Appendices for the 2024 Wholesale Electricity Market Electricity Statement of Opportunities

18 June 2024

A document supporting the 2024 Wholesale Electricity Market Electricity Statement of Opportunities report for the Wholesale Electricity Market

Important notice

Purpose

The Australian Energy Market Operator (AEMO) publishes the Wholesale Electricity Market Electricity Statement of Opportunities (WEM ESOO) under clause 4.5.11 of the Wholesale Electricity Market Rules. This publication is generally based on information available to AEMO as of May 2024 unless otherwise indicated.

Disclaimer

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

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

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Contents

Notes

- This supporting document of the WEM ESOO uses many terms that have meanings defined in the Wholesale Electricity Market Rules (WEM Rules) 2024 and the Wholesale Electricity Market Amendment (Reserve Capacity Reform) Rules 2023. The WEM Rules meanings are adopted unless otherwise specified. Terms which are defined in the WEM 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.
- All data in this Appendices for the WEM ESOO is based on Capacity Years unless otherwise specified. A Capacity Year commences in 08:00 Trading Interval on 1 October and ends in 07:30 Trading Interval on 1 October of the following calendar year.
- Consumption/demand is operational consumption/demand unless otherwise specified in this Appendices for the WEM ESOO. A definition of operational consumption and demand can be found in Chapter 1 and in the Glossary.
- The three seasons reported in this Appendices for the WEM ESOO are 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) months.
- This Appendices for the 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 WEM 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 2024 Long Term PASA Study Horizon, which covers the 2024-25 to 2033-34 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 2023-24 to 2028-29, and the second half refers to the period 2029-30 to 2033-34.
- The compound annual growth rate was used to calculate the average annual growth rate. AEMO refined the calculation by using 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. 2023-24 and 2028-29 were used as year 0 to calculate the five-year average annual growth rates for the first half and second half of the outlook period, respectively.

A1. Consumption and demand forecasting inputs

Each year, AEMO updates its 10-year projections of energy consumption and peak demand for three scenarios and presents them in the WEM ESOO. These updates are based on stakeholder consultation and various model inputs.

For the 2024 WEM ESOO, AEMO has aligned the Low, Expected, and High scenarios with the *Progressive Change*, *Step Change*, and *Green Energy Exports* scenarios developed as part of the 2023 IASR[1], respectively. The 2023 IASR scenarios include Australia's increased commitment to meeting net zero emissions by 2050.

The 2024 scenario mapping is in line with the 2023 WEM ESOO, because the scenarios still reflect the changing landscape of social, technological, and political factors. For further information on the scenarios, see Chapter 1 in the report.

AEMO provided external consultants with scenario assumptions to develop or update key inputs for the 2024 WEM ESOO consumption and demand forecasts, and consulted with stakeholders on the forecasting inputs via Forecasting Reference Group meetings, including:

- **State-based macroeconomic projection** (see Section A1.1) – accounting for economic drivers such as inflation, population, and investments that impact demand, supply, and energy prices. This resulted in two forecast outcomes for Western Australia:
  - State economic performance and demographic projections.
  - Influence of global commodity prices, trade, and industrial composition at the state level.
- **Residential electricity connection forecasts** (see Section A1.2) – accounting for population growth and increases in new dwellings, in conjunction with historical residential connections numbers. This resulted in the residential connections forecasts for the SWIS.
- **State-based forecasts of DER uptake** (see Section A1.3) – incorporating post-pandemic spending behaviour, investment opportunities, and global supply chain constraints. This resulted in two key forecast outcomes for the SWIS:
  - Uptake of DPV and DESS for the business and residential sectors.
  - Uptake of EVs, EV charging profiles and consumption, EV sales, and fleet share.
- **State-based energy efficiency forecast** (see Section A1.4) – accounting for the impact of policy-led sectoral energy efficiency savings on energy use. This produced two key forecast outcomes for the SWIS:
  - Estimation of energy efficiency savings.
  - Energy efficiency improvement in industrial, commercial, and residential sectors.

[1] For detail see https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

- **Whole-of-economy multi-sector modelling** – leveraging the 2022 multi-sector modelling outcome to inform the pace and breadth of the energy transformation in the SWIS. This ensured consistent emissions abatement outcomes, aligned with the scenario narratives, the World Energy Outlook[2] scenarios, and Representative Concentration Pathways[3]. The key forecast inputs included:
  - Electrification through fuel-switching for industrial, commercial, and residential sectors (see Section A1.5).
  - Electricity required for the forecast magnitude of green hydrogen production for domestic use and export purposes (see Section A1.6).

AEMO undertook a **detailed survey of existing LILs and an assessment of new LILs** in the SWIS (see Section A1.7). This resulted in two forecast inputs:

- Scale of new LILs, an evaluation of the long-term projects in the pipeline informed by Western Power's assessment of project connections.
- Scale of existing LILs, identified and categorised based on an extensive list of National Metering Identifiers (NMIs).

A1.1 Economic and population growth outlook

Input vintage[4]	March 2024
Source	Deloitte Access Economics (DAE)
Updates since 2023 WEM ESOO	Updated forecast developed in Q1 2024.

AEMO engaged Deloitte Access Economics (DAE) to provide forecasts for Western Australia's gross state product (GSP) and population. DAE developed the 2024 economic forecasts for Australia at both the state and national level.

Economic growth refers to the expansion of a nation's capacity to produce goods and services. The current and expected future level of economic growth affects investment and spending in an economy and influences how consumers, businesses, and governments allocate their resources.

Figure 1 presents the forecast real economic growth for Western Australia over the 10-year outlook period for the 2023[5] and 2024 WEM ESOOs. In the 2024 forecasts, a moderate growth is anticipated for household spending in Western Australia, resulting in slow economic growth projections, varied across the scenarios.

A drop in Western Australia's GSP growth is forecast until 2024-25, largely driven by high inflation and interest rates decreasing economic activities and household disposable income, which is then projected to ease. In addition, slower global economic growth is forecast to reduce demand for Western Australia's export resources in the short term. The relative slowing in Western Australia's GSP growth around 2029-30 is driven by a forecast

[2] See IEA, World Energy Outlook 2023, at https://www.iea.org/reports/world-energy-outlook-2023.

[3] See https://www.ipcc-data.org/guidelines/pages/glossary.

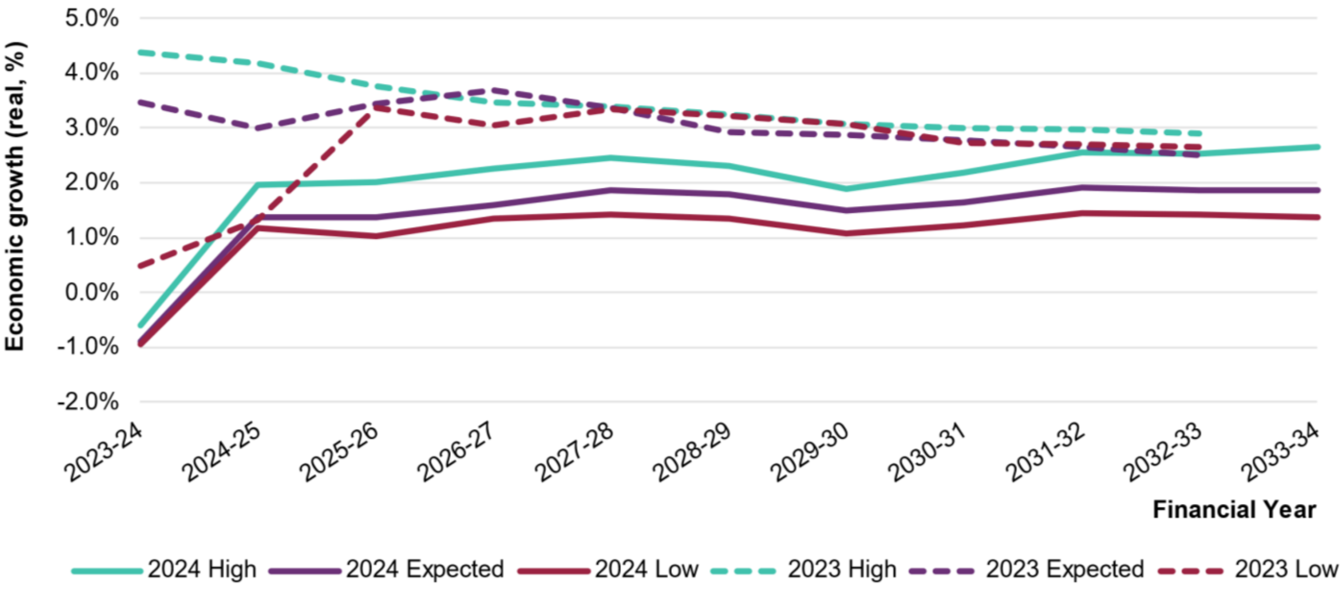
[4] It indicates when the input was developed for the 2024 WEM ESOO forecasting.

[5] AEMO engaged Oxford Economics Australia to provide forecasts for WA GSP and population for the 2023 WEM ESOO. For detail see Oxford Economics Australia, Macroeconomic Projections Report, 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf.

peak in the housing cycle around 2028-29, with a slight weakening in 2029-30. In the longer term, mining sector growth in Western Australia will be driven by exporting minerals used in the energy transition. Counteracting this, the transition towards net zero is likely to weaken demand for fossil fuel exports from Western Australia, with the mining sector forecast to make up less of the state's economy. More specifically:

- The Low scenario includes slower economic growth and less policy coordination in achieving current domestic and global policy objectives towards a transition to net zero (but includes the actions required to meet current policy commitments). Sectors including manufacturing, utilities, and construction are projected to decrease over the forecast period, aligning with the emissions profile required to meet Australia's current climate commitments.
- The Expected scenario includes moderate economic growth combined with strong policy coordination. However, slower global economic growth is forecast to reduce demand for Western Australia's export resources.
- The High scenario includes higher economic growth both domestically and internationally with strong policy coordination. Economic growth is boosted by a strong manufacturing sector, and the capital investment required to progress the energy transition.

Figure 1 Forecast real Western Australia economic growth under three scenarios, 2023-24 to 2033-24 financial years

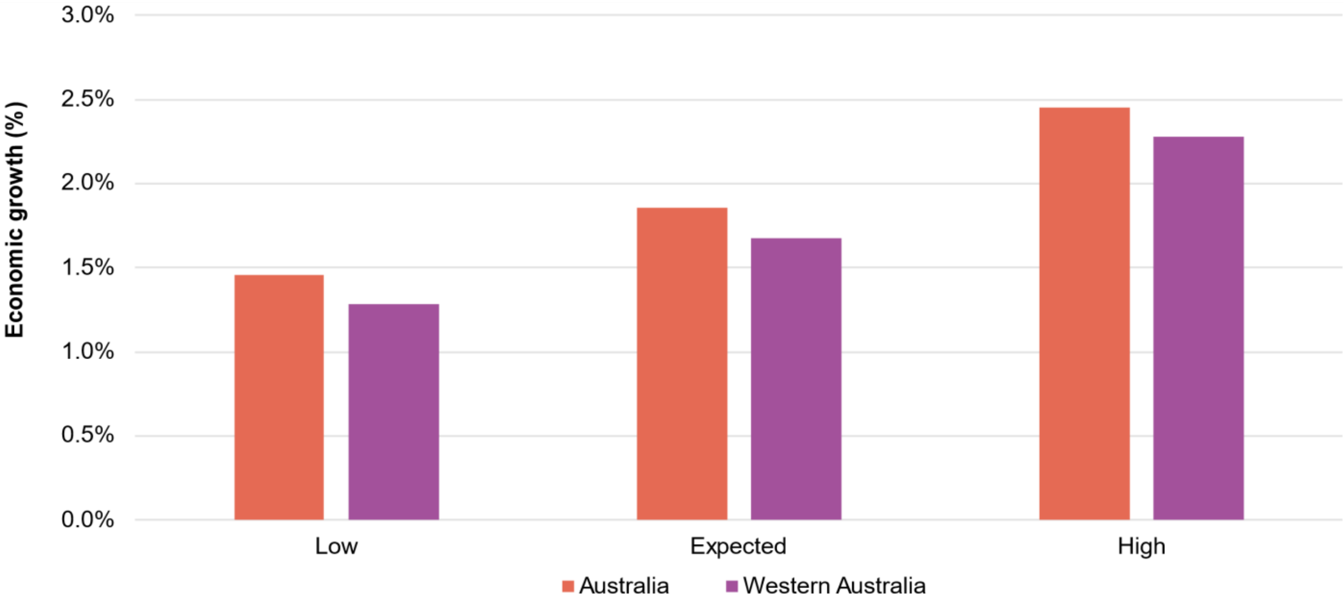


Source: Deloitte Access Economics and Oxford Economics Australia.

This projected growth in Western Australia is more modest than that shown in the 2023 WEM ESOO, due to the changing economic conditions, including weaker prices in commodities such as iron ore, nickel, and lithium since the 2023 forecasts. The forecast near-term reductions in growth rates influence the longer-term growth rates, which are lower than those in the 2023 WEM ESOO.

Figure 2 compares economic growth in Western Australia and Australia-wide. The Western Australian economy is projected to grow slower than the national rate, primarily due to projections of the state's mining industry[6] shrinking as a share of the economy over the outlook period, resulting from the changing economic conditions noted above.

Figure 2 Forecast national and Western Australian economic average annual growth rates under three scenarios, 2023-24 to 2033-34 financial years



Source: Deloitte Access Economics.

Population growth is one of the key factors that influences economic growth. There are different types of population growth:

- **Migration-driven population growth** – increases the labour force, resulting in greater production of goods and services as well as their demand within an economy. Economic growth attracts individuals seeking better opportunities, resulting in more interstate and international population movements. This leads to investment in infrastructure development, further contributing to economic growth.
- **Natural population growth** (from lower mortality or higher fertility rates) – has a similar effect of increasing the labour force and benefiting the economy, but comes with a significant time lag.

In the short term, the more moderate forecast population growth in Western Australia (see **Figure 3**) is a result of an intersection of a current low fertility rate[7] and recovering post-Covid international migration[8], which is overriding post-COVID net influx from interstate migration[9]. Over the long term, state population is projected to

[6] The mining industry is the state's largest industry and accounts for a significant volume of the nation's minerals and petroleum exports. Demand for Western Australia's resource commodities is forecast to be subdued following a slower global economic activity weigh on exports.

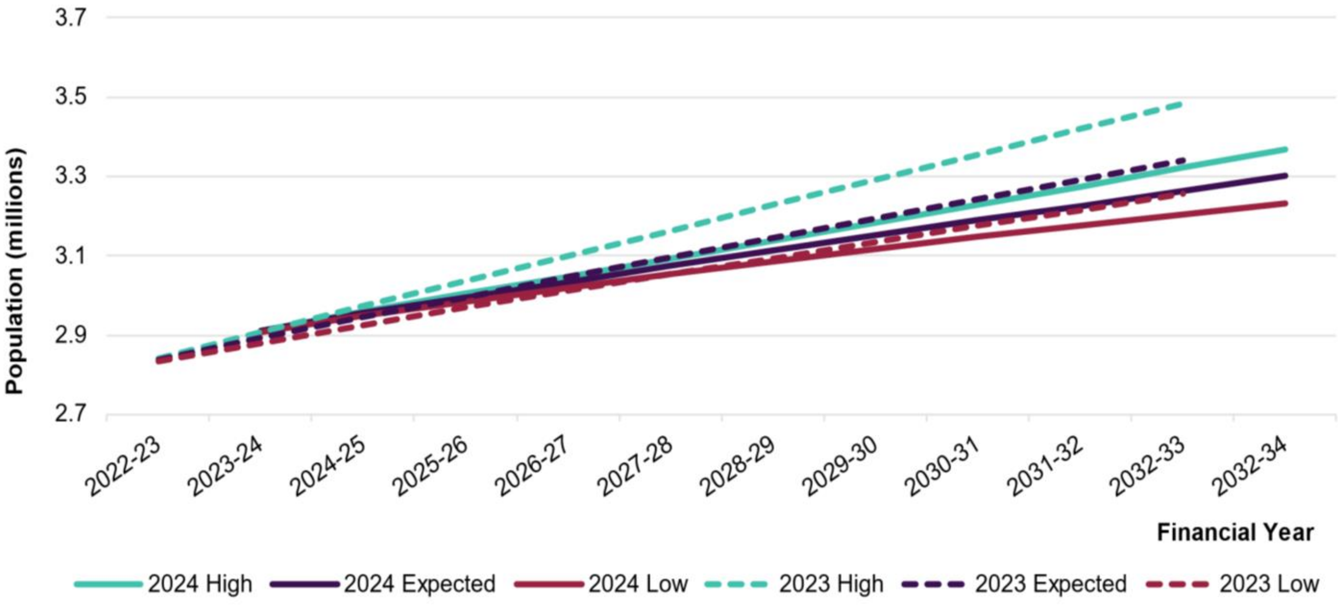
[7] For detail see Davis, A., 2024. "Australians are having fewer babies and our local-born population is about to shrink: here's why it's not scary", at https://www.uwa.edu.au/news/article/2024/april/australians-are-having-fewer-babies-and-our-local-born-population-is-about-to-shrink-heres-why-its-not-that-scary.

[8] For detail see Government of WA, 2023. *Census 2021 highlights*, at https://www.omi.wa.gov.au/docs/librariesprovider2/statistics/022434omi-census-highlight-report-feb23.pdf.

[9] For detail see Taylor, B., 2024. *Shifting demographics: Australia's altered population landscape,* at https://sgsep.com.au/publications/insights/australias-shifting-demographics.

grow, although slightly below the national rate, primarily due to a return to normal levels of Western Australia's international migration.

Figure 3 Forecast Western Australian population under three scenarios, 2023 and 2024 WEM ESOOs (millions)



Source: Deloitte Access Economics.

In comparison, the 2023 WEM ESOO projected a stronger growth in population, primarily driven by a stronger economic outlook.

A1.2 Residential electricity connection forecasts

Input vintage	March 2024
Sources	ABS Deloitte Access Economics Synergy
Updates since 2023 WEM ESOO	Updated with AEMO's latest actual connections data

AEMO's forecast of residential electricity consumption is mainly driven by forecast growth in electricity connections. As Western Australia's population increases, so does the expected number of new households which require electricity connections.

AEMO forecasts the number of residential connections using the SWIS connections model used in the population forecasts, in conjunction with historical residential connections numbers provided by Synergy.

In all scenarios (as **Figure 4** shows), the proportion of connections to attached dwellings[10] is projected to increase, indicating a growing trend towards urban infill. The total number of detached houses is also forecast to grow, indicating an increase in the future nominal hosting capacity for DER, including DPV and DESS. As the proportion

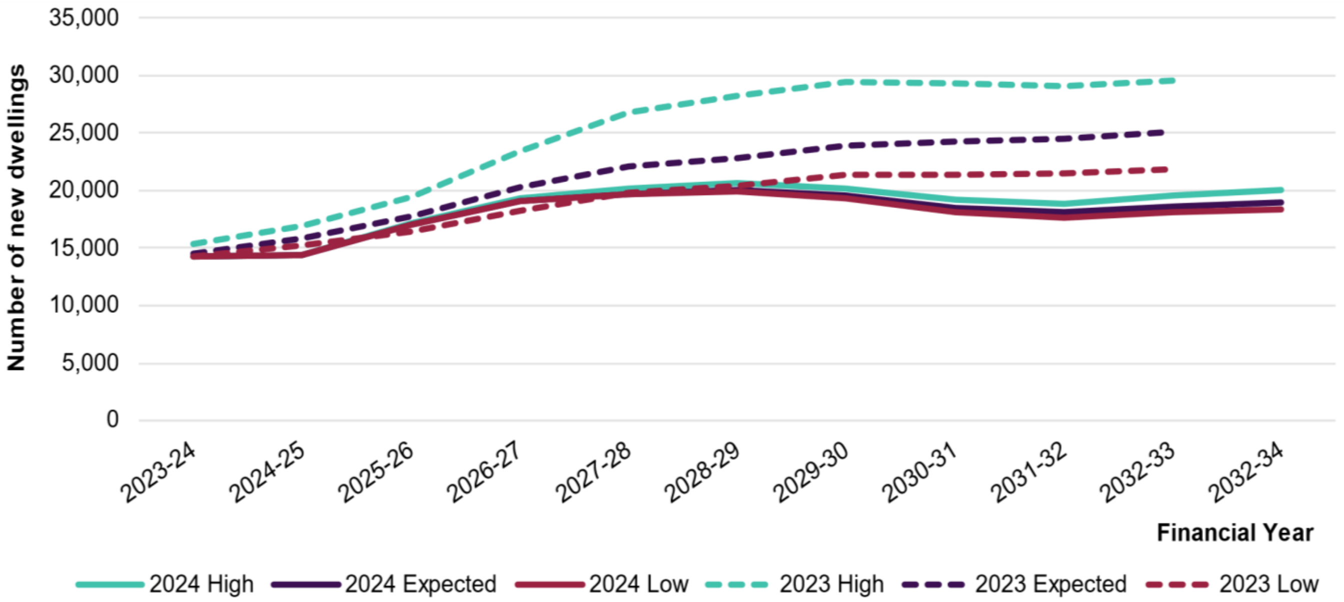
[10] Attached dwellings are residential housing units that share structural components (such as a floor, wall, or ceiling) with other housing units. Examples of attached dwellings include townhouses and apartments.

of the population living in attached dwellings increases, the capacity to host DER relative to the population is likely to decrease over time, as attached dwellings are less suitable for hosting DER resources than detached houses.

Over the longer term, growth in dwelling investment is expected to reflect underlying demand for new housing, along with an allowance for replacement of the existing stock. Underlying demand is determined by population growth and the need for new housing to meet this growth.

As the economy slows, fewer housing completions are forecast. However, as the economic growth rate recovers, more completions are forecast. The housing cycle is forecast to peak in 2027-28, after which the number of completions is forecast to reduce.

Figure 4 Forecast for SWIS annual new residential connections under three scenarios, 2023-24 to 2033-34



Source: AEMO and Deloitte Access Economics.

A1.3 Distributed Energy Resources forecasts

The term 'DER' encompasses consumer-owned devices that can generate or store electricity as individual units. Some DER have the 'smarts' to actively manage energy import and export. The forecasting component generally refers to components including DPV systems (which includes PVNSG, representing unregistered large PV systems ranging from 100 kW to 10 MW), DESS, and EVs.

AEMO engaged two consultants to inform the 2023 WEM ESOO DER forecasts – GEM and CSIRO. Both consultants used the same underlying assumptions and scenario narratives but employed separate forecasting models. This provided AEMO with greater confidence in this key forecast component. CSIRO also provided EV uptake projections and EV daily charging patterns[11].

For the 2024 WEM ESOO, AEMO has obtained updated forecasts from a single consultant for each component. GEM provided updated forecasts for DPV and DESS, while CSIRO provided an updated forecast for EV. AEMO

[11] CSIRO, *Electric Vehicle Projections 2022*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf.

escalated the 2023 CSIRO's DPV and DESS forecasts by the same growth rates forecast from GEM's revised DPV and DESS forecasts to maintain the spread of scenario forecasts[12]. AEMO blended the two consultants' forecasts to update the DPV and DESS forecasts for the 2024 WEM ESOO in the same manner as was applied in 2023.

Table 1 summarises the 2024 WEM ESOO DER forecast components and input sources.

