.5	6.5	6.5	6.5	6.5	6.5
2015	4.0	6.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
2016	4.0	6.0	6.5	6.5	6.5	6.5	6.5	7.0	6.5	6.5
2017	4.0	6.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
2018	4.0	6.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
2019	4.0	6.0	6.5	7.0	7.0	6.5	6.5	6.5	6.5	7.0
2020	4.0	6.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.0
2021	4.0	6.5	7.0	7.5	7.0	7.0	7.5	7.5	7.5	7.5
2022	4.0	6.0	7.5	7.0	7.5	7.0	7.5	7.0	7.0	6.5
2023	4.0	7.0	8.0	8.5	8.0	8.0	8.0	7.5	7.5	7.5
Median	**4.0**	**6.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**

3.1.2 Mid Peak Electric Storage Resource Obligation Interval

Individual Expected scenario demand forecasts of POE levels of less than 10% POE and 50% were analysed to identify the Peak Demand Periods[62] in accordance with the Mid Peak and Flexible ESROI WEM Procedure. The Peak Demand Periods, which are inputs for the determination of the indicative Mid Peak ESROI, are identified as:

- for 2025-26 and 2026-27, the period between the start of the 16:00 Trading Interval and the end of the 19:30 Trading Interval for the shoulder and summer seasons, and the period between the start of the 17:00 Trading Interval and the end of the 20:30 Trading Interval for the winter season, and
- for 2027-28, the period between the start of the 15:00 Trading Interval and the end of the 20:30 Trading Interval for the shoulder and summer seasons, and the period between the start of the 16:00 Trading Interval and the end of the 21:30 Trading Interval for the winter season.

[62] Refer to WEM Procedure: Mid Peak and Flexible Electric Storage Resource Obligation Intervals. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

AEMO has reviewed the preliminary ESR Obligation Intervals (aligned to Peak Demand Periods) determined from the indicative Mid Peak ESROI, taking into account the operational requirements of the SWIS under the Medium Term PASA, and determined that the Peak ESRODs should be set on a Business/Non-Business Day basis to ensure system adequacy[63].

For 2025-26 and 2026-27, the final outcome of the ESR Duration Requirement is summarised in **Table 11**. Overall, among the three seasons and business days/non-business days, the Mid-Peak ESROI is determined to be shifted up to three Trading Intervals from the indicative Mid Peak ESROI to accommodate the increased large solar farm output during the afternoon compared to the subsequent night-time and limited DSP availability later in the evening.

Table 11 ESR Duration Requirement, Peak Demand Period, Indicative Mid Peak ESROI, Mid Peak ESROI and Peak ESROD determined for 2025-26 and 2026-27

Capacity Year	Season	ESR Duration Requirement (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
2025-26	Summer	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Winter	8	17:00-20:30	18:30	19:00 / 18:30	17:30-21:00 / 17:00-20:30
2026-27	Summer	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Winter	8	17:00-20:30	18:30	19:00 / 18:30	17:30-21:00 / 17:00-20:30

For 2027-28, the set of Mid Peak ESROIs are determined to be the same as those for 2025-26 and 2026-27 for the same reasons (see **Table 12**). The total installed capacity of ESRs with an ESR Duration Requirement of eight Trading Intervals (four hours) is expected to be greater than those with an ESR Duration Requirement of 12 Trading Intervals (six hours) for 2027-28, even if both committed and probable Facilities are accounted for.

[63] The same determination was made for the 2024 WEM ESOO.

Table 12 ESR Duration Requirement, Peak Demand Period, Indicative Mid Peak ESROI, Mid Peak ESROI and Peak ESROD determined for 2027-28 for the two ESR Capacity Credit status group

ESRs	Season	ESR Duration Requirement (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
Received Capacity Credits within any of the four previous Capacity Years	Summer	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	16:00-19:30	17:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Winter	8	17:00-20:30	18:30	19:00 / 18:30	17:30-21:00 / 17:00-20:30
Otherwise	Summer	12	15:00-20:30	17:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00
	Shoulder	12	15:00-20:30	17:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00
	Winter	12	16:00-21:30	18:30	19:00 / 18:30	16:30-22:00 / 16:00-21:30

3.1.3 ESROD Uplift

The ESROD Uplift reflects the difference between the total amount of Capacity Credits assigned to ESR in the 2024 Reserve Capacity Cycle and the degree to which that capacity is capable of minimising peak demand, which will be lower than the Capacity Credits assigned where the ESR Duration Requirement has increased. Grandfathering arrangements ensure these Facilities will continue to be certified using the duration in which they first received Capacity Credits (for a period of 10 years), the ESROD Uplift therefore provides a quantification of overallocation of Capacity Credits to ESR. Based on 1,298 MW of ESR Capacity, and an increase in ESR Duration Requirement from four hours to six hours, this results in an ESROD Uplift of 256 MW when applying the methodology under Appendix 11 of the ESRM Rules, outlined in Appendix A5.2.3. This value is applicable for Capacity Year 2027-28 and has been applied to the Limb A requirement from 2027-28 (see Chapter 5).

3.1.4 Flexible ESROI

Similar to the Mid Peak ESROI, the Flexible ESROI represents the last Trading Interval, which in conjunction with the Flexible Capacity Obligation Duration (eight Trading Intervals, as per the ESM Rules) sets the period of consecutive Trading Intervals over which Flexible ESR is required to be available for dispatch. **Table 13** presents the Flexible ESROI determined for 2027-28. AEMO has assessed that there is a very low likelihood that ESR dispatch would be required for both flexible capacity and peak demand on the same day. This assessment follows an analysis of demand trace forecasts based on 14 historical weather reference years.

Table 13 Flexible ESROI

Capacity Year	Season	Flexible Capacity Obligation Duration (number of Trading Intervals)	Flexible ESROI (interval starting)	Timestamps (intervals starting)
2027-28	Shoulder	8	18:00	14:30-18:00
	Winter	8	18:00	14:30-18:00

Note: the ESM Rules do not require the determination of the timestamps for Flexible ESROI. AEMO calculated the timestamps for information purposes.

3.2 DSP requirements

The requirements related to DSP include the Indicative DSP Dispatch Threshold, the Peak DSP Dispatch Requirement and the Flexible DSP Dispatch Requirement. The Peak DSP Dispatch Requirement is the minimum number of Trading Intervals in which a DSP is required to be available for dispatch in the applicable Capacity Year. The Flexible DSP Dispatch Requirement is the minimum number of Trading Intervals in the applicable Capacity Year in which a DSP with Flexible Capacity Credits must be available for dispatch in addition to its Peak DSP Dispatch Requirement.

3.2.1 Indicative DSP Dispatch Threshold

The Indicative Demand Side Programme Dispatch Threshold is the demand level at which capacity from DSPs is expected to be required, determined in accordance with clause 4.5.12(f) of the ESM Rules. The threshold is calculated as the MW peak demand for 50% POE, which for 2027-28 is 4,543 MW, minus the Capacity Credits issued to DSPs for 2026-27 (169 MW). The Indicative Demand Side Programme Dispatch Threshold for the 2027-28 is determined to be 4,374 MW.

3.2.2 Peak and Flexible DSP Dispatch Requirements

This section presents requirements relating to DSP, which are the Peak DSP Dispatch Requirement and the Flexible DSP Dispatch Requirement. These requirements set the obligations for DSPs providing Peak and Flexible Capacity, setting the number of Trading Intervals in which services can be dispatched by AEMO. These determinations replace hard-coded quantities in the ESM Rules.

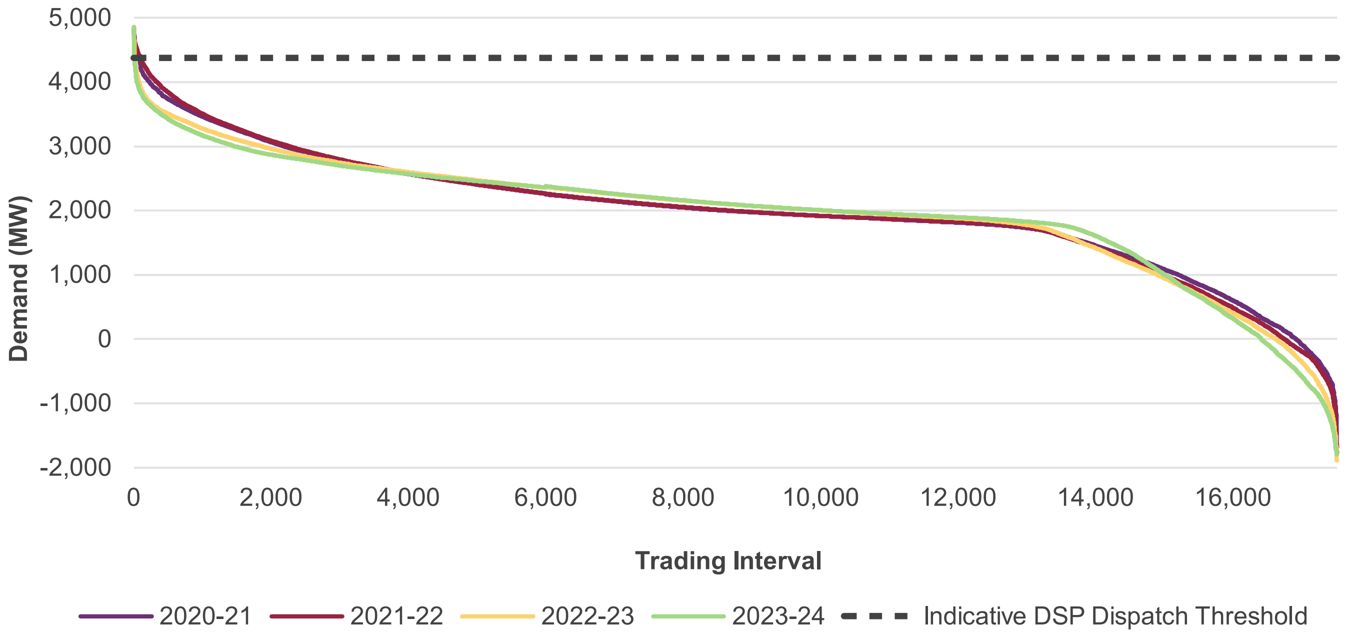
The assessment takes the Indicative DSP Dispatch Threshold and quantifies the average number of Trading Intervals for each year of the Reference Demand Profile in which demand exceeds this threshold as the Peak DSP Dispatch Requirement. The Flexible DSP Dispatch Requirement is the greater of eight Trading Intervals and the Peak DSP Dispatch Requirement.

The reference demand profile, constructed in accordance with Appendix 7 of the ESM Rules, is constructed from demand data from the four highest demand years in the previous five years, modified to:

- account for demand side reductions and distributed PV growth, and
- equal the 10% POE demand forecast and expected annual energy consumption.

Figure 22 presents the calculated Reference Demand Profile (RD) as a duration curve, for each of the four highest demand years within the RD Profile Reference Period (the 5 Years ending 1 October 2024). For each assessed year, it shows the number of Trading Intervals with demand exceeding the Indicative Demand Side Programme Dispatch Threshold.

Figure 22 Reference Demand (RD) Profiles for the four highest demand years within the RD Profile Reference Period (MW)



In accordance with clauses 4.5.12(g) and 4.5.12(h) of the ESM Rules, the Peak DSP Dispatch Requirement and the Flexible DSP Dispatch Requirement are to be determined for the third Capacity Year of the WEM ESOO study horizon, which for the 2025 WEM ESOO means the 2027-28 Capacity Year. **Table 14** presents the Peak DSP Dispatch Requirement and the Flexible DSP Dispatch Requirement for 2027-28, a reduction from previous years as a result of the new rules for AEMO to determine the requirement, replacing the hard-coded requirement.

Table 14 The Peak DSP Dispatch Requirement and the Flexible DSP Dispatch Requirements

Capacity Year	Expressed as	Peak DSP Dispatch Requirement (Hours / Trading Intervals)	Flexible DSP Dispatch Requirement (Hours / Trading Intervals)
2025-26	Number of hours / Trading Interval	200 / 400	Not applicable to Flexible DSP
2026-27		50 / 100	Not applicable to Flexible DSP
2027-28		23.75 / 47.5	23.75 / 47.5

4 Supply forecasts

This chapter presents the forecasts of supply for each Capacity Year in the 10-year outlook period, and a summary of the network limitations identified in the NAQ calculation for the 2024 Reserve Capacity Cycle.

The SWIS supply mix is changing, with coal-fired generation, capable of producing electricity irrespective of weather conditions or running hours, largely being replaced by capacity with different operating characteristics, including intermittent renewables and duration-limited ESR and DSP. In the Expected scenario:

- Supply increases in the first two years of the outlook period (by 353 MW and 319 MW in 2025-26 and 2026-27, respectively) compared to the forecasts in the 2024 WEM ESOO. The increase in 2025-26 is primarily due to the assumed earlier start of committed ESR capacity, while the increase in 2026-27 is due to the additional capacity procured under the RCM, being primarily comprised of ESR.
- A total of 1,695 MW of thermal generation is expected to retire or become unavailable from the SWIS over the next decade. A total of 1,287 MW of committed projects is forecast to enter the market over this same period, including 818 MW of ESR capacity, plus a mix of DSP, renewables and thermal capacity.
- Beyond committed projects, a further 507 MW of probable projects are anticipated to come online in 2027-28. ESR facilities represent 87% of this probable capacity[64].

4.1 New generator and storage assumptions

Supply forecasts consider existing capacity and new projects that are sufficiently progressed in the development pipeline. This includes capacity from generation, ESR, and DSP. Each 2025 WEM ESOO scenario includes a varying level of new supply that is determined based on how advanced the project is. Only existing and committed projects are included in the Expected scenario.

AEMO uses the 2025 EOIs[65] for CRC and responses to the 2025 Long Term PASA formal information requests (FIR) from Market Participants and Western Power to assess project progression, using the following three criteria:

1. **Environmental approvals** – evidence of a project's status in environmental approval processes.
2. **Network connection** – evidence of connection progress to the SWIS, based on information provided by Western Power.
3. **Finance decision** – evidence that new projects are well progressed towards a final investment decision (FID).

Many of these significant project milestones are unlikely to be achieved until the new project proponent has confidence that capacity credits will be available. Therefore, for each new project (or upgrade) planning to be operational for the current Reserve Capacity Cycle or later, AEMO calculates a percentage score based on how advanced they are against these evaluation criteria. A percentage score of 80% or more qualifies a project as "committed", a score between 50% and 80%

[64] This includes 665 MW of four-hour duration ESR. Since the ESR Duration Requirement has increased from four hours to six hours, this ESR's potential contribution to the Reserve Capacity Target is reduced to 439 MW.

[65] See 2025 Expression of Interest summary report, 2025, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2025/2025-expression-of-interest-summary-report.pdf?la=en.

qualifies a project as "probable", and all remaining new projects are classified as "proposed". For further details on the evaluation methodology, refer to Appendix A3.1.

The four new projects (Boddington Giga Battery, Merredin BESS, Muchea Big Battery and Waroona Renewable Energy project – Stage 1) that have been successful under the CIS in Western Australia, are subject to this same evaluation criterion[66].

New projects that have already received Capacity Credits for 2026-27 or are contracted for 2024-26 and 2025-27 NCESS – Reliability Services[67] automatically meet the definition of a committed facility, unless they are already online. AEMO assesses the timing of these projects through progress reports[68]. **Table 15** summarises the Facility classifications and their inclusion in the 2025 WEM ESOO modelling scenarios[69].

Table 15 Description of capacity classes and inclusion in the 2025 WEM ESOO scenarios

Capacity classification	Description	Included in 2025 WEM ESOO scenario
Existing capacity	Registered Facilities that are currently operational and have been: • assigned Capacity Credits for 2026-27 and reflecting any announced or assumed retirements, or • contracted for the 2024-26 Peak Demand NCESS[A], or • contracted for the 2025-27 Peak Demand NCESS[B].	All (Low, Expected, High)
Committed capacity[C]	New projects that are not yet operational and have: • been assigned Capacity Credits for 2026-27, or • scored 80% or higher in the new project status evaluation, or • been contracted for the 2024-26 Peak Demand NCESS, or • been contracted for the 2025-27 Peak Demand NCESS.	Expected and High only
Probable capacity	New projects that are a candidate for registration and have submitted a valid 2025 Long Term PASA FIR or 2025 EOI and scored between 50% and 80% in the new project status evaluation.	High only (plus in a sensitivity on the Expected scenario)
Proposed capacity	All new projects that have been proposed but scored less than 50%, so have not met the criteria to be in the existing, committed, or probable capacity categories.	None

A. For 2024-26 Peak Demand NCESS (the procurement of Reliability Services for 2024-25 and 2025-26), capacity is forecast to be available for Registered Facilities and upgrades of Registered Facilities for the contract period.
B. For 2025-27 Peak Demand NCESS (the procurement of Reliability Services for 2025-26 and 2026-27), capacity is expected to be available for Registered Facilities and upgrade of Registered Facilities for the entire outlook period.
C. For 2024-26 and 2025-27 Peak Demand NCESS capacity, the forecast capacity limited to contract period is overridden if any of the Facilities meet the score requirement in the new status evaluation or assigned Capacity Credits for 2026-27.

'Proposed capacity' projects were not included in any reliability modelling scenario. Existing capacity was included in each scenario until its scheduled retirement date or the date from which it was assumed to be unavailable. The scenario classification for Low and High scenarios relates only to supply forecasts. Only the Expected scenario was applied for the purposes of reliability modelling. AEMO conducted sensitivity analysis on the Expected scenario to test the impact on the reliability assessment if probable projects were included.

[66] See https://www.dcceew.gov.au/about/news/capacity-investment-scheme-supports-four-new-projects-wa.

[67] See https://www.wa.gov.au/system/files/2022-12/Coordinator%20of%20Energy%20Determination%20-%20Reliability%20Service%20-%20f2.pdf and https://www.wa.gov.au/system/files/2023-10/coordinator-of-energy_determination-reliability_service-october_2023.pdf.

[68] Market Participants holding Capacity Credits for Facilities that are not yet operational are required to submit a report on their progress as per clause 4.27.10 of the ESM Rules.

[69] This Chapter uses information available as of 4 June 2025, for each project in the criteria evaluation outcome.

4.1.1 Forecast committed and probable capacity

A total of 1.7 GW of new generation and storage capacity (based on maximum capacity) is forecast to be committed to supply in the SWIS during this outlook period. **Table 16** presents a list of committed and probable capacity forecast to be available for the 2025 Long Term PASA.

Table 16 Committed and probable projects and storage capacity developments, by Capability Class, 2025-26 to 2034-35

Commitment status	Capacity provided by	Capability Class[A]	Maximum Capacity (MW)[B]	Storage Capacity (MWh)[B]	Anticipated full commercial operation date[C]
Committed capacity	2024-26 Peak Demand NCESS – DSP[D]	Capability Class 2	120	N/A	March 2025
	2025-27 Peak Demand NCESS – DSP[E]	Capability Class 2	98	N/A	March to October 2025
	Kwinana Waste to Energy Project	Capability Class 1	36	N/A	May 2025
	2024-26 Peak Demand NCESS – ESR[D]	Capability Class 2	50	200	October 2025
	2025-27 Peak Demand NCESS – ESR[E]	Capability Class 2	312	1212	October 2025
	2025-27 Peak Demand NCESS – ESR/DSP[E]	Capability Class 2	19	N/A	October 2025
	Electricity Generation and Retail Corporation Collie Battery	Capability Class 2	500	2000	December 2025
	East Rockingham RRF Project Co Pty Ltd	Capability Class 1	29	N/A	October 2026
	Kingia Plains Energy's Arrowsmith gas project	Capability Class 1	85	N/A	October 2026
	Nomad Energy Merredin ESR	Capability Class 2	100	400	November 2026
	King Rocks Wind Firm	Capability Class 3	150	N/A	June 2027
	Warradarge Wind Firm upgrade	Capability Class 3	102	N/A	October 2027
	Other Facilities operated by gas and Diesel, as assessed with 2025 WEM ESOO FIR and 2025 EOI information	Capability Class 1	92	N/A	March 2025 to September 2027
	Other ESR Facilities as assessed with 2025 WEM ESOO FIR and 2025 EOI information	Capability Class 2	25	40	October 2027
Probable Capacity	Boddington Giga Battery	Capability Class 2	324	1296	October 2027
	Muchea Big Battery	Capability Class 2	150	600	March 2028
	Waroona Renewable Energy Project – Stage 1	Capability Class 2	80	320	October 2027
	Other Solar Facilities as assessed with 2025 WEM ESOO FIR and 2025 EOI information	Capability Class 3	110	N/A	October 2027
	Other ESR Facilities as assessed with 2025 WEM ESOO FIR and 2025 EOI information	Capability Class 2	111	120	May 2026 to October 2028

A. Capability Classes 1, 2 and 3 are as defined in Chapter 1.
B. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding. If ESR duration capacity was not provided by a Market Participant, AEMO assumed availability for one hour as a conservative approach.
C. Full commercial operation dates are either provided by the Market Participants or a Facility's obligation date for providing Capacity Credits and Peak Demand NCESS. AEMO assesses the timing of these projects through progress reports and market research. AEMO's ESOO methodology may apply delays with completion assumed after the proponent-advised dates, with delays reflected in progress reports.
D. For detail on Facilities contracted for the 2024-26 Peak Demand NCESS services, see https://aemo.com.au/consultations/tenders/tenders-and-expressions-of-interest-for-ncess-reliability-services-wa.
E. For detail on Facilities contracted for the 2025-27 Peak Demand NCESS services, see https://aemo.com.au/consultations/tenders/expressions-of-interest-and-tender-for-ncess-reliability-services-2025-27-wa.

The probable Facility list is not exhaustive due to confidentiality of the 2025 EOI submissions. For any other confidential information to AEMO from Market Participants, this table presents an aggregation of values by their technology type as appropriate. Detail on forecast existing, committed and probable capacity is in Appendix A4.

4.1.2 Generator retirement and unavailability assumptions

Several coal-fired generators are expected to retire or become unavailable during the outlook period, with the potential for ageing gas fleet to also exit the market. **Table 17** summarises the retirement and unavailability assumptions in this year's WEM ESOO modelling. By the end of the 10-year outlook period, a total of 1,695 MW of thermal generation is anticipated to leave the system.

Table 17 Generator retirements or unavailability assumed in the 2025 WEM ESOO modelling

Facility	Owner	Capacity Credits for 2026-27	Modelled retirement or unavailability date	Reason for unavailability
Collie Power Station	Synergy	317.2 MW	1 October 2027	Announced
Bluewaters Power Station units 1 and 2	Bluewaters Power	217.0 MW per unit (434 MW total)	1 October 2027[A]	Assumed (discussed below)
Muja D Power Station units 7 and 8	Synergy	211.0 MW per unit (422 MW total)	1 October 2029	Announced
Pinjar gas turbines 2, 3, 4, 5, and 7	Synergy	177.3 MW total	1 October 2029	Assumed (discussed below)
Pinjar gas turbines 9, 10, and 11	Synergy	344.4 MW total	1 October 2032	Assumed (discussed below)
Total MW assumed to exit the market		**1,694.8 MW**		

A. The 2025 WEM ESOO considered an alternative Bluewaters sensitivity scenario where Bluewaters power station units 1 and 2 were assumed unavailable from 1 October 2030. The impact of this delayed unavailability is discussed in Chapters 5.

The following considerations informed these closure assumptions:

- In June 2022, the Western Australian Government announced the retirement of the Synergy-owned coal-fired power stations, and on 27 September 2024, AEMO received formal notification from Synergy of its intention to cease operating Collie Power Station on 1 October 2027[70].
- The age of the Pinjar gas turbines is between 29 and 35 years and they have been experiencing an increase in their Forced Outage rate. The retirement of these gas turbines in the 2025 WEM ESOO modelling aligns with the Benchmark Reserve Capacity Price (BRCP) Reference Technology Review's maximum asset life assumptions[71].
- The current Western Australian Government State Agreement with The Griffin Coal Mining Company Pty Ltd, which supplies the Bluewaters Power Station, is due to expire in June 2026[72]. On 27 May 2025, the Premier of Western Australia reiterated in Parliament that the subsidies for the mine ($220 million in this year's State Budget), which had previously been deemed necessary for its continued operation, will cease upon the expiry of the existing State

[70] See Western Australian Government, *State-owned coal power stations to be retired by 2030 with move towards renewable energy*, 2022, at https://www.wa.gov.au/government/announcements/state-owned-coal-power-stations-be-retired-2030-move-towards-renewable-energy. AEMO received formal notification on intentions of ceasing operation from Market Participants, see https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/notifications-of-facility-retirements.

[71] See https://www.wa.gov.au/system/files/2023-11/epwa-brcp_reference_technology_review-v2.1.pdf.

[72] *Collie Coal (Griffin) Agreement Act 1979*. See https://www.legislation.wa.gov.au/legislation/prod/filestore.nsf/FileURL/mrdoc_47736.pdf/$FILE/Collie%20Coal%20(Griffin)%20Agreement%20Act%201979%20-%20%5B01-e0-00%5D.pdf?OpenElement.

Agreement[73]. While AEMO understands Bluewaters has stockpiles of coal to meet reserve capacity requirements for 2026-27, due to the risk Bluewaters will not be able to establish a new coal supply arrangement past this point, AEMO considers it prudent not to assume the availability of this power station from 2027-28 onwards in the reliability assessment.

Importantly, the decision to consider the potential unavailability of the Bluewaters units in the Expected scenario neither restricts Bluewaters from submitting a CRC application for its two units nor pre-empts a particular CRC assessment outcome for these facilities. AEMO will consider any CRC applications provided as part of the 2025 Reserve Capacity Cycle and undertake assessments in line with the relevant ESM Rules and WEM Procedure.

AEMO has also conducted sensitivity analysis, assuming Bluewaters' operations are unavailable from 1 October 2030, so that the reliability impact of the early closure of Bluewaters can be quantified. This assumption does not reflect any formal decision made by the owners or operators of the facility to retire the generation plant in 2030-31 or any other year.