Table 1 Forecast blending of consultant forecast for key DER components, by scenario, 2024 WEM ESOO

	High	Expected	Low
DPV	GEM	Average[A] of CSIRO and GEM	CSIRO escalated per the Expected scenario[B]
PVNSG	GEM	GEM	CSIRO escalated per the Expected scenario
DESS	Average of CSIRO and GEM	Average of CSIRO and GEM	Escalated[C] CSIRO
DESS VPP[D]	Average of CSIRO and GEM	Average of CSIRO and GEM	Escalated CSIRO
EV	CSIRO	CSIRO	CSIRO

A. Average represents the average of the 2024 GEM forecast and the 2023 CSIRO forecast escalated according to 2024 GEM forecast.
B. 2023 CSIRO forecast (Low scenario) escalated according to 2024 Expected scenario versus 2023 Expected scenario.
C. 2023 CSIRO forecast escalated according to 2024 GEM forecast.
D. Percentages of DESS assumed to participate in VPP remain unchanged from the 2023 WEM ESOO forecasts.

The consultant forecasts for each scenario were selected based on the best match with the scenario narratives. This helps maintain relative differences between scenarios, and ensures sufficient spread between forecasts to reflect the uncertainty inherent in long-term forecasts.

CSIRO's outlook was more closely aligned with the lower starting assumptions of the Low scenario, while the elevated outlook seen in GEM's forecasts best represented the ambitious assumptions of the High scenario. AEMO considers the approach outlined in **Table 1** provides a balanced view of outlooks.

A1.3.1 Distributed photovoltaics

DPV installations continue to be popular in Western Australia. Their installed capacity is expected to grow significantly over the outlook period across all three scenarios (see **Figure 5** for forecasts by sector, and **Figure 6** for a comparison between the 2023 and 2024 WEM ESOOs).

Long-term uptake of DPV installation is forecast to continue over the outlook period, driven by forecast reductions in the cost of PV systems, population growth, and the relatively short payback period for DPV investments. Installation of DPV capacity is supported to 2030 under the Small-scale Renewable Energy Scheme (SRES), which provides Small-scale Technology Certificates (STC) to consumers installing DPV systems. This is a subsidy provided under the national Renewable Energy Target.

Since the 2023 WEM ESOO, PV manufacturing investments across the supply chain have led to prices falling significantly[13]. These cost reductions have led to a forecast of higher system numbers over the forecast period to the mid-2030s.

[12] See Section 2.1 of the 2024 *Forecasting Assumptions Update Report* for further information, at https://aemo.com.au/en/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

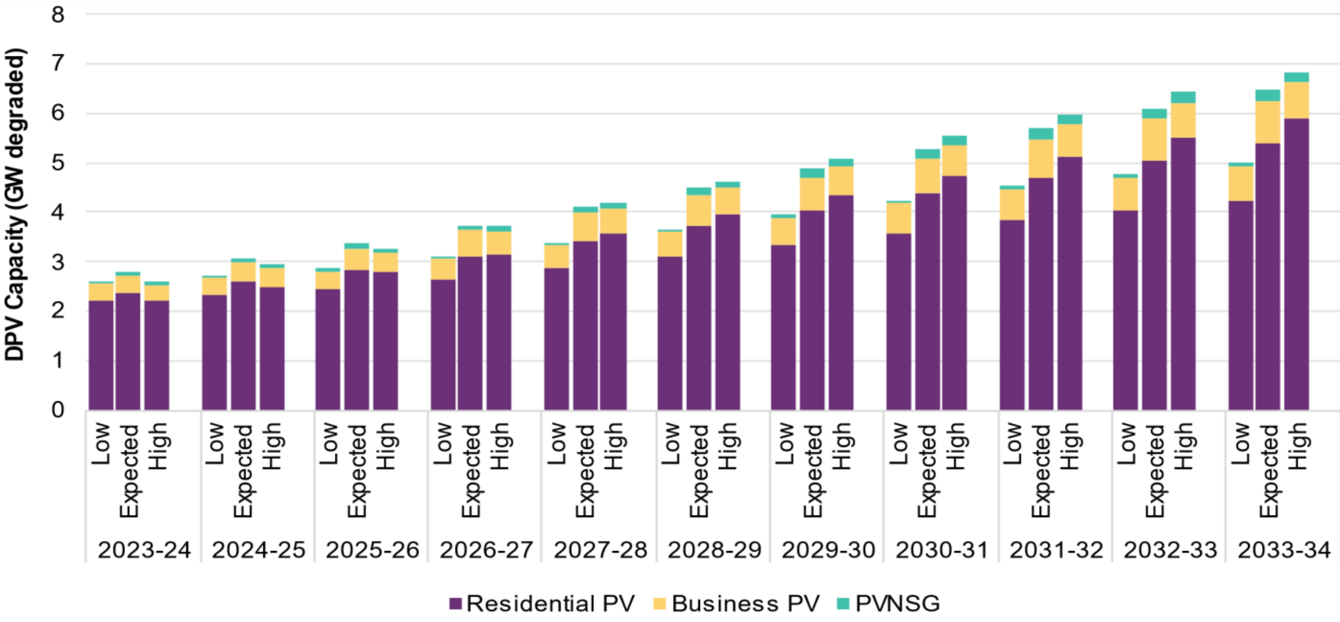
[13] See Buckley and Dong (2023) *Solar pivot: A massive global solar boom is disrupting energy markets and speeding the transition*, Climate Energy Finance, June 2023.

Following the initial reductions in the cost of DPV systems, AEMO has assumed the rate of cost reductions will slow over the outlook period. This is because PV system installation costs are tied to Australian labour costs, which are unlikely to decline as quickly as the cost of the PV modules themselves.

Owner-occupied houses currently have around 40% DPV uptake in the SWIS[14]. Some detached dwellings may not be optimal candidates for DPV installation due to shading, roof construction or ownership considerations (rental premises may be less likely to invest in DPV systems without alternative financial models). The forecasts recognise the increasing opportunity for DPV installations occurs on other dwelling types, such as townhouses, terraces and, to a lesser extent, apartments.

The increase seen in the 2024 forecast relative to the 2023 forecast is driven by the increasing number of dwelling completions and the increasing size of each installed DPV system.

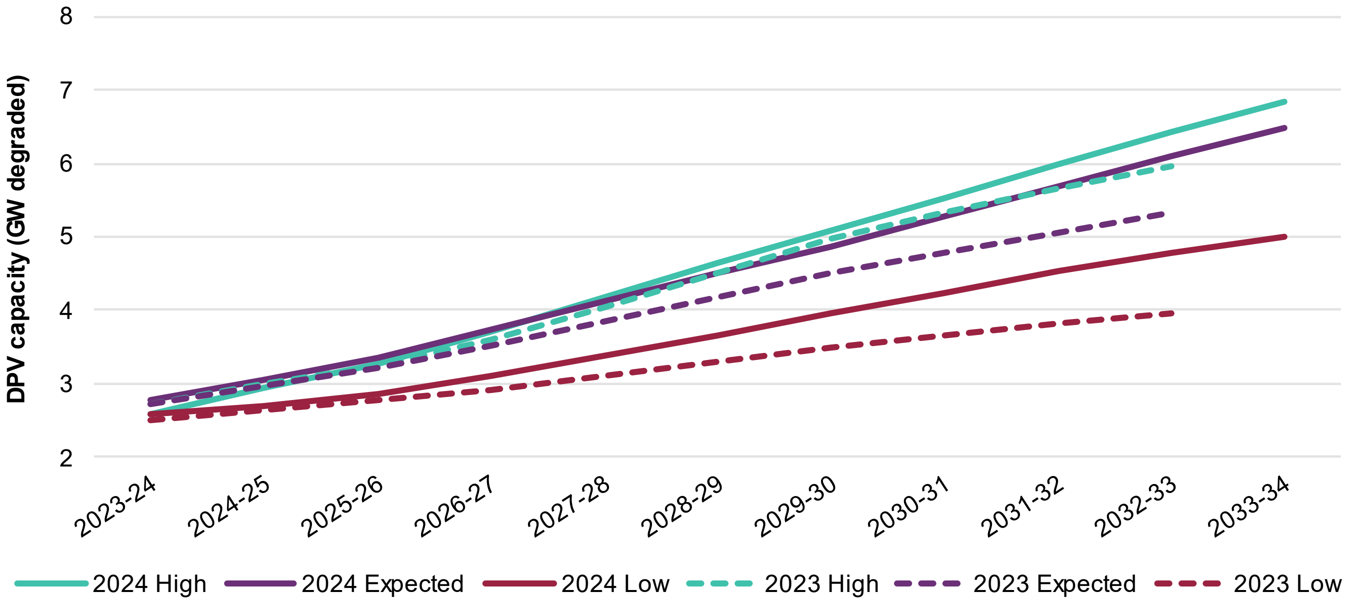
Figure 5 Total installed DPV capacity by sector under three scenarios, 2023-24 to 2033-34 (GW degraded)



Note: forecast DPV values are inclusive of expected degradation of solar panel output over time. CSIRO applied a degradation rate of 0.5% per annum and GEM applied a degradation rate of 0.7% per annum.
Source: CSIRO, GEM, and AEMO.

[14] The Australian PV Institute developed percentage of dwellings with a PV system by state/territory. See https://pv-map.apvi.org.au/historical.

Figure 6 Total installed DPV capacity under three scenarios, 2023 and 2024 WEM ESOOs, 2023-24 to 2033-34 (GW degraded)



Note: forecast DPV values are inclusive of expected degradation of solar panel output over time. CSIRO applied a degradation rate of 0.5% per annum and GEM applied a degradation rate of 0.7% per annum.
Source: CSIRO, GEM, and AEMO.

A1.3.2 Distributed Battery Energy Storage Systems

Distributed residential and commercial battery systems have the potential to materially alter future demand profiles, particularly with respect to maximum and minimum daily demand. DESS enable consumers to increase self-consumption by storing excess DPV generation to later offset consumption during peak times. Reducing DPV export tariffs[15] further incentivise the installation of DESS capacity.

Battery energy storage forecasts are sensitive to improvements in technology costs, as well as the rate of customer adoption. Further, AEMO assumes additional system benefits of DER will be made available through aggregation of DER assets and participation in the market as VPPs. The timing and structure of VPPs and models for participation are under development as part of the WA Government's DER Roadmap[16] and supporting pilots such as Project Symphony[17].

Over time, AEMO expects aggregation and orchestration of DER via VPPs will influence DESS demand profiles. The extent of this impact depends on factors including:

- The energy storage capacity and charge/discharge power of the battery system installed.
- The capacity of any DPV system or controlled load installed at the same premises, and the volume and timing of energy consumption of the household or business.

[15] For example, starting from 31 August 2020, new DPV systems installed in the SWIS are eligible for the Distributed Energy Buyback Scheme. This scheme compensates at a rate of 2.5 cents per kWh of solar electricity supplied to the grid for most of the day, as opposed to the previous rate of 7.135 cents per kWh under the Renewable Energy Buyback Scheme. See https://www.synergy.net.au/Your-home/Manage-account/Solar-connections-and-upgrades/Distributed-Energy-Buyback-Scheme.

[16] See https://www.wa.gov.au/government/distributed-energy-resources-roadmap.

[17] See https://aemo.com.au/en/initiatives/major-programs/wa-der-program/project-symphony.

- The development and implementation of arrangements that enable VPPs to access returns for the provision of services (to the WEM and/or network for example).
- Customer-driven requirements that may also impact DESS demand profiles, including the configuration of DESS system and/or optimisation objectives if operating autonomously and/or technical aspects such as energy to power ratio and round-trip efficiency.

For DESS VPPs, a percentage of the total installed DESS capacity is reserved and captured in the reliability modelling. In this operation type, DESS operation is optimised to reduce overall system costs while functioning as a controllable form of grid-scale battery storage.

Figure 7 and **Figure 8** show the forecast for DESS capacity in terms of power and storage capacity respectively. The 2024 WEM ESOO forecasts the capacity of DESS in the SWIS will increase over the current outlook period, but there remains substantial uncertainty about the uptake level due to uncertainty over costs of battery systems, as evidenced by the forecast spread across the scenarios. **Figure 8** shows that the 2023 WEM ESOO projected a higher rate of decline of cost of battery systems, leading to higher uptake in both Expected and High scenarios, while the Low scenario projected similar uptake to the 2024 forecast.

Figure 7 Forecast installed DESS capacity in the SWIS under three scenarios, 2022-23 to 2033-34 (MW)

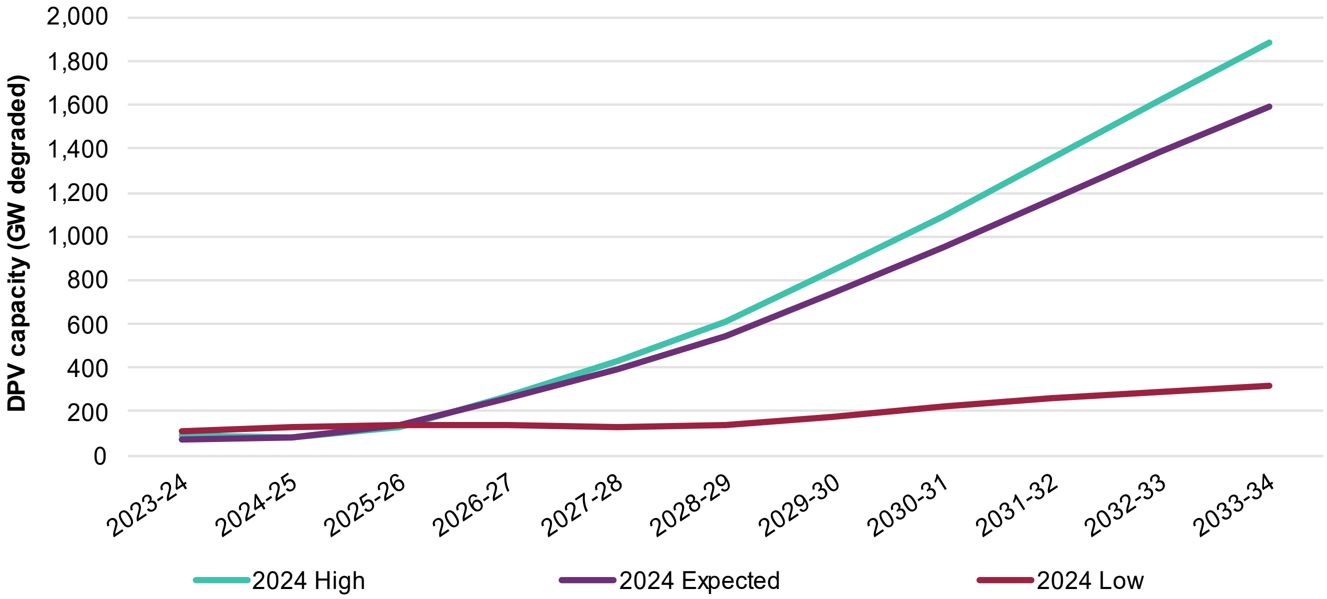
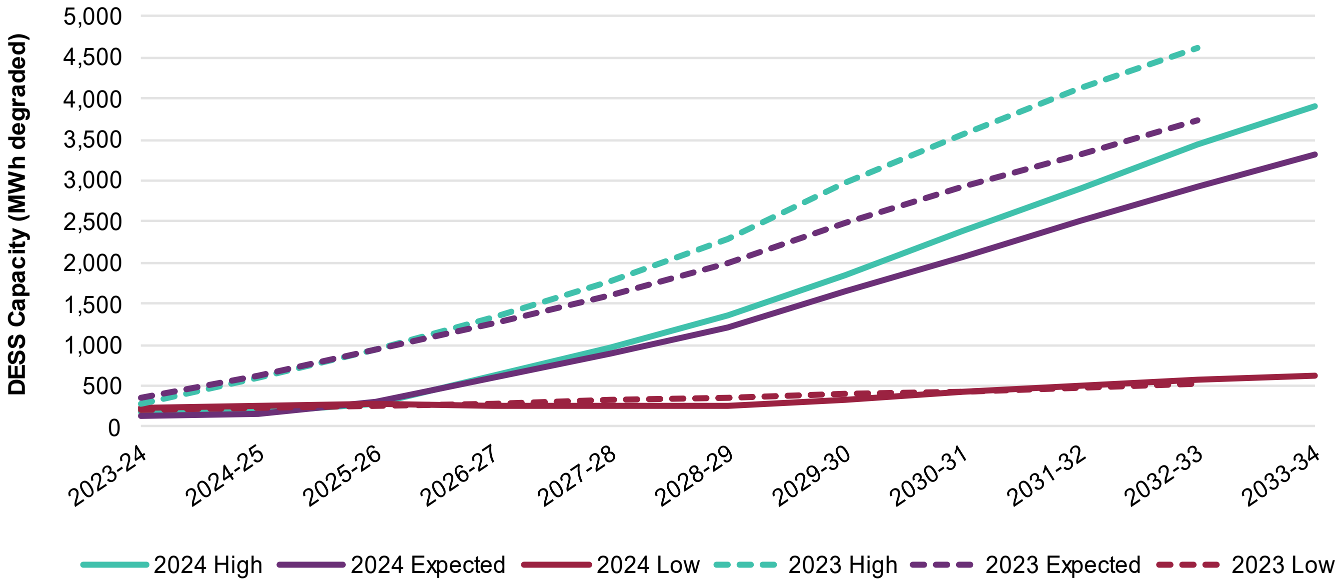


Figure 8 Forecast DESS storage capacity in the SWIS under three scenarios from the 2023 and 2024 WEM ESOOs, 2022-23 to 2033-34 (MWh degraded)



Note: The term "Degraded" reflects that DESS storage capacity will reduce in their efficiency and effectiveness over time and recognises the increase in average system size on replacement.
Source: CSIRO, GEM and AEMO.

A1.3.3 Electric vehicles

Input vintage	March 2024 – reforecast since the 2023 IASR
Sources	CSIRO
Updates since 2023 WEM ESOO	EV model updated with recent EV sales, Australian Infrastructure and Transport Statistics - Yearbook 2023, and the reduced application scope of the Fuel Efficiency Standard.

AEMO engaged CSIRO to conduct detailed modelling of EVs, encompassing battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). The EV forecasts took into account the potential implementation of a nationwide New Vehicle Efficiency Standard (NVES), alongside existing state policies.

The Western Australian Government's EV initiatives combine financial incentives, infrastructure development, and a long-term plan for grid integration. For example, the Zero Emissions Vehicle Rebate Scheme provides a $3,500 rebate for new EVs or hydrogen fuel cell vehicles, with 10,000 rebates available. Infrastructure efforts include the WA EV Network, allocating $23 million for fast-charging stations along major routes, and the Charge Up Grant Scheme, which covers up to 50% of EV charging infrastructure costs for local governments. The state Electric Vehicle Action Plan aims to integrate EVs into the grid for a reliable, efficient transition to a low-carbon future.

The EV forecasts have been informed by insights across a range of sources, including EV sales data and road statistics from peak bodies and government departments, trial data on charging behaviours, and public charging electricity usage data. Notably, the analysis of public charging data has enriched AEMO's understanding of -fast charge usage patterns.

The rise of EVs presents opportunities for consumers to actively shape power system outcomes. As consumers transition to EVs, their charging habits will evolve. Consumer charging requirements and available options will significantly influence the daily demand profiles within the WEM. Encouraging consumer participation in programs facilitating coordinated charging will be crucial. These behaviours, which vary across scenarios, will play a pivotal role in shaping the future landscape. More data is available in the 2024 WEM ESOO EV Workbook.

The EV uptake forecasts have been updated for this WEM ESOO to reflect:

- **The latest actual sales figures of BEV and PHEV** – recent quarterly vehicle sales data[18,19], surpassing the 2023 WEM ESOO forecasts under the Expected scenario, indicates a notable increase in EV sales. Consequently, AEMO's short-term forecasts have been adjusted upwards, particularly impacting the Low scenario.
- **The proposed fuel efficiency standard** – the relationship between an anticipated NVES and EV sales is multifaceted, as a standard does not uniformly impact sales across all scenarios. The influence varies depending on factors such as the required level of fuel efficiency and the specifics of implementation, including vehicle categories, timeframe, and rules.
  - AEMO acknowledges the progress made by the Federal Government in considering a NVES. Following public submissions in May 2023, a detailed impact analysis titled "Cleaner, Cheaper Cars to Run: the Australian New Vehicle Efficiency Standard" was released in March 2024[20]. This report explores three options, each outlining potential pathways for tightening fuel efficiency standards for cars and light commercial vehicles by 2029. Option B of the impact analysis, which aims to reach parity with US standards by 2028 and maintain that level going forward, has been designated as the preferred option. Stakeholder input and a review of the policy proposal suggest that the NVES is likely to encourage broader adoption of EVs in the medium term, with an increase in hybrids and PHEVs in the short term.
  - Following this study, on 17 May 2024 NVES legislation, effective from 1 January 2025, passed through the Australian Parliament, aiming to reduce around 60% emissions from new passenger vehicles and roughly halve the emissions of new commercial vehicles by 2030[21]. The 2024-25 Federal Budget includes provision of $84.5 million over five years to help establish and implement this scheme.
  - The 2023 WEM ESOO modelling included an Expected scenario with 55% of new sales of light vehicles being electric by 2030, translating to a 52% full-fleet EV share (accounting for slower adoption in heavy vehicles). Given the emergence of alternative options for meeting targets, a 50% light vehicle sales share is considered more realistic for the Expected scenario for the 2024 WEM ESOO EV forecasts.
  - For the other scenarios, the range of forecasts for EV sales by 2030 has narrowed, because the scope of the NVES is now applicable to all scenarios. However, as the NVES does not guarantee a specific EV sales share[22], uncertainty regarding EV sales persists. This uncertainty can still be explored across the scenarios, with forecasts outlined in **Table 2**.

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[18] Electric Vehicle Council 2023, *State of electric vehicles*, at https://electricvehiclecouncil.com.au/wp-content/uploads/2023/07/State-of-EVs_July-2023_.pdf.

[19] FCAI (Federal Chamber of Automotive Industries) 2023, VFACTS report: New vehicles sales, FCAI.

[20] Department of Infrastructure, Transport, Regional Development, Communications, and the Arts, 2024, Cleaner, Cheaper Cars to Run: the Australian New Vehicle Efficiency Standard, at https://oia.pmc.gov.au/sites/default/files/posts/2024/04/ImpactAnalysis-NVES.pdf.

[21] Minister for Climate Change and Energy 2024, *Joint media release: An Australian-made New Vehicle Efficiency Standard*, at https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-australian-made-new-vehicle-efficiency-standard.

[22] Implementing a NVES improves the chances of meeting EV sales targets, but the target can be achieved through the average of a variety of internal combustion vehicles and EVs, making it uncertain which sales target will be reached. Factors such as supplier strategy and consumer preferences also play a role.

Table 2 2030 EV light vehicle sales shares

WEM ESOO Scenario	Low	Expected	High
2023 WEM ESOO	39%	55%	66%
2024 WEM ESOO	40%	50%	60%

- Stakeholder feedback on PHEVs – AEMO has taken into account feedback received during consultation regarding the dual drivetrain of PHEVs, acknowledging its importance for communities facing geographical barriers to BEV adoption, as well as the appeal of PHEVs for certain vehicle types and applications. Recent data indicating an increase in PHEV sales has also been considered. Based on these factors, CSIRO has updated the 2024 WEM ESOO PHEV forecasts to adjust an earlier overestimation of the decline in PHEV numbers. This adjustment incorporates the latest PHEV sales figures and extends the period before a decrease in PHEV numbers is anticipated. Despite these considerations, AEMO's assessment suggests that PHEVs are likely to serve as a transitional technology rather than a long-term solution for most consumers.
- Recognition of an updated estimates of lower vehicle depreciation rates (lower scrapping rates) and a decrease in road transport demand – updated information from the BITRE's Australian Infrastructure and Transport Statistics Yearbook 2023[23] on vehicle kilometres travelled, and new vehicle sales data from the Federal Chamber of Automotive Industries VFACTS report[24], were inputs to an updated estimate of vehicle depreciation rates.
  - The return of vehicle depreciation to pre-pandemic levels has altered previous assumptions, suggesting an extended period of lower vehicle utilisation may have mitigated the need for higher depreciation rates to compensate for the period of lower depreciation during the pandemic period. Consequently, future projections for vehicle numbers and new vehicle sales are lower than previously anticipated.
  - The updated data reveals a significant decrease in road transportation as a share of passenger transport, with aviation nearly fully recovering its market share lost during the pandemic. This reduction in road transport demand, coupled with changes in depreciation rates, further diminishes the future demand for vehicles. With vehicle sales now significantly lower, achieving market saturation of EV (defined as a 99% EV fleet share) within the previously projected timelines is not feasible in the Expected and High scenarios. The original projection assumed market saturation 10 years after reaching a 100% EV sales share, with a consequent withdrawal of commercial services supporting internal combustion vehicles. However, the new vehicle sales rates indicate that achieving market saturation will take longer than 10 years. The previous and revised dates are detailed in **Table 3**.