4.2 Peak Capacity included in each scenario

AEMO assigns CRC and Capacity Credits based on each facility's technology type[74], with assigned Capacity Credits typically being lower than the nameplate capacity of the facility. According to clause 4.11.4 of the ESM Rules, AEMO needs to assign a Capability Class to apply to the relevant Facility or component when assigning Peak CRC in the 2025 Reserve Capacity Cycle. **Table 18** summarises the CRC and Capacity Credit assignment methodology by a Facility's technology type and Capability Class.

Table 18 CRC and Capacity Credit assignment method by Capability Class and technology type

Facility technology type	Capability Class	Technology description and examples	CRC and Capacity Credit assignment method
Non-Intermittent Generating Systems (NIGS)	Capability Class 1	Thermal generation that uses fuels such as coal, gas, and diesel.	Assessed based on sent-out capacity at 41°C, accounting for derating of the technology at elevated ambient temperatures and historical Forced Outage rates[A].
Intermittent Generating Systems (IGS)	Capability Class 3	Renewable generation, such as solar, wind, and landfill gas.	Assessed based on Relevant Level Method[B], that is estimated contribution during periods of high demand, or actual contribution (for operational Facilities).
ESR	Capability Class 2	Electric storage systems, such as batteries and pumped hydro storage. Existing and committed ESR can have between one- and four-hours duration.	Assessed based on estimated ability to sustain a level of output at 41°C, accounting for derating of the technology over the Peak Electric Storage Resource Obligation Duration (currently four hours) after netting off capacity required for serving Loads associated with the technology and observed performance of the technology[C].
Demand Side Programmes (DSP)	Capability Class 2	Reduce load or increase injection from non-dispatchable loads or embedded generation associated with a load. Represented by DER aggregators comprising behind-the-meter electric storage systems or response from single or aggregated industrial loads.	Assessed based on the amount of load reduction or generation increase from their standard operation.

[73] See https://www.parliament.wa.gov.au/hansard/daily/lh/2025-05-27/pdf/download.

[74] The methodology used for assessing and assigning CRC and Capacity Credits may differ depending on Facility Class as outlined in clause 4.10.2 of the ESM Rules.

Facility technology type	Capability Class	Technology description and examples	CRC and Capacity Credit assignment method
		DSP has a limited window of operation (between 8:00 am and 8:00 pm) and limited number of running hours per year. It is set at a minimum of 200 hours per annum for 2025-26 and 50 hours for annum for 2026-27. Frequent use of DSP resources may lower the annual energy consumption, as well as the effective peak demand.	

A. The CRC quantity may be reduced if the Forced Outage rate calculated as per clause 3.21.7 of the ESM Rules exceeds 10%: see clause 4.11.1A of the ESM Rules.
B. Relevant Level Method as per Appendix 9 of the ESM Rules.
C. For a Non-Scheduled Facility comprising only an ESR, it is assessed based on the Relevant Level Method as per clause 4.11.1(bD) of the ESM Rules.

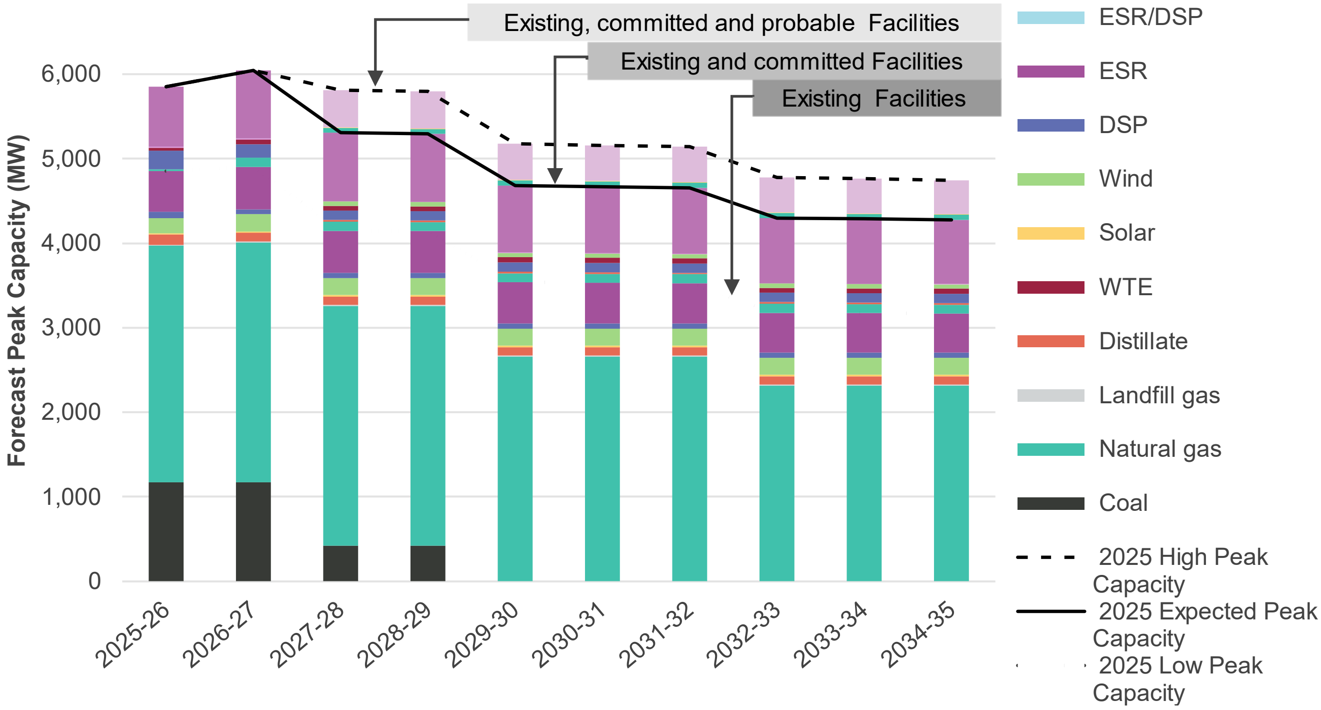
The forecast Peak Capacity for the initial two Capacity Years, 2025-26 and 2026-27, is determined by the assigned Capacity Credits and NCESS Contract quantities for the respective years, with adjustments for full operation dates based on progress reports and market research. For the subsequent Capacity Years, AEMO estimates the potential amount of forecast Peak Capacity based on the technology type and the adjustment required for Facilities with historical Forced Outage rates exceeding a prescribed Forced Outage Threshold that have not been mitigated through significant maintenance or upgrade[75].

Figure 23 shows the Peak Capacity mix by technology type, for the Low, Expected, and High scenarios over the outlook period.

There is an overall reduction in forecast Peak Capacity between 2025-26 to 2034-35 across all three scenarios. This is driven by the assumed unavailability and retirements of thermal generators. **Table 19** summarises the key observations.

[75] Under clause 4.11.1A of ESM Rules, if a facility or Separately Certified Component has been in Commercial Operation for at least 12 months and has had a Forced Outage rate above the Forced Outage Threshold over the past 36 months, AEMO must adjust its Peak Certified Reserve Capacity, unless it has re-entered service after significant maintenance or an upgrade within the last 12 months.

Figure 23 Forecast Peak Capacity by technology type, under three scenarios, 2025-26 to 2034-35 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities and large-scale standalone batteries.

Table 19 Summary of key observations, by scenario

Scenario	Low	Expected	High
Overall net change in capacity between 2025-26 and 2034-35	1,688 MW decrease	1,581 MW decrease	1111 MW decrease
Observations	• There is a slight increase in capacity up to 2026-27, largely attributed to the additional capacity from the 2024-26 Peak Demand NCESS and 2025-27 Peak Demand NCESS projects. • The maximum forecast capacity is 4,904 MW in 2026-27, 58% of which is provided by Facilities operated by natural gas.	• An increase in capacity is projected up to 2026-27. Largely attributed to the additional capacity from the 2024-26 Peak Demand NCESS and 2025-27 Peak Demand NCESS projects along with addition of committed capacity to the existing capacity. • Maximum forecast capacity is 6,048 MW in 2026-27, adding 1,144 MW of committed capacity to the existing capacity, 71% of which are contributed by ESR. The projected net capacity decreases from 2027-28 onwards with assumed retirement of thermal generators.	• An increase in capacity is projected up to 2026-27, with addition of probable capacity to the committed and existing capacity projected in the Expected scenario. • Maximum capacity is 6,048 MW in 2026-27. The projected net capacity decreases from 2027-28 and onwards with assumed retirement of thermal generators, despite adding 507 MW of probable capacity to committed and existing capacity, 87% of which is contributed by ESR.

4.3 Forecast Flexible Capacity

Flexible Capacity is a new component of the RCM in the WEM, introduced from the 2025 Reserve Capacity Cycle onwards. This is to provide incentive for Market Participants to connect Facilities that can start, stop, ramp up and ramp down within a four-hour period.

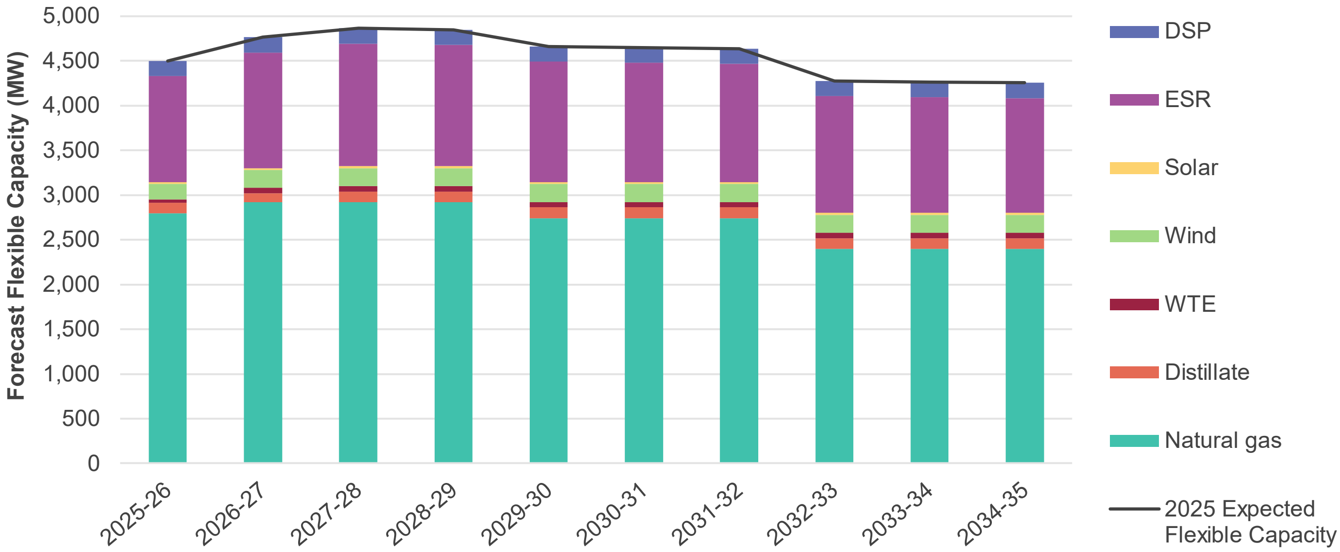
All technology types are potentially eligible for Flexible Capacity, with different minimum eligibility requirements[76] for each technology type. AEMO will assign Flexible Capacity to Facilities meeting the minimum eligibility requirements based on the maximum output the Facility can achieve within four hours from a cold state, with the quantity of Flexible Capacity capped at the level of assigned Peak Capacity Credits.

Figure 24 presents the existing and committed Flexible Capacity mix by generation type for the Expected scenario in the 2025 WEM ESOO outlook period.

The 2025 WEM ESOO Flexible Capacity forecast assumes that all technology types that can apply for 2025 CRC, will apply. The practical outcomes are likely to vary, depending on the CRC applications received and how clause 4.20.5A(a) of the ESM Rules applies to those applications.

On average, over this outlook period, 59% of the Flexible Capacity is forecast to be contributed by Facilities operated by natural gas, followed by a 29% contribution from ESRs. The remainder is anticipated to be contributed by DSP, distillate and WTE Facilities. The total Flexible Capacity from existing and committed Facilities is forecast to reach its maximum in 2027-28 at 4,863 MW and decrease thereafter following the assumed retirements of gas facilities.

Figure 24 Forecast Flexible Capacity by technology type, Expected scenario, 2025-26 to 2034-35 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities and standalone large-scale batteries.

Chapter 5 presents the outcome of the Flexible RCT assessment.

4.4 Drivers of forecast capacity supply

Forecast capacity supply to the SWIS during the 2025 WEM ESOO outlook period is primarily driven by existing and committed Facilities' assigned Capacity Credits for 2025-26 and 2026-27 or Facility contracts for 2024-26 and 2025-27 NCESS – Reliability Services. A total of 5,953 MW of Capacity Credits were assigned to 72 Facilities for 2026-27, a 1,236 MW increase on the Capacity Credits assigned to 67 Facilities for 2025-26. A total of over 400 MW of capacity was procured through the 2025-27 NCESS from existing facility upgrades and new Facilities. Network constraints limited some existing and

[76] For detail on the minimum eligibility requirements, see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/wa_wem_consultation_documents/2024/fcmer_2025/20241101-flexible-capacity-minimum-eligibility-requirements-final-report.pdf?la=en&hash=E3471CEAE64E3DC82272F305964A0738.

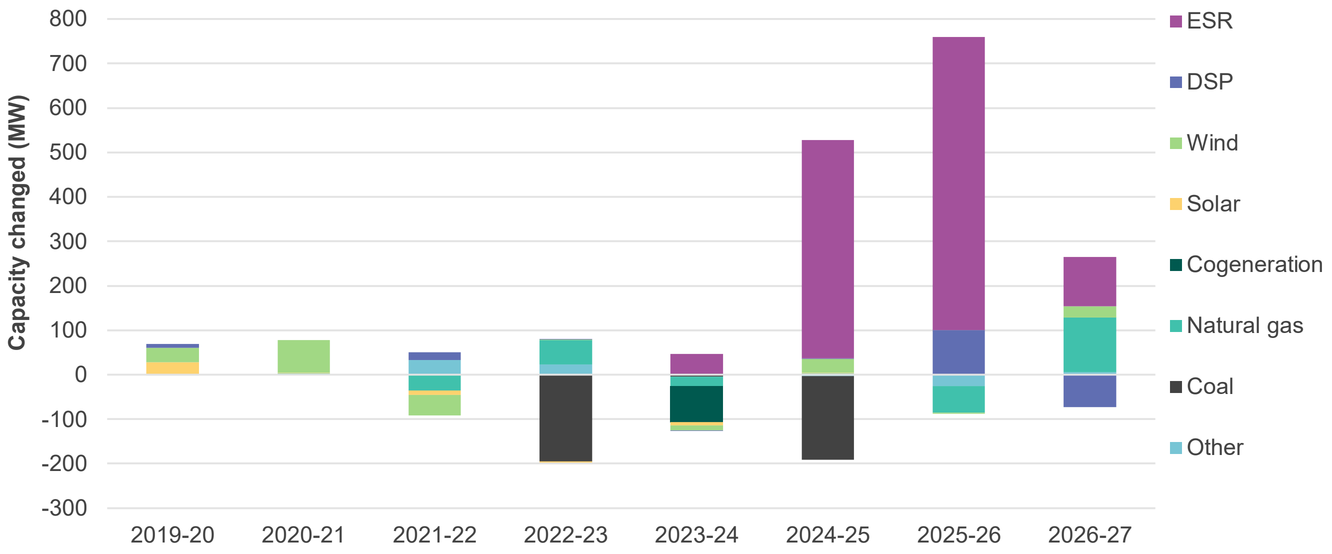
new Facilities' supply capability, with 10 Facilities experiencing NAQ reductions totalling 166 MW in the 2024 Reserve Capacity Cycle. Ageing Facilities progressing to retire also reduced supply from existing facilities, with a total of 1,695 MW forecast to retire in this outlook period. The impacts of these changes are summarised below, while the changes in Capacity Credits for 2026-27 are detailed in Appendix A3.2.

4.4.1 Change in forecast supply capacity

Figure 25 illustrates the acceleration of investment in the WEM, with 2024-25 representing a record year with the maximum change in supply capacity ever experienced in the WEM. It highlights the retirement of thermal generation (including Muja C Unit 5 in 2022-23 and Muja C Unit 6 in 2024-25) and the replacement of that generation with ESR, DSP and to a lesser extent, new wind and solar projects.

A total of 284 MW of additional existing and committed capacity was assumed to be available in 2026-27 compared to 2025-26. This is largely due to 123 MW of additional capacity from gas Facilities, 25 MW of additional capacity from wind Facilities, 25 MW of additional capacity from waste to energy Facilities, and 111 MW of additional capacity from ESR. This total assumed additional capacity exceeds the 92 MW reduction in assumed capacity from diesel Facilities (19 MW) and DSP (73 MW).

Figure 25 Change in actual and forecast Peak Capacity in the 2024 and 2025 WEM ESOOs by technology type, 2019-20 to 2026-27 (MW)



Notes:

- From 2019-20 to 2023-24, these values represent assigned Capacity Credits. For 2024-25, values are based on forecast Peak Capacity under the Expected scenario in the 2024 WEM ESOO. For 2025-26 and 2026-27, values are based on forecast Peak Capacity under the Expected scenario in the 2025 WEM ESOO.
- The ESR grouping presented here includes the battery components of hybrid Facilities and standalone large-scale batteries, while the "Other" grouping includes Facilities operated by Landfill gas, distillate, and municipal waste.

4.4.2 Network Access Quantity

The NAQ framework provides for a Facility's CRC to be adjusted down if necessary to account for network constraints[77]. A Facility's NAQ is determined by three key factors – its physical capability, network access limit and its priority order in the NAQ model. AEMO runs the NAQ model following the assignment of CRC and the completion of the trade declaration process[78].

AEMO first applied the NAQ Framework in the 2022 Reserve Capacity Cycle, assigning all Facilities a NAQ equal to their CRC. In the 2023 Reserve Capacity Cycle, three Facilities had NAQ reductions, totalling 15 MW. The 2024 Reserve Capacity Cycle saw a significant shift, with 10 Facilities experiencing NAQ reductions totalling 166 MW. These facilities were all located in the south of the SWIS at: Wagerup, Pinjarra, Collie, Binningup and Kemerton.

These NAQ reductions were due to thermal constraints at lines connecting Mandurah to Pinjarra, Northern Terminal to Henley Brook, and Southern Terminal to Cannington Terminal[79]. The constraint between the Mandurah and Pinjarra is the most impactful, so much so that if it was removed from the model (for example, due to a network augmentation), then all these Facilities would have received NAQ equal to their CRC. These network constraints, and the corresponding facilities that experienced NAQ reductions, are detailed in Appendix A3.2.1.

In some cases, AEMO assigned Capacity Credits lower than the Facilities' corresponding CRC in the 2024 Reserve Capacity Cycle for reasons other than network limitations. For example, the Waroona and Warradarge Upgrade Facilities were assigned CRC but did not receive Capacity Credits because of their prioritisation in the NAQ model[80].

4.4.3 Facility age

Figure 26 summarises the Capacity Credits assigned for 2026-27, categorised by fuel type and age of the associated facility. An ageing facility may be associated with increased scale and frequency of Forced Outages and subject to a reduction of Capacity Credits unless it re-entered service within the previous 12 months after significant maintenance (or an upgrade) as per clause 4.11.1A of the ESM Rules. It is therefore an incentive for Facilities to keep plants reliable to avoid possible reductions in Capacity Credits as reflected in the 2025 WEM ESOO modelling. These are the key insights from Figure 26:

- Energy storage represents 78.3% of new facilities, being those fewer than five years old that received Capacity Credits for 2026-27.
- Thermal fleet, especially coal, remains among the oldest in the capacity mix for 2026-27. Collie Power Station accounts for 317 MW of this ageing fleet, and the Synergy Pinjar gas-fired Facilities are all aged between 26 years and 35 years, representing 552 MW. The Muja D Power Station and the Alcoa Wagerup Facilities, the oldest generators in the SWIS with a service history of 36-40 years, make up 7.4% of the Capacity Credits assigned.

[77] AEMO formulates RCM Constraint Equations in accordance with clause 4.4B.4 of the ESM Rules, which forms part of the NAQ model input. See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/congestion-information-resource/constraints-library/rcm-constraints-library for complete RCM constraint Library and RCM Limit Advice.

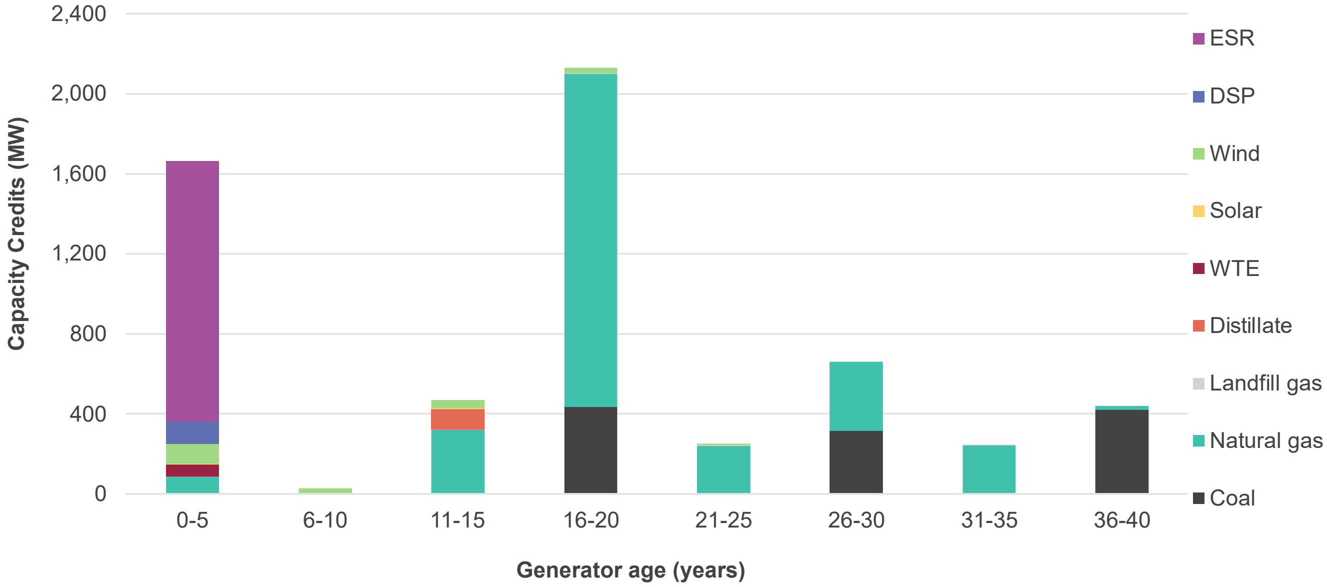
[78] For detail on the NAQ process, see https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/network-access-quantities.

[79] These constraints were significant enough to arise in significant number of peak dispatch scenarios. Network limits that cause constraints in only a small proportion of dispatch scenarios (for example, less than 5% of possible peak dispatch scenarios) do not typically impact the assigned NAQ, in accordance with clause 4.15.9(c) of the ESM Rules.

[80] For further detail, see https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/network-access-quantities/naqprocesssummary_rcc2024.xlsx.

- Gas-powered generation has the broadest age profile, with majority of Facilities ranging from 11 to 35 years old. Facilities operated by natural gas also accounts for the largest portion of Capacity Credits, with 2,921 MW assigned in 2026-27.

Figure 26 Capacity Credits in the SWIS for 2026-27 by technology type and generator age, as of 29 April 2025 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities and standalone large-scale batteries.

4.5 Setting Reserve Margin

The reserve margin is a key component of Limb A of the Planning Criterion. In accordance with clause 4.5.9(a) of the ESM Rules, the Reserve Margin is calculated as the greater of Forced Outage allowance and the largest contingency relative to loss of supply expected at the time of forecast peak demand (including transmission losses and allowing for Intermittent Loads). The following two sections provide:

- analysis for the determination of largest contingency, with the conclusion being that it should continue to be set as the three largest Facilities in the SWIS, and
- analysis of historical Forced Outage trend and calculation for the determination of Forced Outage allowance.

For more details on the methodology for the determination of the reserve margin, refer to Appendix A5.2.1.

4.5.1 Determination of Largest Contingency

The Western Australian summer places significant stress on generation fleet. Extreme temperatures and high electricity demand (typically for cooling and industrial processes) sees higher utilisation of thermal fleet, which can indirectly lead to increased Forced Outages when equipment is under stress. It is essential there is sufficient capacity available in the SWIS at any given time to meet peak demand, so AEMO monitors levels of Forced Outages closely.

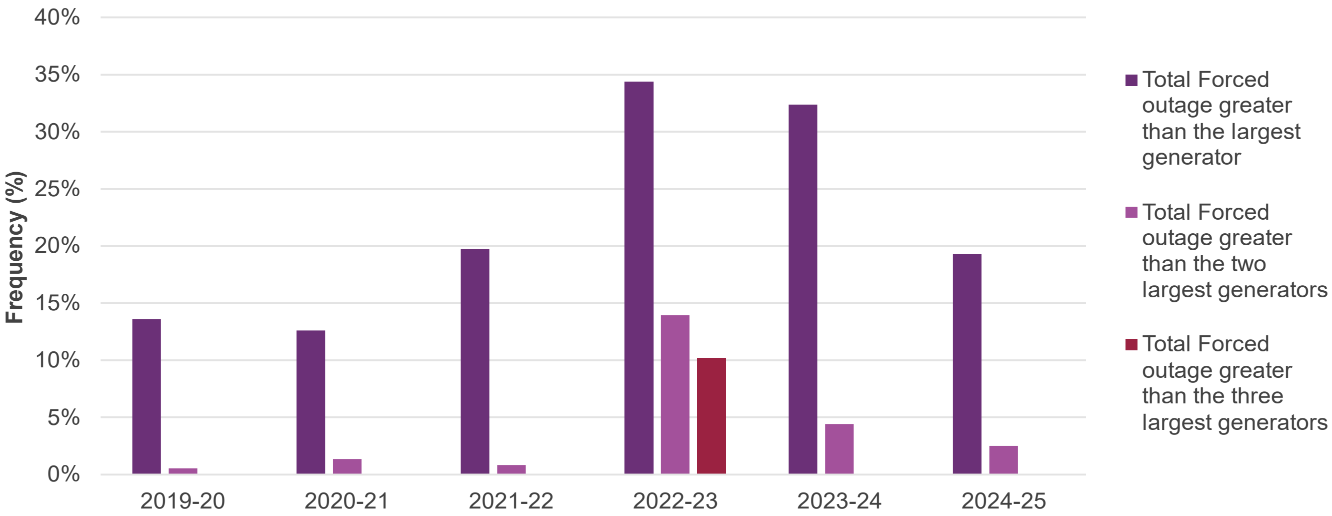
Figure 27 shows the frequency of the total Forced Outages for non-intermittent generating units exceeding the capacity of the largest single generating unit, two generating units, and three generating units during peak periods over the past six Hot

Seasons. To inform the appropriate reserve margin for capacity adequacy (Limb A of the Planning Criterion), AEMO analyses historical Forced Outage rates which may apply during peak demand intervals.

In 2024-25, the scale and frequency of Forced Outages significantly decreased compared to recent years, with Forced Outage frequency results resembling pre-2022-23 levels. However, total Forced Outages greater than the two largest generators remained similar to 2023-24 levels. This result highlights that the total capacity on Forced Outage over peak intervals remains relatively high and that the SWIS may need to operate with Forced Outages exceeding the largest two generating units in future years. AEMO has therefore determined that it is appropriate to maintain reserves equivalent to the third largest unit to ensure system reliability and security.

The three largest generators for 2025-26 and 2026-27 are made up of NewGen Neerabup (331 MW), NewGen Kwinana (328 MW) and Collie (317 MW). Following the assumed retirement of Collie (317 MW) on 1 October 2027, the reserve margin is replaced with Neoen Collie ESR Stage 2 (300 MW) for 2027-28 and onwards.

Figure 27 Frequency of Forced Outage exceeding the single, two, and three largest generators during the peak intervals from 2019-20 to 2024-25 Hot Seasons (%)



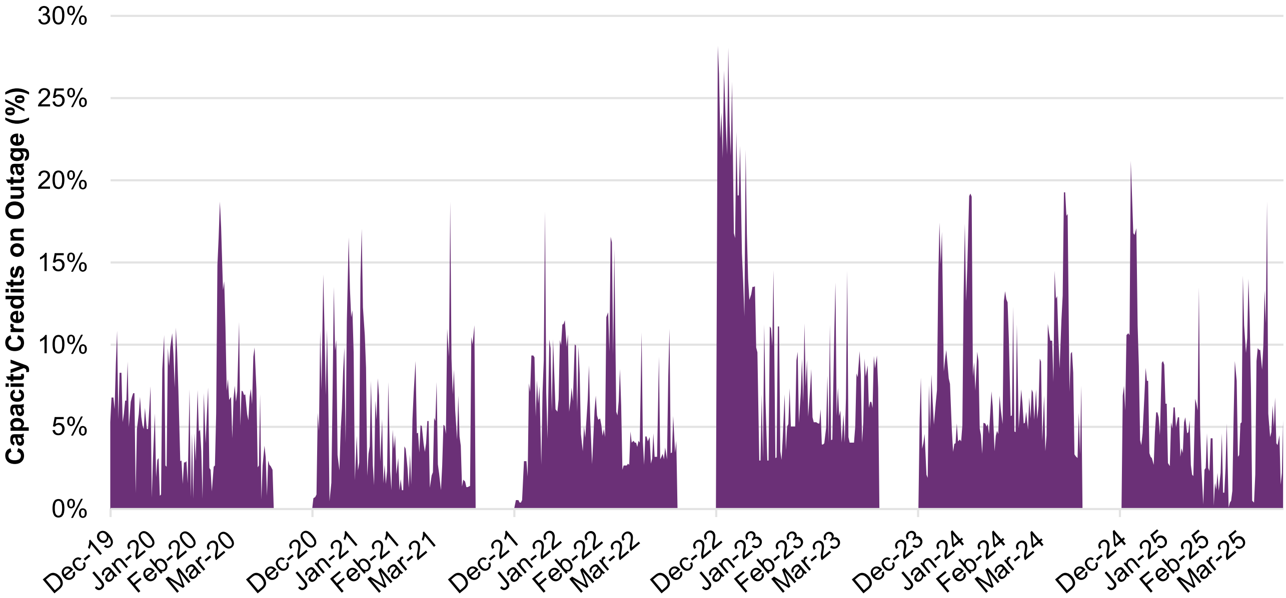
Note: the peak intervals applied for the 2019-20 to 2023-24 Hot Seasons were the 16:30 and 20:00 Trading Intervals, while for the 2024-25 Hot Season were the 17:30 and 21:00 Trading Intervals. The peak intervals are taken from the ESROIs determined for the corresponding Capacity Years.

4.5.2 Forced Outage allowance

AEMO analyses historical Forced Outage rates which may apply during peak demand for the recent six Hot Seasons. Recent trends of tight operational conditions and frequent demand records may pose greater risk of supply shortfalls in the instances of higher Forced Outages during these time periods.

Figure 28 shows the daily maximum Forced Outages of firm capacity as a percentage of assigned Capacity Credits for the 2019-20 to 2024-25 Hot Seasons. The figure shows that prior to the 2022-23 Hot Season, the total Forced Outages during peak periods was less than 20% of Capacity Credits. However, Forced Outages exceeding 20% of assigned Capacity Credits have been observed more frequently in recent years.

Figure 28 **Daily peak percentage of Capacity Credits on Forced Outage during Hot Season for 2019-20 to 2024-25 (%)**



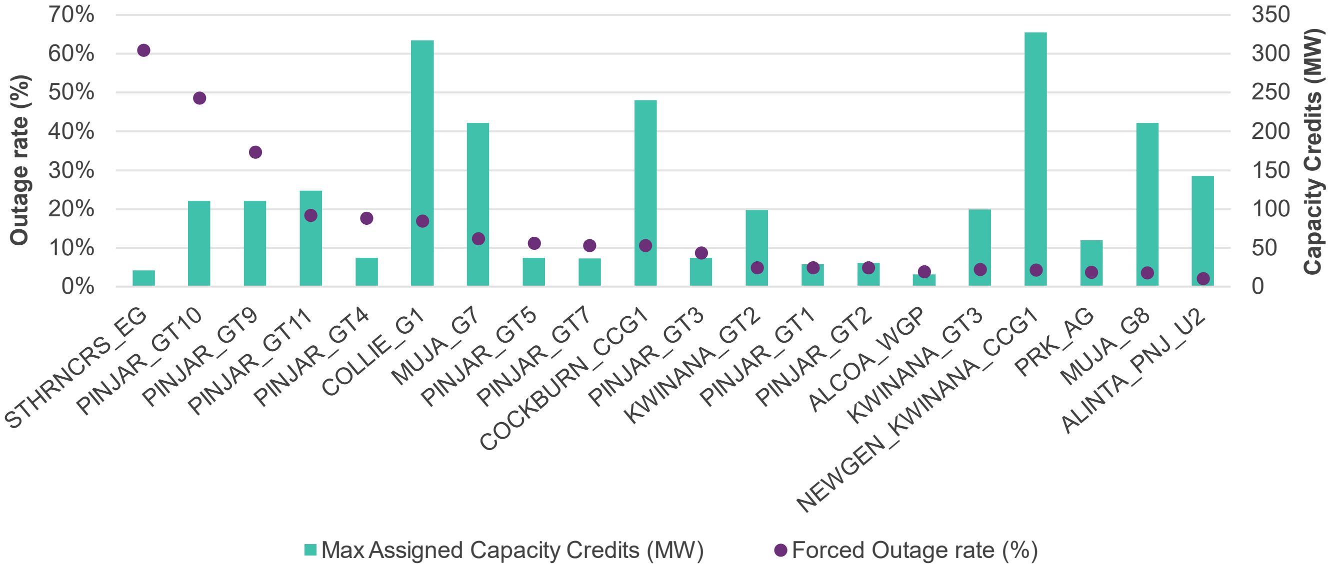
The 2024 WEM ESOO highlighted that the 2022-23 Hot Season saw Forced Outages exceeding 25% of assigned Capacity Credits due to coal supply issues. The 2023-24 Hot Season, while not as extreme as 2022-23, saw high Forced Outages, particularly for the Pinjar Power Station.

Compared to both the 2022-23 and 2023-24 Hot Seasons, the average level of Forced Outages was lower for 2024-25. Despite this, the peak outage levels during 2024-25 were greater than the historical trends, with values peaking at 21% and 19% on 7 and 8 December 2024, respectively.

Figure 29 shows the 20 non-intermittent generating Facilities with the highest level of Forced Outages and their maximum assigned Capacity Credits over the 36 months ending 13 May 2025. While the Forced Outage rate for most Facilities remained similar to last year, the gas turbines at Pinjar experienced an increase in their Forced Outage rate, with two Facilities exceeding 30%. According to clause 4.11.1A of the ESM Rules, AEMO must take into account historical Forced Outage data[81] as part of the assessment of the quantity of the Peak CRC assignment. In this process, AEMO will determine whether a reduction in assigned CRC will apply to these Pinjar units in this Reserve Capacity Cycle.

[81] If a Facility, or Separately Certified Components, has been in Commercial Operation for at least 12 month and has had a Forced Outage rate greater than the Forced Outage Threshold over the preceding 36 months (or fewer, if applicable), then unless the Facility has re-entered service within the last 12 months after significant maintenance or an upgrade, AEMO must assign a reduced quantity of Peak Certified Reserve Capacity.

Figure 29 Outage rate (%) and maximum Capacity Credits (MW) assigned by Facility for the 36 months as of 13 May 2025



Notes:

- Outage rate was calculated by dividing the outage MW by the Capacity Credit of the relevant year at each interval, then averaging this value over the 36-month period.
- Maximum Capacity Credits assigned is the largest amount of Capacity Credits assigned to a given Facility among each Capacity Year in the 36-month period (2021-22 to 2024-25).
- Retired Facilities (KALAMUNDA_SG and MUJA_G5) and Facilities that have been operational for less than 12 months (KWINANA_ESR1) have not been included.
- The outage data for STHRNCRS_EG was not considered for 2023-24 as it did not receive Capacity Credits for that Capacity Year.

The minimum Forced Outage allowance is calculated as per clause 4.5.9(a)(i) of the ESM Rules by multiplying the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages, based on Forced Outage rates averaged over the preceding 36 months. The estimated fleet Forced Outage rate is determined as 3.8% and the Forced Outage allowance for each Capacity Year is calculated by multiplying the 10% POE demand by the estimated fleet Forced Outage rate.

The resulting Forced Outage allowance is 180 MW in 2025-26 and increases to 216 MW by 2034-35. As this is less than the largest contingency throughout the entire outlook period the reserve margin is set by the largest contingency.

4.6 Regulation Raise requirements

In addition to the reserve margin, the capacity adequacy to satisfy reliability standards is driven by the 10% POE peak demand, the Regulation Raise as well as the ESROD Uplift component (see Chapter 5). Regulation Raise is formulated as the existing Regulation Raise requirement escalated by 3% of new wind capacity in Northern SWIS (North Country, Mid West, Central Midlands and Neerabup nodes), 1.8% of new wind capacity in other SWIS nodes, 5% of new grid-scale solar PV capacity, and 4% of new distributed PV capacity.

The Regulation Raise calculated for each Capacity Year is summarised in **Table 20**.

Table 20 Summary of Regulation Raise component for each Capacity Year

Capacity Year	Frequency regulation[A]	New wind capacity in Northern SWIS[B]	New wind capacity in other SWIS nodes[B]	New grid-scale solar PV capacity	New distributed PV capacity (MW)	Regulation Raise (MW)
2025-26	110	-	-	-	584	**133**
2026-27	110	-	-	-	853	**144**
2027-28	110	102	150	-	1,123	**161**
2028-29	110	102	150	-	1,366	**170**
2029-30	110	102	150	-	1,588	**179**
2030-31	110	102	150	-	1,792	**187**
2031-32	110	102	150	-	1,976	**195**
2032-33	110	102	150	-	2,148	**202**
2033-34	110	102	150	-	2,319	**209**
2034-35	110	102	150	-	2,500	**216**

A. Frequency Regulation Raise is as determined by the ERA and is set to be up to 110 MW between 5:30 am and 8:30 pm when the peak demand during daytime is most likely to occur. See https://www.erawa.com.au/cproot/23398/2/Australian-Energy-Market-Operator-s-202324-ancillary-services-requirements---Decision-Paper.PDF.

B. The new wind capacity presented here is based on the maximum capacity for King Rocks wind farm (150 MW) and Warradarge wind farm upgrade (102 MW).

5 Reliability assessment

This chapter presents the outcomes of the 2025 reliability assessment and the resulting system needs. This includes determination of the Peak RCT and Flexible RCT[82] and an assessment of EUE and Capability Classes, as well as ESR and DSP requirements. In summary:

- EUE is forecast to be outside tolerance (Limb B) for the 2025-26 Hot Season, notably between 8:00 pm and 10:30 pm when DSP is no longer available and ESR is largely exhausted. Amending Rules have been drafted to address this issue in the future[83].
- A substantial and growing energy shortfall is expected from 2027-28 following the exit of Collie Power Station and assumed unavailability of Bluewaters Power Station.
- Adequate Flexible Capacity is forecast for the entire outlook period, with surplus more than 2,000 MW for 2025-26 and gradually narrowing to about 1,000 MW by 2034-35 as some thermal generators are expected to become unavailable.
- Investment in at least 110 MW of new generation capacity (Capability Classes 1 and 3) is needed in this 2025 Reserve Capacity Cycle to keep annual EUE within tolerance in 2027-28.
- The sub-regional shortfall analysis identifies capacity shortfalls in the Eastern Goldfields and North Country, and highlights the critical importance of the East Enhancements Project (EEP) and CEL-North network augmentations to maintain sub-regional and system-wide reliability.
- The duration requirement for new ESR in the 2025 Reserve Capacity Cycle is set to 12 Trading Intervals (six hours).

5.1 Introduction

This chapter provides the outcomes of the reliability assessment undertaken in line with the assessment framework required by the ESM Rules and reports associated Reserve Capacity Cycle parameters for the third Capacity Year (2027-28).

AEMO has undertaken the reliability assessment with support from Ernst & Young (EY). Further detail on methodology and assumptions is provided in EY's 2025 Reliability Assessment Methodology and Assumptions Report[84].

[82] AEMO carries out the Long Term PASA study every year to forecast the RCT for each Capacity Year of the Long Term PASA Study Horizon, and publishes the results in the WEM ESOO. The RCT is AEMO's estimate of the total amount of capacity of Energy Producing Systems and DSP capacity required in the SWIS to satisfy the Planning Criterion. The RCT is updated in each Long Term PASA Study for the relevant Capacity Years to reflect the current forecasts. In this 2025 WEM ESOO, the Flexible RCT is determined for the first time, as discussed further in this chapter.

[83] See Electricity System and Market Amendment (Tranche 8) Rules 2025, Schedule 9 which (once gazetted) will amend clause 4.10.1(f)(vi) of the ESM Rules to specify that the periods when the Facility can be dispatched must include 'for a Reserve Capacity Cycle from the 2026 Reserve Capacity Cycle onwards, the periods between 6:00 AM and 10:00 AM and 2:00 PM and 10:00 PM on all Business Days'.

[84] At https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

5.2 Reliability Assessment Methodology

AEMO uses the Planning Criterion (see Section 1.5.1 for more details) to set the Peak and Flexible RCT for each Capacity Year in the 10-year outlook period. For both Peak and Flexible Capacity, the RCT for the third year in the Long Term PASA Study Horizon is referred to as the RCR. This WEM ESOO sets the RCR for 2027-28.

The methodology for determining the Limb A, B and C requirements is summarised in **Table 21**.

Table 21 Summary of methodologies used to determine Limb A, B and C of the Planning Criterion

Limb A (capacity adequacy)	Limb B (energy adequacy)	Limb C (flexibility adequacy)
Sets the capacity required to meet the annual peak demand and margins	**Sets the capacity required to limit the allowable amount of EUE**	**Determines the amount of Flexible Capacity required for ramping**
Calculated using the following building blocks: • Annual peak demand, forecast for the Expected scenario under 10% POE. • An allowance for Intermittent Loads. • An allowance for Regulation Raise (RR), which takes into account: – the current requirement for RR, and – the impact of intermittent generators (wind, large-scale solar, distributed PV) on the forecast requirement of RR. • A reserve margin, being the greater of: – the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand which is determined to be equivalent to sum of the largest three Facilities, and – Forced Outage allowance, expressed as the forecast peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages. • The ESROD Uplift quantifies the overallocation of Capacity Credits assigned to ESR with shorter duration than required by the ESR Duration Requirement (in accordance with grandfathering provisions). To correct this, the ESM Rules have introduced a provision to calculate this gap and add it to the RCT determined in accordance with Limb A of the Planning Criterion.	EUE is assessed by dispatch modelling of the WEM, taking into account forecast demand and supply: • Forecast demand taking into account an MDT of 300 MW assumed for ESM which AEMO has identified as the level required to maintain system security, including local region (both South and North) reactive power management requirements. • Network constraints not considered, to determine a target for unconstrained capacity[A]. The impact on EUE with transmission network constraints added to the modelling is explored in Section 5.10.3. • For the purposes of modelling in this 2025 WEM ESOO, the capacity of non-intermittent generation is capped at the assigned NAQ level (wind and solar are modelled at their installed capacity levels). • EUE due to local distribution network issues is not captured in the modelling. • The modelling involved 100 random (Monte Carlo) patterns of generator Forced Outages overlaid across 14 historical weather reference years. This produced 1,400 iterations for each Capacity Year and was used to inform the assessment of EUE, capturing a range of weather variability and random Forced Outage patterns impacting the availability of supply. • All EUE presented is the average of unserved energy from the 1,400 iterations modelled for each Capacity Year. • To minimise the risk of EUE, the Limb B assessment assumes that planned maintenance of thermal plant occurs outside of the Hot Season.	Calculated using the following building blocks: • The highest Four-Hour Demand Increase which quantifies the expected maximum upwards ramp of SWIS demand[B] over a period of contiguous four hours which needs to be satisfied by an adequate amount of Flexible Capacity. • The reserve margin is calculated as the highest Four-Hour Demand Increase multiplied by the proportion of Flexible Capacity expected to be unavailable at the time of the highest forecast Four-Hour Demand Increase due to Forced Outages. • Both the 10% POE and 50% POE demand is used in this assessment and the determination of Four-Hour Demand Increase based on the higher of the two.

A. Network congestion is accounted for by AEMO in the NAQ framework when assigning Capacity Credits to capacity providers.

5.3 Observed emerging challenges to reliability of supply

Capacity shortfalls potentially resulting in unserved energy can be induced by a combination of demand and supply factors. This section investigates emerging challenges to reliability by analysing the operating conditions of the SWIS during system stress periods[85] related to:

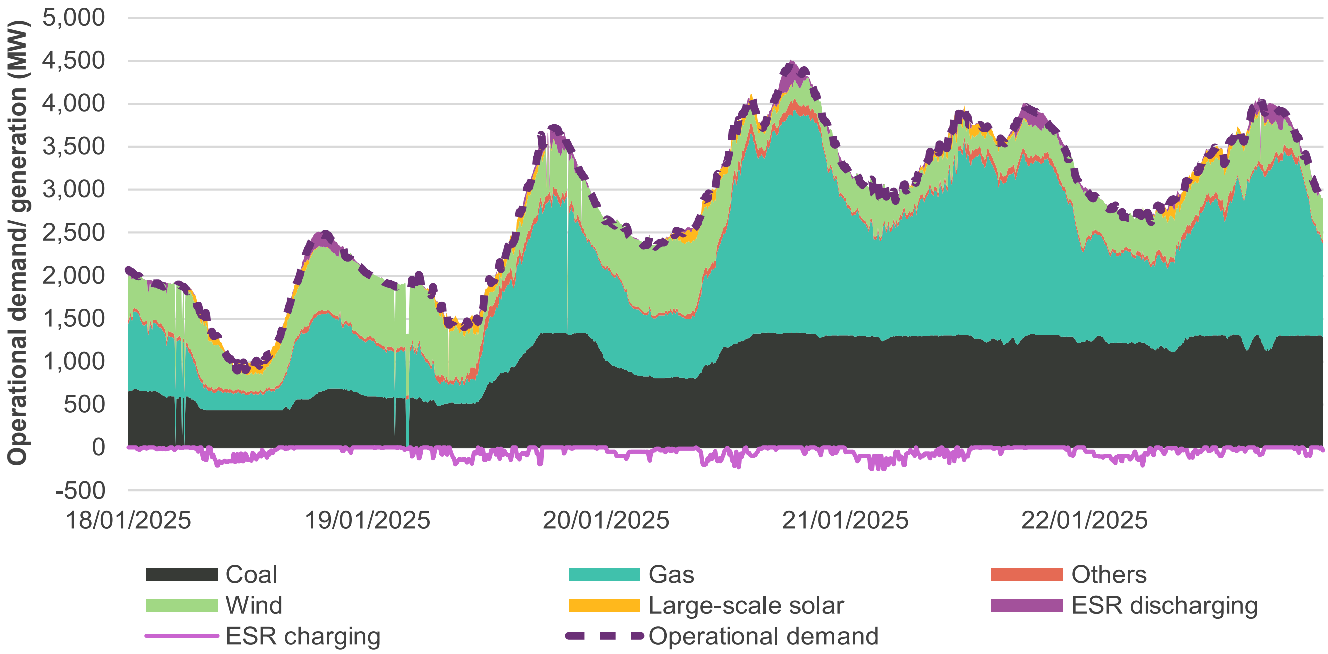
- record peak demand periods (such as 20 January 2025), and
- significant swings (volatility) in operational demand caused by changes in distributed PV output (attributed to sudden changes in cloud cover) such as on 4 August 2024, 19 November 2024 and 13 March 2025.

5.3.1 Record peak demand days

Record peak demand days were observed in January 2025, driven by high temperatures. The supply mix during this peak event was primarily comprised of firm capacity (gas and coal) and, to a lesser extent, renewables (wind and solar) and ESR. During these periods, AEMO activated voluntary demand-side response mechanisms (DSP, Supplementary Capacity and NCESS) to reduce operational demand.

Figure 30 shows the operating conditions of the SWIS in the period during which the highest new operational demand record of 4,486 MW occurred on 20 January 2025 at 6:30 pm[86].

Figure 30 Operational demand and generation during record peak operational demand period (20 January 2025) (MW)



Notes:

- Other includes biomass, distillate, and waste-to-energy.
- Operational demand includes the reductions from demand-side response mechanisms (DSP, Supplementary Capacity and NCESS) activated by AEMO as well as ESR charging loads.

[85] The stress periods indicated above were identified based on analysis of historical data between 1 June 2024 and 20 May 2025.

[86] For the 18:30 Trading Interval based on non-loss adjusted meter data, which included the 5-minute peak demand record of 4,486 MW in the 18:30 Dispatch Interval (based on non-loss adjusted SCADA data).

On the same day, underlying demand also reached a record high. During the time of operational demand peak, the contribution of coal and gas is significant (greater than 85% in total) and wind was notably lower than at the peak period on the two days prior (only 4%). This highlights the value of existing one- to four-hour ESR in helping cover the peak. However, as thermal generation withdraws from the system, if not replaced by new generation sources, there will need to be greater reliance on ESR and DSP to maintain reliability over a longer period under these extreme weather conditions.

5.3.2 Upward ramps and volatility of operational demand

Another emerging challenge to reliability of supply relates to the sharp rise in demand as distributed PV reduces as the sun sets (as seen on 4 August 2024), and the volatility of operational demand across shorter timeframes where demand can swing by more than 500 MW within a single Trading Interval due to cloud cover suddenly reducing distributed PV output (as seen on 19 November 2024 and 13 March 2025).

Figure 31 Operational demand on days with high demand ramps and high demand volatility (4 August 2024, 19 November 2024, 13 March 2025) (MW)

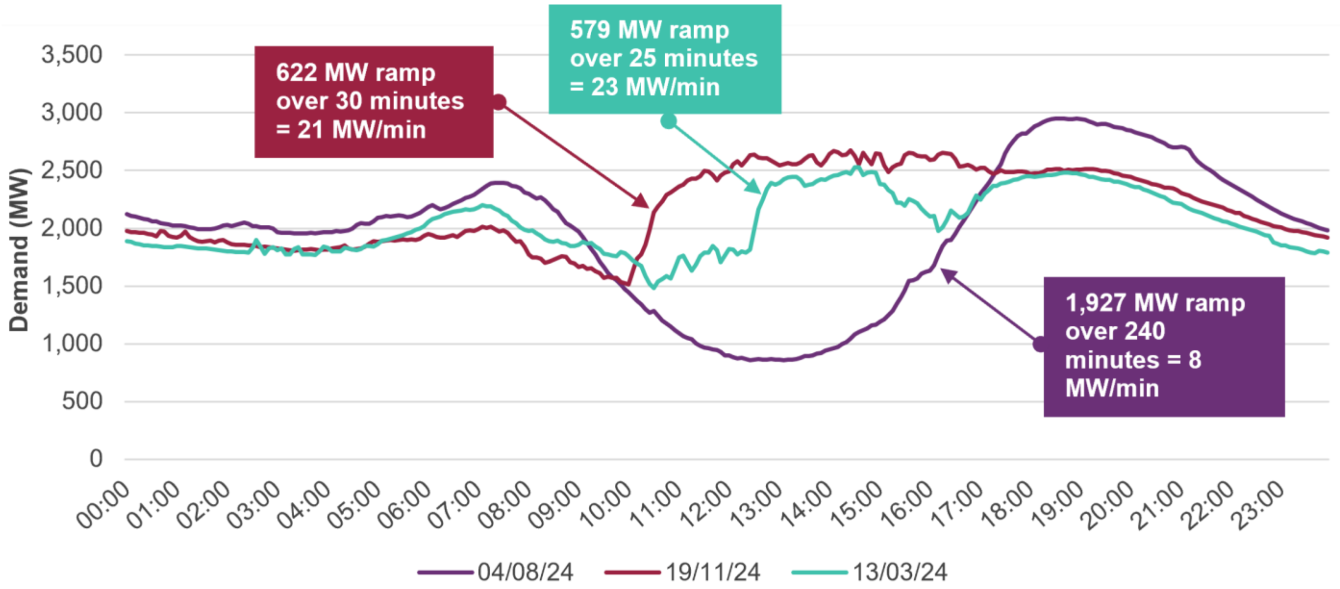


Figure 31 illustrates these challenges by presenting changes in operational demand and conditions across three different days:

- 4 August 2024, which had low operational demand in the middle of the day due to clear skies, supporting high distributed PV output. As distributed PV output reduced towards the evening, operational demand increased rapidly, resulting in the highest increase in demand (1,927 MW) over the period of four consecutive hours between 2:10 pm and 6:10 pm[87].