Table 3 Changes to market saturation (99% EV fleet share) dates

WEM ESOO Scenario	Low	Expected	High
2023 WEM ESOO	2060	2050	2045
2024 WEM ESOO	2060	2055	2050

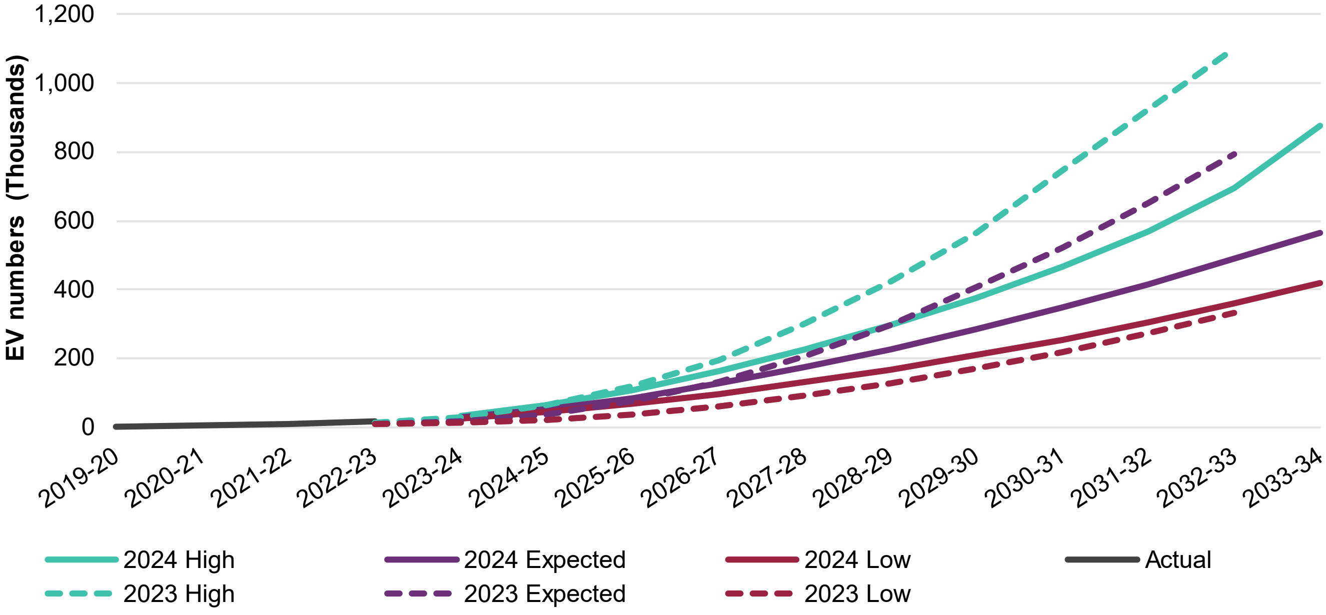
[23] See https://www.bitre.gov.au/publications/2023/australian-infrastructure-and-transport-statistics-yearbook-2023.

[24] VFACTS reports the numbers of new motor vehicle sales by dealers and direct sales by manufacturers throughout Australia. See https://www.fcai.com.au/get-vfacts/.

Figure 9 shows the projections for BEV and PHEV fleet size in the WEM by scenario, compared to the 2023 WEM ESOO forecasts. The 2024 WEM ESOO forecasts are notably lower than those of 2023 for the Expected and High scenarios. This adjustment stems from a potentially reduced scope of application for the NVES, lower scrapping rates, and lower road transport demand, despite recent strong sales and increased PHEV forecasts. Conversely, the Low scenario sees a higher forecast compared to the 2023 WEM ESOO due to NVES considerations.

Despite these revisions, the projected growth of EVs remains significant, offering a substantial opportunity to decarbonise Western Australia's transportation sector. In the Expected scenario, EV numbers are forecast to grow at an average annual rate of 34.9%, from around 28,500 in 2022-23 to more than 550,000 by 2033-34.

Figure 9 Actual and projected BEV and PHEV fleet size in the WEM under three scenarios, 2023 and 2024 WEM ESOOs, 201920 to 2033-34 ('000)



Source: EVC, FCAI, and CSIRO.

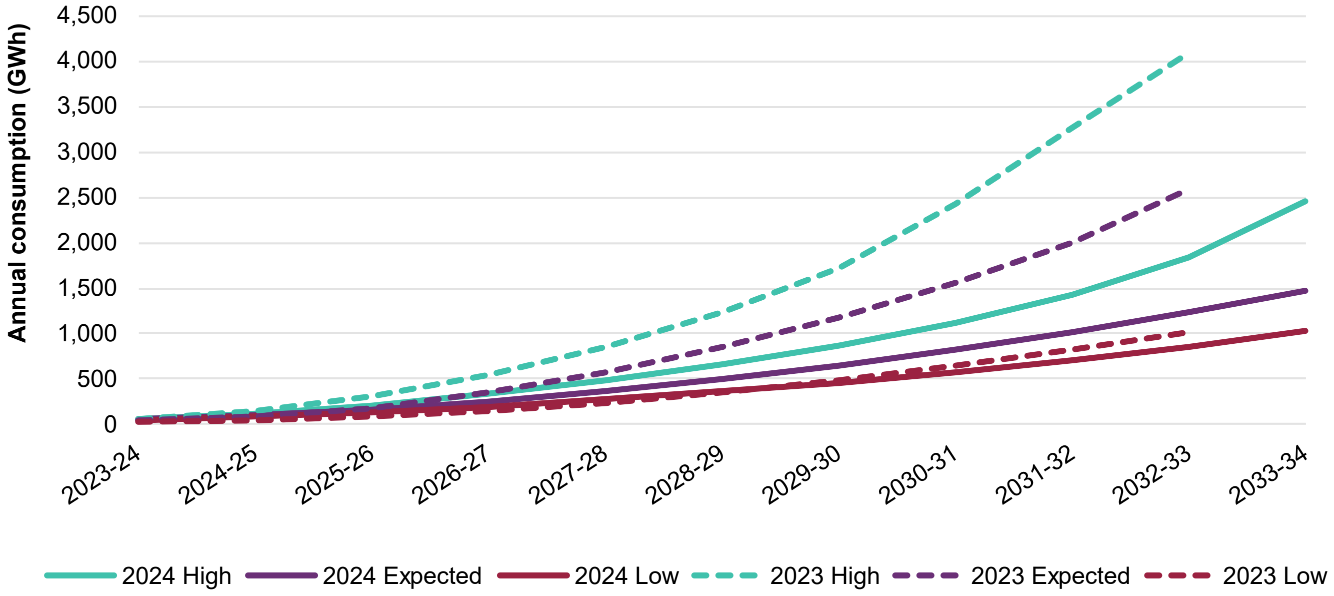
Energy use associated with EVs

Figure 10 shows electricity consumption from EVs, derived from the fleet mix of vehicle types and assumed travel distances. This consumption forecast aligns with the projected uptake of EVs, as illustrated in **Figure 9**.

Compared to the 2023 WEM ESOO forecasts, anticipated electricity consumption from EVs for the Expected and High scenarios is markedly lower over the forecast period. This decline is attributed to the reduced forecast uptake of EVs, coupled with lower vehicle utilisation rates. The Low scenario maintains a comparable level of EV electricity consumption to the 2023 WEM ESOO, driven by an increase in fleet size fuelled by recent sales and the potential implementation of a NEVS, which offsets the impact of decreased utilisation.

In the 2024 WEM ESOO, EVs are projected to consume nearly 1.5 TWh and 2.5 TWh by 2033-34 in the Expected and High scenarios, respectively. These figures represent approximately 8% and 14% of the current total operational consumption in the WEM.

Figure 10 Projected BEV and PHEV fleet electricity consumption under three scenarios, 2023 and 2024 WEM ESOOs, 2022-23 to 2033-34 (GWh)



Source: CSIRO

EV charging profiles

In the 2023 WEM ESOO, a comprehensive set of half-hourly charging profiles was developed to capture the connection between various EV driver charging patterns and the corresponding load on the power system. These profiles were tailored to different vehicle types, timeframes (months, years), and day categories (weekdays/weekends). The most recent charging profiles feature updated names and descriptions (see **Table 4**), aimed at providing enhanced transparency regarding the relationship between tariffs and charging behaviour.

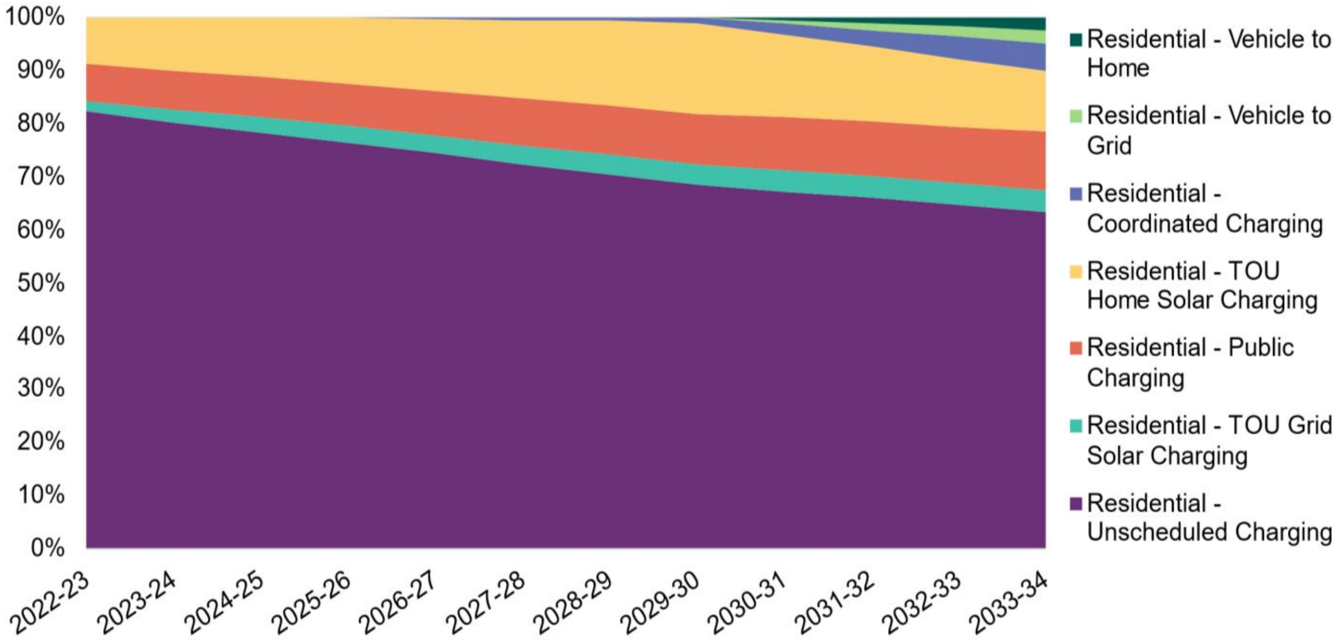
Table 4 EV Charging profiles

2024 WEM ESOO charging profile name	2023 WEM ESOO name	Description
Unscheduled	Convenience	Unscheduled home charging that occurs on a flat tariff
Time of use (TOU) Home Solar	Night	Traditional TOU tariff without day incentives, other than use of home solar
TOU Grid Solar	Day	Where a TOU tariff includes day charging incentives, and even customers without solar are incentivised to use abundant low cost solar via the grid
TOU Dynamic	Coordinated	TOU tariff, but dynamically priced to reflect solar energy availability. Used for charging only – does not include vehicle-to-home (V2H) and vehicle-to-grid (V2G) power flows.
Public	Fast/Highway (FHWY)	Public L2 and fast charge
V2G/V2H	V2G/V2H	Vehicle to home/grid (dynamic system-controlled charging)

Compared to the 2023 WEM ESOO forecast, the 2024 forecast reflects more refined consideration of the role of public charging. This includes its significance in managing vehicle range and addressing the needs of drivers who lack access to home or workplace charging facilities. Notably, the 'public' EV charging profile, previously referred to as Fast/Highway, has been refined, with updated projections regarding the share of utilisation of public and private chargers.

Figure 11 shows the modelled split of charging types over time[25]. It considers various trial data referred to in CSIRO's report, stakeholder feedback, and the anticipated evolution of TOU tariffs.

Figure 11 Split of charging types for medium residential vehicles, Expected scenario, 2022-23 to 2033-34



Source: CSIRO and AEMO.

For the TOU charging categories:

- Initially, the majority of EV owners use TOU Home Solar, which is based on traditional TOU with peak/shoulder/off-peak periods. This incentivises charging during overnight off-peak hours or utilising DPV if available. However, these traditional TOU plans have limitations. They do not fully encourage EV drivers to take advantage of the abundant and low-cost solar power that is frequently available during daytime hours.
- TOU Grid Solar is an evolution from its predecessor, addressing its limitations by offering pricing that aligns more closely with daytime solar availability. This lower daytime rate is accessible to all consumers, irrespective of DPV ownership. However, while solar energy is typically abundant during the day, the tariff does not account for daily weather fluctuations. Consequently, EV drivers remain incentivised to charge, even on days when significant cloud cover reduces solar generation.
- TOU Dynamic shares similarities with TOU Grid Solar but can be optimised to match power system needs. For instance, if cloud cover emerges in the mid-afternoon, prices swiftly transition from very low (encouraging solar soaking) to a moderate value, prompting those with flexibility to defer charging. As it offers the highest incentives to charge during times of abundant solar power, the TOU Dynamic share increases over time.

[25] The charge split forecasts represent the outlook for future charging behaviours rather than reflecting today's tariff structure.

A1.4 Energy efficiency savings forecast to grow strongly throughout the outlook period

Input vintage	March 2024
Sources	Strategy Policy Research (SPR, 2023)
Updates since 2023 WEM ESOO	Updated in Q1 2024 with AEMO's latest forecasts

The forecasts for energy efficiency savings[26] reflect the potential role of energy efficient choices in reducing energy consumption. These forecasts consider energy savings attributable to the quality and quantity of investment in new technologies, buildings, and processes, uptake of energy efficient appliances and equipment in business and residential sectors, alongside fuel-switching[27]. The forecasts account for varying levels of policy ambition coupled with demand drivers (such as population, building stock growth, and building stock type), to align with the scenario narratives.

The energy efficiency forecasts consider these government measures aimed at lowering energy consumption:

- Building energy performance requirements contained in the Building Code of Australia 2010 and the National Construction Code (NCC) 2019 and NCC 2022.
- The Greenhouse and Energy Minimum Standards program of mandatory product labelling requirements and/or minimum energy performance standards for different classes of appliances and equipment.
- Building rating and disclosure schemes for existing commercial offices, including the Commercial Building Disclosure (CBD) and the National Australian Built Environment Rating System (NABERS) Energy for Offices.
- Hypothetical introduction of new universal mandatory disclosure and minimum energy performance standards, for existing residential and non-residential building classes, excluding the share of buildings already rated under NABERS or CBD.
- A hypothetical industrial assessment program modelled on the former Energy Efficiency Opportunities program.

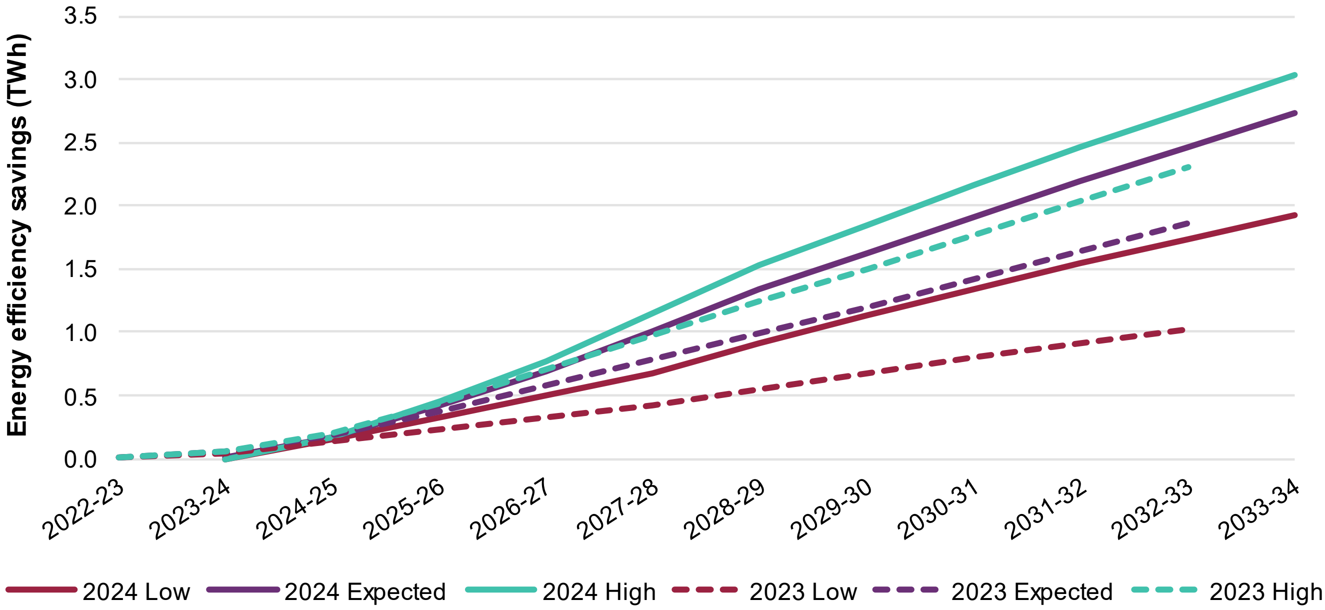
Figure 12 shows the total energy efficiency savings forecast for the BMM and residential sectors.

In addition to government measures, the forecast also considers market-driven energy efficiency investments that are not a result of specific policy incentives. For example, appliances such as lighting fixtures become more energy efficient over time. Energy efficiency savings for LILs are included within their survey responses and are therefore captured in the LIL forecast results (in Section A1.7). Energy efficiency savings are forecast to grow throughout the outlook period. In the short term, savings derived from energy efficiency improvements are lower in the residential sector than in BMM, but are higher in the medium to long term, reflecting the impacts of investments, policy ambitions and demand drivers. The overall pace of savings from energy efficiency improvements surpasses the 2023 WEM ESOO following the inclusion of market-driven impacts.

[26] Energy efficiency relates to how much energy is consumed to perform a task whereby policy seeks to improve this efficiency. For detail, see https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf.

[27] Fuel-switching under energy efficiency improvement is only considered to the extent that incremental impacts on the fuel mix are attributable to efficiency policy measures.

Figure 12 Forecast total energy efficiency savings in the BMM and residential sectors under three scenarios, 2023 and 2024 WEM ESOOs, 2022-23 to 2033-34 (TWh)



Source: SPR and AEMO.

A1.5 Electrification is forecast to grow strongly, dominated by industrial fuel-switching opportunities

Input vintage	March 2024
Sources	CSIRO and ClimateWorks Centre (CWC) AEMO LIL surveys
Updates since 2023 WEM ESOO	Updated in Q1 2024 with AEMO's latest forecasts

AEMO recognises that decarbonisation of the Australian economy requires fuel-switching towards low and no emissions alternatives. The SWIS electrification forecasts[28] have been developed according to AEMO's 2022 multi-sector modelling. In addition, AEMO has included updates on the LIL electrification plans identified in the 2024 LIL survey responses, particularly for the alumina refineries which account for the majority of electrification in the SWIS. AEMO has included the potential electrification of future loads (including the transport sector) alongside existing loads in the 2024 WEM ESOO forecasts. The key factors considered were:

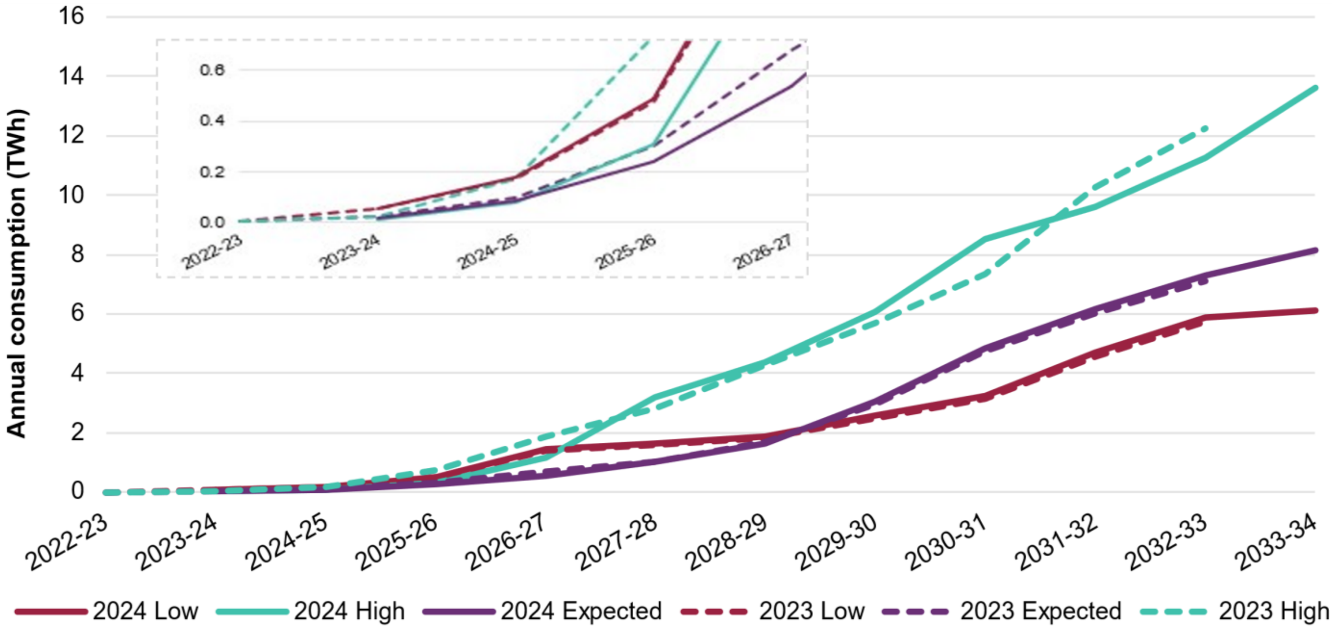
- **A range of electrification outcomes** – residential and commercial building sectors' electrification of space heating, cooking, and water heating appliances (from gas or liquefied petroleum gas), electrification of the transport sector (covered by the EV forecasts presented in Section A1.3.3), and electrification in the business sector.

[28] Electrification includes any process that involves fuel-switching to electricity, such as replacing a gas hot water system with a heat pump, electrified heating, and cooling of air.