[87] This calculation aligns with the timeframe prescribed by the ESM Rules for the Limb C assessment.

- 19 November 2024 and 13 March 2025, which exhibited steep ramps[88] and high volatility[89] in demand due to variable weather conditions such as thunderstorm and cloud cover, resulting in fluctuations in distributed PV output and subsequently operational demand.

The challenges emerging from upward demand ramps measured across four contiguous hours are addressed by the assessment performed for Limb C. However, the emerging challenge of high demand volatility and steep upward ramps prevailing for shorter periods than four contiguous hours is not within the scope of the Limb C assessment.

5.4 Peak capacity requirement (Limb A)

Table 22 shows the building blocks of Limb A and the amount of Peak Capacity required to satisfy Limb A in each Capacity Year of the 10-year outlook period. Supply-demand balance is assessed in Section 5.8.

The upward trend in the capacity required to satisfy Limb A is driven by the increasing trajectory of 10% POE peak demand, an increase in the Regulation Raise component (driven by increasing penetration of intermittent generation, in particular distributed PV) as well as the addition of the ESROD Uplift component (see Section 3.1.3).

Table 22 Limb A building blocks and the total amount of capacity needed to satisfy Limb A (MW)[A]

Capacity Year	10% POE peak demand	Intermittent Loads	Reserve margin	Regulation Raise	ESROD Uplift[B]	Capacity required to satisfy Limb A
2025-26	4,734	7	976	133	-	5,850
2026-27	4,783	7	976	144	-	5,910
2027-28	4,856	7	958	161	256	6,238
2028-29	4,938	7	958	170	256	6,330
2029-30	5,027	7	958	179	256	6,428
2030-31	5,142	7	958	187	256	6,551
2031-32	5,265	7	958	195	256	6,681
2032-33	5,384	7	958	202	256	6,807
2033-34	5,489	7	958	209	256	6,918
2034-35	5,674	7	958	216	256	7,111

A. All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.
B. From 2027-28, the Limb A capacity requirement also takes into account the ESROD Uplift. See Section 3.1.3 for more details.

5.5 Energy adequacy (Limb B)

EUE, expressed in MWh, represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply).

Table 23 shows the results of the assessment conducted for the Expected scenario and two sensitivity scenarios, one to investigate the impact of the assumed Bluewaters closure date on EUE, and another to investigate the impact that probable projects, if progressed, would have on EUE.

[88] Despite steep slopes, these ramps were of smaller magnitude than the ramp observed on 4 August 2024.

[89] Volatility is defined as the upward and downward fluctuations (variability) occurring from one five-minute interval to the next five-minute interval.

For the Expected scenario and the two sensitivity scenarios, modelled EUE exceeds the 0.0002% reliability standard in 2025-26, decreases in 2026-27 to 0.0001%, and again exceeds the standard from 2027-28 onwards.

Table 23 Expected unserved energy, Expected scenario and two sensitivities[A]

Capacity Year	Reliability Standard	Expected scenario		Bluewater sensitivity scenario[B]		Probable projects sensitivity [C]	
		Annual EUE (MWh)	EUE as % of annual consumption	Annual EUE (MWh)	EUE as % of annual consumption	Annual EUE (MWh)	EUE as % of annual consumption
2025-26	0.0002%	53	0.0003%	53	0.0003%	53	0.0003%
2026-27	0.0002%	13	0.0001%	13	0.0001%	13	0.0001%
2027-28	0.0002%	1,335	0.0075%	55	0.0003%	140	0.0008%
2028-29	0.0002%	1,939	0.0106%	112	0.0006%	286	0.0016%
2029-30	0.0002%	68,478	0.3640%	5,436	0.0289%	27,634	0.1469%
2030-31	0.0002%	165,963	0.8557%	165,293	0.8523%	77,244	0.3983%
2031-32	0.0002%	173,516	0.8691%	173,516	0.8691%	83,136	0.4164%
2032-33	0.0002%	701,801	3.3920%	701,801	3.3920%	436,442	2.1095%
2033-34	0.0002%	981,452	4.5408%	981,452	4.5408%	678,644	3.1398%
2034-35	0.0002%	1,541,046	6.7208%	1,541,046	6.7208%	1,138,938	4.9671%

A. The Bluewaters sensitivity scenario assumed that both Bluewaters generating units retire on 1 October 2030, as opposed to 1 October 2027, which is assumed for the Expected scenario. This scenario was modelled to illustrate the impact of the Bluewaters retirement date on EUE.
B. The Probable projects sensitivity assumed the inclusion of probable projects in addition to the existing and committed Facilities already under the Expected scenario.

Modelled occurrences of EUE are generally driven by a combination of the following factors:

- Higher 10% POE peak demand in the initial years of the forecast compared to the 2024 WEM ESOO.
- Insufficient committed firm energy producing capacity to complement intermittent renewable generation (wind and solar) and duration-limited capacity (ESR and DSP).
- Intervals with insufficient available generation due to unit outages (planned or forced), low renewable availability, unavailability of DSP, or low state of charge of ESR.
- Impact of NAQ reductions, effectively limiting the capacity available for dispatch from certain Facilities due to network limits.

An extended analysis of EUE is provided below (with further details presented in Appendix A5.3). Commentary on the types of generation required to address this EUE risk and opportunities for investment are discussed in Chapter 7.

5.5.1 Analysis of expected unserved energy results

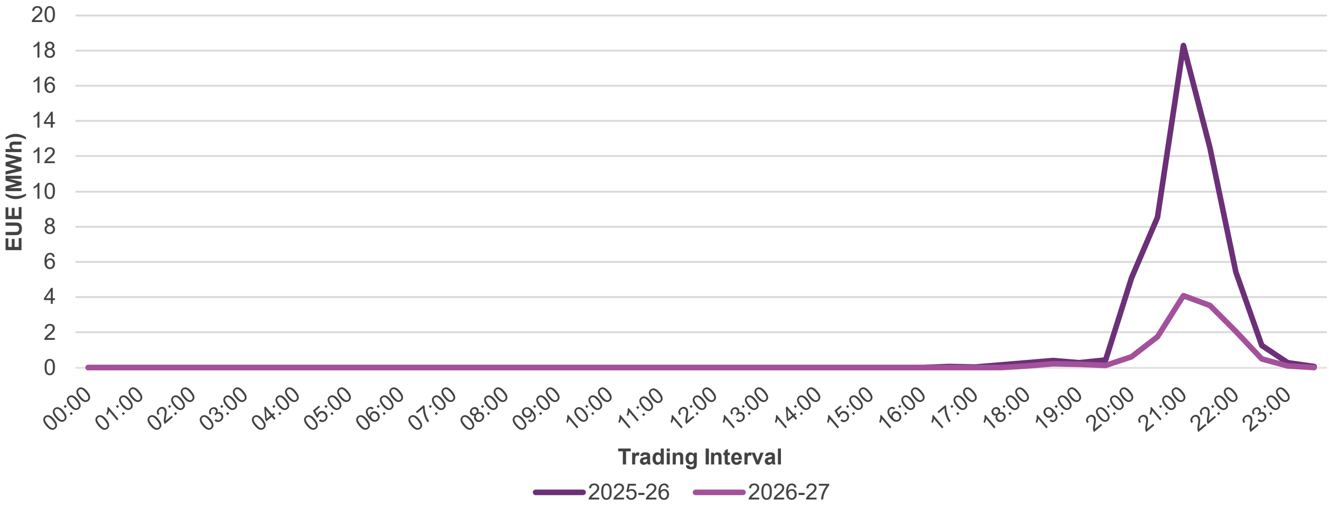
In 2025-26 and 2026-27, unserved energy is expected to occur in the late evening

In 2025-26 and 2026-27, modelled EUE is observed from 8:00 pm under extreme peak conditions, when DSP is no longer required to be available[90], and four-hour ESR is largely exhausted. These peak demands typically occur under extreme heatwave conditions, with temperatures overnight also being elevated, leading to sustained high demand periods.

[90] DSP is currently only required to be available between 8:00 am and 8:00 pm under clause 4.10.1(f)(vi) of the ESM Rules.

As **Figure 32** shows, modelled EUE in 2026-27 is lower compared to 2025-26, despite the assumed year-on-year increase in peak demand and annual consumption. The drop in EUE to below the 0.0002% reliability standard is primarily driven by the assumed net increase in supply of 192 MW[91], exceeding the year-on-year increase in demand of 49 MW.

Figure 32 Modelled time-of-day average expected unserved energy in 2025-26 and 2026-27 (MWh)



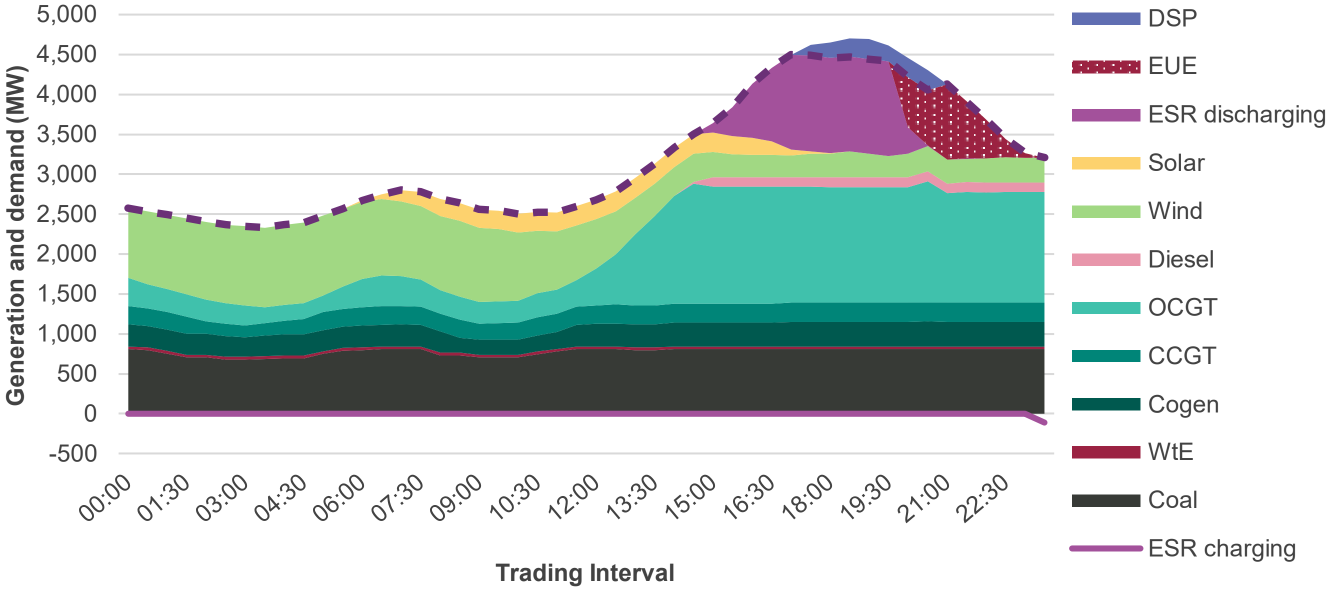
Source: EY

Figure 33 highlights a sample day in March 2026 where forecast high demand coincides with low availability of wind in the late afternoon, contributing to the occurrence of EUE.

As shown in the figure, a steep ramp to peak demand is observed and ESR is required to start discharging at the 15:00 Trading Interval once all available generation of other technology type has reached full output. The contribution of ESR rapidly declines starting at the 20:00 Trading Interval, and depletes to negligible levels in 30 minutes. This demonstrates that with the anticipated fleet of two-hour and four-hour ESR, there is insufficient capacity to cover the entire duration of the period of high demand.

[91] Addition of existing and committed capacity totalling 284 MW, which exceeds the assumed reduction of 92 MW of capacity.

Figure 33 Modelled supply generation, demand profiles, and expected unserved energy for a one-day period capturing an EUE event in 2025-26 (sample day in March 2026, Monte Carlo forced outage iteration #65, reference year 2015-16) (MW)



Notes:

- ESR is fully charged prior to the start of this sample day. This is due to the approach ESR is modelled for the purposes of reliability assessment. Rather than cycle daily or energy arbitrage, ESR is modelled to charge when it can and then discharge only when required to avoid EUE.
- DSP includes those with assigned Capacity Credit or NCESS contract, therefore, may be available during their obligation time periods, respectively.

Source: EY

In 2027-28 and 2028-29, unserved energy is expected to occur from the early evening

From 2027-28 until the end of the WEM ESOO study period, EUE exceeds the 0.0002% reliability standard and exhibits a strong upward trend by 2034-35.

Analysed on a time-of-day basis (see **Figure 34)**, modelled EUE in 2027-28 and 2028-29 is of considerably greater magnitude and emerges earlier than in 2025-26 and 2026-27. This is primarily driven by increasing demand and the retirement and assumed unavailability of coal-fired generation.

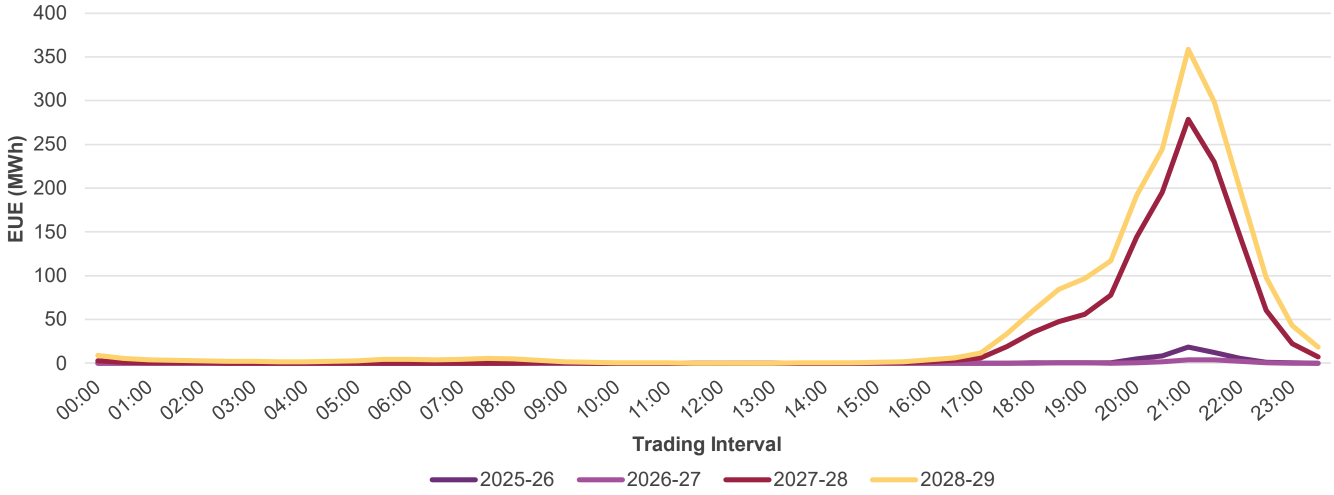
Starting from October 2027, 751 MW of coal units are assumed to exit the SWIS, replaced with 282 MW of new entrant capacity, made up of 252 MW of wind capacity[92], 20 MW of diesel capacity, and 25 MWh of ESR capacity. The assumed exit of coal units results in a decrease in dispatchable capacity capable of generating during peak demand periods. This coal generation is assumed to be partially replaced with new capacity of different operating characteristics (of which the majority are ESR), resulting in the observed increase in EUE in 2027-28 and 2028-29.

Compared to EUE in 2025-26 and 2026-27 (which emerges from the 20:00 Trading Interval), EUE in 2027-28 and 2028-29 emerges from the 17:00 Trading Interval, which coincides with the timing when peak periods of SWIS operational demand occur (generally between the 17:00 and 18:30 Trading Intervals).

In 2027-28, the occurrence of EUE is seen in both summer and winter months. From 2028-29, EUE begins to emerge in shoulder months, and occurs in all months of the year from 2029-30 and onwards. See Appendix A5.3.2.

[92] Equivalent to 51 MW of Capacity Credit determined using the Relevant Level Methodology.

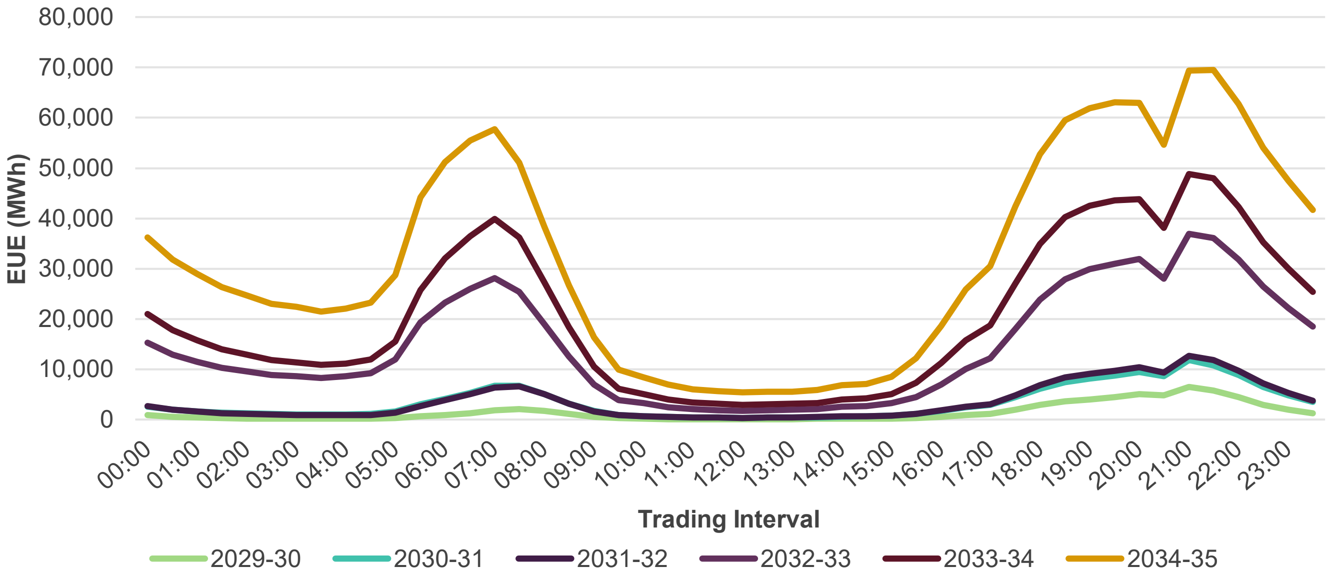
Figure 34 Modelled time-of-day average expected unserved energy across 2025-26 to 2028-29



From 2029-30, unserved energy is expected to occur in both the morning and the evening

As shown in **Figure 35**, compared to the initial years of the study, EUE exhibits a strong increase from 2029-30, and continues to grow to 1.5 TWh, or 6.7% of annual energy consumption, in 2034-35.

Figure 35 Modelled time-of-day average expected unserved energy from 2029-30 to 2034-35 (MWh)



This is driven by the forecast continued increase in demand and consumption, combined with further retirements of thermal capacity (422 MW of coal[93] and 177 MW of gas[94] in 2029-30, with a further 344 MW of gas[95] in 2032-33), and a lack of new energy-generating capacity to replace it.

[93] Muja G7 and G8 units.

[94] Pinjar GT2-GT7 units.

[95] Pinjar GT9-GT11 units.

In the absence of additional investment, EUE emerges in the morning peak demand period in 2029-30 and grows year-on-year across all times of day (as shown in Figure 35).

There is a noticeable dip in EUE around 8.30 pm, which increases year-on-year. This is due to a combination of factors. The modelled Regulation Raise requirement reduces at 8.30 pm, reflecting the end of the peak Regulation Raise period, which is higher than the off-peak requirement to cover the variability of solar which is not a factor in the off-peak period. The requirement grows year-on-year and therefore the size of the dip increases each year. EUE then increases again as the contribution from Facilities which are assumed to operate during modelled ESROI only, drops off from 9.00 pm, and storage reserves are depleted.

5.6 Flexible capacity requirement (Limb C)

Table 24 shows the results of the assessment to determine whether there is adequate supply flexibility to cover the midday to evening demand ramp, conducted for the first time, and in line with the methodology described in Appendix A5.2.6. As per clause 4.5.9(c) of the ESM Rules, the Flexible Capacity is determined as the sum of the highest Four-Hour Demand Increase expected in the relevant Capacity Year and a reserve margin. The reserve margin is calculated as the highest Four-Hour Demand Increase multiplied by the proportion of Flexible Capacity expected to be unavailable at the time of the highest forecast Four-Hour Demand Increase due to Forced Outages. The proportion of Flexible Capacity expected to be unavailable at the time of the highest forecast Four-Hour Demand Increase due to Forced Outages is calculated by taking the average weighted historical Forced Outage rates where available, or generic Forced Outage data for new Facilities. For more details on the methodology, see Appendix A5.2.6.

Table 24 Limb C building blocks and the total amount of capacity needed to satisfy the Flexible RCT (MW)

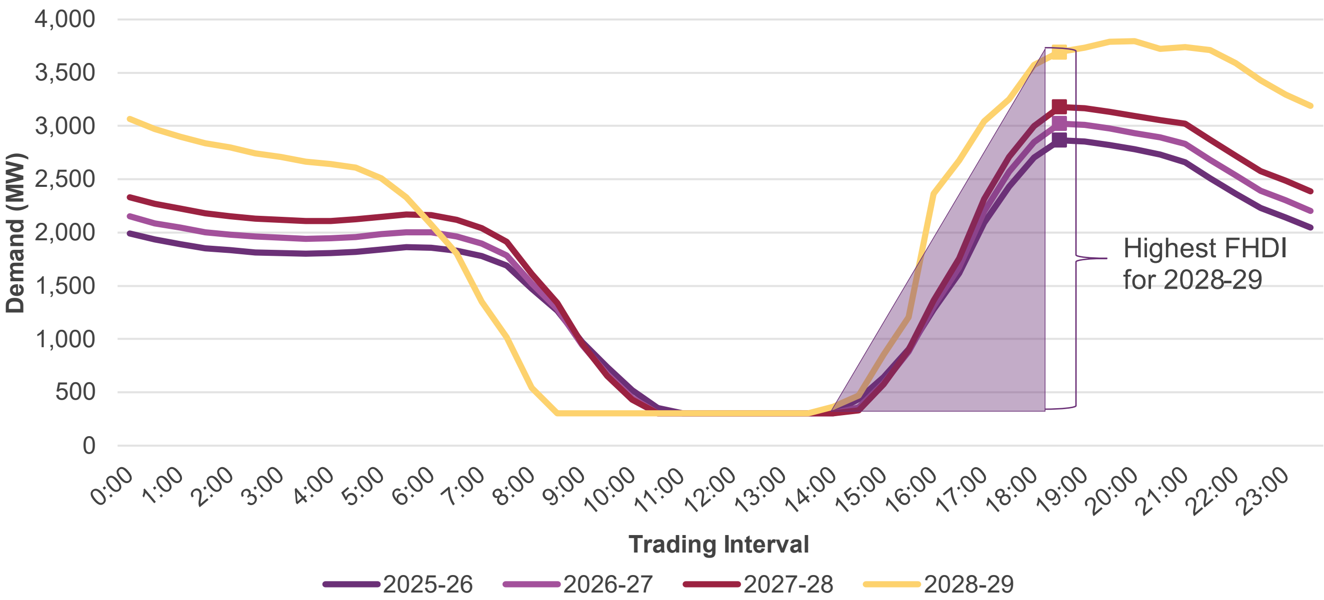
Capacity Year	10% POE, Expected			50% POE, Expected			Flexible RCT
	Highest Four-Hour Demand Increase	Equivalent demand ramp rate in MW/min	Reserve margin[A]	Highest Four-Hour Demand Increase	Equivalent demand ramp rate in MW/min	Reserve margin[A]	
2025-26	2,203	9	99	2,201	9	99	2,302
2026-27	2,312	10	98	2,310	10	98	2,410
2027-28	2,426	10	101	2,425	10	101	2,527
2028-29	2,531	11	106	2,531	11	106	2,637
2029-30	2,627	11	103	2,627	11	103	2,730
2030-31	2,715	11	107	2,715	11	107	2,822
2031-32	2,796	12	111	2,796	12	111	2,907
2032-33	2,872	12	46	2,871	12	46	2,917
2033-34	2,935	12	47	2,935	12	47	2,982
2034-35	3,017	13	49	3,016	13	49	3,066

A. Refers to reserve margin under clause 4.5.9(c) of the ESM Rules.

The growth in Four-Hour Demand Increase is driven by the increasing spread between daily maximum and minimum operational demand, which in turn results in a greater slope (ramp) measured over the period of four contiguous hours.

This is illustrated in **Figure 36** for four selected Capacity Years, showing days when the annual highest Four-Hour Demand Increase was observed. The minimum of 300 MW shown in the operational demand trace is due to the application of the assumed MDT. A higher, or lower, MDT would change the size of the Four-Hour Demand Increase.

Figure 36 Modelled time-of-day operational demand for days when the highest Four-Hour Demand Increase occurred for 2025-26 to 2028-29 (MW)



Note: the weather reference year is 2010-11, 10% POE.

The year-on-year increasing trend in the highest Four-Hour Demand Increase indicates a growing need for Flexible Capacity to meet the upward ramp of operational demand. While ESR can ramp quickly and help alleviate the risk of a capacity shortfall, ESR is only effective if sufficiently charged to provide capacity and energy over a sufficient duration.

5.7 Peak and Flexible RCT

Table 25 shows the Peak RCT and Flexible RCT determined for all years of the 2025 WEM ESOO horizon. The pink shaded cells highlight the respective RCRs relevant for this Reserve Capacity Cycle. As stipulated in the Planning Criterion, all limbs must be satisfied. The determination of Limb B RCT is required if EUE exceeds 0.0002% and the Peak RCT is determined as the maximum of RCT determined by the Limb A and Limb B RCTs.

The 2025-26 Peak RCT is set by Limb B, which is the first time this Limb prevails. As already discussed, this is primarily driven by forecast higher peak demand than in the 2024 WEM ESOO, with energy shortfalls largely occurring after 8:00 pm when DSP is no longer available[96] and four-hour ESR is largely exhausted.

In the remaining years of the outlook period, the Peak RCT continues to be set by Limb A, partly due to the inclusion of the ESROD uplift.

[96] DSP is currently only required to be available between 8:00 am and 8:00 pm under clause 4.10.1(f)(vi) of the ESM Rules.

Table 25 Peak RCT and Flexible RCT (MW)

Capacity Year	Peak RCT set by	Peak RCT	Flexible RCT
2025-26	Limb B	5,905	2,302
2026-27	Limb A	5,910	2,410
2027-28	Limb A	6,238	2,527
2028-29	Limb A	6,330	2,637
2029-30	Limb A	6,428	2,730
2030-31	Limb A	6,551	2,822
2031-32	Limb A	6,681	2,907
2032-33	Limb A	6,807	2,917
2033-34	Limb A	6,918	2,982
2034-35	Limb A	7,111	3,066

The Peak RCT for 2027-28 is 6,238 MW, which sets the RCR for 2025 Reserve Capacity Cycle. This is 444 MW higher than the 2027-28 Peak RCT forecast in the 2024 WEM ESOO. The higher RCT is driven by the higher peak demand forecast as well as the addition of the new ESROD Uplift component. The growing shortfall from 2027-28 highlights a sustained need for further capacity investment to satisfy Limb A.

Across the 2025 WEM ESOO horizon, the requirement set by Limb C remained below the requirements set by Limb A and Limb B. If the converse were true, Limb C would have set both the Flexible RCT and the Peak RCT for a given year.

5.8 Supply-demand balance for Peak and Flexible Capacity

5.8.1 Peak Capacity

Table 26 and **Figure 37** compare the Peak RCT for the outlook period with the expected level of capacity in each year of the outlook period for the Expected scenario and High sensitivity scenario. They show that more capacity will need to be procured through the RCM to satisfy the Planning Criterion over the next decade.

The Expected scenario considers only existing and committed facilities in the supply forecasts. Adding probable facilities to the supply forecasts would reduce the shortfall by 507 MW from 2027-28. Under the Expected scenario, AEMO forecasts:

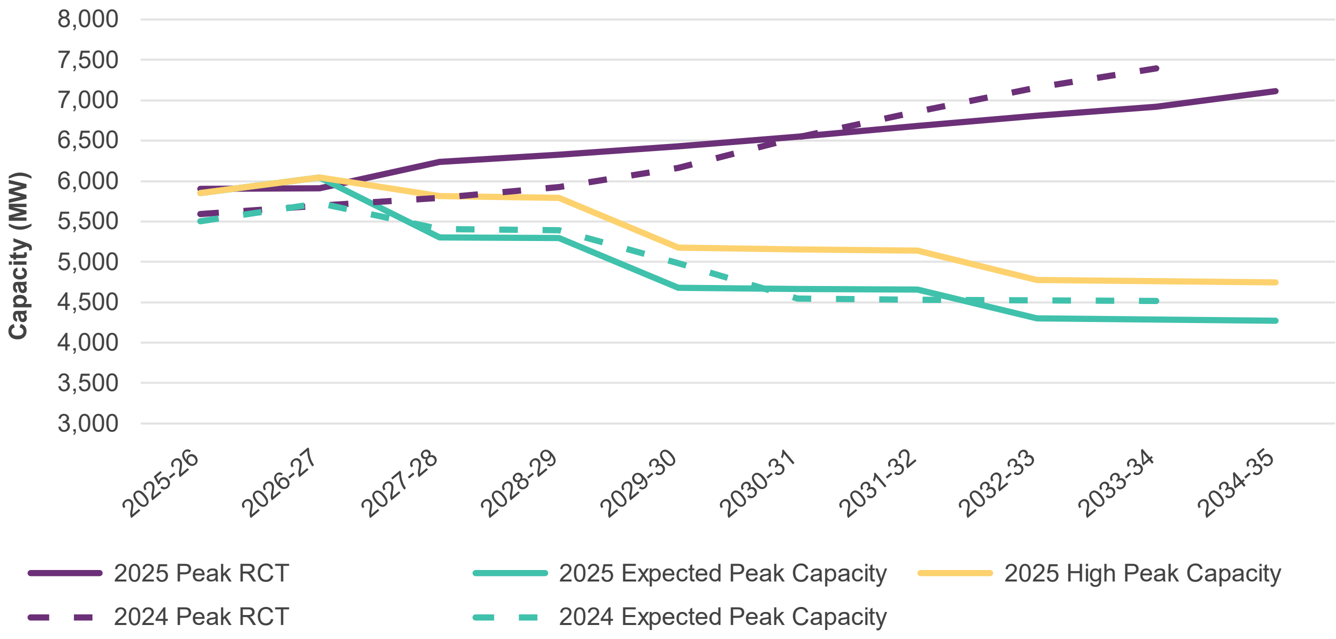
- a relatively small shortfall of 50 MW (-0.8%) for 2025-26 assuming timely delivery of committed projects – AEMO will further assess the likelihood of the shortfall risk for the 2025-26 Hot Season to determine any quantity of Supplementary Capacity required to be procured, and will consider unavailability of capacity due to known Planned Outages, fuel challenges and potential delays to connection of new committed capacity by 1 October 2025,
- a surplus of 138 MW (2.3%) for 2026-27, which is less than the surplus of 498 (9.0%) forecast in the 2024 WEM ESOO, and
- a shortfall of 932 MW (-14.9%) for 2027-28, with the shortfall increasing steadily thereafter as coal- and gas-fired generation retires and peak demand continues to rise, reaching a shortfall of 2,758 MW by 2034-35.

Table 26 Supply-demand balance of Peak Capacity for the Expected and Probable projects sensitivity scenario, 2024-25 to 2033-34[A]

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Peak RCT[B] (MW)	5,905	5,910	6,238	6,330	6,428	6,551	6,681	6,807	6,918	7,111
Expected scenario										
Peak Capacity (MW)	5,855	6,048	5,306	5,293	4,680	4,668	4,655	4,298	4,286	4,275
Peak Capacity shortfall (-) or surplus (MW)	-50	138	-932	-1,037	-1,747	-1,883	-2,026	-2,508	-2,632	-2,836
Probable projects sensitivity scenario										
Peak Capacity (MW)	5,855	6,048	5,812	5,794	5,176	5,158	5,140	4,778	4,761	4,744
Peak Capacity shortfall (-) or surplus (MW)	-50	138	-425	-536	-1,252	-1,393	-1,541	-2,028	-2,157	-2,367

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. The quantities reported are the RCTs. The RCRs for 2025-26 and 2026-27 are 5,543 and 5,529 MW (determined in the 2023 and 2024 WEM ESOOs) respectively.

Figure 37 Supply-demand balance of Peak Capacity, Expected scenario, 2025-26 to 2034-35 (MW)



If projects classified as 'probable' are commissioned by October 2027, the forecast capacity shortfall for 2027-28 would reduce to 425 MW. However, most of the probable facilities currently in the pipeline are battery storage, meaning energy shortfalls would continue after 2027-28 unless more energy-producing generation enters the system.

EOIs received at the commencement of this 2025 Reserve Capacity Cycle demonstrated that investment interest in the WEM remains strong[97]. The majority of these are battery storage, and many are only in the early stages of project development, either with no network Access Proposal or incomplete Environmental Approvals. These projects are too speculative to be included in the supply forecasts when measured against the capacity classification criteria defined in Appendix 3.1.

[97] See 2025-expression-of-interest-summary-report.pdf.

5.8.2 Flexible Capacity

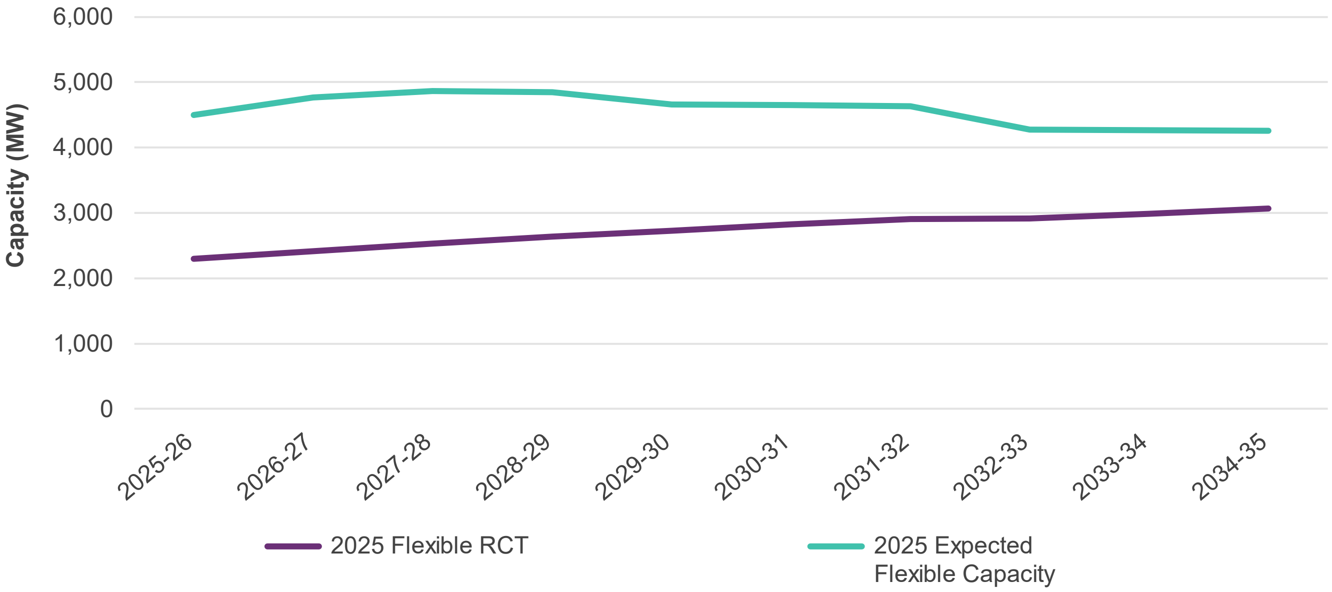
Flexible RCT is a new requirement for 2025 WEM ESOO. **Table 27** and **Figure 38** present the forecast supply-demand balance of Flexible Reserve Capacity across the outlook period.

Table 27 Supply-demand balance of Flexible Capacity for the Expected scenario, 2025-26 to 2034-35

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Flexible RCT (MW)	2,302	2,410	2,527	2,637	2,730	2,822	2,907	2,917	2,982	3,066
Forecast Flexible Capacity (MW)	4,500	4,764	4,863	4,850	4,659	4,647	4,634	4,278	4,266	4,254
Flexible Capacity shortfall (-) or surplus (MW)	2,199	2,353	2,336	2,213	1,929	1,825	1,727	1,360	1,284	1,188

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. Flexible Capacity commences in 2027-28. The Flexible RCTs and anticipated supply for 2025-26 and 2026-27 are presented to fulfill requirements of the ESM Rules.

Figure 38 Forecast supply-demand balance of Flexible Capacity, Expected scenario, 2025-26 to 2034-35 (MW)



AEMO forecasts adequate Flexible Capacity for the entire outlook period, with the surplus more than 2,000 MW for 2025-26 and gradually narrowing to about 1,000 MW by 2034-35 as some thermal generators are expected to become unavailable.

As thermal generation leaves the market, particularly gas (which is typically fast-starting and flexible), it must be replaced by capacity that has a quick ramp rate, minimal stable loading levels, and fast restart time. Battery storage, while able to ramp quickly, is only effective if it is charged. As overall electricity consumption increases and peak demand rises, there is a risk grid-scale batteries will not be fully charged and ready to deploy to meet sudden increases in demand. ESR therefore must be complemented with a sufficient energy-producing capacity to make sure batteries are charged, and that there is enough fast-start generation to deploy during high demand intervals.

5.9 Capability Class assessment

If existing and committed capacity is forecast to result in unserved energy exceeding the 0.0002% reliability standard under Limb B of the Planning Criterion in 2027-28, then AEMO must determine the minimum capacity required to be provided by Capability Classes 1 and 3 to satisfy Limb B. If additional capacity from Capability Classes 1 and 3 is required, then new Facilities from Capability Classes 1 and 3 that have not been assigned a NAQ in any previous Reserve Capacity Cycle will be treated as 'Network Augmentation Funding Facilities' for the purposes of NAQ prioritisation under new clause 4.5.12A of the ESM Rules.

As highlighted in Section 5.5 of this WEM ESOO, based on existing and committed supply capacity (less anticipated retirements and assumed unavailability), AEMO forecasts EUE to exceed the 0.0002% reliability standard in 2027-28.

To determine the minimum capacity required to be provided by Capability Classes 1 and 3 to limit EUE to 0.0002% of annual energy consumption[98], AEMO with support from EY:

- First modelled the impacts of filling the 2027-28 Peak RCT shortfall of 932 MW entirely with generic six-hour duration battery storage (representative of Capability Class 2)[99].
  - AEMO found that by adding 932 MW of battery storage, EUE was still above the reliability threshold, at 0.0005% (94 MWh). This demonstrates that Capability Class 2 alone is not sufficient to satisfy the Planning Criteria, as explained further later in this section.
  - As such, new Facilities from Capability Classes 1 and 3 that have not previously been assigned NAQs will be treated as 'Network Augmentation Funding Facilities' for the purposes of NAQ prioritisation in the 2025 Reserve Capacity Cycle.
- Then, iteratively modelled the outcomes of increasingly displacing a MW of generic battery storage capacity with a MW of generic firm generation capacity (Capability Class 1) until EUE was limited to 0.0002%.
  - AEMO found that EUE is reduced to within the reliability threshold of 0.0002% by replacing 110 MW of battery storage with 110 MW of firm generation.
  - As such, the minimum additional capacity required to be provided from Capability Classes 1 and 3 is 110 MW.
- Then, iteratively modelled the outcome of increasingly displacing Capability Class 1 capacity with Capability Class 3 capacity.
  - AEMO considers that various ratios of Capability Classes 1 and 3 would satisfy Limb B.
  - As such, an appropriate share could be informed by the deliverability of projects (how progressed they are on approvals, network access and reaching FID) and the extent to which they could alleviate regional reliability or system strength issues.

[98] Capability Class 1, 2 and 3 are as defined in Chapter 1.

[99] Note that this assessment only considered generic storage and does not take into account the actual battery storage projects identified as 'probable' under AEMO's commitment criteria. Additional analysis confirmed that, even with all probable projects included, a minimum level of new Capability Class 1 or Capability Class 3 generation would still be required.

The approach adopted for this assessment minimises the total amount of Capability Class 1 and Capability Class 3 capacity that would need to be procured while still meeting the 0.0002% reliability threshold. Further details of the methodology are contained in Appendix A5.2.7.

Table 28 shows the outcome of the Capability Class assessment for 2027-28 for the Expected scenario. The minimum additional capacity required from Capability Classes 1 and 3 is 3,937 MW, which is 110 MW more than the amount of existing and committed capacity for those Capability Classes. In addition to the 110 MW, a further 822 MW of capacity (from any combination of Capability Classes 1, 2 or 3) is required to meet the Peak RCT in 2027-28.

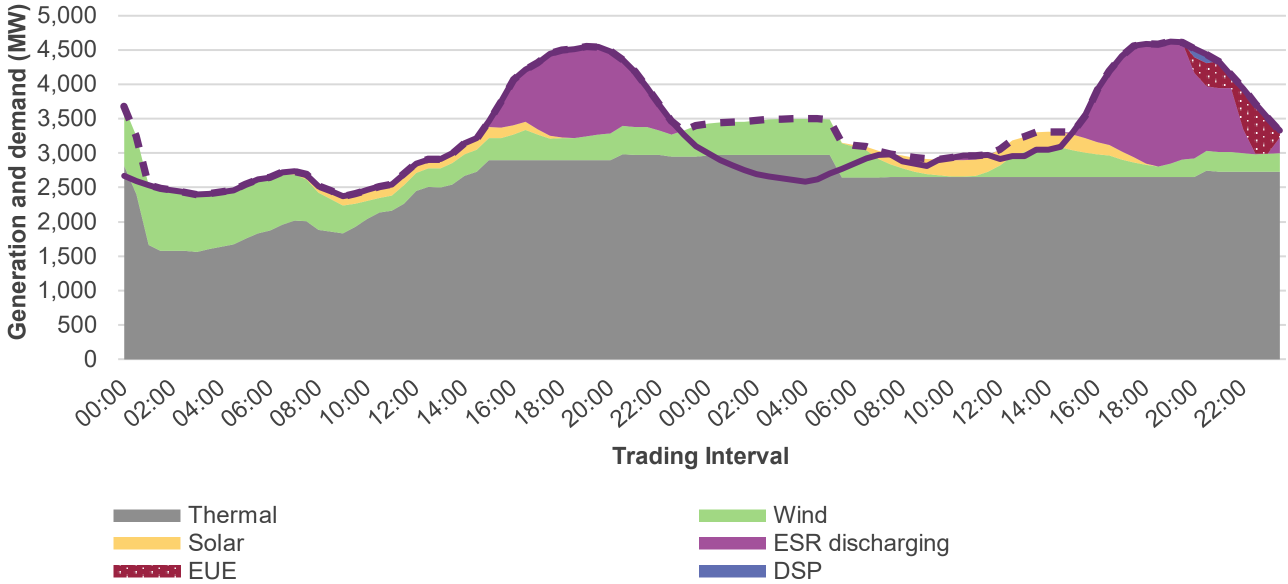
Table 28 Capability Class requirements (MW) for 2027-28, Expected scenario

Assessment	2027-28 (MW)
Peak Reserve Capacity Target (RCT)	6,238
Less: Existing and committed capacity	(5,306)
Total shortfall against Peak RCT	932
Minimum capacity required from Capability Classes 1 and 3	3,937
Less: Existing and committed capacity from Capability Classes 1 and 3	(3,827)
Shortfall of Capability Classes 1 and 3	110
Residual shortfall that can be met by any Capability Class	822

Figure 39 demonstrates that without more energy-producing capacity (from either Capability Class 1 or Capability Class 3), there will be periods when there is not enough available generation to allow ESR to adequately recharge in order to be discharged to meet the next peak. The unserved energy in this example is driven by a combination of factors:

- Low availability of thermal generation, driven by the anticipated retirement of Collie Power Station and assumed unavailability of Bluewaters Power Station from 1 October 2027, and forced outages in Monte Carlo simulation #3.
- Depletion of ESR state of charge and inability to recharge before the second peak demand period.
- Limitations on running hours of demand-side response.
- Low wind availability, which limits the amount of ESR charging on the second day, compared to the first day.

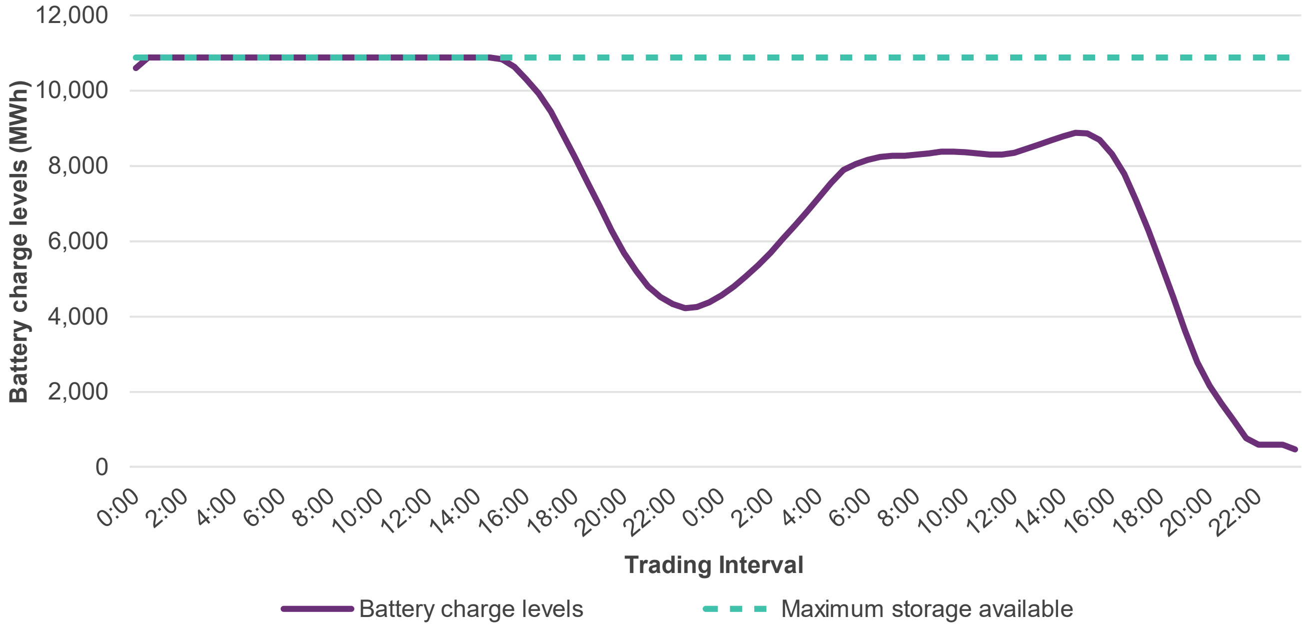
Figure 39 Supply mix with 932 MW of six-hour ESR added but unable to fully charge before expected unserved energy event (sample two-day period is 24-25 February 2028, Monte Carlo forced outage iteration #3, reference year 2010-11) (MW)



Source: EY

Figure 40 shows that for the same event, over the same time period, ESR is not able to be fully charged from one evening peak to another. In this example, the reservoir does not completely empty as one ESR facility is on Forced Outage and therefore neither charges nor discharges over this time period.

Figure 40 State of charge with 932 MW of six-hour ESR added but unable to fully charge before expected unserved energy event (sample day in February 2028, Monte Carlo forced outage iteration #3, reference year 2010-11) (MWh)



5.10 Assessment of sub-regional capacity shortfalls

5.10.1 Background

The ESM Rules require AEMO to identify and assess any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors and which cannot be addressed by additional Peak Capacity outside that sub-region.

This assessment of EUE isolated to specific sub-regions of the SWIS uses the same electricity market dispatch modelling framework as the Limb B assessment, but includes a transmission substation level granularity of demand as well as the implementation of network constraint equations.

These network constraints[100] can, at times, prevent power flows from one sub-region of the SWIS to another and potentially result in involuntary load shedding in a given sub-region. EUE could be reduced in these instances either through investment in additional local supply within the sub-region, or through network augmentations to alleviate the constraints.

The sub-regional assessment assumed two critical planned network developments proceed as follows:

- The EEP was modelled to be in service in 2025-26. This project improves the power transfer capability on the 220 kV network between Muja and the Eastern Goldfields and on select 132 kV line circuits around the Mid East region. The project involves uprating of components and secondary systems on these line circuits and includes upgrades to the Muja terminal.
- CEL-North was modelled in two stages, consistent with the approach undertaken for the 2024 WEM ESOO, but with a one-year delay applied to each stage to reflect delivery risks commonly associated with large infrastructure projects. The first stage of CEL-North, assumed to be in service in 2027-28, involves reconfiguring and establishing 132 kV line assets in the north metropolitan region. The second stage of CEL-North, assumed to be in service in 2028-29, involves establishment of a second 330 kV circuit and associated 330 kV infrastructure between the Midwest and the Perth Metropolitan area, along with further 132 kV reconfiguration works.

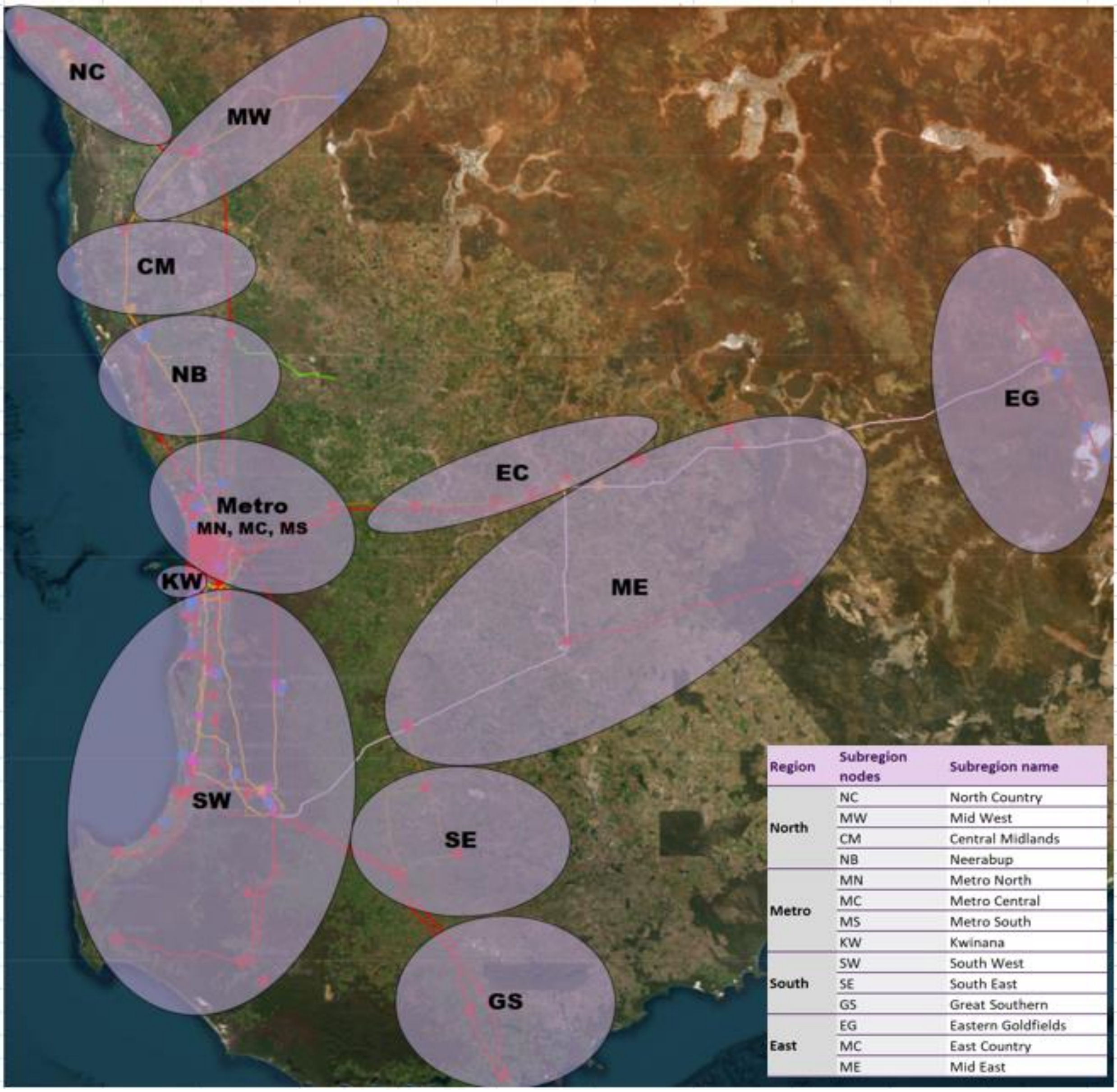
This year, the sub-regional assessment also sees the introduction of dynamic line ratings on applicable transmission circuits for use in transmission network thermal constraint equations.