- **Cost-efficiency of electrification** – the cost-efficiency of electrification relies on various factors, including appliance replacement expense, electricity infrastructure capabilities and costs, and the accessibility of alternative low-emission fuels like hydrogen and biomethane.

Figure 13 shows the electrification forecasts for all sectors in the SWIS, excluding EVs.

Figure 13 Forecast total annual electricity consumption from business and residential electrification (excluding EVs) under three scenarios, 2022-23 to 2033-34 (TWh)



Note: The highest annual business and residential electricity consumption from electrification is forecast in the Low scenario between 2023-24 and 2026-27. See the 2024 WEM ESOO Data Register for further information.
Source: AEMO, CSIRO and CWC.

In all three scenarios, electrification in the BMM and residential sectors is forecast to grow significantly from current levels, largely due to business electrification in the SWIS. This suggests electrification stands as one of the most cost-effective emissions reduction strategies across all scenarios, alongside other strategies such as energy efficiency improvements and renewable energy adoption.

In the short term, electrification in the Low scenario surpasses both the other scenarios, while in the medium term it surpasses the Expected scenario. This is because in the Low scenario, electrification is projected to play a greater role in reducing carbon emissions compared to the other scenarios, whereas the other rely more on alternative approaches, such as improving energy efficiency and switching to low-emission fuels like hydrogen and biomethane. This projection is similar to the 2023 WEM ESOO results.

A1.6 Forecast growth in hydrogen production is delayed compared to the 2023 WEM ESOO and is influenced by opportunities for export

Input vintage	March 2024
Sources	CSIRO and CWC
Updates since 2023 WEM ESOO	Updated in Q1 2024 with progress measured against AEMO's assessment framework

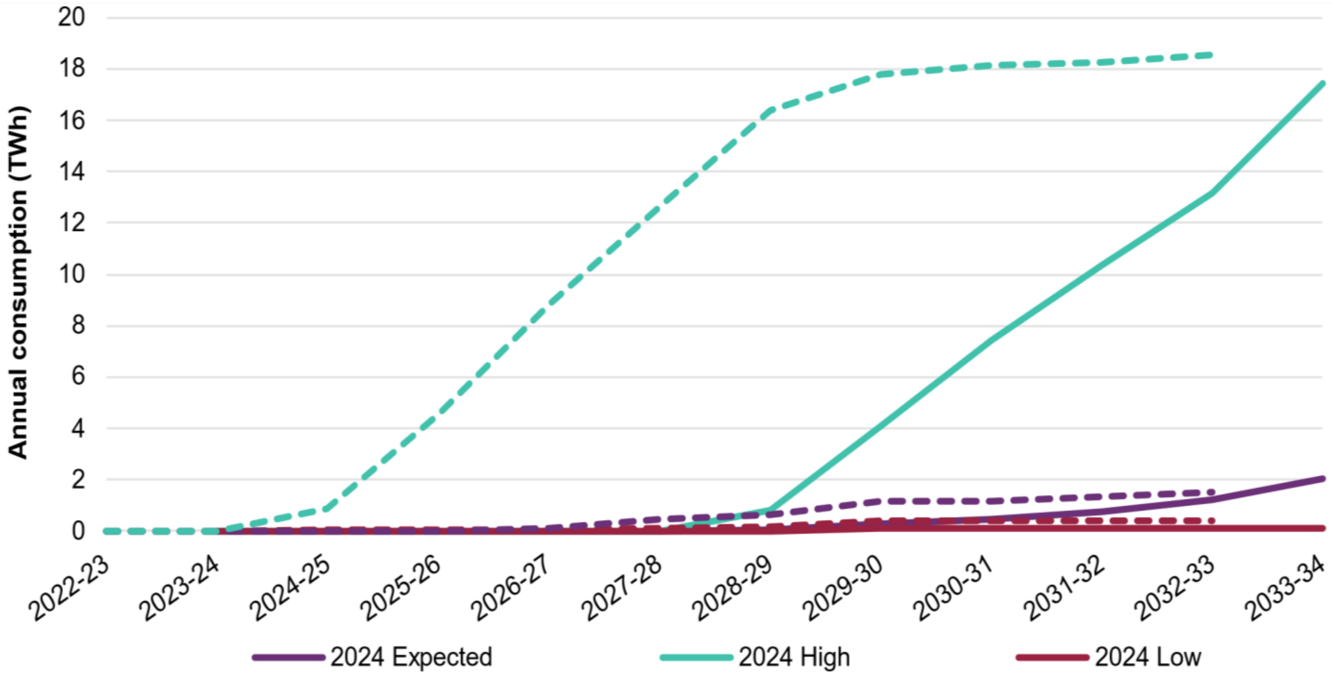
Significant hydrogen production announcements have been made in Western Australia, as evidenced by CSIRO's HyResource listing of projects[29]. Only four small-scale projects are currently in operation. The 2022 multi-sector modelling study included electricity consumption forecasts for hydrogen production within the SWIS.

AEMO's forecast considered electricity consumption arising from electrolysers producing hydrogen from renewable sources – often referred to as 'green hydrogen'. AEMO's hydrogen assumptions vary by scenario because the trajectory of capital cost reductions and uptake timing is highly uncertain. The assumed hydrogen production for domestic use (including the transport sector) and export is informed by the multi-sector modelling outcome, with AEMO making subsequent adjustments to accommodate the uncertainty associated with the speed, scale, and timing of hydrogen projects. The key factors considered were:

- **Hydrogen for domestic purposes** – domestic hydrogen uptake is mainly projected in the industry and transport sectors while competing with electrification and biomethane. It has the strongest uptake in the High scenario, due to a high assumed learning rate and maturing export market to drive down costs.
  - Gas distribution networks are expected to provide a delivery means for blended hydrogen, with up to 10% blending share across all three scenarios.
- **Hydrogen for export purposes** – Western Australia has strong potential to export green hydrogen, attributed to its high-quality renewable energy potential and a history as a reliable international energy and resource supplier.

Figure 14 shows forecast total annual consumption in the SWIS for hydrogen production, for both domestic use and export purposes.

Figure 14 Forecast total electricity consumption for hydrogen production in the SWIS under three scenarios, 2023 and 2024 WEM ESOOs, 2022-23 to 2033-34 (TWh)



Source: AEMO, CSIRO and CWC.

[29] See https://research.csiro.au/hyresource/projects/facilities.

In the Expected and High scenarios, uptake of hydrogen production in the short to medium term is largely attributed to the domestic use of hydrogen to replace existing gas and liquid hydrocarbon fuels use. Long-term growth is largely attributed to the export opportunities. In the Low scenario, uptake in hydrogen production is significantly influenced by domestic use throughout the outlook period.

Compared to the 2023 WEM ESOO, the pace of growth of hydrogen production is slower. This is due to AEMO reevaluating its hydrogen outlook and integrating a five-year lead time for non-committed projects, as well as a five-year production ramp-up to match the multi-sector modelling forecast levels. This adjustment is a result of slower than anticipated progress of major hydrogen investment, which reflects uncertainty surrounding the pace, scale, and timing of hydrogen projects.

In the High scenario, the 2023 WEM ESOO allowed for a greater proportional blend of hydrogen in distribution networks in the long term, reflecting the opportunity for more significant changes in the use of gas and renewable gases by consumers after 2030.

A1.7 Large industrial loads

Input vintage	March 2024
Sources	Surveys/Interviews AEMO meter database Western Power LIL forecasts of multi-sector modelling Company announcements
Updates since 2023 WEM ESOO	Updated with AEMO's latest actual connections data and existing and new LIL forecasts

LILs are users that consume or are forecast to consume at least 10 MW for a minimum of 10% of the time each year (around 875 hours a year), or at least 50 GWh per year. LILs consumed approximately 30% of all operational consumption in the SWIS in the current Capacity Year.

For existing LILs forecasts, AEMO surveyed LIL owners to gain understanding of their anticipated future consumption and demand forecasts. These surveys included any planned brownfield expansions or closures of existing LILs. AEMO's surveys also sought to identify any future electrification and/or energy efficiency upgrades that are planned for the facility. The surveys were supplemented by obtaining additional information through interviews as required.

For new greenfield LILs forecasts, AEMO undertook market research to identify prospective projects under development and assess the project development statuses. AEMO has also liaised with Western Power in relation to new connections for this WEM ESOO, which has provided a detailed forward-looking load connection list, ranging from conceptual through to committed projects.

Since the 2023 WEM ESOO, several LILs in the mining, transport and minerals processing sectors have been connected. This means they are no longer part of the new LIL forecast; they are now included under the existing LIL forecast. Additionally, three LILs have been included in the new LIL list for the first time. Most of these projects are in the manufacturing sector.

AEMO's methodology accounted for both long-term government decarbonisation policy targets and that operators usually apply for Environmental Protection Authority (EPA) approvals three to four years in advance of their expected final investment decision (FID) for a project. Consistent with the 2023 WEM ESOO, AEMO only considered the EPA approval status criterion for projects that are expected to come online within four years, with a decarbonisation criterion used for longer-term projects.

For all new LIL projects, two scoring systems were applied:

- For projects that are expected to come online within the next four years.
- For projects expected to start more than four years ahead.

The new LIL projects were evaluated on a graded scale using the weighting values summarised in **Table 5** according to:

- Western Power's assessment on the likelihood of the project connecting to the SWIS.
- Whether the project proponent has publicly announced that it has taken a positive FID and/or the project has commenced construction.
- Whether the project is a carbon reduction project. This captured projects that are part of the energy transition. Examples include projects that involve hydrogen production or extraction and processing of critical minerals such as lithium, cobalt, and rare earth elements. The purpose of adding this criterion is to give weight to those projects aligned to government and corporate policy to decarbonise, as well as those that stand to benefit from the global energy transition.
- The project's current state of progress through environmental approval stages. The stages were scored from 0% for "no application submitted" through to 100% for "Stage 5 (approved)". For projects that were expected to be online within four years, the system gave a weight to EPA approval, which is needed for a project to progress. No weight was given for EPA application for projects expected to be brought online more than four years ahead.

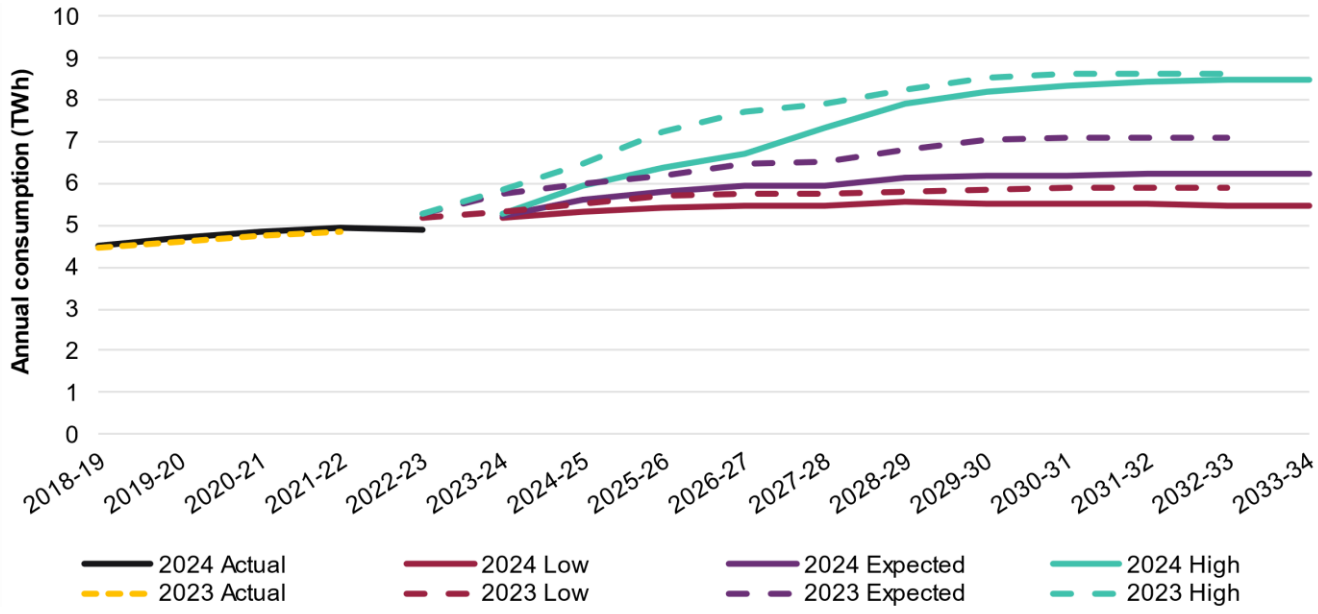
Table 5 Weighting for evaluation criteria for LIL projects

Criteria	Projects expected online within four years	Projects expected online more than four years ahead
Western Power active stage	30.0%	33.3%
Status of EPA approval	30.0%	-
Likelihood of FID	30.0%	33.3%
Is this a carbon reduction project?	10.0%	33.3%

Figure 15 compares existing and new LIL consumption forecasts for the Low, Expected, and High scenarios from the 2023 and 2024 WEM ESOOs, and shows actual LIL consumption from 2018-19 to 2022-23. LIL consumption shown here does not include electricity consumption from hydrogen production and electrification of LILs[30].

[30] For discussion on electricity consumption associated with LIL electrification and in the hydrogen sector, see Sections A1.5 and A1.6, respectively.

Figure 15 Actual and forecast total electricity consumption for existing large industrial loads in the SWIS under three scenarios, 2023-24 to 2033-34 (TWh)



Source: AEMO and Western Power.

2024 WEM ESOO projections include growth in existing LIL driven by activities in mining (driven by gold, iron ore, and non-metallic mineral mining), and manufacturing (such as basic inorganic chemical and other non-ferrous metal manufacturing) sectors. The growth in new LILs is driven by basic inorganic chemical manufacturing, such as lithium mining and refining, expansions of rail passenger transport, as well as the anticipated addition of Perth's third desalination plant[31] and university campus in the Perth CBD[32]. The consumption from existing and new LILs, in total, is forecast to grow throughout the outlook period. Compared to the 2023 WEM ESOO, the 2024 WEM ESOO projects LILs to grow more slowly, due to the weaker outlook for new projects and several large projects experiencing delays.

[31] For detail see https://www.watercorporation.com.au/Our-water/Desalination/Alkimos-Seawater-Desalination-Plant.

[32] For detail see https://www.citycampus.ecu.edu.au/construction.

A2. Reliability assessment methodology and EUE analysis

This appendix provides further detail on the modelling approach taken to address various aspects of the reliability assessment, including the expected unserved energy (EUE) assessment, determination of Availability Duration Gap Load Scenario (ADGLS), Capability Classes, and Availability Curves, as well as further detail on the EUE outcomes reported in Chapter 4. An EUE results workbook is provided separately alongside the WEM ESOO publication for reference.

A2.1 High-level approach to expected unserved energy assessment modelling

The EUE assessment determines whether the forecast Reserve Capacity is capable of meeting demand such that the EUE is within the limit of 0.0002% defined in the Planning Criterion for each Capacity Year in the 2024 Long Term Projected Assessment of System Adequacy (PASA) Study Horizon and determines the amount of Reserve Capacity required to maintain EUE below the threshold.

The reliability assessment was undertaken by EY using a proprietary electricity market dispatch model and a set of inputs and assumptions agreed by AEMO. The model consisted of a co-optimised energy market and Essential System Service (ESS) dispatch engine and several software tools that were used to develop input data and analyse output data. The model had the following key features:

- The simulation assessed the capacity gap (demand minus dispatched capacity) for every half-hour interval of each Capacity Year sequentially, given a specific capacity mix, demand profile, network constraints, ESS requirements, planned outage schedules, generator and storage forced outages, ramp rate limitations, storage modelling, and renewable resource variability.
- Half-hourly demand profiles were developed using annual demand and consumption forecasts from the 2024 WEM ESOO, including DER forecasts, applied as input into the model.
- A large number of Monte Carlo iterations (total of 1,200) were used to capture potential outcomes of different random forced generator outages (100) and weather conditions (for example, shape of demand, wind and solar availability) corresponding to different historical reference years (12).
- Each iteration yielded an estimate of unserved energy. For each Capacity Year, the EUE was calculated as the **average** of the total estimates of unserved energy from all 1,200 iterations for a given Capacity Year.

Details of the model can be found in EY's 2023 reliability assessment methodology[33].

The underlying basis for the modelling remains largely the same as the 2023 reliability assessment.

There have been several updates for approach improvement as well as alignment with the updated WEM Rules requirements:

[33] See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2023/aemo-reliability-assessment-2023--ey.pdf?la=en.

- Determination of the Contingency Raise requirement – in the 2023 Report, the Contingency Raise Requirement was set as a static MW number determined exogenously to the model and applied in every half-hour interval, representing a conservative approach to the headroom required to be reserved for potential Contingency Raise requirements. For this year's reliability assessment, a more dynamic approach was implemented, whereby the model calculated the largest contingency from interval to interval and used this information to set the requirement. The requirement therefore updated in each interval, for each of the 100 iterations across each of the 12 historical weather reference year model runs.
- Assessment of regional shortfalls – to investigate regional shortfalls in more detail, EY's approach this year was to run the model with hypothetical generators at selected regions in the SWIS and observe their generation as a proxy for the unserved energy that cannot be met in that particular location by generation outside of that region.
- Treatment of hydrogen load – in the 2023 reliability assessment, hydrogen load was modelled as a flat load at 10% of its installed capacity (in MW), on the basis that the load would reduce to that level in the instance of grid emergencies or otherwise prior to incurring unserved energy. To include a fuller representation of the load that is unserved in these instances, the modelling this year included the hydrogen load drawing 10% of its maximum demand over peak times, and operating to its maximum outside of these times such that the full forecast energy over the year was modelled. This increased the reported EUE in the absence of new generation capacity but did not ultimately impact the Limb B requirement, because the Capacity for Reliability (CFR) to achieve the 0.0002% reliability standard was unchanged by the different treatment of flexible hydrogen demand.
- Treatment of 'Capacity for Reliability' – in the 2023 assessment, CFR was modelled as additional generation that did not interact with storage or help to preserve the running hours of DSP. This was a conservative approach, however this year, with a changing capacity mix and large amounts of storage entering the WEM, the CFR was assumed to be available for storage to charge from and also to preserve the running hours of DSP.

A2.2 Assessment of the sufficiency of supply against Limb A requirement

The Limb A sufficiency assessment is a deterministic calculation comparing the Limb A requirement against the sum of forecast Reserve Capacity associated with the AIC of Energy Producing Systems (EPS) and DSPs for each Capacity Year of the 2024 Long Term PASA Study Horizon[34]. For the purposes of the reliability assessment, Anticipated Installed Capacity (AIC) is comprised of supply classified under the Expected scenario based on the approach outlined in Section 3.1. Refer to Section 3.2.3 for facility retirements assumptions.

A comparison of the forecast Reserve Capacity with the requirements of Limb A results in the outcomes shown in **Figure 16,** with the following key observations:

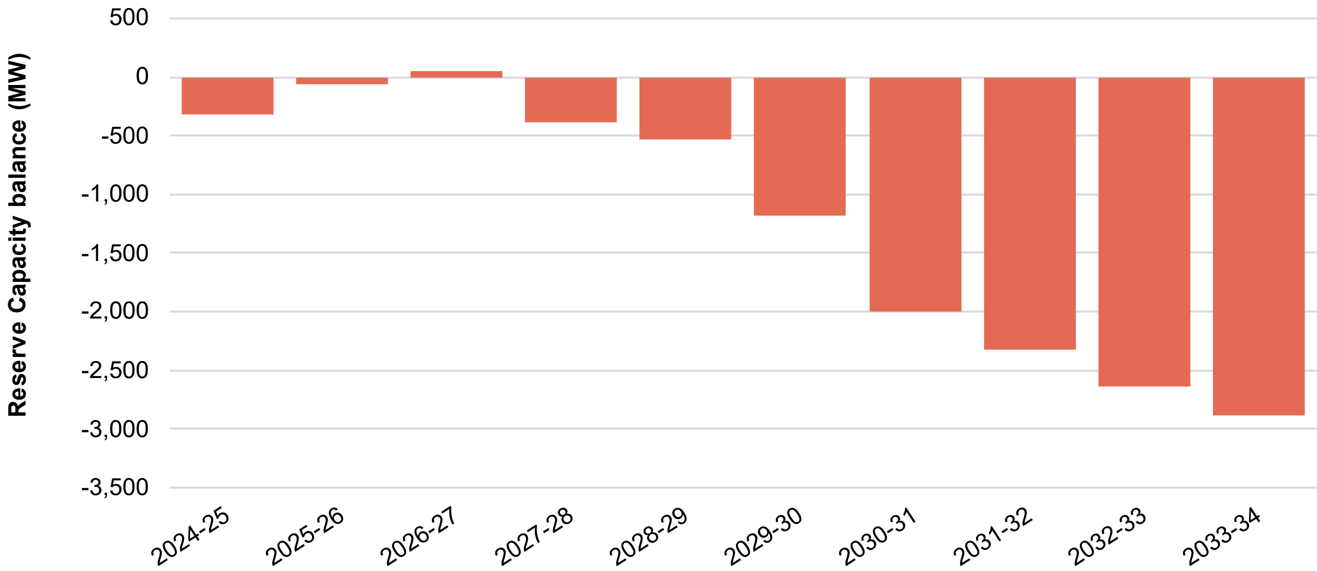
- The forecast Reserve Capacity shortfall progressively narrows, approaching the Limb A requirement in the initial years, reaching a surplus of 46 MW for 2026-27. This surplus reflects substantial new entrant capacity from NCESS Facilities, which are predominantly ESR and DSP Facilities and thus have forecast Reserve

[34] Facility categories in the WEM include Generation Systems, Distribution Systems, Transmission Systems, Load or DSPs. Unless exemptions apply, Facilities connected to the SWIS and participating in the WEM must be registered with AEMO.

Capacity equal to or nearly 100% of their dispatchable capacity. In addition, 2026-27 is prior to the assumed retirements of Collie, Muja D and later Bluewaters.

- In subsequent Capacity Years, the forecast Reserve Capacity balance steadily decreases, and the capacity shortfall reaches almost 3,000 MW by 203334. The increasing requirements of Limb A, combined with the assumed exit of all coal power stations in the WEM by 2030 and no further assumed new entrants beyond the end of the 2025 to 2027 NCESS contract period, contribute to this growing gap and highlight the opportunities for investment.

Figure 16 Difference between forecast Reserve Capacity balance and Limb A requirements (MW)



A2.3 Modelling to determine Limb B requirements

The steps to determine the Limb B requirements were as follows:

- Step 1: Run the dispatch model with the AIC and half-hourly demand profiles to calculate the EUE for each Capacity Year.
- Step 2: Assess the calculated EUE and determine whether a re-run is required for each Capacity Year based on the conditions outlined in **Table 6**.

Table 6 Limb B calculation conditions

EUE	Limb B modelled AIC compared to Limb A requirement	Re-run is required
Less than 0.0002%	Limb B modelled AIC < Limb A requirement	No
Less than 0.0002%	Limb B modelled AIC > Limb A requirement	Yes
More than 0.0002%		Yes

- Step 3: Re-run as required for the relevant Capacity Year by setting Limb B capacity to just under the Limb A requirement (by 1 MW). If EUE remains below the 0.0002% reliability standard, then Limb A sets the RCT. If EUE exceeds the standard, further modelling is required to establish the Limb B requirement.

The following provides the results for each of these steps for 2024 reliability assessment.

A2.3.1 Determining the Limb B requirement

Step 1

Table 7 presents the initial modelling outcomes, with EUE outcomes shown for each Capacity Year. This shows that EUE was within the reliability standard for 2024-25 to 2027-28 but exceeded the 0.0002% standard with year-on-year increases from 2028-29 and onwards. This was due to growing operational consumption volumes, the retirement of coal generation, and no assumed new capacity entry beyond 2026-27.