Figure 41 presents a diagram of the potentially congested network areas investigated in this sub-region analysis.

The sub-regional assessment may also identify EUE occurring at the SWIS Regional Reference Node (RRN), which is the Southern Terminal 132 kV substation. This may indicate an overarching lack of supply across the system rather than limitations of the network, although addressing supply gaps may also require more transmission to get supply to the load centres.

[100] Transmission network transfer limits due to thermal ratings of line circuits, or system stability requirements.

Figure 41 Diagram of congested areas



Source: EY

5.10.2 Sub-regional expected unserved energy

The reliability assessment undertaken under Limb B has identified a growing capacity shortfall in all years but 2026-27. As discussed in the preceding sections, this is driven primarily by increasing demand, retirements of coal and gas power stations, and inadequate replacement capacity.

Sub-regional EUE modelling results presented in **Figure 42** align with this observation, where the EUE is predominantly observed for the RRN (Southern Terminal 132 kV) from 2027-28, indicating a general system-wide capacity shortfall that is not isolated to a specific sub-region.

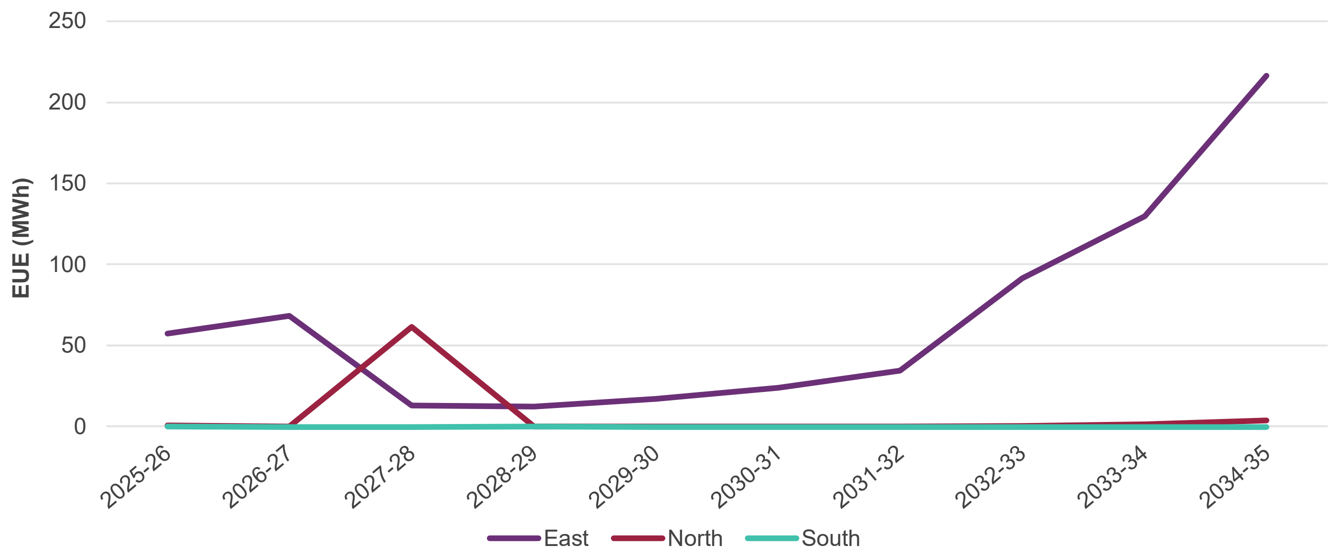
Figure 42 Expected unserved energy at the RRN compared to all other network regions (MWh)

Source: EY.

As **Figure 43** shows, the modelled EUE volumes outside the Southern Terminal RRN are observed in:

- the East region, comprising the East Country (EC), Mid East (ME), and Eastern Goldfields (EG) nodes, and
- the North region, comprising the North Country (NC), Mid West (MW), and Neerabup (NB) nodes.

Figure 43 Expected unserved energy in the East, North and South regions (MWh)



Source: EY.

East region

In the East region of the SWIS, modelled EUE is related to constraints on the 220 kV line, 132 kV lines that may limit the import of power into each of the nodes in the region, and 132 kV lines that transport power within the node. There is insufficient local generation to support current and forecast future demand in the region, with a number of customers connected via protection schemes (the Eastern Goldfields Load Permissive Scheme [ELPS])[101]. Planned 220 kV line uprates, the implementation of dynamic line ratings on two 132 kV lines in the region associated with EEP, and the introduction of further dynamic line ratings along more 132 kV in 2027-28 infrastructure are forecast to improve power transfer capability into the region.

Continued load growth in the region is forecast to result in 132 kV lines within the node limiting supply to specific demand points. While more subdued in this year's forecast compared to the 2024 WEM ESOO, continued growth associated with mining and the electrification of industrial processes is expected to drive demand growth in the East region. Improved power transfer capability within the region will be needed to ensure that the demand for electricity can be met. The region may also benefit from more local supply capacity at selection connection points. Western Power is currently evaluating NCESS proposals to improve reliability during islanding events across the next five years.

North region

The EUE in the North region of the SWIS is related to a number of constraints that impact power flows through the 132 kV network around the Neerabup and Mid West nodes. These constraints are actively managed by a number of operational schemes that are used to change the network topology depending on certain operating conditions.

The modelling also identifies a potential sub-regional capacity shortfall in 2027-28 within the Mid West region, during assumed outage windows to facilitate construction and commissioning of a portion of the CEL-North transmission network (resulting in the transfer capability being below full operational capability during these windows). Outage windows will be carefully co-ordinated by Western Power and AEMO during the delivery of the project to minimise the risk of EUE.

These shortfalls are expected to be resolved by completion of CEL-North, through improved power transfer capability throughout the region. This highlights the critical importance of the CEL-North project for both unlocking existing capacity to help meet Mid West load, and for enabling connection of further capacity to address a system-wide capacity shortfall.

5.10.3 Importance of new transmission augmentations

The delivery of new transmission network to connect additional supply capacity is critically important to improve the reliability outlook for the SWIS. The co-ordinated delivery of transmission network and generation supply also ensures the SWIS is developed efficiently and in a manner that minimises costs to consumers over the long-term.

While the determination of the RCT and the assessment of Limb B in the Planning Criterion is performed without the modelling of transmission network congestion (as per the ESM Rules), the presence of transmission network congestion does occur, and this can impact the ability of generation to be dispatched under particular operating conditions. This is observed through higher volumes of EUE and higher capacity shortfalls in the reliability simulations performed with network constraints compared against reliability simulations without. This means that investment in generation and storage capacity alone is not enough to ensure the WEM meets the reliability standard, as there are circumstances where EUE may still occur due to network limitations.

Table 29 demonstrates that with network constraints applied, EUE exceeds 0.0002% in all years of the outlook period.

[101] Western Power's ELPS enables the connection of customers in the Eastern Goldfields. Customers are supplied electricity when the network capacity is available and curtailed when it is not. ELPS customers are automatically notified that they need to reduce their load and are required to respond in a set amount of time. This helps to ensure other existing customer services are not put at risk.

Table 29 Expected unserved energy with and without network constraints, 2025-26 to 2034-35 (%)

Capacity Year	Unit	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
EUE – without network constraints	% of annual consumption	0.0003	0.0001	0.0075	0.0106	0.3640	0.8857	0.8691	3.3920	4.5408	6.7208
EUE – with network constraints	% of annual consumption	0.0007	0.0005[A]	0.0086	0.0115	0.3772	0.8784	0.8941	3.4508	4.6171	6.8200

A. This does not mean Limb B of the Planning Criterion is not satisfied in 2026-27. The Planning Criterion is modelled without network constraints.

The retirement and assumed unavailability of existing coal fired power stations in the South-West region is a key driver of potential system-wide capacity shortfalls across the next five years. Given that much of the existing 330 kV bulk transmission network has been built to transport power from the Muja/Collie regions to metropolitan demand centres, the retirement of existing coal-fired power stations will make network capacity available along these key 330 kV flow paths. New generation that is connected along these existing 330 kV pathways will access new headroom made available due to these retirements.

This WEM ESOO has been developed based on significant new network augmentations proposed under the EEP and the CEL-North Project being delivered. These are both significant projects set to enable the connection of new utility-scale renewables and firming capacity projects in the eastern and northern regions of the SWIS. However, the generation capacity shortfall identified in the ESOO reaffirms the need for continued transmission investment in the SWIS beyond these two projects.

Furthermore, the transition to more weather-dependent generation resources means it is essential that future transmission network augmentation enables generation to be connected in regions that have strong, diverse supply characteristics that complement the future generation capacity mix. Enabling the connection of a more diverse and complementary generation mix helps reduce the risk of extreme weather patterns exacerbating capacity shortfalls (although it does not remove it entirely).

A co-ordinated approach to the development of generation and network is facilitated through the WEM planning cycle that involves the SWIS *Whole of System Plan*, Western Power’s Transmission System Plan and the WEM ESOO. AEMO’s Western Australian *Gas Statement of Opportunities* (GSOO) also provides insights into the role of gas-powered generation as a major source of gas demand in Western Australia.

There is an opportunity to continue to improve how these planning processes interact with each other in the future, which will enable greater co-ordination in generation and network planning. In the absence of co-ordinated development between supply, network and demand, transmission network augmentations are at risk of being developed in isolation to address a localised issue, without consideration of a wider perspective of what is occurring at a system level.

5.10.4 Potential network options to support the SWIS

Transmission network development is driven by a combination of factors including (but not limited to) where new generation capacity is developed and where transmission network constraints may limit power to be transferred to regional areas contributing to EUE risk.

Under the ESM Rules, the WEM ESOO is required to identify potential capacity supply and transmission options that would alleviate shortfalls. Western Power further assesses the need for transmission network augmentations through its annual

Transmission System Plan Process and network investment framework, while EPWA's *Whole of System Plan* also presents a view of how new generation and network can be co-ordinated.

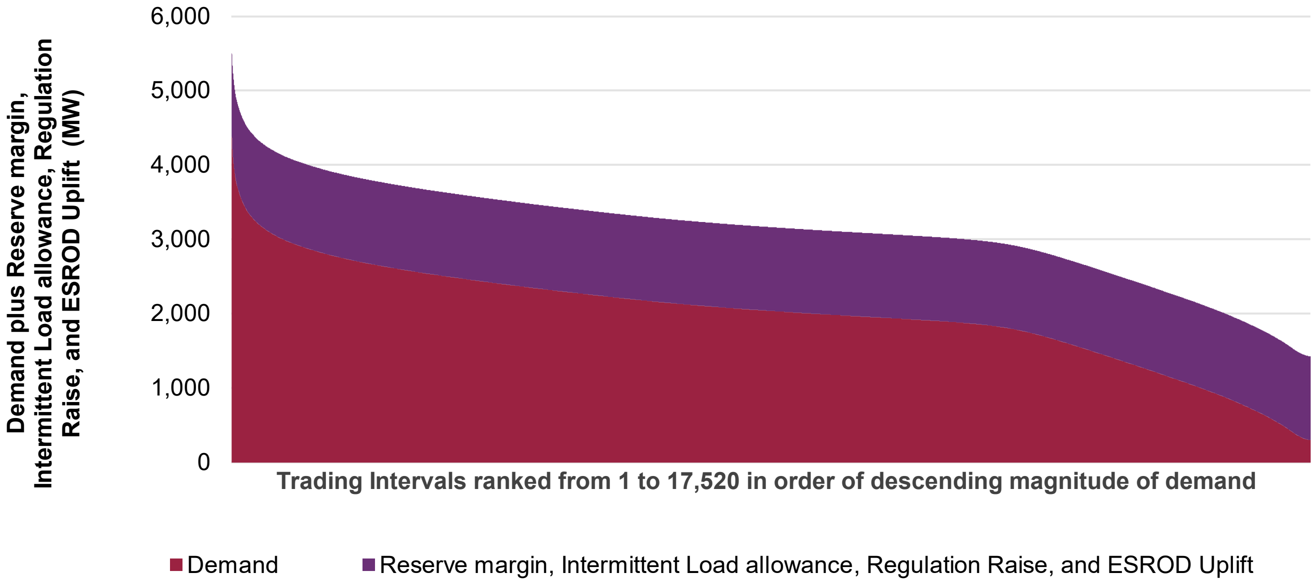
Potential options that may assist in mitigating capacity shortfalls on the SWIS are discussed in Chapter 6[102].

5.11 Availability Curves

The Availability Curve[103] is a two-dimensional duration curve of forecast minimum capacity requirement for each Trading Interval over a Capacity Year. It shows the demand arranged in an order based on magnitude over a Capacity Year, with demand on the vertical axis and Trading Intervals on the horizontal axis. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads, Regulation Raise, and ESROD Uplift (for the applicable Capacity Years). For more details on the methodology for the development of Availability Curves, refer to Appendix A5.2.8.

The Availability Curves for 2026-27 and 2027-28 are shown in **Figure 44** and **Figure 45**, respectively. These curves can be used to determine the number of hours when the capacity requirement exceeds a given level of demand plus an amount of available capacity margins.

Figure 44 Availability Curve, 2026-27 (MW)

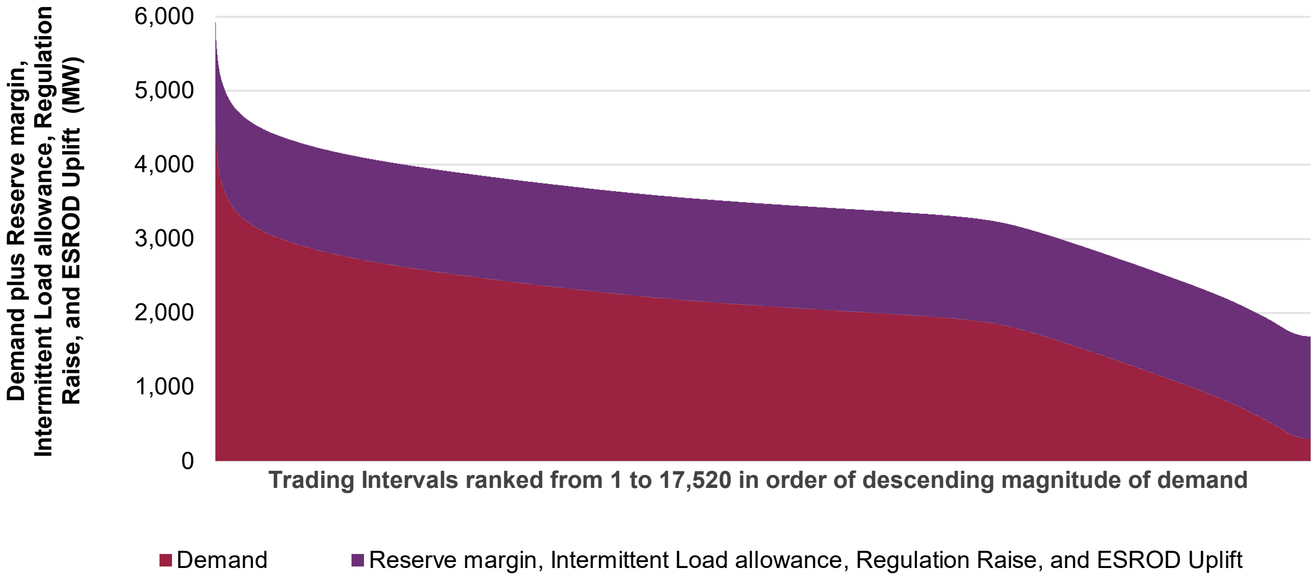


Source: AEMO and EY.

[102] This assumes CEL-North and EEP are already in place.

[103] The Availability Curve is defined in clause 4.5.10(e) of the ESM Rules, and is required for the second and third Capacity Year of the Long Term PASA Study Horizon under clause 4.5.13(f). The Availability Curves are determined by developing a half-hourly load profile, which is based upon a series of reference years and scaling this profile to align with the 10% POE forecast at the annual peak and minimum, and the expected annual energy forecast across the full year. Note that for both Availability Curves (more noticeable for 2027-28) the lower end of demand remains constant at a minimum of 300 MW as a result of the implementation of a minimum demand threshold in reliability modelling.

Figure 45 Availability Curve, 2027-28 (MW)



Source: AEMO and EY.

6 System strength assessment

This chapter explores the impacts on system strength in key locations as synchronous generation (that is, coal- and gas-fired generation) is retired and replaced with IBR such as utility-scale batteries, wind and solar generation:

- System strength is projected to decline sharply in key locations as synchronous generation retires and IBR are connected.
- In the South West region, Shotts Terminal (a substation located near Collie) is forecast to shift from being one of the strongest areas of the network to a weak area due to the closure of coal-fired power stations and connection of approximately 650 MW of grid-following battery storage by 2027.
  - Remedial measures including targeted operational responses and investment in assets or services will likely be required in the near term to address system strength shortfalls at Shotts Terminal.
- In the Eastern Goldfields, Merredin Terminal and Cunderdin are already known to operate under low levels of system strength conditions; this will be exacerbated if additional IBR are connected and further synchronous generation is retired without remedial actions being taken.
- In the North Country, delivery of Western Power's CEL-North transmission upgrade will improve system strength for existing and committed projects, but connection of further IBR is expected to significantly weaken the region and will require remediation.

The energy transition will require investment in new assets and capabilities to maintain system security, including for system strength, frequency management, voltage control, ramping capability, and system restart services over the coming decade. These themes are explored in detail in AEMO's SWIS Engineering Roadmap[104] and are the focus of several reforms as part of the Co-ordinator of Energy's Power System Security and Reliability Standards Review[105].

This chapter focuses on system strength – a vital characteristic of any power system.

Synchronous generation, such as coal- and gas-fired generation, currently plays a major role in maintaining system strength in the SWIS. As these synchronous generators retire from the power system and largely get replaced with IBR, system strength will weaken, giving rise to potential fault current, voltage stability and inverter ride-through issues. Investment in new synchronous machines (generators or condensers), updated protection schemes[106], additional substation interconnections, alternative voltage regulation and stabilising equipment, and/or advanced inverter capabilities such as grid-forming are expected to help mitigate these risks. It is therefore vital that system strength is continually assessed and forms part of system planning.

[104] See https://aemo.com.au/initiatives/major-programs/engineering-roadmap.

[105] See https://www.wa.gov.au/government/document-collections/power-system-security-and-reliability-standards-review.

[106] Such as duplicated differential protection, which do not require utilisation of IBR fault response to operate correctly. Differential protection inherently provides accurate fault location (directionality) and only requires sufficient fault current from one direction to operate, which makes it well suited for scenarios where some parts of the system have low synchronous fault current levels.

This chapter presents an initial assessment of system strength in sub-regions of the SWIS based on existing and committed supply (less expected retirements) and committed network capacity to highlight the potential risks of declining system strength and opportunities for investment in mitigations.

AEMO consulted with Western Power in deriving and analysing the results. Further studies are required to identify appropriate solutions to mitigate emerging system strength risks. The results will inform the need to procure system strength services via the NCESS framework and the prioritisation of SWIS Engineering Roadmap actions and potential procurement processes to mitigate emerging risks.

The following sections outline AEMO's system strength assessment approach and outcomes by sub-region. Further detail on the screening methodology and scope of study can be found in the *WEM System Strength Screening Methodology for 2025 ESOO*, which is published in conjunction with this WEM ESOO. In addition, Appendix A6.1 provides an overview of the current regulatory framework applying to system strength and details on the planning and regulatory initiatives that will be vital for ensuring that system strength in the SWIS is maintained at acceptable levels. This includes:

AEMO has undertaken a Short Circuit Ratio (SCR) assessment to indicate system strength at various locations on the SWIS.

SCR is the ratio between the three-phase short circuit level and the rated output of the IBR, as measured at the IBR's connection point.

The lower the SCR, the harder it is to control or protect the system.

- the Co-ordinator of Energy's Power System Security and Reliability Standards Review, that aims to implement a centralised planning and investment function for system strength to facilitate new connections in the SWIS,
- AEMO's SWIS Engineering Roadmap[107], which leverages AEMO's work as part of the 2022 Engineering Roadmap to 100% Renewables and associated reports to advance the technical, operational and planning requirements needed in the SWIS to support operational capability for higher levels of renewable generation, and
- Western Power's Transmission System Plan[108], which provides a set of investment options (network and non-network solutions) for developing the transmission system and must meet Power System Security and Power System Reliability requirements and the long-term interests of consumers.

What is system strength?

System strength is an umbrella term for a range of power system phenomena and issues that are loosely related to network fault levels (also called short circuit levels), namely:

- fault current contribution for the correct operation of protection systems,
- voltage sensitivity and the propensity for voltage oscillations, and
- voltage waveform stability for grid-following IBR to remain synchronised after disturbances.

The formal definition of system strength in the ESM Rules captures this by focusing on the power system's ability to maintain the voltage waveform. In simpler terms, this means keeping the voltage signal steady and robust, even when the system is under stress.

[107] At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/swis-engineering-roadmap.pdf?la=en&hash=A65DB858E3058106C3FB1989C1FB77D.

[108] See https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/transmission-system-plan--network-opportunity-map/.

Synchronous generation – such as coal- and gas-fired generation – are spinning machines that help form, support and anchor the voltage waveform. They provide inertia which naturally helps make the grid strong and stable. Additionally, they are strong sources of fault current, and, in their presence, the three-phase fault level is typically high.

IBR (such as wind farms, solar farms and grid-following ESR) on the other hand, limit their fault current, as they are programmed to protect themselves. Furthermore, their fault responses vary across different types of inverters due to different hardware, firmware and algorithms, making them less predictable and more complex to model.

In parts of the network that are electrically distant (that is, weakly connected) or where there are lots of IBR (such as solar or wind farms), the voltage waveform can be more sensitive to fluctuations caused by changes in active and reactive power flow, causing the area to exhibit low levels of system strength. In these areas, the system is more likely to experience voltage instability, or unmanageable disturbances during faults or switching events, all of which can affect the performance of connected generators and protection systems.

Short Circuit Ratio as an indicator of system strength

In a three-phase electrical system like the SWIS, the three-phase fault level refers to the maximum amount of electrical current that flows through a power system when all three electrical phases (wires) are simultaneously short-circuited. The SCR is the ratio between the three-phase fault level and the rated output of the IBR connected at that location.

At a location, if the SCR is high, then the grid is strong compared to the size of the IBR connected in that location. It is easier to maintain voltage stability, and the generation can operate more smoothly and reliably. On the other hand, if the SCR is low, voltage becomes unstable. IBR might have trouble staying connected, especially following a disturbance, and it is harder to control or protect the system, which creates risks to safe network operation. In extreme cases, instability of the voltage waveform may lead to cascading failures of the power system and interruption of energy supply to energy consumers. Based on their specific location and network connection, in some cases, IBR can be tuned during the connection process to operate at lower SCR levels.

AEMO has identified connection points with an SCR below five and above three to indicate a weak grid and an SCR below three to indicate a very weak grid. SCR above five typically indicates that a location is sufficiently strong to support the stable operation of the power system.

To enable a reliable and secure energy transition, it is essential that levels of system strength are monitored, and changes in system strength are forecast in a timely manner so that low levels of system strength can be remediated.

Options for remediation include making use of technologies like synchronous condensers or grid-forming ESR, or installing clutches on gas-fired generators to allow them to operate in synchronous condenser mode even when not generating, or additional substation transmission interconnection (meshing).

If not remediated, direct intervention by AEMO may be required as part of real-time operations to undertake remedial action to maintain Power System Security and Power System Reliability. This action may include curtailing IBR and/or requiring the commitment of non-IBR generation.

6.1 Minimum fault level requirements

Minimum fault level requirements are more complex than a single number can capture. For planning purposes, it is prudent for minimum fault values to be based on needing sufficient security services available to cover the full range of typical operational conditions. Operationally, AEMO can further optimise and schedule only those security services which are needed to meet an expected operational shortfall.

In the NEM, AEMO generally considers the worst-case minimum requirement observed across three dimensions:

- the minimum value required to satisfy protection requirements,
- the minimum value required to satisfy voltage step change, and
- the minimum value required to ensure system stability under all typical operating conditions and configurations (in other words, the maximum observed fault current requirement for stable system operation across a range of tested system conditions).

In effect, these minimums represent the levels needed to ensure the system can operate securely under all typical operating conditions and configurations. This is different than an instantaneous minimum requirement, which could feasibly be lower under specific system conditions. That is, falling below the minimum requirements does not automatically guarantee the system is unstable – but it does indicate that there are at least some system conditions identified under which it would be.

This is a reasonable approach when needing to choose a single minimum value against which to assess security planning activities; however, AEMO acknowledges that the operational minimum requirements could be lower under specific system conditions and depending on the distribution of fault current sources at the time.