Table 7 Modelled EUE based on Expected demand scenario operational consumption and AIC, 2024-25 to 203334

Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Operational consumption (GWh)	18,018	18,082	18,287	18,530	19,188	20,800	22,833	24,465	26,118	27,868
Unserved energy (GWh)	0.023	0.008	0.0015	0.011	0.098	23	465	770	1,470	2,377
EUE % of operational consumption	**0.0001**	**0.00004**	**0.00001**	**0.00006**	**0.00051**	**0.11**	**2.0**	**3.1**	**5.6**	**8.5**

Source: EY.

Step 2

Table 8 summarises whether a re-run was required for each Capacity Year. The modelled AIC was compared against the Limb A requirement. For 2024-25, 2025-26 and 2027-28, the modelled AIC was below the Limb A requirement and EUE was below the reliability standard. Therefore, Limb A sets the RCT in these years.

For 2026-27, although EUE was below the standard, the modelled AIC exceeded the Limb A requirement, requiring a re-run of the modelling to determine if Limb B required capacity exceeds the Limb A requirement. For 2028-29 onwards, EUE was above the standard, while Limb B modelled AIC was below the Limb A requirement. A re-run of the modelling was required to determine if the capacity needed to reduce EUE to within the standard would result in the Limb B modelled AIC plus CFR exceeding the Limb A requirement.

Table 8 Comparison of Limb A requirement with Limb B modelled capacity and initial conclusion on RCT

Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Limb A requirement (MW)	5,501	5,589	5,696	5,794	5,925	6,165	6,545	6,861	7,159	7,395
Limb B modelled AIC (MW)	5,183	5,526	5,742	5,403	5,396	4,987	4,543	4,535	4,524	4,515
Conclusion	Limb A	Limb A	Re-run model	Limb A	Re-run model	Re-run model	Re-run model	Re-run model	Re-run model	Re-run model

Source: EY.

Step 3

The EUE results are shown in **Table 9**. EUE remained below 0.0002% for all of the re-runs and therefore, the RCT is set by Limb A for these Capacity Years.

Table 9 Outcomes of electricity market modelling to determine Limb A or Limb B to set the RCT

Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Limb A requirement (MW)	5,501	5,589	5,696	5,794	5,925	6,165	6,545	6,861	7,159	7,395
Limb B modelled AIC plus CFR (MW)	N/A	N/A	5,695	N/A	5,924	6,164	6,544	6,860	7,158	7,394
Unserved energy (MWh)	N/A	N/A	2.2	N/A	0	1	0	0	0	0
EUE % of operational consumption	N/A	N/A	0.00001	N/A	0.0000	0.00001	0	0	0	0

Source: EY.

A2.4 Breakdown of EUE by historical weather reference year, by month, and by time of the day

A2.4.1 EUE by different weather historical reference years

Table 10 provides a breakdown of EUE by historical weather reference year for each Capacity Year in the 2024 WEM ESOO outlook period. After 2029-30, the general shortfall among all historical weather reference year suggests that EUE is driven by a combination of increasing consumption, retirements, and no assumed new entry.

Table 10 Annual EUE (MWh) by historical weather reference year for each Capacity Year

Weather reference year/Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
2010-11	29	2	-	27	150	45,725	388,604	699,229	1,322,091	2,157,325
2011-12	9	-	-	-	16	21,701	527,180	790,449	1,507,988	2,436,437
2012-13	41	33	1	27	204	40,942	570,776	854,010	1,540,242	2,452,493
2013-14	9	-	-	-	3	6,996	363,837	613,702	1,382,974	2,233,381
2014-15	45	4	14	8	33	27,604	390,904	687,292	1,277,917	2,230,278
2015-16	11	3	2	10	113	17,489	471,988	740,846	1,530,894	2,503,267
2016-17	20	-	-	-	99	20,480	477,545	797,475	1,444,051	2,326,627
2017-18	33	45	1	15	227	31,487	565,411	961,512	1,613,958	2,517,906
2018-19	-	-	-	-	125	11,646	478,650	836,733	1,506,535	2,418,119
2019-20	68	8	-	41	194	24,779	455,882	721,407	1,547,687	2,414,478
2020-21	2	-	-	1	4	6,314	423,573	754,405	1,516,162	2,464,339
2021-22	5	1	-	-	6	18,483	469,920	782,490	1,445,972	2,371,075

Weather reference year/Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Average EUE	23	8	2	11	98	22,804	465,356	769,963	1,469,706	2,377,144

Source: EY.

A2.4.2 EUE by month

Table 11 presents the EUE by month for each Capacity Year over the 2024 Long Term PASA Study Horizon. The result shows that EUE occurs only during summer months for Capacity Years prior to 2028-29. The occurrence of EUE is seen in both summer and winter months after 2028-29, and in all months of the year from 2029-30 and onwards. EUE is higher during winter months than summer months, reflecting the shift in forecast peak demand to be higher in winter than summer. Furthermore, as the coal-fired plants retire, the impact of reduced solar and wind energy resources winter months is more pronounced, leading to an increase in EUE quantities.

Table 11 EUE (MWh) by month and Capacity Year

Month/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
October	-	-	-	-	-	3	271	8,674	11,654	90,098
November	-	-	-	-	-	2	743	12,975	31,753	39,870
December	0	-	-	-	0	399	10,500	24,302	62,452	69,959
January	6	0	-	0	5	1,026	26,312	45,955	81,512	148,816
February	13	4	1	8	48	10,707	38,111	70,033	106,257	175,762
March	4	4	0	2	22	865	15,252	34,269	71,904	134,585
April	-	-	-	-	1	337	63,663	38,563	155,171	271,295
May	-	-	-	-	-	8	34,372	43,926	105,819	207,573
June	-	-	-	-	1	699	61,052	105,685	190,048	315,451
July	0	-	-	0	1	6,519	129,861	201,009	324,747	437,027
August	-	-	-	-	21	2,101	66,219	116,850	239,798	330,963
September	-	-	-	-	-	139	19,000	67,723	88,591	155,745
Total EUE	23	8	2	11	98	22,804	465,356	769,962	1,469,706	2,377,144

Source: EY.

A2.4.3 EUE by time of day

Table 12 to **Table 14** present EUE by month and time of day (in these cases averaging across all historical weather reference years) for summer, shoulder, and winter seasons. The results show that the time of the year is determining factor in the occurrence of EUE up to 2029-30, despite difference in the timing among the seasons. The coverage of EUE is longer in summer and winter than in shoulder seasons. Beyond 2029-30, the time of day remains a significant determinant of the extent of EUE, with EUE forecast to occur throughout the day, peaking during evening and continuing until early morning hours for summer and shoulder seasons, and exhibiting dual peaks during morning and evening hours for winter seasons.

Table 12 EUE (MWh) by Trading Interval and Capacity Year for summer season

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
0:00:00	-	-	-	-	0.0	144.1	2,212.3	5,058.0	10,769.8	18,766.9
0:30:00	-	-	-	-	-	82.6	1,651.0	4,140.6	9,472.9	17,206.3
1:00:00	-	-	-	-	-	52.0	1,264.2	3,441.6	8,452.6	15,954.7
1:30:00	-	-	-	-	0.0	35.3	978.7	2,883.8	7,542.5	14,780.9
2:00:00	-	-	-	-	-	25.5	784.6	2,490.2	6,899.8	13,932.0
2:30:00	-	-	-	-	-	18.6	620.7	2,123.5	6,247.2	13,063.8
3:00:00	-	-	-	-	-	14.2	525.1	1,897.9	5,841.1	12,529.2
3:30:00	-	-	-	-	-	10.0	428.1	1,658.2	5,388.8	11,883.8
4:00:00	-	-	-	-	-	8.9	399.6	1,600.3	5,352.7	11,923.9
4:30:00	-	-	-	-	-	8.2	392.6	1,591.8	5,321.0	12,027.7
5:00:00	-	-	-	-	-	13.6	536.8	1,948.8	5,972.9	13,264.9
5:30:00	-	-	-	-	-	12.7	552.2	1,890.9	5,569.3	12,558.7
6:00:00	-	-	-	-	-	14.2	592.1	1,855.5	5,120.4	11,311.4
6:30:00	-	-	-	-	-	11.7	473.5	1,450.4	3,823.8	8,415.0
7:00:00	-	-	-	-	-	12.3	387.0	1,089.2	2,681.7	5,577.9
7:30:00	-	-	-	-	-	11.3	304.5	772.6	1,780.3	3,493.5
8:00:00	-	-	-	-	-	7.4	173.5	495.3	1,101.6	2,049.6
8:30:00	-	-	-	-	-	8.5	127.4	374.6	825.1	1,506.4
9:00:00	-	-	-	-	-	4.3	112.2	307.3	630.8	1,118.2
9:30:00	-	-	-	-	-	1.5	128.1	340.4	710.4	1,262.8
10:00:00	-	-	-	-	-	1.0	123.2	305.3	630.9	1,168.2
10:30:00	-	-	-	-	-	1.0	119.4	289.8	575.6	1,055.8
11:00:00	-	-	-	-	-	1.5	140.0	276.9	523.8	962.8
11:30:00	-	-	-	-	-	1.8	148.6	288.6	555.5	1,037.8
12:00:00	-	-	-	-	-	3.0	156.6	291.0	558.5	1,018.4
12:30:00	-	-	-	-	-	5.4	170.7	311.7	603.1	1,056.8
13:00:00	-	-	-	-	-	9.9	215.3	376.8	704.2	1,204.1
13:30:00	-	-	-	-	-	17.2	248.4	448.3	826.9	1,405.8
14:00:00	-	-	-	-	-	25.9	298.5	569.3	1,017.6	1,661.5
14:30:00	-	-	-	-	-	24.0	306.6	603.1	1,009.4	1,660.3
15:00:00	-	-	-	-	-	30.7	423.5	909.5	1,488.9	2,469.4
15:30:00	-	0.0	-	-	-	43.6	621.1	1,285.7	2,122.3	3,621.7
16:00:00	0.0	0.1	-	-	-	81.3	996.1	1,976.8	3,367.3	5,589.2
16:30:00	-	-	-	-	-	120.0	1,294.1	2,575.7	4,318.0	6,437.4
17:00:00	0.2	0.1	-	0.0	0.1	221.2	1,845.8	3,630.5	5,964.7	8,769.3
17:30:00	1.2	0.3	-	0.2	1.0	398.2	2,873.1	5,249.2	8,281.5	11,685.8
18:00:00	3.1	0.8	0.1	0.7	4.1	699.9	4,365.5	7,577.1	11,742.7	16,212.7

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
18:30:00	4.8	1.3	0.2	1.6	7.4	981.3	5,534.8	9,471.2	14,608.4	19,976.3
19:00:00	4.6	1.3	0.2	1.6	9.7	1,131.8	6,260.9	10,751.8	16,384.3	22,495.4
19:30:00	3.6	0.9	0.2	1.4	9.9	1,247.7	6,773.9	11,656.5	17,695.0	24,275.6
20:00:00	2.7	0.6	0.1	1.1	7.6	1,321.6	6,929.2	11,524.9	17,790.5	24,478.1
20:30:00	1.6	1.4	0.3	0.5	5.0	1,228.3	6,470.2	10,792.9	16,718.7	23,168.3
21:00:00	0.5	0.9	0.1	1.2	10.6	1,231.1	6,467.0	10,671.3	16,548.2	23,055.7
21:30:00	0.2	0.4	0.2	1.3	9.5	1,261.5	6,943.2	11,909.7	19,239.3	28,711.6
22:00:00	0.1	0.1	0.2	0.7	6.1	1,004.9	6,065.0	10,652.6	17,649.1	26,646.7
22:30:00	0.0	0.0	0.1	0.3	3.0	695.8	4,937.0	9,041.1	15,617.6	24,093.4
23:00:00	-	-	-	0.1	0.7	449.2	3,876.5	7,563.8	13,880.3	22,161.4
23:30:00	-	-	-	0.0	0.1	261.3	2,926.5	6,146.6	12,198.1	20,414.6

Source: EY.

Table 13 EUE (MWh) by Trading Interval and Capacity Year for winter season

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
0:00:00	-	-	-	-	0.0	13.8	3434.6	7301.7	16229.9	25402.9
0:30:00	-	-	-	-	-	5.3	2421.9	5614.1	13565.4	22105.6
1:00:00	-	-	-	-	-	2.6	1834.1	4530.1	11722.5	19751.8
1:30:00	-	-	-	-	-	1.4	1431.4	3742.5	10279.1	17868.7
2:00:00	-	-	-	-	-	0.8	1209.3	3267.5	9352.8	16603.6
2:30:00	-	-	-	-	-	0.6	1035.9	2884.6	8561.1	15496.6
3:00:00	-	-	-	-	-	0.5	965.6	2729.8	8232.0	14972.1
3:30:00	-	-	-	-	-	0.5	926.7	2627.0	7992.1	14566.3
4:00:00	-	-	-	-	-	0.5	1041.1	2824.0	8328.1	14978.0
4:30:00	-	-	-	-	-	0.9	1290.1	3276.6	9148.6	16063.5
5:00:00	-	-	-	-	-	4.0	2247.1	4941.5	12080.8	19852.5
5:30:00	-	-	-	-	-	17.3	3825.8	7451.2	16127.8	24906.6
6:00:00	-	-	-	-	0.1	79.7	7162.7	12437.7	23431.4	33672.5
6:30:00	-	-	-	-	0.5	194.6	10596.7	17196.0	29644.6	40688.1
7:00:00	-	-	-	-	1.1	362.6	13066.6	20412.4	33118.6	44079.9
7:30:00	-	-	-	-	0.8	350.0	10700.2	16685.9	27250.5	36456.7
8:00:00	-	-	-	-	0.5	167.3	5675.3	9300.2	16356.3	22781.6
8:30:00	-	-	-	-	0.2	58.8	2557.1	4615.6	8995.3	13150.9
9:00:00	-	-	-	-	0.1	19.4	1057.8	2054.3	4360.6	6660.0
9:30:00	-	-	-	-	-	4.0	691.0	1340.7	2882.9	4309.4
10:00:00	-	-	-	-	-	2.6	568.1	1128.9	2628.8	4296.8

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
10:30:00	-	-	-	-	-	1.2	407.7	814.7	1932.8	3239.0
11:00:00	-	-	-	-	-	2.0	360.0	714.1	1652.9	2740.7
11:30:00	-	-	-	-	-	1.9	318.6	643.4	1544.4	2580.4
12:00:00	-	-	-	-	-	1.9	300.2	601.3	1495.2	2511.7
12:30:00	-	-	-	-	-	2.5	331.1	668.3	1554.1	2541.2
13:00:00	-	-	-	-	-	2.9	342.1	717.2	1630.0	2607.2
13:30:00	-	-	-	-	0.0	2.8	362.6	760.7	1726.7	2785.6
14:00:00	-	-	-	-	0.0	4.2	429.0	956.6	2180.2	3473.4
14:30:00	-	-	-	-	0.0	5.1	500.1	1089.1	2419.2	3681.5
15:00:00	-	-	-	-	0.1	6.4	507.8	1175.0	2743.2	4474.5
15:30:00	-	-	-	-	0.1	11.9	908.1	2058.8	4605.1	7419.5
16:00:00	-	-	-	-	0.2	24.5	1758.2	3868.7	8351.5	12921.2
16:30:00	-	-	-	-	0.3	46.0	2712.2	5532.2	10883.9	16384.2
17:00:00	-	-	-	-	0.4	116.4	4846.8	8991.5	16204.7	23192.4
17:30:00	0.0	-	-	-	0.9	331.4	9078.7	14778.0	24655.1	34098.5
18:00:00	0.0	-	-	0.0	2.0	562.9	12826.2	19409.8	30991.9	42063.8
18:30:00	-	-	-	-	2.1	662.3	14955.4	22020.0	34428.7	46130.2
19:00:00	-	-	-	-	1.6	783.2	16071.3	23509.7	36262.4	47867.6
19:30:00	-	-	-	-	1.8	843.6	16693.0	24418.5	37123.0	48796.2
20:00:00	-	-	-	-	2.1	887.7	16492.0	24013.9	36189.9	47575.0
20:30:00	-	-	-	-	1.8	790.0	15331.9	22428.9	33870.2	45121.7
21:00:00	-	-	-	-	2.1	977.9	16503.3	24175.3	36443.9	48737.5
21:30:00	-	-	-	-	1.6	929.5	16370.4	24699.4	39530.9	52838.6
22:00:00	-	-	-	-	0.8	585.8	13046.3	20398.3	33812.8	46216.8
22:30:00	-	-	-	-	0.3	299.8	9811.6	16194.9	28278.5	39878.9
23:00:00	-	-	-	-	0.2	111.0	7123.0	12726.9	23827.0	34780.3
23:30:00	-	-	-	-	0.0	36.8	5005.9	9816.2	19965.6	30120.2

Source: EY.

Table 14 EUE (MWh) by Trading Interval and Capacity Year for shoulder season

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
0:00:00	-	-	-	-	-	3.3	2,837.50	5,089.20	12,807.40	27,088.60
0:30:00	-	-	-	-	-	2	2,381.80	4,370.30	11,578.90	25,311.10
1:00:00	-	-	-	-	-	1.5	2,133.10	3,967.60	10,820.30	24,050.70
1:30:00	-	-	-	-	-	1	1,912.30	3,624.30	10,105.20	22,838.00
2:00:00	-	-	-	-	-	0.9	1,789.50	3,445.60	9,720.70	22,188.10

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
2:30:00	-	-	-	-	-	0.6	1,652.50	3,254.60	9,295.80	21,492.00
3:00:00	-	-	-	-	-	0.5	1,596.10	3,215.00	9,167.70	21,297.80
3:30:00	-	-	-	-	-	0.3	1,528.10	3,162.60	8,961.90	20,959.60
4:00:00	-	-	-	-	-	0.4	1,621.80	3,378.20	9,404.80	21,707.20
4:30:00	-	-	-	-	-	0.7	1,779.60	3,703.50	10,038.10	22,857.30
5:00:00	-	-	-	-	-	2	2,499.10	4,754.20	12,217.20	26,637.40
5:30:00	-	-	-	-	-	4.9	3,456.60	5,833.50	14,223.40	29,085.50
6:00:00	-	-	-	-	-	12.8	5,134.00	7,636.50	17,361.70	32,121.30
6:30:00	-	-	-	-	-	16.5	5,483.20	7,577.20	16,701.60	29,713.00
7:00:00	-	-	-	-	-	17	4,641.50	6,169.10	12,975.70	22,920.70
7:30:00	-	-	-	-	-	13.5	2,961.10	3,963.20	8,132.00	14,764.90
8:00:00	-	-	-	-	-	6.5	1,449.20	1,913.70	3,999.70	7,723.10
8:30:00	-	-	-	-	-	3.9	801.6	1,027.90	2,178.00	4,415.60
9:00:00	-	-	-	-	-	1.2	440.2	545.1	1,169.70	2,513.90
9:30:00	-	-	-	-	-	0.8	339.8	362.9	850.4	1,841.40
10:00:00	-	-	-	-	-	0.7	343.8	359.3	906.8	1,947.90
10:30:00	-	-	-	-	-	0.8	274.3	290.8	721.9	1,554.20
11:00:00	-	-	-	-	-	1	247.8	268.5	705.7	1,442.10
11:30:00	-	-	-	-	-	0.9	242	247.8	693.4	1,387.40
12:00:00	-	-	-	-	-	0.6	213.3	202.7	623.9	1,264.70
12:30:00	-	-	-	-	-	0.6	227.4	190.1	638.2	1,272.60
13:00:00	-	-	-	-	-	0.9	273.1	224	723.7	1,344.70
13:30:00	-	-	-	-	-	1.3	345.1	287.1	847.1	1,530.80
14:00:00	-	-	-	-	-	1.4	410.4	331.8	1,069.10	1,958.70
14:30:00	-	-	-	-	-	1.9	514.9	406	1,258.90	2,157.50
15:00:00	-	-	-	-	-	2.2	567.5	465.2	1,389.30	2,501.40
15:30:00	-	-	-	-	-	3.5	799.4	743.5	1,952.20	3,641.10
16:00:00	-	-	-	-	-	5.9	1,194.20	1,249.80	2,940.50	5,602.50
16:30:00	-	-	-	-	-	8.4	1,451.70	1,582.80	3,461.30	6,163.70
17:00:00	-	-	-	-	-	11.8	2,069.70	2,251.50	4,710.00	8,385.50
17:30:00	-	-	-	-	-	17.5	2,996.30	3,504.80	7,101.80	12,337.80
18:00:00	-	-	-	-	-	25	3,979.80	4,769.90	9,616.20	16,357.50
18:30:00	-	-	-	-	0.1	33	4,736.10	5,756.40	11,493.10	19,567.00
19:00:00	-	-	-	-	0.1	33.9	5,156.30	6,336.40	12,635.80	21,424.80
19:30:00	-	-	-	-	0.3	34.7	5,416.40	6,972.80	13,599.20	22,985.60
20:00:00	-	-	-	-	0.3	44.9	5,416.80	7,190.60	13,847.50	23,605.00
20:30:00	-	-	-	-	0.2	37.7	5,258.90	6,869.30	13,569.40	23,305.60

Trading Interval/ Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
21:00:00	-	-	-	-	0.2	35.7	5,811.80	7,789.30	15,747.60	27,037.40
21:30:00	-	-	-	-	0.1	36.9	6,220.40	9,024.50	18,921.50	34,434.00
22:00:00	-	-	-	-	0	27.1	5,500.00	8,193.50	17,501.60	32,378.70
22:30:00	-	-	-	-	-	14.5	4,622.90	7,128.80	15,810.40	29,986.90
23:00:00	-	-	-	-	-	9.4	3,965.10	6,436.70	14,811.70	29,074.80
23:30:00	-	-	-	-	-	5.9	3,354.90	5,791.90	13,980.30	28,402.80

Source: EY.

A2.4.4 EUE events of interest

This section provides more detailed analysis for each of the three distinct periods (2024-25 to 2027-28, 2028-29, and 2029-30 to 2033-34) over the Long Term PASA Study Horizon identified in Chapter 4 of the 2024 WEM ESOO, under Section 4.5.1.

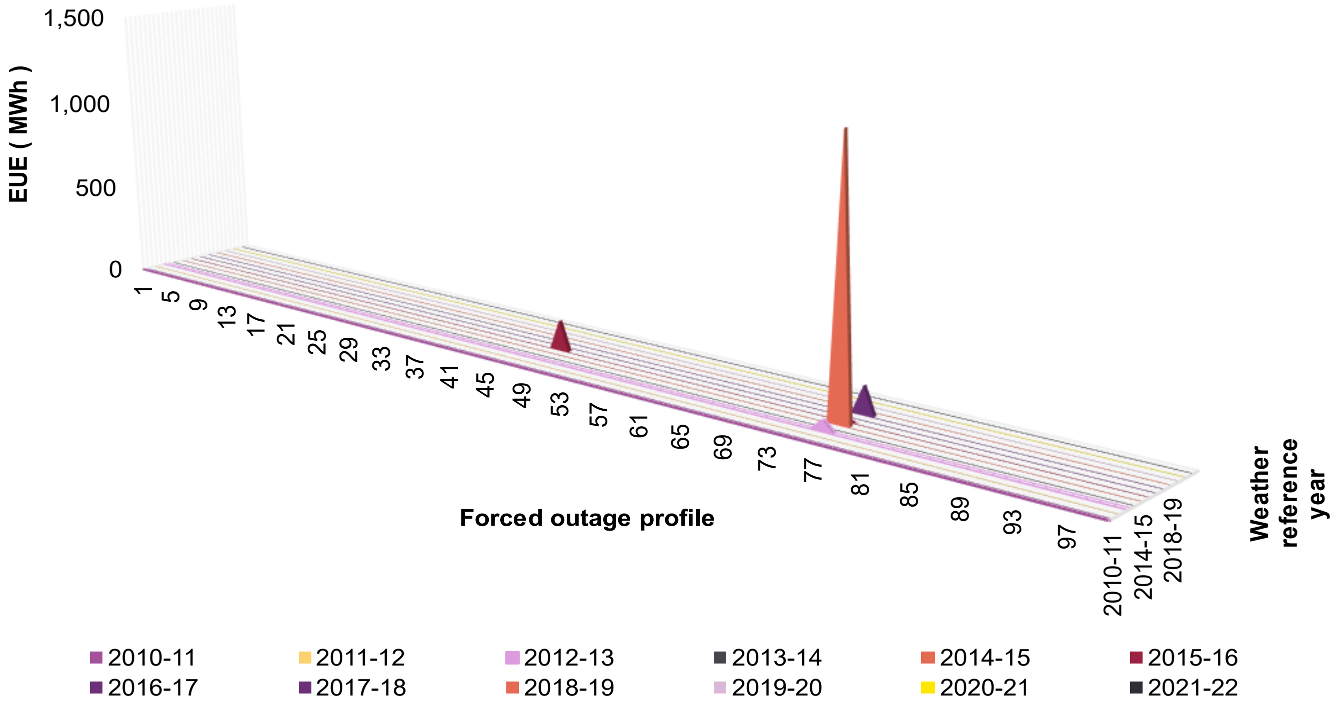
2024-25 to 2027-28

During this period, EUE is within the reliability standard on average across the 1,200 iterations of each Capacity Year modelled. To stay within the reliability standard, EUE needs to be less than around 37 MWh (0.0002% of the forecast operational consumption) for these years. The majority of the simulations show no EUE, or EUE of less than 0.0002%. A small number of simulations show EUE due to a particular combination of weather and outage patterns.

As an example, for 2026-27 (shown in **Figure 17**), the average EUE among all 1,200 simulations is well below the reliability standard (1.5 MWh, or 0.00001% of forecast annual energy consumption). There are only five EUE events[35] out of the 1,200 iterations modelled. The highest EUE among all 1,200 simulations is 1,400 or 0.008%, which corresponds to iteration 76 and 2014-15 weather reference year.

[35] Note that here an EUE event is defined as unique EUE intervals of one half-hour interval or more (i.e., an event beginning at 4.30pm and ending at 6.30pm is one event, EUE starting at 7pm (following a gap of one interval) would be a second and separate event).

Figure 17 Forecast EUE by iteration and historical for weather reference year 2026-27 (MWh)

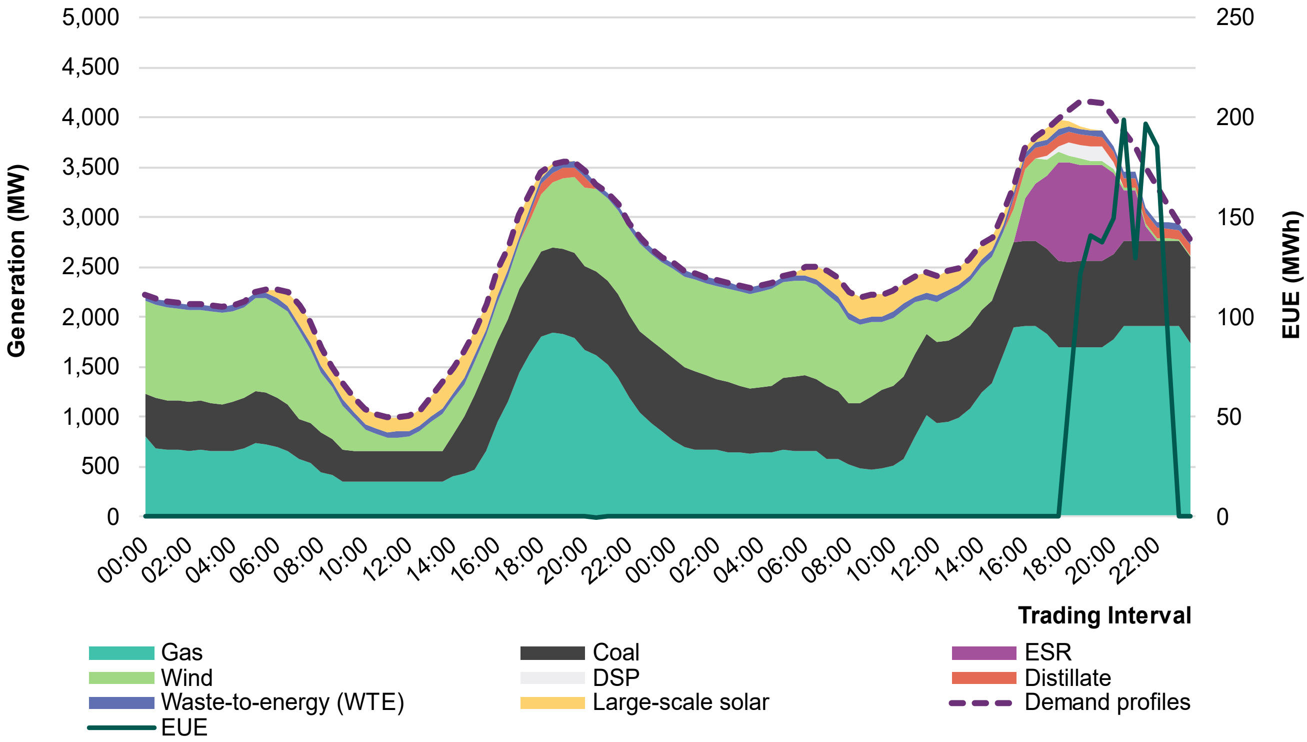


Source: EY.

Taking the highest EUE event for 2026-27 (a Business Day in February 2027, iteration 76, weather reference year 2014-15) and analysing the combination of drivers that result in this specific iteration and weather reference year (see **Figure 18** for a two-day generation and demand profile and **Figure 19** for a supply snapshot at time of EUE is at its maximum):

- The EUE event covers Trading Intervals from 18:00 to 22:30 (5 hours), with the maximum almost 200 MWh at the 20:30 Trading Interval. This Trading Interval is outside of solar hours such that over 3,600 MW of DPV is not available. In addition, this Trading Interval is not within the DSP obligation time period (8am to 8pm).
- Iteration 76 has a significantly higher forced outage at the time than on average across all other iterations (more than 1,400 MW unavailable for gas, coal, and ESR due to forced outage).
- The reference year 2014-15 has a significant drop in wind availability starting from around eight hours prior to the EUE event, resulting in minimal contribution from wind generation (see **Figure 20**).

Figure 18 Supply generation (MW), demand profiles (MW), and EUE (MWh) for a two-day period capturing an EUE event (a Business Day in Feb 2027, iteration 76, reference year 2014-15)



Source: EY.

Figure 19 Snapshot of supply availability at 20:30 Trading Interval during an EUE event (a Business Day in Feb 2027, iteration 76, reference year 2014-15 (MW))

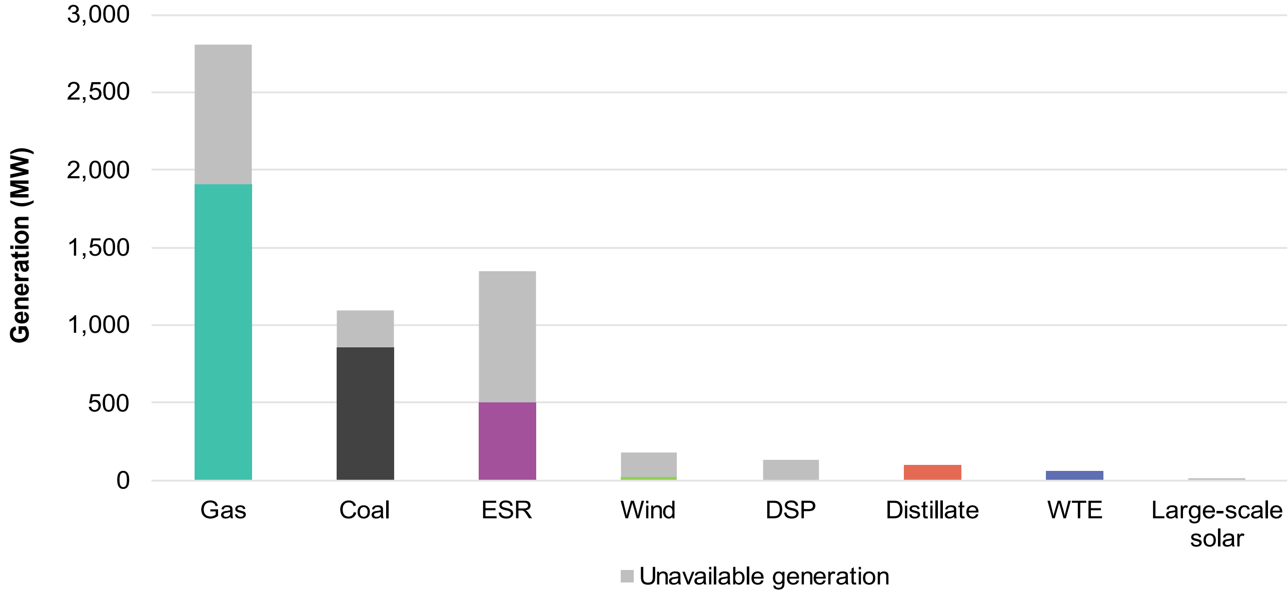
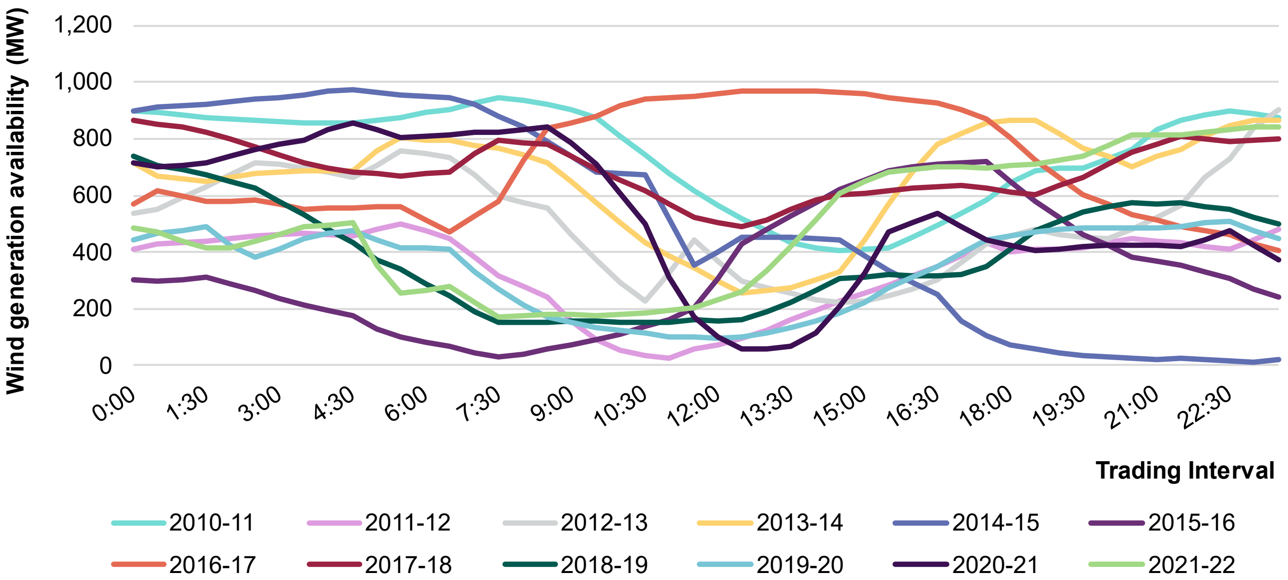


Figure 20 Supply wind availability profile during an EUE event, business day in Feb 2027, reference year 2014-15 (MW)

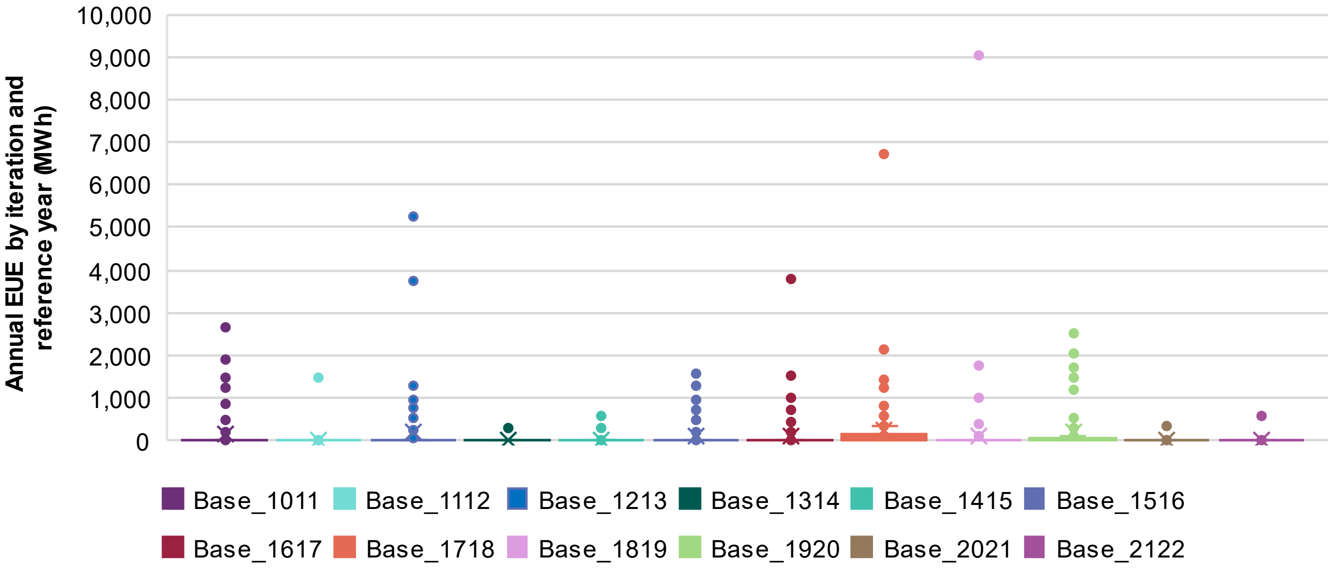


Source: EY.

2028-29

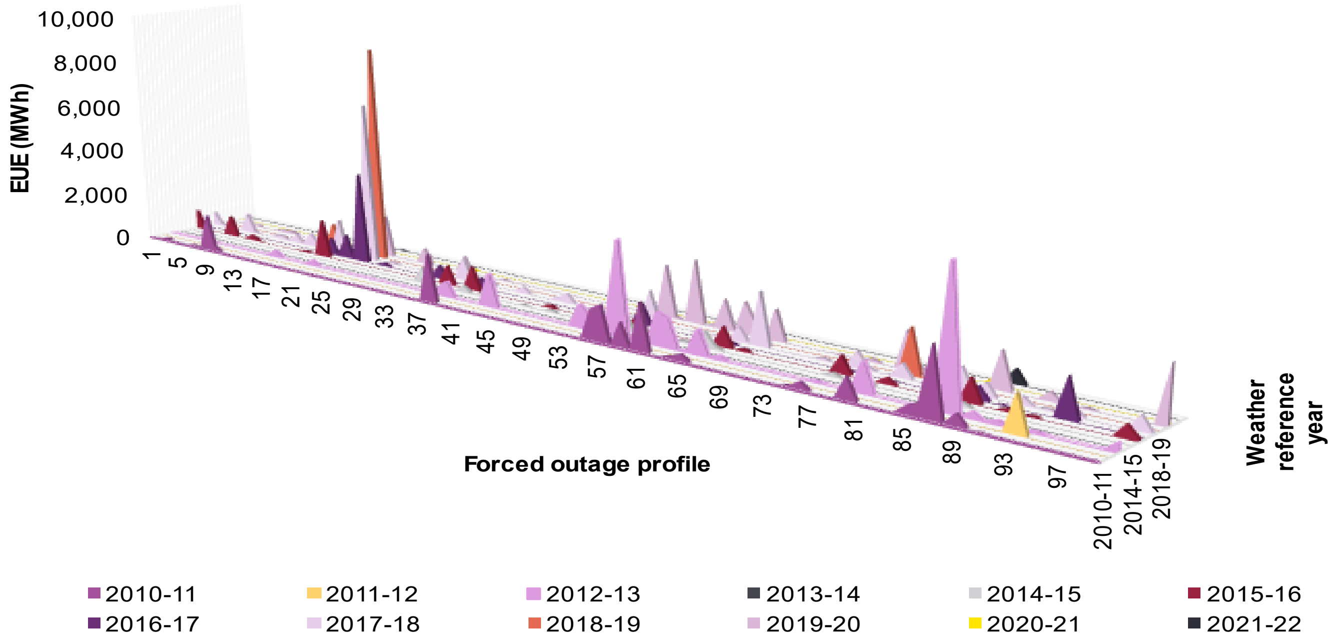
In 2028-29, EUE increases above the reliability standard, however not to the extent seen in later years. At this point, Muja D and Bluewaters coal powered stations are still participating in the WEM, and operational consumption has not yet increased significantly. EUE outcomes are shown for this Capacity Year to demonstrate how EUE outcomes can vary around an average that is very close to the reliability standard (see **Figure 21** and **Figure 22**). Although the majority of iterations (around 1,000 of 1,200) have no EUE over the year, around 160 iterations experience EUE above the reliability standard (annual EUE over around 38 MWh would breach the 0.0002% standard given forecast operational consumption for 2028-29).

Figure 21 Box and whisker plot of annual EUE by iteration and weather reference year for Capacity Year 2028-29 (MWh)



Source: EY.

Figure 22 Forecast EUE by iteration and historical weather reference year for 2028-29 (MWh)

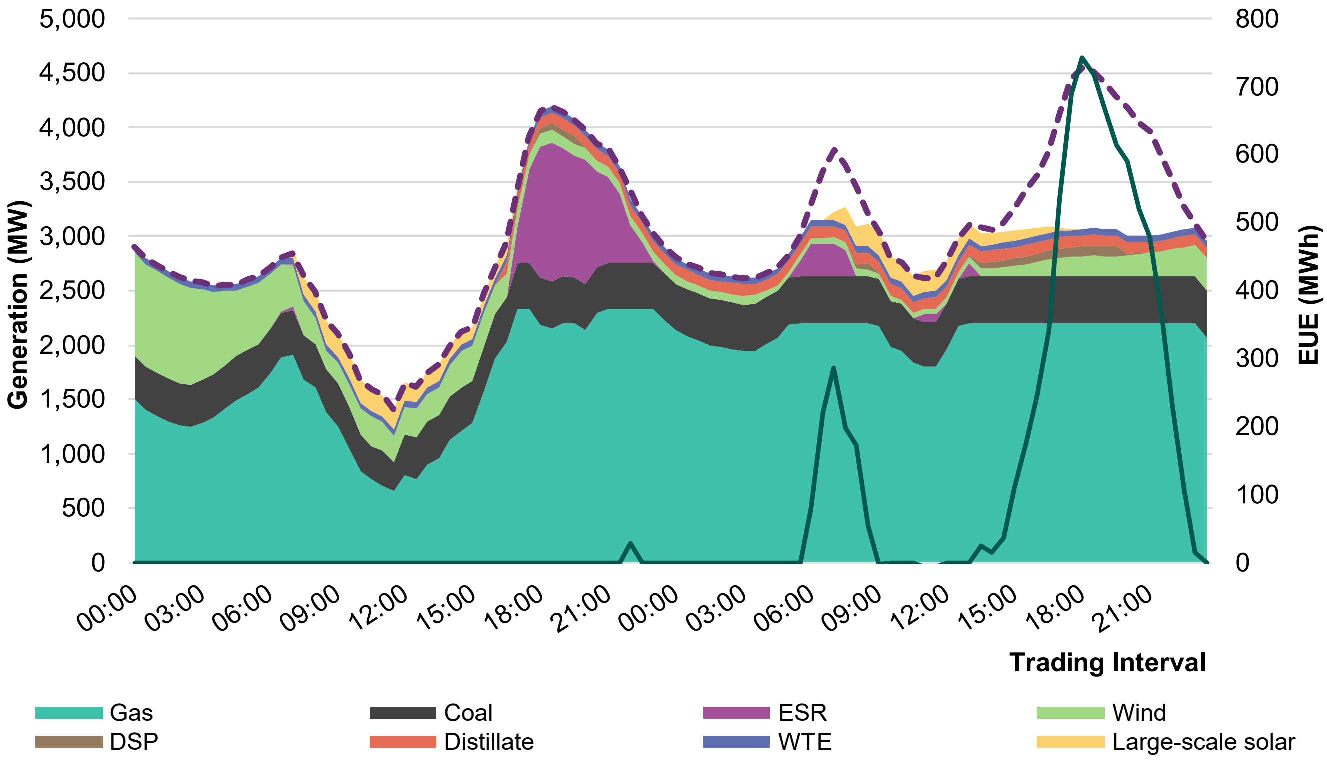


Source: EY.

Taking the highest EUE event for 2028-29 (a Business Day in August 2029, iteration 23, weather reference year 2018-19), examining the conditions at the time (see **Figure 23** for a two-day generation and demand profile and **Figure 24** for a supply snapshot at time of EUE is at its maximum):

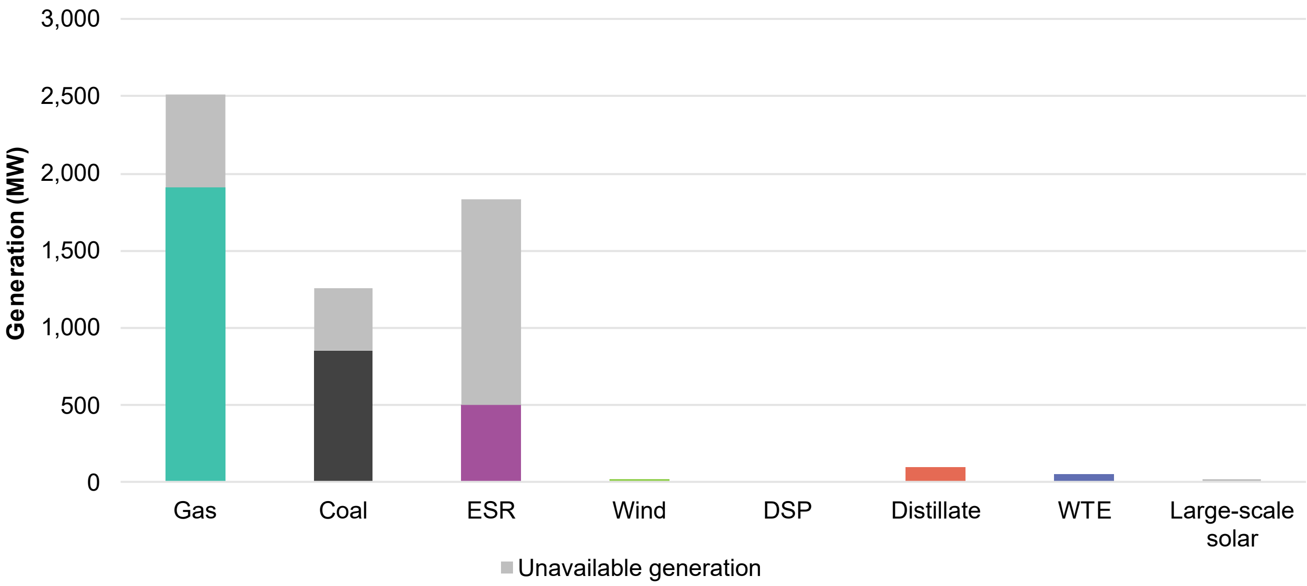
- The EUE event covers 13:30 to 23:00 Trading Intervals (10 hours), with the maximum reaching more than 700 MWh at 18:00 Trading Interval. An EUE event peaking at almost 300 MWh is also shown on that morning in Trading Intervals 06:00 to 08:30 (3 hours).
- Iteration 23 has relatively higher forced outages at the time than all other iterations (more than 1,000 MW unavailable for gas and coal due to forced outage).
- The profile from this weather reference year has a relatively lower solar availability on the date of the EUE event. This leads to a higher operational demand throughout the entire day than in other reference years as more than ~500 MW of DPV is unavailable during the time of peak solar irradiance.
- During the evening and overnight period preceding this day, wind output is also notably lower.
- The combination of lower wind output, low DPV output, and high forced outage of non-intermittent generators leads to the first EUE event in the morning. ESR reservoirs are consequently completely depleted. By the time of the evening peak of operational demand, there is significant lack of supply from a range of technology types, including the top contributors at times of peak operational demand.