Current and proposed arrangements on minimum fault level requirements in the SWIS

There are currently no obligations to report minimum fault level requirements in the SWIS. There is an existing obligation in the Technical Rules (clause 5.5.1) for Western Power to publish maximum fault levels at each transmission node. However, there is not currently any obligation under the ESM Rules for any entity in the SWIS to determine, maintain and publish minimum three-phase fault levels for the transmission network.

Western Power does publish the minimum short circuit levels at each of its major transmission nodes as part of the Transmission System Plan network data set[17]. However, this information is calculated only for the first year of the Transmission System Plan's 10-year planning horizon.

The Co-ordinator of Energy (Co-ordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the Power System Security and Reliability Standards that apply in the SWIS, including a revised system strength framework that will provide greater clarity on roles and responsibilities for determining and maintaining system strength.

System strength in the South West (Collie) region

Despite the absence of minimum fault level requirements, it is still possible to estimate whether or not further investment may be needed in the Collie region (and other locations) based on engineering judgement and observed operating conditions as discussed below. However, the level of confidence in the scale and type of investment required to address concerns is lower. For this reason, more analysis will be undertaken as a matter of urgency, in collaboration with Western Power, to provide confidence in, and understanding of, potential system strength shortfalls.

Advice provided by Western Power indicates that, even with the projected reduction in SCR from the closure of all coal-fired generation and the connection of committed IBR in the region by 2030, the protection system in the Shotts Terminal area can be adjusted to be adequately sensitive for operation at the network minimum fault levels. As further detailed studies are required for system strength, AEMO and Western Power will be working collaboratively and continuously to update and verify the network minimum fault levels required to support the power system as it transitions.

The most pressing need is sufficient system strength to facilitate the new IBR connections (wind, solar and ESR) required to maintain reliability following the closure of coal-fired generation.

Currently, system strength issues are only addressed as Facilities seek to connect, but more proactive investment in centralised system strength services, or even bundled services, may be a lower cost alternative for the SWIS.

For example, there are current system limit requirements for minimum operational demand in the South West (Collie) region. These operational requirements have been provided by Western Power in the form of a Limit Advice to ensure there is a minimum number of synchronous generators online for reactive power support during periods of low operational demand. In addition, inertia requirements are managed via dispatch.

The coal-fired power stations in the South region have been a reliable source of both voltage support and inertia. With the committed retirement of these Facilities in this region, the options to support voltage and maintain a sufficient level of inertia become limited and the Limit Advice will need to be adjusted accordingly.

Although connecting new IBR in the South region has the potential to negatively impact fault current level, where the IBR are designed for grid-forming operation they could help support system strength, address existing voltage constraints and contribute to the future need for inertia after coal-fired generation retirements. If, on the other hand, the new IBR are designed for grid-following operation, further investment in synchronous condensers or gas-powered generation will likely be required. There is additional complexity in tuning multiple IBR Facilities, in close proximity, that are designed for grid-forming operation. As such it is recommended that the connection of such Facilities should be located near to grid-following Facilities.

6.2 Approach to system strength assessment

To assess system strength, AEMO undertook SCR[109] assessments at 15 locations on the transmission system, covering 25 IBR connection points of committed and some probable IBR in consultation with Western Power. The locations were selected based on IBR connection information and forecasts (in the case of CIS projects). Power station retirement assumptions were aligned with the WEM ESOO Expected scenario, with sensitivity analysis also conducted assuming the unavailability of Bluewaters' operations from 1 October 2030.

AEMO calculated the three-phase fault level from synchronous generators at key transmission busbars to assess the impact on system strength under the Expected case from:

109 $SCR = (S\_(Short{-}Circuit)\ [MVA])/(P\_Rating\ \ [MW])$ where SCR = Short Circuit Ratio, $S\_(Short{-}Circuit)\ [MVA]$ = Short circuit MVA capacity at the point of common coupling and $P\_Rating\ \ [MW]$ = Rated power output of the generating system connected to that same point of common coupling MW.

- anticipated retirement of coal-fired power stations,
- connection of committed and probable IBR and synchronous generation[110], and
- committed network augmentation (CEL-North).

The fault level projections were calculated against post-contingent requirements which ensure that, following a contingency, the system is in a satisfactory operating state.

AEMO conducted a further sensitivity to assess the impact of an additional 100 MW of IBR at each location, to identify where system strength remediation may be required to support investment in renewable generation.

6.3 Summary of system strength projections

AEMO identified six locations that are currently experiencing, or are forecast to experience over the next six years, a shortfall in system strength. **Table 30** summarises the system strength assessment outcomes for the SWIS in each of the sub-regions. **Figure 46** presents this data as a map for 2024, 2027 and 2031, including the impacts of an additional 100 MW of IBR on assessed SCR at each location. Given the level of investment interest at some of these locations (see **Figure 48** in Chapter 7), assuming an additional 100 MW of installed IBR, beyond what is already committed, is considered a very conservative estimate of likely development interest in these locations.

These system strength results highlight:

- **A significant reduction in System Strength at Shotts Terminal (in the Collie region)**. Shotts Terminal is historically a location with strong system strength with the current configuration of synchronous facilities and network. Based on the SCR screening, Shotts Terminal is forecast to experience a material reduction in SCR over the assessment period. This is due to installation of a significant amount (~0.75 GW) of additional IBR from mid-2025 and the retirement of the Collie Power Station. By 2031, all coal generation currently connected in the area is expected to have retired, further reducing fault current in the area.
- **The small margins for new IBR connection** before the SCR at non-metro nodes degrades to very weak levels.

Given the need for new investment in generation as highlighted in Chapters 5 and 7, the results underline the need for the investment to be undertaken in a way that supports, or is commensurate with, any further investments and actions necessary to remediate low levels of system strength.

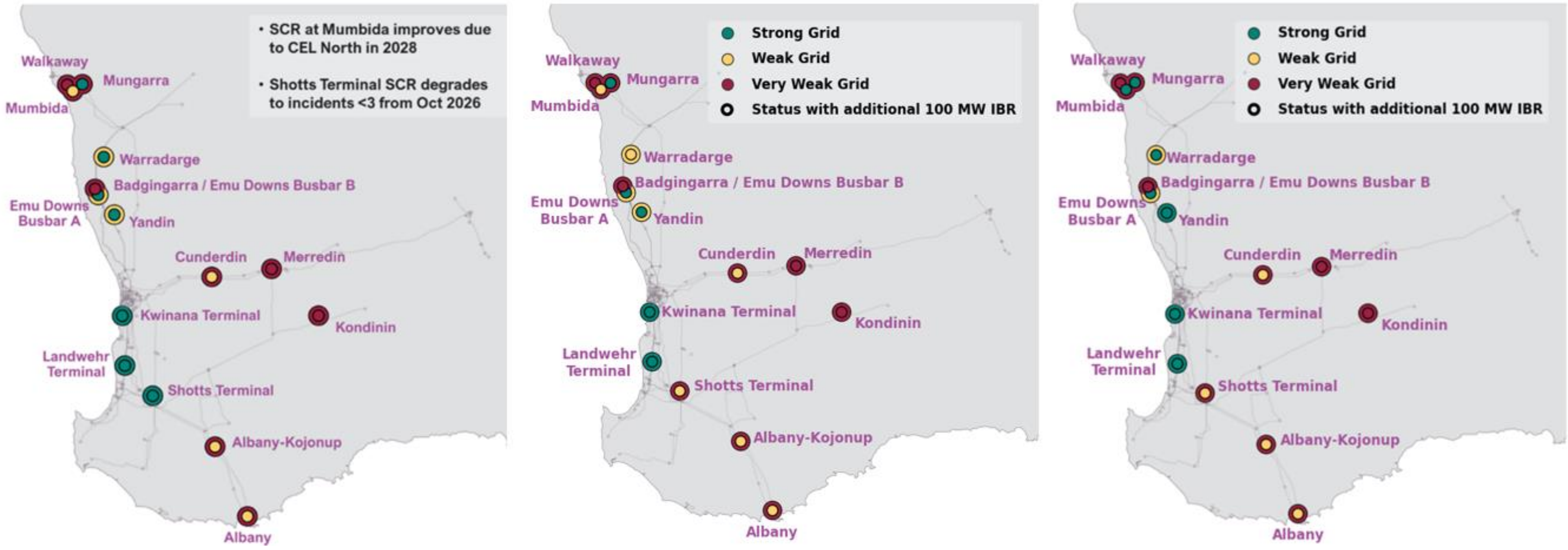
Table 30 System strength outcomes by SWIS Region, October 2024 to October 2031

SWIS Region	Transmission system location	SCR projections over assessment period	Assessment outcomes	Remediation requirement
North (North Country)	Badgingarra / Emu Downs Busbar B	SCR<3 (very weak) Fault current lowers after CEL - North upgrade	Delivery of CEL-North) transmission upgrade in 2028 is expected to improve system strength at most of the IBR connection points in the North Region except Badgingarra/Emu Downs Busbar B.	Increased fault level would increase system strength in the region and allow further connection of IBR in future. The existing very weak grid condition identified at Walkaway is expected to
	Emu Downs Busbar A	SCR>10 Fault current increases after CEL - North upgrade		

[110] The same facility list was used as for the reliability assessment in Chapter 4.

SWIS Region	Transmission system location	SCR projections over assessment period	Assessment outcomes	Remediation requirement
	Mumbida	3<SCR<5 (weak) Fault level increases after CEL - North upgrade	This location exhibits lower system strength during an outage due to de-meshing of the 132 kV system through CEL-North. The CEL-North augmentations will support significant opportunity for new connections in the North, over a gigawatt of potential projects have registered interest. However, just 100 MW of additional IBR would degrade system strength to weak at the modelled locations.	persist and be managed in the area through non-thermal network constraints (Limit Advice). There is opportunity for proposed synchronous facilities, if appropriately designed, to contribute to system strength remediation in this region. For example, installing a clutch in a gas turbine would allow it to provide system strength services even when not generating.
	Mungarra	5<SCR<6 Fault current increases after CEL - North upgrade		
	Walkaway	SCR<3 (very weak) Fault level increases after CEL - North upgrade		
	Warradarge	5<SCR<8 Fault current decreases after Warradarge Wind Farm upgrade, but then increases to above 5 after CEL - North upgrade		
	Yandin	5<SCR<10 Fault level increases after CEL - North upgrade		
Metro South	Kwinana Terminal	10<SCR<30 Expected to remain at this level over assessment period	System strength was assessed to be strong at the Kwinana Terminal and will remain strong based on current forecast IBR connections and synchronous generator retirements.	Currently not required.
South	Albany and Albany-Kojonup	3<SCR<5 (weak) Expected to remain at this level over assessment period	Shotts Terminal will experience a material reduction in system strength from strong to weak for most of the assessment horizon due to the retirement of coal generation and connection of multiple IBR. The IBR connection points at the remaining locations in the South region are expected to experience lower levels of system strength or maintain their current levels.	The South region, particularly at Shotts Terminal, will require action to maintain system strength. One option is to consider the role of grid-forming inverter technology in managing stable operation for existing and/or new IBR.
	Landwehr Terminal	10<SCR<30 Fault level lowers with coal retirement and IBR connection, but SCR remains above 5 to end of the assessment period		
	Shotts Terminal	8<SCR<30 Fault level declines mid-2025 to 4<SCR<6 with instances as low as 3		
East (Eastern Goldfields)	Cunderdin	4<SCR<6 and remains at this level over assessment period despite coal retirements	These locations are considered to have very weak system strength and, without remediation, all IBR connection points within these locations will continue to experience very low (and potentially declining) levels of system strength	All locations would benefit from an increase in fault level, particularly at Merredin Terminal. Existing concerns of voltage stability are managed in the area through reactive support equipment owned by Western Power
	Kondinin	SCR<3 (very weak) Expected to remain at this level over assessment period despite coal retirements		
	Merredin Terminal	SCR<3 (very weak) Fault level lowers by 2028 with coal retirement and connection of 100 MW of BR connection		

Figure 46 System strength assessment outcomes – October 2024 (left), October 2027 (middle) and October 2031 (right)



Timely investment in remedial measures will be necessary to support system strength

Remedial measures, including targeted operational responses, will likely be required by AEMO or the Network Operator from later this year to address system strength shortfalls for those locations assessed as being at risk. Given lead times for investment in assets or services to support system strength, longer term procurement for this investment is also time critical. AEMO will use the system strength assessment outcomes, and additional analysis to be undertaking in coming months, to inform the need to procure system strength services via the NCESS framework as a remedial action.

Table 31 below provides an overview of the various actions that AEMO and/or the Network Operator can take to address low levels of system strength and their implementation timeframes. It is essential that planning for remediations, including those with a longer timeframe, is commenced with some urgency so the SWIS is adequately prepared for the energy transition.

Table 31 Remedial options and implementation timeframes

Remedial strategy	Solution option	Example	Implementation timeframe
Procurement measures (for centralised services)	Locational provision of system strength via existing Facilities	Conversion of existing synchronous facilities to enable permanent or switched operation as a synchronous condenser	Within two years (depending on technology)
	Synchronous condenser or new generation with clutch to enable operation as synchronous condenser	A dedicated synchronous condenser that is continuously connected	Over five years for new development
	Network solution	Targeted transmission system augmentations (to mesh weak areas, or alternative protection schemes)	As part of the connections process, otherwise, within two years
Connection measures	Remediation action scheme	Scheme to manage IBR generation	Within connection timeframe
	Technology solution	Use of grid-forming technology rather than grid-following technology	Within connection timeframe
	Synchronous Facility	Synchronous generation or synchronous condenser	Within connection timeframe
Real-time operational measures	IBR curtailment	MW and/or megavolt-amperes (MVA) limitation on IBR	Prior to next five-minute dispatch interval
	Commitment of synchronous generation	MW requirement on non-IBR Facility	Dependant on Facility
	IBR re-dispatch	Re-dispatch of IBR and, if necessary, commitment of other Facilities	Prior to next five-minute dispatch interval
	Network outage management	Manage network outages	Within Pre-Dispatch period
	Facility outage management	Manage outages of Facilities with synchronous generation	Within Pre-Dispatch period
	Change IBR mode of operation	For specific, local IBR, change mode i.e. from Voltage Control to Reactive or Power Factor Control Mode to remediate specific controller behaviour	Within Trading Interval

6.4 Next steps

AEMO's system strength assessment has identified areas of the SWIS that will experience materially reduced or low levels of system strength, based on the low SCR exhibited at IBR connection points. These areas may experience voltage instability, particularly during outage conditions, resulting in unexpected disconnections of sensitive equipment or maloperation of protection equipment.

The assessment, which was undertaken in the absence of minimum three-phase fault level requirements, highlights the need and urgency of implementing the Power System Security and Reliability Standards Review outcomes. AEMO supports the proposal to implement a revised system strength framework for the WEM with clarity on roles and responsibilities for determining and maintaining system strength.

Of particular importance are related proposals for a centralised planning and investment function that aligns network and power system planning through a common fleet outlook, minimum fault level requirements (for network protection) and co-ordinated assumptions for forecasting. This alignment is necessary to identify system strength requirements and to deliver co-ordinated, cost-effective system strength remediations to address existing issues and facilitate new IBR connections in the SWIS.

The system strength assessment involved a collaborative process of setting agreed assumptions, scope and methodology with Western Power, which may be drawn on in developing the detail of a system strength framework in the ESM Rules.

Further analysis and detailed studies

While measures will be taken in the Shotts Terminal area to ensure the proper operation of protection systems, sufficient system strength is needed in the South, East and North regions to enable new IBR connections to maintain reliability following the closure of coal-fired generation. AEMO will continue working collaboratively with Western Power to iterate current studies using updated information on new and proposed Facility connections and to undertake detailed studies to facilitate an understanding of the system requirements at each 'at risk' location and the viable remedial options. The detailed studies will determine the following:

- The areas in the SWIS where a dispatch resolution would provide a viable short-term solution. For example, Western Power's assessment of Network Limits will inform whether IBR curtailment or the commitment of nearby synchronous generation would adequately manage system strength. AEMO and Western Power will need to assess which operational processes would require revision.
- Whether and how existing facilities can contribute to the remediation of low levels of system strength through the provision of specialised new services. The NCESS framework enables AEMO, the Network Operator or the Co-ordinator of Energy to identify the need for new services that market mechanisms do not already provide and to transparently procure the service where there is sufficient justification.
- Where there is opportunity for the performance of existing and/or new facilities (synchronous generation and IBR) to contribute to the remediation of low levels of system strength as part of the connections process and Generator Performance Standards (GPS) framework. For example, there may be an option for:
  - the IBR to operate as a grid-forming device (where the IBR supports this capability) to help alleviate voltage stability concerns in an area, or

  - the synchronous generator to install a clutch and operate as a synchronous condenser.
- Whether network augmentation to mesh weak areas of the network provides the best option for remediating low levels of system strength in one or more areas.
- Which areas of the SWIS would see the most effective improvement to Power System Security and Stability by connecting a synchronous condenser. In practical terms, a synchronous condenser would be viable if the SWIS' inherent strength was found to be insufficient to support secure and reliable operation. One or more of the following circumstances would need to persist:
  - The short-circuit fault level is too low.
  - There is inadequate reactive power and voltage support.
  - IBR are constrained too frequently and for too high a proportion of capacity.

Where detailed studies specifically identify that network augmentation or synchronous condensers are required to remediate system strength:

- non-network services could be procured via an NCESS contract where this presented a more efficient solution to network augmentation, or
- synchronous condensers could be procured via NCESS contracts where there is sufficient implementation lead time.

7 Opportunities for investment in supply, system strength and transmission

As ageing coal-fired and gas-fired fired generation exits the SWIS, material investment in new energy-producing generating capacity and storage is required, along with investments in system strength services and the transmission network.

This chapter highlights opportunities for investment to ensure a secure and reliable electricity supply for the SWIS over the next 10 years. In summary:

- The SWIS needs more generation to complement storage and mitigate the risk of batteries not being adequately charged when called on to meet demand.
- Of the 932 MW of additional capacity needed to meet the RCR in 2027-28, at least 110 MW will need to be generation capacity (such as gas, wind, solar or WTE generation) to maintain reliability within tolerance.
- Investment in synchronous machines and/or grid-forming inverters as well as network augmentations are expected to be necessary to ensure system security and unlock future renewable investments. Opportunities to deliver both reliable and secure supply can be realised through design decisions.
- Timely delivery of CEL-North is critical to support additional capacity and address sub-regional and system-wide shortfalls. Further investment in new transmission networks will also be required to connect additional generation to support decarbonisation and maintain reliability.

7.1 Introduction

Chapter 5 presents the reliability outcome for Peak and Flexible capacity for the 10-year outlook period as well as regional shortfall analysis which identified expected restrictions on transmission capability. Chapter 6 explores the impacts of system strength as synchronous generation is expected to retire and be replaced with IBR, such as ESR and wind and solar generation.

The identified challenges translate to investment opportunities (Section 7.2) in the capacity market as well as system strength (Section 7.3) and transmission network (Section 7.4), which are covered in this chapter.

7.2 Peak and Flexible Capacity investment opportunities

7.2.1 Additional capacity likely to be required for the 2025-26 Hot Season

As outlined in Section 5.8.1, there is a likelihood that AEMO will need to procure at least 50 MW of Supplementary Capacity this coming Hot Season. Supplementary Capacity is a mechanism under the RCM that enables AEMO to procure additional capacity within six months prior to the start of a Capacity Year. In assessing whether Supplementary Capacity is required, and the quantity that is needed to keep EUE within tolerance, AEMO takes into account any major outages, fuel disruptions, or delays to connection of new committed capacity.

The forecast shortfall of 50 MW in 2025-26 is contingent on the timely delivery of committed projects of 1,572 MW (committed projects include Alinta Wagerup ESR, Synergy's Collie ESR [COLLIE_ESR4 of 176 MW and COLLIE_ESR5 of 175 MW], and Neoen's ESR [COLLIE_BESS of 300 MW]). AEMO is monitoring the progress of committed projects and encourages proponents to take action to mitigate any potential delays. Any delay in these committed projects may translate to a higher magnitude Supplementary Capacity requirement.

AEMO will carry out further assessment to confirm whether procurement of Supplementary Capacity is required for 2025-26. The decision and quantity of Supplementary Capacity will be informed by available information at the time of trigger, including in relation to any delays to commercial operations and any operational limits which may reduce availability of capacity. If Supplementary Capacity is required, AEMO will publish the quantity, timeline and guidelines for procurement on the AEMO website.

7.2.2 Timely delivery of committed Peak Capacity and increased investment in Capability Classes 1 and 3 is essential to meeting the Reserve Capacity Requirement in 2027-28

Figure 47 presents a summary of existing, committed and probable capacity for 2027-28. The RCT determined for 2027-28 is 6,238 MW, which sets the RCR for the 2025 Reserve Capacity Cycle. A total of 5,306 MW of capacity is expected to be available, comprising 4,147 MW existing and 1,158 MW committed capacity. The shortfall to be procured through the RCM is therefore 932 MW. The Capability Class Assessment has indicated that at least 110 MW of this additional capacity is required to be from Capability Class 1 or Capability Class 3 facilities to keep EUE below 0.0002% of annual consumption.

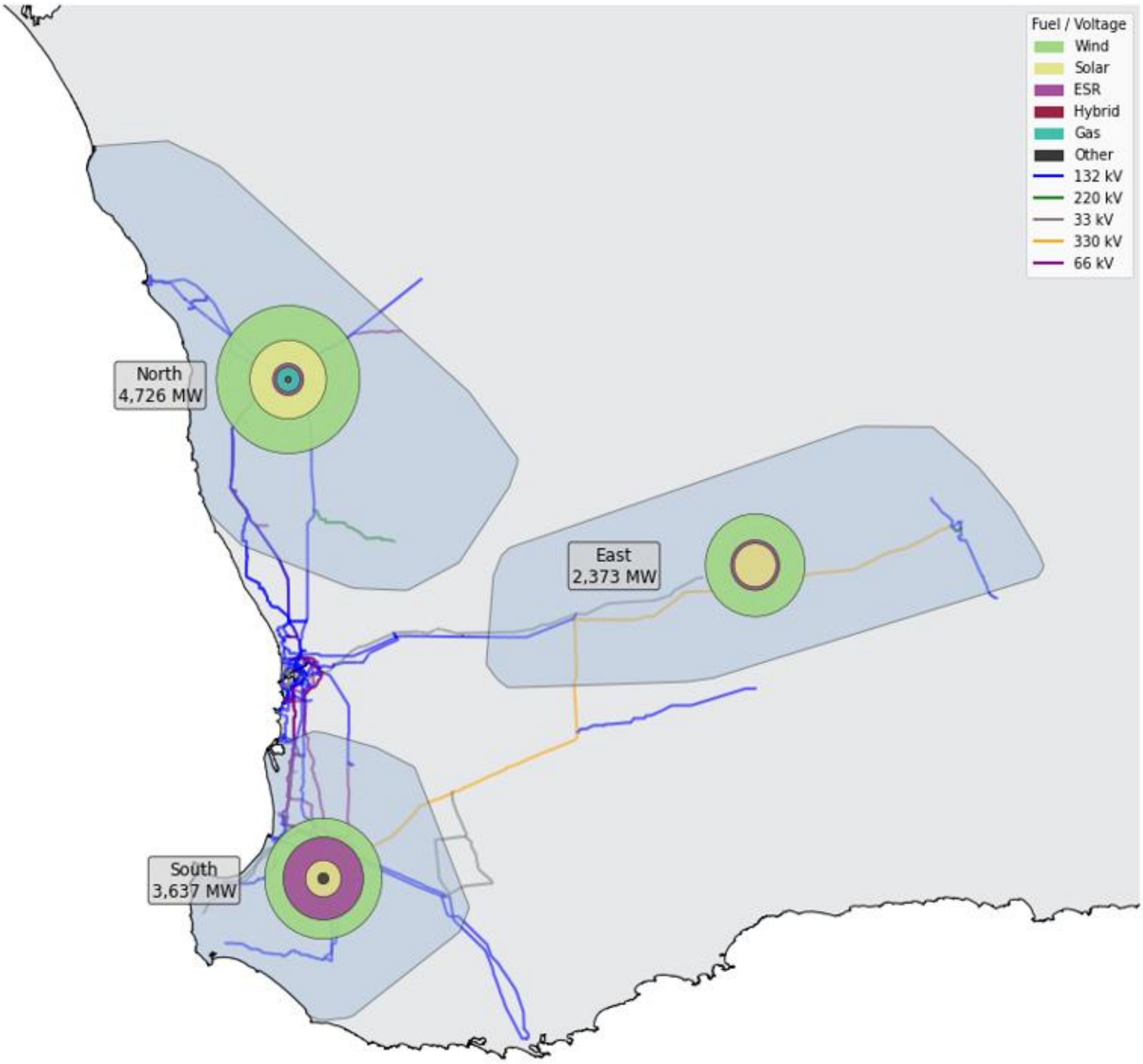
Figure 47 Forecast Peak Capacity for 2027-28 (MW)

If the 507 MW of probable capacity is added – noting probable capacity is not assumed in the Expected scenario – there remains a shortfall of 425MW. Further, only 60 MW of this probable capacity is Capability Class 1, and 7 MW is Capability Class 3.

The projected capacity shortfalls highlight that it is imperative the committed capacity is brought online quickly, and steps should be taken to accelerate the connection of probable capacity. Even then, further investment is required to bridge the gap for 2027-28.

Outside the scope of existing, committed and probable projects, AEMO is aware of a substantial pipeline of projects[111] that could be developed in response to this investment opportunity. AEMO notes that these projects would require accelerated environmental and planning approvals, network connection and final investment decisions. **Figure 48** illustrates the pipeline of projects in the SWIS which may be developed over time, amounting to 10.7 GW of projects of varying stages of development.

Figure 48 New projects by region in the SWIS (MW)



Source: 2025 Long Term PASA FIR – Western Power

[111] A total of 2,494 MW of potential Peak Capacity was submitted through 48 valid nominated EOIs, as part of the 2025 EOI process. See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2025/2025-expression-of-interest-summary-report.pdf?la=en.

To address energy shortfalls identified in Chapter 5, additional capacity brought online should feature generation capacity, including firm non-energy limited capacity (such as gas-fired Facilities meeting the 14-hour fuel requirement) and renewable generation such as wind or solar Facilities.

7.2.3 Reserve Capacity Price (RCP)

The 2025 CRC window for applications closes on 8 July 2025. AEMO will assign Capacity Credits for 2027-28 on 14 October 2025.

Peak and Flexible Reserve Capacity Price (Peak and Flexible RCP)

AEMO will determine the Peak and Flexible RCP for 2027-28 in October 2025, following assignment of Peak Capacity Credits and Flexible Capacity Credits[112], respectively. This will be determined with reference to the 2025 BRCP.

AEMO will determine the Peak and Flexible RCP in accordance with clause 4.29.1 of the ESM Rules. To allow for a sharper investment signal, Flexible Capacity Credit holders will be eligible for a top up payment if the Flexible RCP is determined to be greater than the Peak RCP.

The Economic Regulation Authority (ERA) will update the BRCP for the 2026 Reserve Capacity Cycle in accordance with clauses 4.16.11(b) and 4.16.12 of the ESM Rules, including any revised ESR Duration Requirement being published in the 2025 WEM ESOO, appropriate reference technology, uncongested network location and technical parameters specified in these clauses.

The RCP is the price paid for Capacity Credits procured centrally through AEMO and is calculated annually using the formula stipulated in the ESM Rules[113]. The key components of the RCP formulation include the BRCP and the level of excess capacity or deficit[114]. The Peak RCP for 2026-27 has been set at $216,092/MW/year for new Facilities and $160,392/MW/year for Transitional Facilities[115]. The BRCP for both Flexible and Peak Capacity is $360,700/MW/year for 2027-28[116]. This ERA determination is based on the estimated cost of constructing and connecting a 200 MW/800 MWh ESR to the SWIS and its fixed operational and maintenance costs over a 15-year life.

Figure 49 shows the historical trend for the BRCP and Peak RCP for the different types of Facilities, as well as the capacity excess or deficit. In summary:

[112] Flexible Capacity, a capacity product, is to be determined from the 2025 Reserve Capacity Cycle and future cycles, driven by magnitude, slope, and duration of the ramp up from minimum demand to the evening peak required to manage the increasing penetration of renewable energy on the SWIS. Facilities which can meet an eligibility threshold may be assigned Flexible Certified Reserve Capacity based on the maximum output they can achieve within four hours from a cold state, with the quantity of Flexible Certified Reserve Capacity capped at the level of Peak Certified Reserve Capacity.

[113] The calculation of both Peak and Flexible RCP is under clause 4.29.1 of the ESM Rules.

[114] The purpose of the level of excess capacity or deficit component in the RCP formula is to reflect price signal.

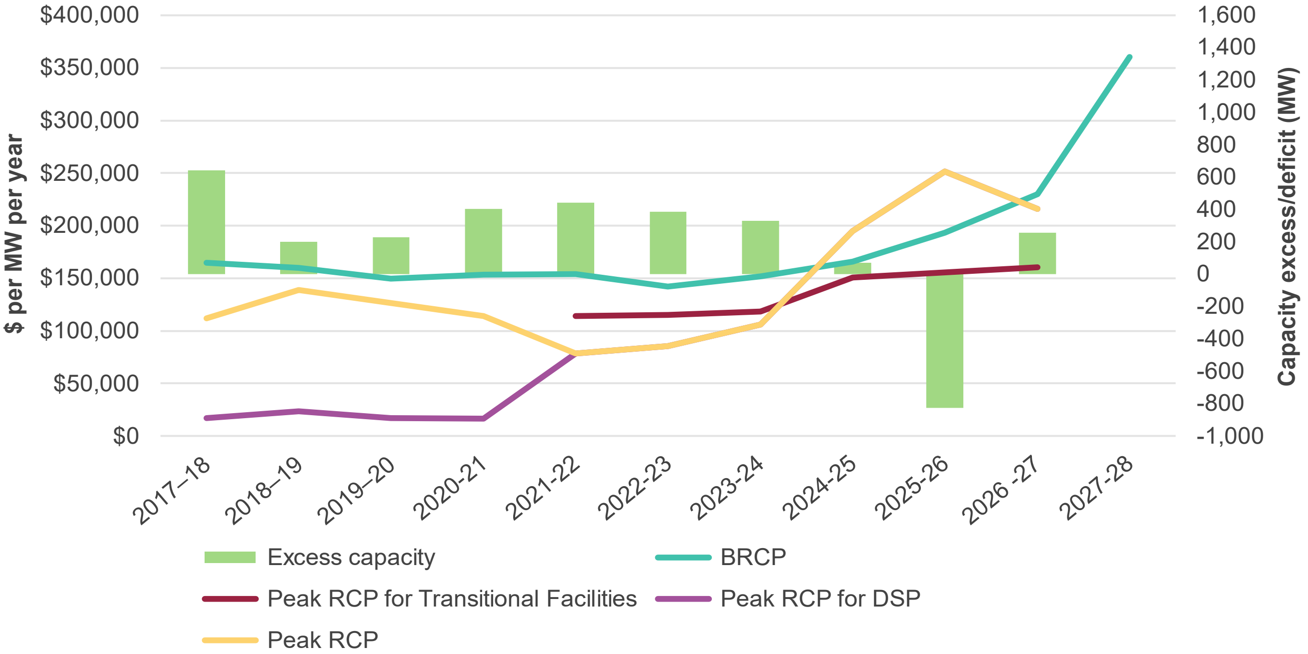
[115] Transitional Facilities are generation facilities that were assigned Capacity Credits for the 2018 Reserve Capacity Cycle and received an alternative RCP. The ESM Rule amendments that commenced on 22 February 2020 have introduced transitional arrangements for Transitional Facilities to provide a price floor of $114,000 and a price cap of $140,000 for these facilities, subject to CPI adjustment for the subsequent 10 years.

[116] See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/benchmark-reserve-capacity-price.

- There is a long-term increase in BRCP, most notably for 2027-28, as the ERA's 2025 BRCP final determination is 57% higher than the 2024 BRCP[117].
- The Peak RCP is significantly higher in recent years due to the ESM Rule amendment in RCP formulation[118], increase in BRCP and decrease/increase in capacity excess/deficit, with 2025-26 marking a long-term high of $251,420 when there was a capacity deficit of 826 MW.
- The Peak RCP has exceeded the Peak RCP for Transitional Facilities after 2023-24.

The trend in the Peak RCP highlights the improvement in compensation in the capacity market, driven by a combination of ESM Rules amendments and insufficient capacity to meet demand. This provides a strong signal for investment in new capacity, but does not differentiate capacity by its capability or location. The trend of Flexible RCP is not presented here, as the Flexible RCP will be determined for the first time for 2027-28.

Figure 49 RCP, BRCP and capacity excess/deficit, 2017-18 to 2027-28



Notes:

- DSPs were paid according to the DSP RCP prior to 2020-21. Since then, the DSP RCP was removed and DSPs have been receiving the same RCP as other new Facilities. See https://www.wa.gov.au/system/files/2021-11/RCM-Review-2021-Scope-of-works.PDF.
- The BRCP determined for 2027-28 is applicable for both Peak and Flexible RCP determination.

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[117] The significant increase in BRCP is mostly due to change in the required reference technology from a 160 MW open cycle gas turbine peaking generator to a 200 MW/800 MWh lithium-ion battery, which is more expensive to build and install. One of the factors for the higher cost is more land may be required in specified uncongested network location (Kwinana and Pinjar). See https://www.erawa.com.au/cproot/24516/2/BRCP-2025-Notice-Publication-of-Final-Determination-of-the-2025-BRCPs.pdf.

[118] The ESM Rules were amended on 22 February 2020 to implement the changes to the pricing curve to increase responsiveness to the excess or shortage of capacity from the 2019 Reserve Capacity Cycle. See https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals.

7.3 System strength investment opportunities

AEMO, with support from Western Power, is undertaking further detailed studies to identify the system requirements at each at-risk location of the SWIS and the viable remedial options. The procurement of system strength services may be necessary through the existing NCESS framework to address concerns at Shotts Terminal and Merredin Terminal substations in the next five years.

While Western Power advises that measures can be taken in the Shotts Terminal area to ensure the proper operation of protection systems, sufficient system strength will be required at both locations to enable the operation of committed IBR (largely ESR) following the closure of coal-fired generation. System strength remediation is also likely required in the North Country to accommodate the scale of connection interest from wind farm proponents in the area.

There is currently opportunity for proposed synchronous facilities and IBR to contribute towards system strength remediation in the North Country and South region, via the connections process and Generator Performance Standards framework. Options include fitting synchronous generation facilities with a clutch to enable operation as a synchronous condenser and enabling the IBR to operate as a grid-forming device (where the IBR supports the capability). Investment in new capacity with these design decisions in mind provides for efficiencies in addressing both reliability and system strength outcomes.

7.4 Transmission network investment opportunities

Transmission network investment is essential to increase power transfer capability across the SWIS and enable supply capacity to be connected in sub-regions that have strong and diverse supply characteristics to complement the current generation capacity mix, meet future demand needs and replace the energy and capacity lost from retiring baseload plant.

This WEM ESOO has assumed the EEP and the CEL-North network augmentations are delivered with no more than one year's delay. These are both significant projects that will help enable the connection and dispatch of new utility-scale renewables and firming capacity projects in the eastern and northern regions of the SWIS.

Beyond these projects, continued and co-ordinated transmission investment will be needed to ensure the timely connection of new supply projects to maintain reliability of the SWIS.

The sub-regional capacity shortfalls identified in the Eastern region can be addressed by new supply capacity in the Goldfields. An NCESS service is currently in consultation for this region.

This ESOO notes the need for additional firm capacity in 2027-28. Depending on where this capacity is connected to, additional network augmentation may be needed to ensure this capacity can be connected.

The sub-regional analysis highlights that with existing and committed capacity there is a system-wide capacity shortfall on the SWIS that needs to be addressed across the 10-year outlook. Transmission network investment will be needed to ensure the capacity can be connected and the network has the power transfer capability to transfer the power to the demand centres across the SWIS.

Several network investment opportunities to improve network transfer capacity and enable sufficient generation to connect are summarised below. Western Power is assessing and will publish any need for transmission network augmentations through its annual Transmission System Plan Process and network investment framework.

Table 32 Summary of network investment opportunities

Region	Drivers	Potential benefit	Other information
Eastern Goldfields / East Country regions	The current transmission network supplying the East Country and Eastern Goldfields regions is subject to power transfer limits that restrict the import of power. The region is subject to a series of complex constraints that involve thermal and stability limitations. The connection of future load in the region will continue to be impacted by these constraints on supply. Opportunities exist for supply solutions that improve reliability outcomes for this region both in the short-term and long-term. A longer-term solution for the region is being investigated with the Goldfields Regional Network concept a part of a possible development plan for the region[A]. Under this proposal, new transmission network infrastructure would be constructed to support regional growth and decarbonisation. This represents an opportunity for private sector investment in the network and supply infrastructure required for the region.	Improved reliability in the region, for example during islanding events.	Western Power is currently evaluating NCESS proposals to improve reliability during islanding events, across the next five years. The Goldfields Region Electricity Forum recently discussed the concept of the Goldfields Regional Network as an alternative solution that warrants further consultation.
Kwinana	The WEM ESOO highlights the need for additional generation capacity with the Kwinana region being a possible development location. This, coupled with forecast demand growth in the Kwinana region may also result in 132 kV network limitations restricting the transfer of power within the Kwinana node. The region may benefit from greater transfer capability throughout the 132 kV networks and potentially greater interconnectivity between the 330 kV and the 132 kV.	Increased 132 kV power transfer capability within the local Kwinana 132 kV network acting together with a new South West 330 kV terminal (or greater transfer capability between the Kwinana 330 kV and Kwinana 132 kV network) can relieve congestion associated with the meshed 132 kV network that exists in between Kwinana and the South West. The augmentation enables future demand to be connected at Kwinana including potential benefits for hydrogen developers and generation supply developments in the region.	Previous planning activities have highlighted this part of the network (the Western Trade Coast) as one that may benefit from network investment to enable connection of future industrial loads across the longer-term. In the short-term, additional network transfer capacity may be driven more by generation development in this region rather than load.
South West (Collie region) 330kV network	There is a clear need for additional capacity to be connected on the SWIS across the 10-year outlook period. The retirement of baseload thermal generation capacity in the Collie region may make headroom available on the existing 330 kV bulk transmission network. This region has strong 330 kV interconnectivity with metropolitan demand centres with multiple high capacity circuits. Providing access to this network capacity may help address reliability shortfalls in a more efficient manner. This region also has access to potentially	Future new supply capacity that is developed in the South-West and the South-East part of the SWIS may benefit from having additional connection assets to access the 330 kV backbone[B]. Forecast reductions in system-wide EUE as a result of connecting new generation supply capacity to the existing 330 kV network backbone.	Previous planning activities have highlighted the benefits of transmission investments east and south of Collie to utilise existing transmission infrastructure and to support the development of large-scale wind generation projects that are currently under development. These wind resources provide a different wind profile from generation that is being developed in the north (through CEL North), providing some redundancy and risk mitigation against regional renewable resource droughts.

Region	Drivers	Potential benefit	Other information
	strong and diverse wind profiles that complements the existing and future generation fleet.		
South West 132kV network	Forecast demand growth in the South West region may result in 132 kV network limitations restricting import capability on the transmission network around the South West. This is driven mainly by electrification of industries and potential expansion of new large industrial loads.	Increased 132 kV power transfer capability on the network supplying the South-West region.	Further generation development in the South West and South East may also benefit from increased 132 kV transfer capability.
Central region (Perth metropolitan) (Neerabup, North Metro, Metro South, Perth region)	Forecast demand growth in the Perth metropolitan region may result in 132 kV network limitations in sub-regions of the SWIS, particularly on the networks that are around key metropolitan terminal sites. These regions have limited large-scale supply options due to minimal land availability and network solutions may be subject to delivery challenges associated with highly built-up areas. These areas may benefit from co-ordinated aggregation of DER and or demand flexibility services.	Increased 132 kV power transfer capability around the major terminal stations in the metropolitan region to import power from regional generation which may include new augmentations or thermal line uprates.	Previous planning updates have also highlighted this central region (described as Perth Metropolitan) for further network investment.
Dynamic line ratings	Thermal ratings of line circuits on the SWIS have historically been set based on worst case operating conditions that are typically based on summer peak demand conditions. These ratings are used as inputs into constraint equations that define the thermal technical envelope of the SWIS.	The use of dynamic line ratings allow transmission circuits to be operated safely across a wider range of operating conditions, increasing utilisation of these circuits. This helps regions where transmission network limits may constrain power flow into the region.	Western Power is implementing dynamic line ratings to optimise the capacity of its transmission lines by using field sensors and real-time weather data to adjust line ratings.

A. See https://www.wa.gov.au/organisation/energy-policy-wa/goldfields-region-electricity-forum.
B. See https://www.wa.gov.au/system/files/2024-05/swis-transmission-planning-update.pdf.

List of tables and figures

Tables

Figures

Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the Electricity System and Market Rules (ESM Rules). Meanings under the ESM Rules are adopted unless otherwise specified.

Term	Definition
10-year outlook period	2024-25 to 2034-35 Capacity Years, inclusive.
Business mass market (BMM)	BMM covers those business loads that are not included in the LIL sector.
Business sector	Business sector includes industrial and commercial users. This sector is subcategorised further to include large industrial loads (LILs) and business mass market (BMM).
Committed and prospective LIL	New LILs are segmented into committed and prospective LILs based on AEMO's evaluation criteria, including final investment decision (FID), environmental approval, network access status, and decarbonisation (see Appendix A2.4 for further information). Committed LILs are included in both expected and high scenarios, while prospective LILs are only included in the high demand growth scenario.
Committed capacity	Capacity includes new projects that are candidates for registration and have been assigned Capacity Credits for 2025-26 or have scored 80% or higher in the new project status evaluation. This category also includes Facilities contracted for the 2024-26 Peak Demand NCESS, and Facilities contracted or expected to be contracted for 2025-27 Peak Demand NCESS.
Consumption	The amount of power used over a period of time, conventionally reported as megawatt hours (MWh), gigawatt hours (GWh), or terawatt hours (TWh), depending on the magnitude of power consumed. It is reported on a "sent-out" basis (excluding electricity used by a generator[119]) unless otherwise stated.
Delivered consumption (or demand)	The total amount of electricity supplied to customers from the grid, which excludes the portion of their consumption/demand that is met by behind-the-meter (typically distributed PV) generation.
Demand	The amount of power consumed at any time. Peak and minimum demand is measured in megawatts (MW) and averaged over a 30-minute period. It is reported on a "sent-out" basis (excluding electricity used by a generator) unless otherwise stated.
Distributed battery storage	Behind-the-meter battery storage systems installed for residential, commercial, and large commercial, that do not hold Capacity Credits in the WEM.
Distributed energy resources (DER)	Includes distributed PV, distributed battery storage, and electric vehicles (EVs).
Distributed energy storage systems (DESS)	Small distributed behind-the-meter battery storage systems installed for residential and business sector customers, that do not hold Capacity Credits in the WEM.
Distributed photovoltaics	Used to capture both rooftop PV and PV non-scheduled generation (PVNSG).
Electric vehicle (EV)	Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
Electrification	Replacement of technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically-powered equivalents, such as electric vehicles or heat pumps.

[119] This may be called 'auxiliary load', 'parasitic load', or 'self-load', and refers to energy generated for use within power stations.

Term	Definition
ESOO operational consumption[120] (or demand)[121]	Electricity consumption (or demand) that is met by sent-out electricity supply of all market registered energy producing units[122]. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (or demand) of EVs but excludes electricity consumption (or demand) met by distributed PV generation. Operational consumption includes energy efficiency losses of distributed battery storage operation. Operational demand includes impacts of distributed battery storage discharging (reducing operational demand) and charging (increasing operational demand).
ESOO unscheduled operational consumption (or demand)[123]	Operational consumption/demand that excludes any consumption/demand associated with scheduled loads (such as ESR charging). Peak and minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase or reduce operational demand (including storage, co-ordinated EV charging and demand response). Only non-co-ordinated, consumer-controlled battery and EV charging is considered in the unconstrained peak and minimum operational demand forecasts.
Existing capacity	Capacity provided by Registered Facilities that have been assigned Capacity Credits for 2024-25 or 2025-26 and reflecting any announced or anticipated retirements. Existing capacity is included in the low, expected, and high scenarios for the capacity supply forecasts.
Expected unserved energy (EUE)	A normalised metric, which does not have a unit. It represents the estimated percentage of forecast electricity operational consumption for a Capacity Year which cannot be met by all AIC in that Capacity Year.
Installed capacity	The generating capacity (in MW) of a single or multiple generating units.
Large industrial load (LIL)	Users that consume, or are forecast to consume, at least 10 MW for a minimum of 10% of the time (around 875 hours a year) or at least 50 GWh per year. LILs include existing and new LILs.
Limb A	Term attributed to the requirement of the Planning Criterion that stipulates that there should be sufficient available capacity in each Capacity Year to meet the forecast peak demand plus a reserve margin.
Limb B	Term attributed to the requirement of the Planning Criterion that stipulates there should be sufficient available capacity in the SWIS to limit expected unserved energy (EUE) shortfalls to 0.0002% of annual energy consumption.
Limb C	Term attributed to the requirement of the Planning Criterion that stipulates that there should be enough capacity available in the SWIS to meet the highest forecast Four-Hour Demand Increase, plus a reserve margin, in each Capacity Year.
Load shedding	The controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure.
Maximum capacity	Refers to the maximum dispatchable capacity of a Facility to meet Limb B of Planning Criterion, either stemming from Facilities' nameplate capacity or the contracted quantity through 2024-26 and 2025-27 Peak Demand NCESS or forecast Peak Capacity. The net sent-out generation or installed capacity of a facility, as detailed on AEMO's Market Data website.
Operational maximum (peak) and minimum demand	The highest and lowest level of electricity drawn from the grid, measured as an average over a 30-minute period in either summer (December to March[124]), winter (June to August), or shoulder months (April, May, September to November).
Peak demand	The highest amount of demand consumed at any one time. Peak demand refers to operational peak demand unless otherwise stated.
Photovoltaics	Systems to convert sunlight into electricity.
Probability of exceedance (POE)	A measure of the likelihood of a value being met or exceeded. For example, a 10% POE maximum demand forecast is expected to be met or exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be met or exceeded nine years in 10.
Probable capacity	Capacity comprised of new projects that:

[120] Historical operational consumption is measured as the Total Sent Out Generation (TSOG) over a 30-minute Trading Interval. It is a non-network-loss adjusted MWh value.

[121] Historical operational demand is calculated as the TSOG multiplied by two, to convert MWh to MW for a 30-minute Trading Interval. The historical operational peak demand and minimum demand are identified as the highest and lowest operational demand calculated for a Trading Interval in a Capacity Year, respectively.

[122] Includes market generators and ESR.

[123] ESOO (unscheduled) operational consumption/demand terms are also defined in the undertaking of the Long Term PASA WEM Procedure, available at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

[124] These months are aligned with the Hot Season defined in the ESM Rules.

Term	Definition
	• are a candidate for registration and have submitted a valid Expression of Interest for the 2025 Reserve Capacity Cycle (2025 EOI)[125]; and • have scored 50% or more but less than 80% in the new project status evaluation. Probable capacity is included only in the High scenario for the capacity supply forecasts.
Proposed capacity	Capacity includes all new projects that have been proposed but have not met the criteria to be in the existing, committed, or probable capacity categories.
PV non-scheduled generation (PVNSG)	Non-scheduled photovoltaic generators larger than 100 kilowatts (kW) but smaller than 10 megawatts (MW) that do not hold Capacity Credits in the WEM.
Reference year	Future half-hourly demand, wind and solar PV generation is modelled based on several historical reference years to capture a variety of Australian weather patterns.
Reliability Standard	The Planning Criterion defined in clause 4.5.9 of the ESM Rules.
Residential sector	Includes non-contestable[126] residential customers (supplied by Synergy) only.
Rooftop photovoltaics	Photovoltaics installed on a residential building (less than 15 kW) or business premises (less than 100 kW).
Shoulder season	The period including Trading Months of April, May, August, and September.
Summer	The Hot Season as defined in the ESM Rules, including Trading Months of December, January, February, and March.
Unscheduled operational maximum (peak) and minimum demand	This represents the operational peak and minimum demand forecasts that exclude the impact of scheduled load operations (such as ESR charging).
Underlying consumption (or demand)	The total amount of electricity consumption (or demand) used by consumers at their power points. This electricity can be sourced from the grid, or from behind-the-meter distributed energy resources (DER) such as distributed photovoltaics (distributed PV) and battery storage.
Virtual power plant (VPP)	An aggregation or grouping of DER that is actively controlled and co-ordinated via an Orchestration System[127] by an operator. VPPs can operate in a co-ordinated manner to provide services to other parties (such as the wholesale market and/or network).
Winter	The period including all Trading Months from June to August.

Units of measure

Abbreviation	Unit of measure
°C	Celsius
GW	Gigawatt/s
GWh	Gigawatt hour/s
kV	Kilovolt/s
kW	Kilowatt/s
MVA	Megavolt-ampere/s
MVAr	Megavolt-ampere/s reactive
MW	Megawatt/s
MWh	Megawatt hour/s
TWh	Terawatt hour/s

[125] The information that a 2025 EOI must include to be deemed valid is outlined in clause 4.4.1 of the ESM Rules.

[126] A non-contestable customer is a customer that uses less than 50 MWh of electricity per year and is connected to Western Power's distribution network.

[127] A VPP (virtual power plant) orchestration system is a sophisticated software and communication platform that coordinates and controls distributed energy resources (DERs) like solar panels, batteries, and electric vehicles to function as a single, unified power source. This system enables the VPP to provide grid services, participate in energy markets, and respond to real-time energy demand and supply fluctuations.

Abbreviations

Term	Definition
ADG	Availability Duration Gap
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
BMM	Business mass market
BRCP	Benchmark Reserve Capacity Price
CBD	Commercial Building Disclosure
CEL-North	Clean Energy Link – North
CER	Consumer Energy Resources
CFR	Capacity for Reliability
CIS	Capacity Investment Scheme
Co-ordinator	Co-ordinator of Energy
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DESS	Distributed energy storage systems
DSP	Demand Side Programme
EEP	East Enhancements Project
ELPS	Eastern Goldfields Load Permissive Scheme
EOI	Expressions of Interest
EPA	Environmental Protection Authority
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESM	Electricity System and Market
ESOO	Electricity Statement of Opportunities
ESR	Energy Storage Resource
ESROD	Electric Storage Resource Obligation Duration
ESROI	Energy Storage Resource Obligation Interval
EUE	Expected unserved energy
EV	Electric vehicle
EY	Ernst & Young
FCESS	Frequency Control Essential System Services
FHDI	Four-Hour Demand Increase
FID	Final Investment Decision
FIR	Formal Information Request
FRG	Forecasting Reference Group
GEM	Green Energy Market
GEMS	Greenhouse and Energy Minimum Standards

Term	Definition
GPS	Generator Performance Standards
GSOO	Gas Statement of Opportunities
IASR	Inputs, Assumptions and Scenarios report
IBR	Inverter Based Resources
IGS	Intermittent Generating Systems
LIL	Large industrial load
MAC	Market Advisory Committee
MDT	Minimum Demand Threshold
NABERS	National Australian Built Environment Rating System
NAQ	Network Access Quantity
NCC	National Construction Code
NCESS	Non-Co-optimised Essential System Service
NEM	National Electricity Market
NIGS	Non-Intermittent Generating Systems
NMI	National Metering Identifier
NSF	Non-scheduled Facilities
NVES	New Vehicle Efficiency Standard
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PSSR	Power System Security & Reliability
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generator
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Requirement for Collective Response
RCT	Reserve Capacity Target
RD	Requirement Description
RR	Reliability Run
RRN	Regional Reference Node
SCADA	Supervisory Control and Data Acquisition
SCR	Short Circuit Ratio
SEO	State Electricity Objective
SPR	Strategy Policy Research
SRC	Supplementary Reserve Capacity
SRES	Small-scale Renewable Energy Scheme
SSF	Semi-scheduled Facilities
STC	Small-scale technology certificates
SWIS	South West Interconnected System
TSOG	Total Sent Out Generation
VPP	Virtual power plant

Term	Definition
WEM	Wholesale Electricity Market