Figure 23 Supply generation (MW), demand profiles (MW), and EUE (MWh) for a two-day period capturing an EUE event (a business day in Aug 2029, iteration 23, reference year 2018-19)



Source: EY.

Figure 24 Snapshot of supply availability at 18:00 Trading Interval during an EUE event (a business day in Aug 2029, iteration 23, reference year 2018-19)

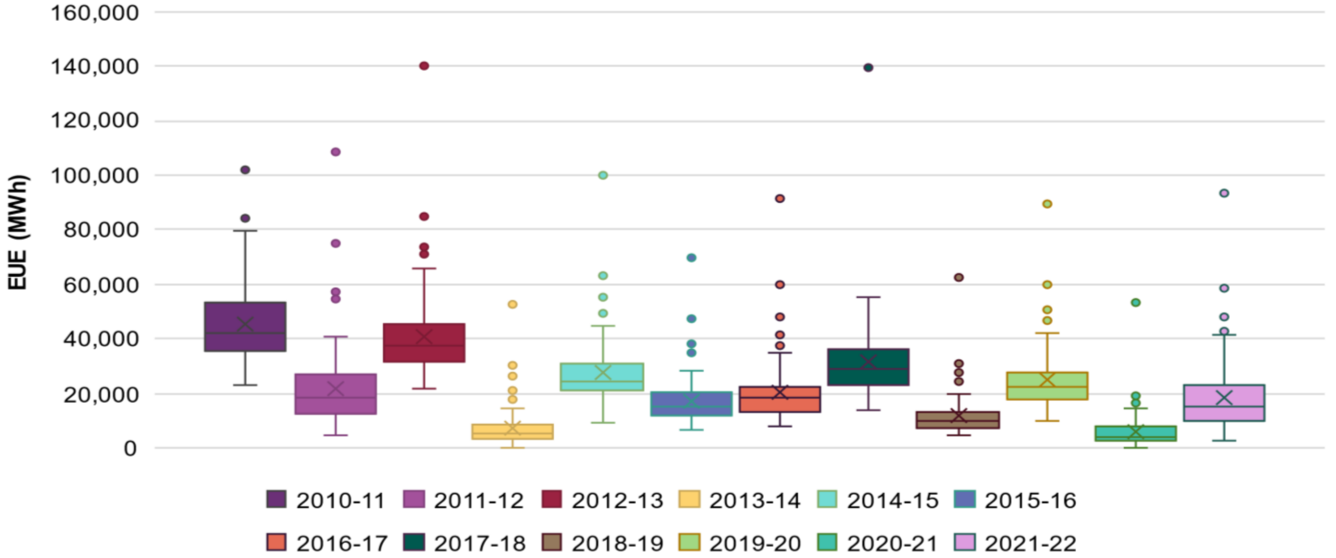


2029-30 to 2033-34

Starting from 2029-30, with the retirement of the last state-owned coal generator in 2029, the assumed exit of Bluewaters coal-powered station in 2030, and the sharp increase in operational consumption, EUE levels rise significantly, as discussed in Section 4.5.1 of the WEM ESOO report For 2029-30 to 2033-34, outage patterns, time of year and time of day are not deciding factors in whether EUE will occur or not. EUE is observed across all iterations, weather reference years, time of day and month. Times of higher demand, low renewable output, or combinations of large units being on outage at the same time will still drive higher levels of EUE relative to other times. However, due to a general shortfall in supply relative to demand, EUE is above the standard in all 1,200 cases.

For 2029-30, **Figure 25** shows how EUE varies across weather reference years and iterations, and the extent of potential outliers. Across all reference years and iterations, the annual average EUE is 22,800 MWh, or around 0.1% of forecast annual energy consumption. However, taking the historical weather reference year 201213 as an example, it can be seen that the maximum value (excluding outliers) is 66,000 MWh (around three times the annual average across the full modelling sample), and the greatest outlier is 140,000 MWh, more than six times the annual average for 2029-30.

Figure 25 Box and whisker plot of annual EUE by iteration and weather reference year for 2029-30 (MWh)



Source: EY.

A2.5 Modelling of Availability Duration Gap Load Scenario and Availability Duration Gap

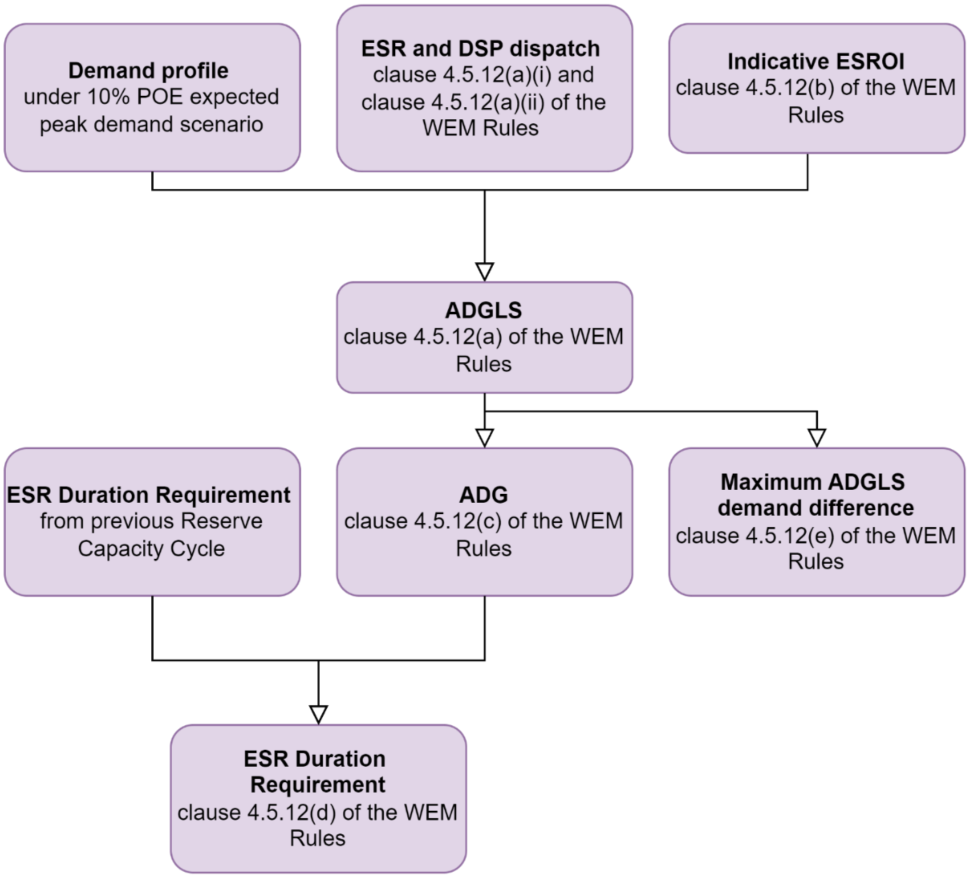
A2.5.1 Approach of the ADGLS, ADG and ESR determination

Clause 4.5.12 of the WEM Rules specifies requirements for determining ADGLS, ADG, and ESR Duration Requirement. **Figure 26** provides a conceptual diagram illustrating the relationships among these determination requirements for calculations with the following key steps:

- **ADGLS determination** – the ADGLS is a load scenario that represents the demand profile under 10% POE Expected peak demand scenario. It incorporates dispatch of ESRs during the Indicative Peak ESROI and the optimal dispatch of DSPs within their operational limitations to reduce the peak demand.
- **ADG calculation** – ADGLS is used to determine the ADG on a daily basis. For each historical weather reference year, ADG is taken as a maximum value observed over all days in the Capacity Year. The median of these maximum values is then calculated across the historical weather reference years and taken as the final ADG value.
- **ESR Duration Requirements** – the ESR Duration Requirement for the current Reserve Capacity Cycle is determined by adding the ADG to the ESR Duration Requirement from the previous Reserve Capacity Cycle.
- **Maximum ADGLS demand difference** – ADGLS is also used to determine Maximum ADGLS Demand Difference, which is the maximum value among all Trading Days in the ADGLS, calculated as the greater of zero and the maximum demand in a Trading Interval that is not an Indicative Peak ESROI in that Trading Day minus the maximum demand in a Trading Interval that is an Indicative Peak ESROI in that Trading Day.

For 2024 WEM ESOO, 12 ADGLS are determined, which correspond to the 10% POE Expected demand traces developed from the 12 historical weather reference years as part of the reliability assessment. This results in 12 sets of all the other determination requirements. The final value for each of these determination requirements is taken as the median of the 12 values.

Figure 26 Conceptual diagram of the ADGLS, ADG, ESR Duration Requirement, and other determination requirements



A2.5.2 Assumptions applied for 2026-27 determination

As per clause 4.5.12(a) of the WEM Rules, the ADGLS for 2026-27 must take into consideration the ESRs and DSPs with Capacity Credits for 2024-25 and 2025-26. The associated details are summarised in **Table 15**. The dispatch of ESRs is based on the Indicative ESROIs defined in Section 4.8 of the WEM ESOO report.

Table 15 ESRs and DSPs with the Capacity Credit for 2025-26 used to determine the ADG for 2026-27

Facility Name	Capacity credit 2025-26 (MW)	Dispatch limitation(s)
KWINANA_ESR1	44.2	
COLLIE_ESR1	200	
SBSOLAR1_CUNDERDIN_PV1	43.6	
PRDSO_WALPOLE_HG1	1.5	
GRIFFINP_DSP_01	20	Maximum 50 hours per year
SYNERGY_DSP_04	33.1	Maximum 50 hours per year
PREMPWR_DSP_02	18.7	Maximum 50 hours per year

A2.5.3 Review of ADGLS approach

Observation of daily ADG values trends

Figure 27 presents the ADG for each Trading Day in the Capacity Year plotted against daily peak demand across the historical weather reference years. There are higher ADG values on Trading Days with low to moderate peak demand.

To illustrate the reason behind this observation, **Figure 28** shows a demand profile for a low to moderate demand day in 2026-27. The demand profile does not have any prominent maximums during the Indicative ESROI and remains relatively flat until around 20:00. This results in a higher number of intervals adjacent to the Indicative Peak ESROI where the demand surpasses the maximum demand in any of the Indicative Peak ESROIs for that Trading Day (ADG of 15 Trading Intervals as shown in this illustration). Notably on such days, the overall demand is significantly lower than the 10% POE value for the capacity year, which would typically result in a surplus of available capacity, leading to lower reliance on ESR to meet peak demand.

To address this issue, an ADG value for Trading Days with daily peak demand equal or above the 90th percentile of the peak demand for the Capacity Year may be more reflective of system needs at peak.

Figure 27 Daily ADG and the daily peak demand (MW) for each Trading Day in 2026-27 for 12 weather reference years determined using the current ADGLS methodology defined in the WEM Rules

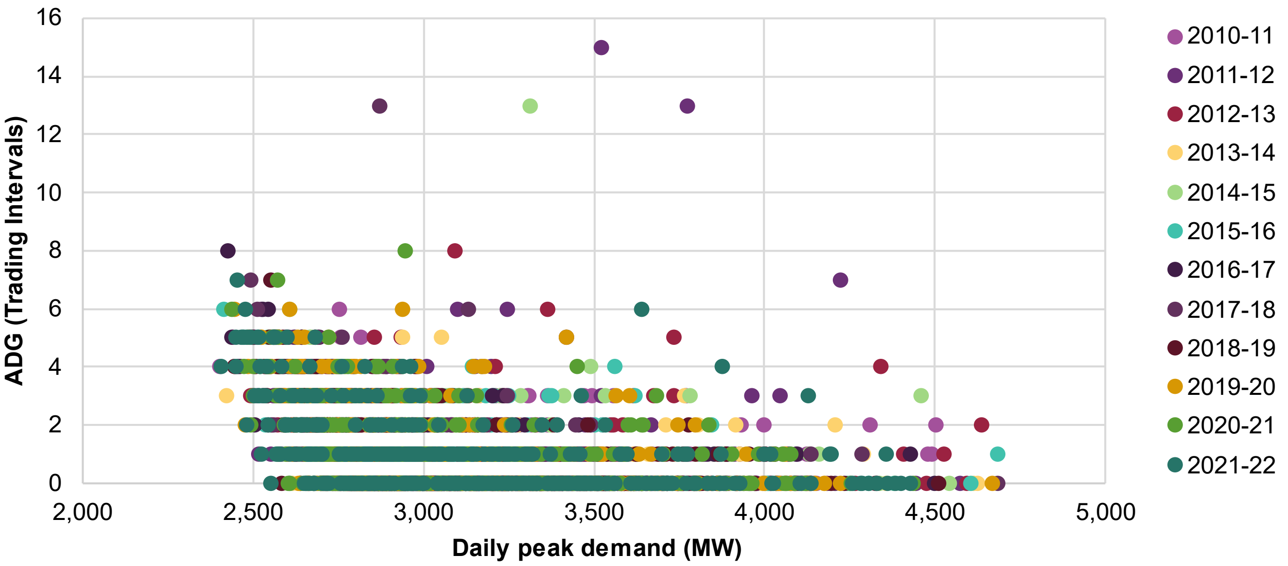
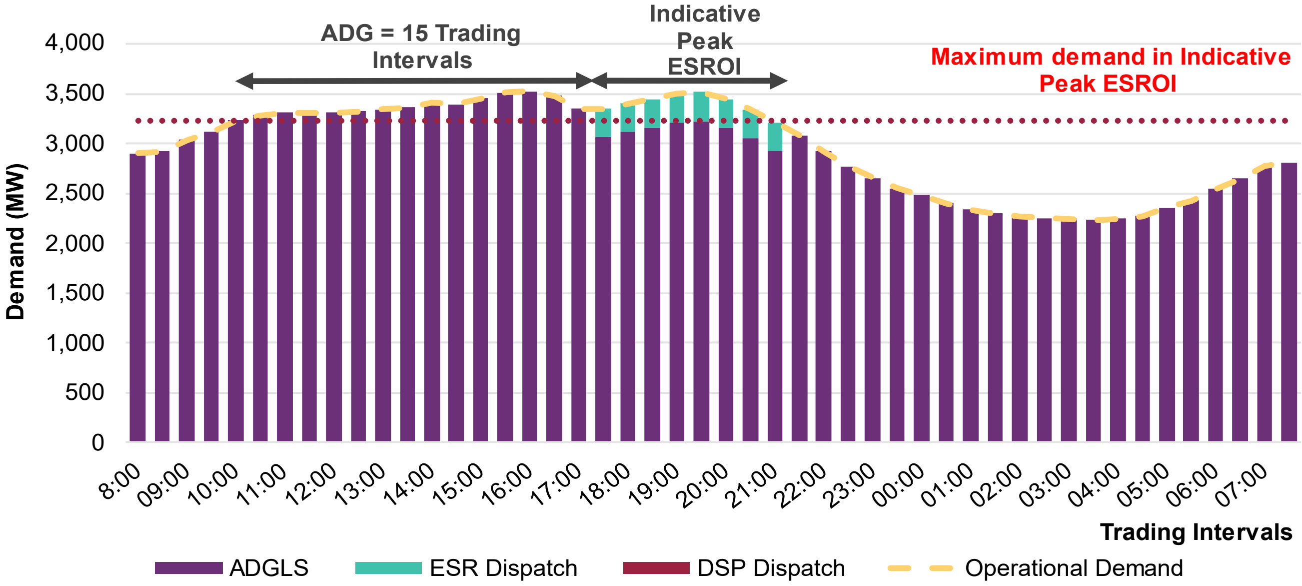


Figure 28 Illustration of ADGLS profile on a typical low to moderate demand day for 2026-27 (MW)



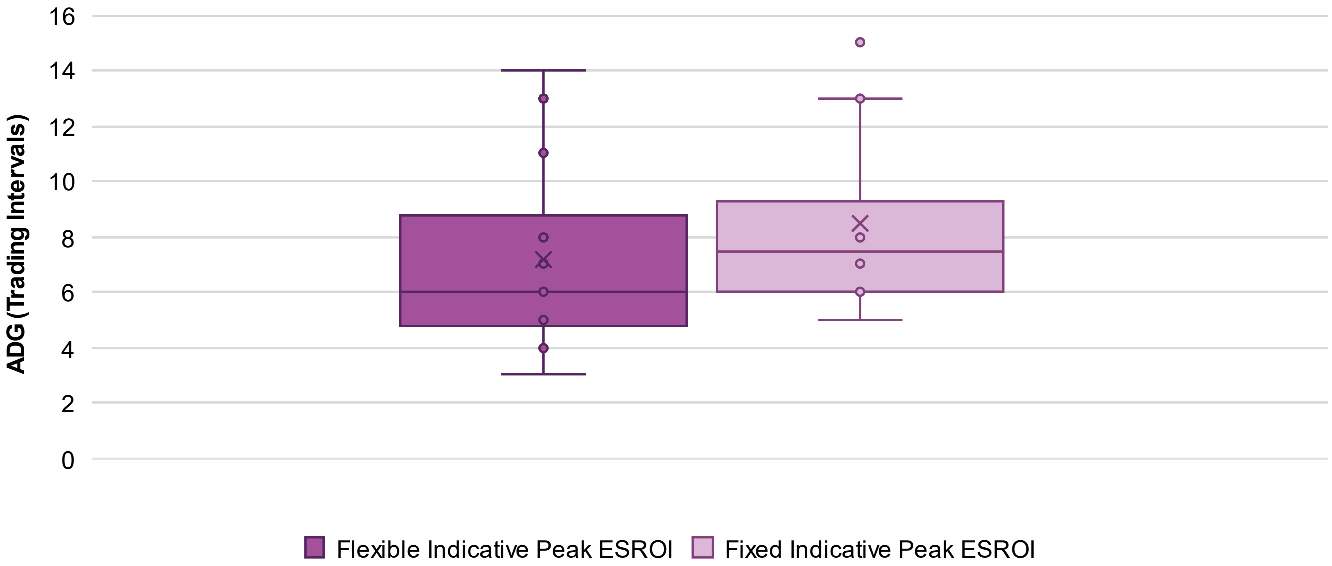
Impact of fixed indicative peak ESROI

According to clause 4.5.12(a)(i) of the WEM Rules, ESRs are to be dispatched evenly across the Indicative Peak ESROI. As demonstrated in the determination for 2026-27 (see Section 4.8 of the WEM ESOO report), the Indicative Peak ESROI is determined in advance. This fixed schedule can result in higher daily ADG values on days with shifted evening peaks.

To address this, AEMO suggests that in the development of ADGLS, ESRs should be dispatched evenly over a set of contiguous Trading Intervals with a duration equivalent to the ESR Duration Requirement from the previous Reserve Capacity Cycle, which minimises the peak demand of each Trading Day. This approach aligns with AEMO's operational flexibility to adjust ESR dispatch prior to each Scheduling Day, optimising the use of ESRs in the SWIS as per Clause 6.3.1 of the WEM Rules.

Figure 29 compares the ADG values for fixed and flexible Indicative Peak ESROI across historical weather reference years. It is evident that implementing flexible ESROI generally reduces the ADG values compared to the fixed Indicative Peak ESROI.

Figure 29 Comparison of ADG values for Fixed and Flexible Indicative Peak ESROI across historical weather reference years



A2.5.4 ADG and ESR Duration Requirements derived using proposed ADGLS methodology

Figure 30 presents the ADG for Trading Days with daily peak demand equal or above the 90th percentile of the peak demand for 2026-27, plotted against daily peak demand after accounting for the flexible Indicative Peak ESROI dispatch intervals, across historical weather reference years. The result shows significant reduction of daily ADG values compared to those derived under the current WEM rules (refer to Section 4.8 of the WEM ESOO report).

Figure 30 ADG values and daily peak demand (MW) for 90th percentile Trading days with Flexible ESR dispatch Intervals across historical weather reference years

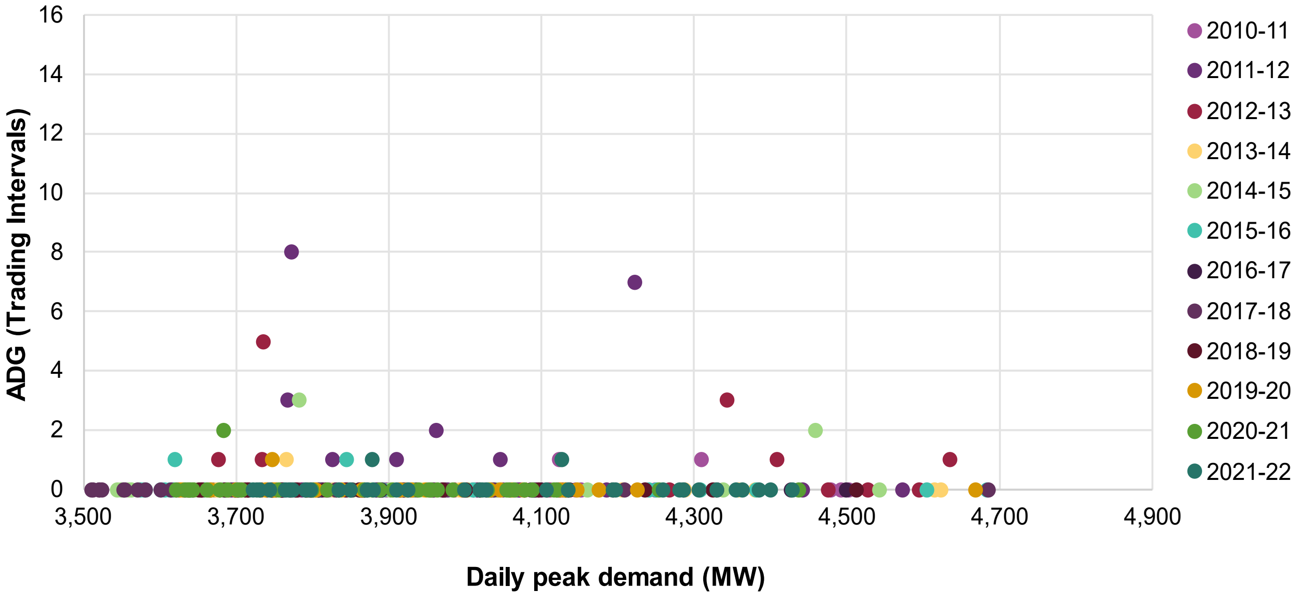
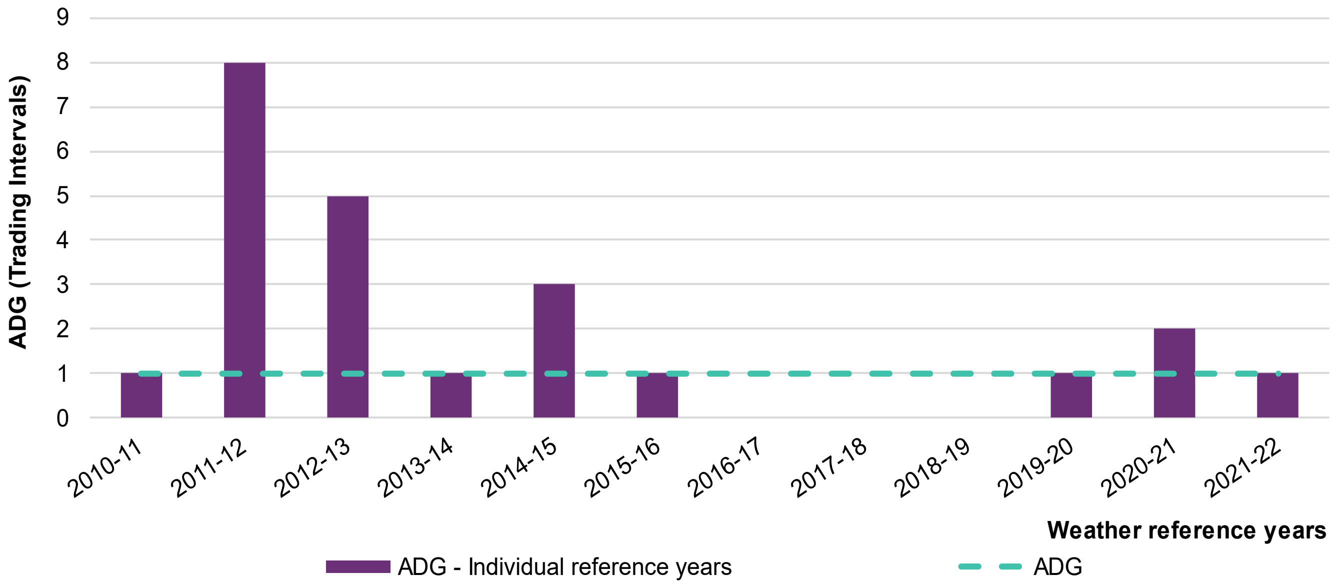


Figure 31 shows ADG values for historical weather reference years, incorporating the proposed changes for the 2026-27 determination. The results lead to a final ADG value of one Trading Interval, and consequently ESR duration requirement of nine Trading Intervals. Please note the results presented here are for information purposes only, as the proposed rule change may still be subject to change as a result of feedback from market consultation.

Figure 31 ADG values and ADG value for historical weather reference years, incorporating the proposed changes



A2.6 Modelling to determine minimum capacity requirements (Capability Classes)

As noted in Section 4.9 of the WEM ESOO report, the WEM Rules have amended the previous two Availability Classes to three Capability Classes. EY determined the minimum amount of capacity to be provided by Capability Class 1 and Capability Class 3 required for 2026-27 (the third year of the Long Term PASA Study Horizon) while limiting EUE to no more than 0.0002% of annual energy consumption, by using the following steps:

- Apply the ADGLS by incorporating into the reliability assessment model for the Capability Class modelling in accordance with clause 4.5.12(i) of the WEM Rules.
- Equalise the modelled capacity and associated AIC with the RCT for 2026-27. As the AIC is above the RCT in this year (5,742 MW compared to 5,696 MW, respectively) this requires reducing the AIC by 46 MW and re-running to review EUE outcomes.
- Adjust capacity depending on EUE outcomes. For the initial step in the modelling, 46 MW is removed from Collie power station (in line with the agreed approach to remove capacity in order of anticipated retirement dates). EUE outcomes are observed and if EUE <0.0002% then the modelling can proceed to iteratively add more capacity to Capability Class 2, while equally reducing capacity from Capability Class 1 and 3, and observing EUE outcomes until no more Class 2 can be added without breaching the reliability standard.

- Capability Class 2 includes both DSP and ESR technology types. Each of these have different energy supply characteristics, with ESR limited by its ability to charge and the size of its storage resource (for example, 2-hour, 4-hour) while in 2026-27 DSP is only required to provide a response for up to 50 hours in the year, between the hours of 8am and 8pm.
- Taking a conservative approach, it has been assumed that the technology type that reaches the EUE limitation first will set the capacity associated with Capability Class 2 and therefore the minimum capacity required for Capability Class 1 and Capability Class 3. The modelling confirms that DSP sets this limitation first, given its more restricted running hours than ESR.
- The total for Capability Class 2 is therefore the sum of the CRC for assumed capacity in the modelling for 2026-27 from existing and committed projects, plus the CRC associated with the additional DSP that could be added to the model before the reliability standard was breached. The outcomes are presented in Section 4.8 of the WEM ESOO Report.

A2.7 Development of Availability Curves

For the 2023 WEM ESOO, the Availability Curves were determined for 2025-26 and 2026-27 (the second and third Capacity Years in the Long Term PASA Study Horizon). Availability Curves were determined by:

- Summing the following two items for each interval of a Capacity Year:
  (a) The forecast demand for the 10% POE Expected demand scenario.
  (b) A constant margin applicable to all demand intervals in a Capacity Year being the difference between the RCT and the forecast peak demand for the 10% POE Expected demand scenario.

If RCT was set by limb A of the Planning Criterion, item (b) of the Availability Curve is equal to the sum of:

- The Intermittent Load allowance,
- The reserve margin and
- The Regulation Raise allowance.

However, if the RCT were to be set by limb B of the Planning Criterion, item (b) is derived as the difference between:

- The RCT (as set by limb B) and
- The forecast 10% POE Expected peak interval demand, that is, the annual maximum value of item (a).

Based on the above, for each of the 2025-26 and 2026-27 Capacity Years modelled, the Availability Curve was developed as follows:

- Ranked demand intervals for the 10% POE Expected scenario (average of reference years) in order of descending magnitude of demand.
- Increased each demand data point by adding a constant margin (item (b) above) being the difference between:
  - the value of the RCT, and
  - the value of the forecast 10% POE Expected peak demand.

A2.8 Supply-demand balance under Low and High scenarios

To forecast the capacity supply-demand balance over the 2024 Long Term PASA Study Horizon under the Low and High scenarios, AEMO has:

- Forecast the RCT for the Low and High scenarios by using the 10% POE peak demand forecasts, Intermittent Loads, Contingency component of the reserve margin and load following under the Expected scenario.
- Forecast capacity supply for the respective scenario.
- Compared these capacity supply models with the RCT.

Table 16 presents the forecast supply-demand balance over the outlook period for the Low scenario. The Low scenario includes the existing Facilities and the retirements outlined in Section 3.2.3 of the WEM ESOO report, and assumes no new Facilities (committed or probable) are brought online.

Table 16 Supply-demand balance for the Low scenario, 2024-25 to 2033-34[A]

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
RCT[B] (MW)	5,501	5,589	5,696	5,794	5,925	6,165	6,545	6,861	7,159	7,395
Capacity (MW)	4,467[C]	4,386[C]	4,267[D]	3,999	3,999	3,605	3,170	3,170	3,169	3,168
Capacity Credit shortfall (-) or surplus (+) (MW)	-1,034[E]	-1,203[E]	-1,429	-1,795	-1,926	-2,560	-3,375	-3,691	-3,991	-4,227
Capacity credit shortfall (-) or surplus (+)	-18.8%[F]	-21.5%[F]	-25.1%	-31.0%	-32.5%	-41.5%	-51.6%	-53.8%	-55.7%	-57.2%

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 2024-25 and 2025-26 are 4,526 and 5,543 MW, respectively.
C. The 2024-25 and 2025-26 available capacity values are the total quantities of Capacity Credits assigned for existing supply capacity.
D. The capacity values for 2026-27 and remaining years represent the forecast quantity of Reserve Capacity for existing supply capacity, as described in Chapter 3 of the WEM ESOO report.
E. Based on the RCRs for 2024-25 and 2025-26, the available capacity figures represent a capacity shortfall of 59 MW and 1,157 MW, respectively.
F. Based on the RCRs for 2024-25, the available capacity figures represent a capacity shortfall of 1.3% and 20.9%, respectively.

Table 17 presents the forecast supply-demand balance over the outlook period for the High scenario. The High scenario includes existing, committed and probable capacity (see Appendix A9) that may be brought online during the Long Term PASA Study Horizon. The retirements are outlined in Section 3.2.3 of the WEM ESOO report.

Table 17 Supply-demand balance for the High scenario, 2024-25 to 2033-34[A]

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
RCT[B] (MW)	5,501	5,589	5,696	5,794	5,925	6,165	6,545	6,861	7,159	7,395
Capacity (MW)	5,183 [C]	5,526[C]	6,256[D]	5,904	5,887	5,472	5,021	5,006	4,991	4,976
Capacity Credit shortfall (-) or surplus (+) (MW)	-317[E]	-63[E]	561	110	-37	-694	-1,524	-1,855	-2,169	-2,418
Capacity credit shortfall (-) or surplus (+)	-5.8%[F]	-1.1%[F]	9.8%	1.9%	-0.6%	-11.2%	-23.3%	-27.0%	-30.3%	-32.7%

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 2024-25 and 2025-26 are 4,526 and 5,543 MW, respectively.
C. The 2024-25 and 2025-26 available capacity values are the total quantities of Capacity Credits assigned for existing capacity plus the NCESS contract service capacity.
D. The capacity values for 2026-27 and remaining years represent the forecast quantity of Reserve Capacity under the High scenario, comprising of existing, committed and probable capacity as described in Chapter 3 of the WEM ESOO report.
E. Based on the RCRs for 2024-25 and 2025-26, the available capacity figures represent a capacity surplus of 657 MW and a capacity shortfall of 17 MW, respectively.
F. Based on the RCRs for 2024-25 and 2025-26, the available capacity figures represent a capacity surplus of 14.5% and a capacity shortfall of 0.3%, respectively.

A2.9 New project status evaluation

New projects that received Capacity Credits for 2025-26, or Facilities contracted for the 2024-26 Peak Demand NCESS, or contracted or expected to be contracted for 2025-27 Peak Demand NCESS, are considered as committed capacity and therefore not tested using the new project status evaluation. All other projects are assessed based on their project score in the new project status evaluation. The projects can be planned, in the approvals phase, or in the construction phase.

Three tests were used to rank the new projects:

1. **EPA approval** – for a project to proceed, the proponent needs to receive environmental approvals from WA's EPA. AEMO assigned following scoring:
   – 0% if the proponent has not yet applied for some or all the required approvals.
   – 50% if all applications have been submitted but are still pending approval.
   – 100% if all required approvals have been granted.
2. **Western Power connection approval** – connection status is obtained by AEMO directly from Western Power. AEMO allocated:
   – 0% for a facility that has not yet submitted an application.
   – 100% for a submitted application.
3. **FID by proponent** – a FID is taken by a proponent once all internal studies and planning has been completed, the environmental approvals are in place, and the commercial work (for example, fuel and sales agreements)

has been finalised. Projects can be at different stage when submitting an Expression of Interest (EOI). AEMO assigned following scoring based project finance status:

- 0% if proponent has not yet applied for financing.
- 25% if proponent has submitted a financing proposal.
- 50% if the financing proposal is approved.
- 100% if the facility has the financing contract executed.

These factors were then weighted using the weighting outlined in **Table 18** to give an overall percentage each new project.

The thresholds for classifying assessed projects are:

- Committed capacity: project score >= 80%.
- Probable capacity: project score >= 50%.
- Proposed capacity: project score < 50%.

Table 18 New project status evaluation methodology

Criteria	Weighting	Options	Score (%)
EPA	0.33	All granted	100
		All applied for	50
		Some or all not applied for	0
Western Power Access	0.33	Access proposal application been submitted to Western Power	100
		Not applied	0
FID	0.33	Contract executed	100
		Proposal approved	50
		Proposal submitted	25
		Not applied yet	0

A3. BESS losses modelling (grid-scale batteries)

The modelling carried out for the reliability assessment has also been used to estimate the losses from the impact of roundtrip efficiency losses from grid-scale batteries. This is a new component of the 2024 WEM ESOO and the first time these estimates have been presented in the ESOO. Losses are a function of the total storage capacity in the WEM, the roundtrip efficiency of each asset, and the operational profile.

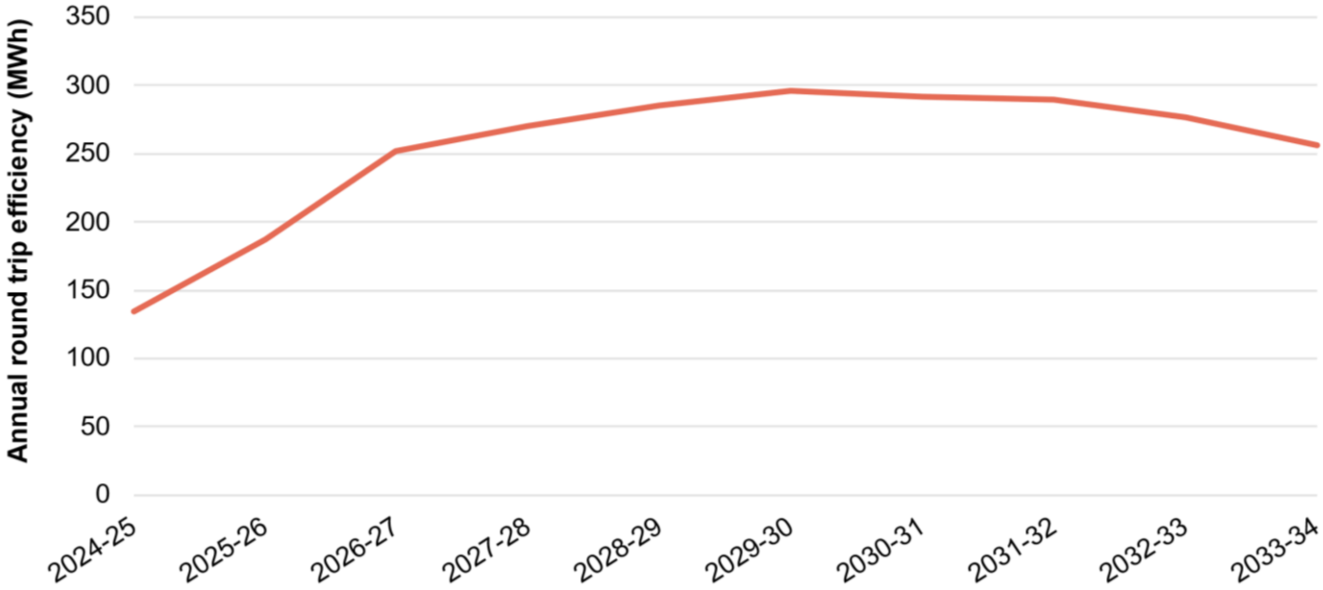
For the modelling of roundtrip efficiency losses for grid-scale batteries:

- Batteries were modelled with an assumed round trip efficiency of 85%.
- Batteries were operated to act on a commercial basis, aiming to maximise energy price arbitrage opportunities. Specific requirements on battery operation (for example, ESROIs) have not been applied in the modelling. The modelling has been carried out with the projected AIC and demand, which resulted in more balanced demand and supply outcomes in the early years and capacity shortfalls in later years of the Long Term PASA Study Horizon. While the maximisation of energy revenue arbitrage of the batteries forms the basis for their charge and discharge patterns, the results will also depend on whether sufficient supply enters the WEM (which may include more storage) for batteries to charge from.
- Generally, the operation of these batteries implies around one cycle of charging and discharging each day, with charging during solar hours, and discharging mostly over the evening peaks but occasionally also in the morning peaks.

Figure 32 shows the outcome of the battery loss modelling. The roundtrip efficiency losses amount to around 140 GWh in 2024-25, then increase steadily with the increase in both installed capacity of storage and utilisation of batteries. The decrease in the final years reflects the imbalance of supply and demand with the lack of new entrants combined with an increase in demand. With high levels of EUE, the opportunity for batteries to charge and discharge is limited by the lack alternative capacity for storage to charge from.

The impact of storage charging on minimum demand levels is covered in Section 2.4 of the WEM ESOO.

Figure 32 Annual impact of grid-scale battery losses, between 2024-25 and 2033-34 (MWh)



Source: EY.

A4. Operational consumption forecasts

Table 19 Operational consumption forecasts in the three demand growth scenarios (GWh)

Capacity Year	Low scenario	Expected scenario	High scenario
2023-24	17,214	17,800	18,506
2024-25	17,280	18,018	19,203
2025-26	17,458	18,082	19,858
2026-27	18,262	18,287	21,180
2027-28	18,188	18,530	24,026
2028-29	18,270	19,188	26,631
2029-30	18,822	20,800	32,238
2030-31	19,301	22,833	38,570
2031-32	20,740	24,465	43,090
2032-33	21,900	26,118	48,140
2033-34	22,085	27,868	55,839
Average growth	2.5%	4.6%	11.7%

A5. Summer peak demand forecasts

Table 20 Summer peak demand forecasts in the Low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	4,302	4,005	3,758
2024-25	4,345	4,067	3,793
2025-26	4,357	4,075	3,819
2026-27	4,528	4,254	4,002
2027-28	4,535	4,292	4,012
2028-29	4,553	4,303	4,026
2029-30	4,682	4,444	4,160
2030-31	4,771	4,525	4,248
2031-32	5,059	4,783	4,527
2032-33	5,313	5,075	4,793
2033-34	5,393	5,141	4,868
Average growth	2.3%	2.5%	2.6%

Table 21 Summer peak demand forecasts in the Expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	4,304	4,007	3,759
2024-25	4,388	4,108	3,835
2025-26	4,464	4,177	3,917
2026-27	4,555	4,278	4,010
2027-28	4,656	4,402	4,102
2028-29	4,772	4,504	4,211
2029-30	4,998	4,740	4,434
2030-31	5,361	5,090	4,794
2031-32	5,662	5,356	5,077
2032-33	5,889	5,621	5,315
2033-34	6,135	5,849	5,541
Average growth	3.6%	3.9%	4.0%

Table 22 Summer peak demand forecasts in the High demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	4,303	4,007	3,759
2024-25	4,449	4,169	3,897
2025-26	4,604	4,314	4,054
2026-27	4,783	4,496	4,223
2027-28	5,282	5,009	4,711
2028-29	5,453	5,172	4,871
2029-30	5,752	5,469	5,170
2030-31	6,340	6,028	5,738
2031-32	6,699	6,355	6,065
2032-33	6,869	6,559	6,252
2033-34	7,570	7,215	6,910
Average growth	5.8%	6.1%	6.3%

A6. Winter peak demand forecasts

Table 23 Winter peak demand forecasts in the Low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	3,808	3,696	3,590
2024-25	3,832	3,721	3,614
2025-26	3,996	3,875	3,777
2026-27	4,111	3,978	3,879
2027-28	4,156	4,027	3,921
2028-29	4,294	4,166	4,055
2029-30	4,398	4,271	4,156
2030-31	4,657	4,517	4,396
2031-32	4,993	4,841	4,717
2032-33	5,161	5,003	4,878
2033-34	5,228	5,070	4,942
Average growth	3.2%	3.2%	3.2%

Table 24 Winter peak demand forecasts in the Expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	3,812	3,700	3,595
2024-25	3,914	3,801	3,693
2025-26	4,011	3,890	3,790
2026-27	4,132	4,003	3,904
2027-28	4,279	4,148	4,037
2028-29	4,541	4,407	4,288
2029-30	4,910	4,766	4,640
2030-31	5,287	5,129	4,993
2031-32	5,609	5,440	5,300
2032-33	5,944	5,766	5,619
2033-34	6,163	5,975	5,826
Average growth	4.9%	4.9%	4.9%

Table 25 Winter peak demand forecasts in the High demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	3,811	3,699	3,594
2024-25	4,026	3,912	3,802
2025-26	4,201	4,076	3,973
2026-27	4,667	4,521	4,412
2027-28	5,110	4,954	4,831
2028-29	5,769	5,601	5,464
2029-30	6,467	6,278	6,122
2030-31	7,028	6,818	6,648
2031-32	7,407	7,177	6,998
2032-33	8,330	8,082	7,890
2033-34	8,762	8,495	8,294
Average growth	8.7%	8.7%	8.7%

A7. Seasonal minimum demand forecasts in the Expected scenario

Table 26 Summer minimum demand forecasts in the Expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	732	636	525
2024-25	620	499	391
2025-26	464	354	239
2026-27	333	212	99
2027-28	224	76	-40
2028-29	67	-64	-204
2029-30	51	-84	-229
2030-31	166	-13	-166
2031-32	188	27	-129
2032-33	205	7	-146
2033-34	211	10	-157
Average growth	-11.7%	-33.7%	-11.4%

Table 27 Winter minimum demand forecasts in the Expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	771	650	534
2024-25	638	518	374
2025-26	531	386	236
2026-27	480	323	148
2027-28	376	241	73
2028-29	325	190	6
2029-30	463	243	61
2030-31	496	311	71
2031-32	648	412	147
2032-33	688	530	260
2033-34	688	480	217
Average growth	-1.1%	-3.0%	-8.6%

Table 28 Shoulder minimum demand forecasts in the Expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2023-24	623	510	377
2024-25	521	381	256
2025-26	332	216	75
2026-27	212	101	-26
2027-28	57	-60	-172
2028-29	-39	-179	-329
2029-30	4	-158	-322
2030-31	96	-78	-230
2031-32	85	-59	-226
2032-33	93	-65	-231
2033-34	84	-76	-233
Average growth	-18.1%	-17.3%	-4.7%

A8. Expected unserved energy results

Table 29 Expected unserved energy results under Expected scenario, 2024-25 to 2033-34

Capacity Year	Operational consumption (MWh)	0.0002% of operational consumption (MWh)	EUE (MWh)	EUE (%)
2024-25	18,018,230	36	23	0.00013%
2025-26	18,082,420	36	8	0.00004%
2026-27	18,287,250	37	1.5	0.00001%
2027-28	18,530,040	37	11	0.00006%
2028-29	19,188,220	38	98	0.00051%
2029-30	20,799,680	42	22,804	0.10964%
2030-31	22,832,890	46	465,356	2.03810%
2031-32	24,464,770	49	769,962	3.14723%
2032-33	26,117,930	52	1,469,706	5.62719%
2033-34	27,867,570	56	2,377,144	8.53014%

Source: AEMO and EY.

A9. Facility and DSP capacities

A9.1 Capabilities of existing capacity

The potential amount of available Reserve Capacity for the period 2026-27 to 2033-34 is estimated to be the same as the Capacity Credits assigned for 2025-26, after accounting for derating of ESR Facilities and reduction of Capacity Credit caused by high historical forced outage rates[36]. For the retiring Facilities, the available Reserve Capacity will revert to zero from retirement until the end of the outlook period.

Table 30 Capacities of existing Facilities

Market Participant	Facility	Capacity Credits 2024-25 (MW)	Capacity Credits 2025-26 (MW)	Max Capacity (MW)	Retirement
Alcoa of Australia	ALCOA_WGP	16.000	16.000	26.000	
Alinta Sales Pty Ltd	ALINTA_PNJ_U1	142.450	142.450	143.000	
	ALINTA_PNJ_U2	142.450	142.450	143.000	
	ALINTA_WGP_GT	196.000	196.000	196.000	
	ALINTA_WGP_U2	196.000	196.000	196.000	
	ALINTA_WWF	15.121	14.006	89.100	
	BADGINGARRA_WF1	25.066	24.285	130.000	
	YANDIN_WF1	33.388	34.540	211.700	
Amanda Energy Pty Ltd	BIOGAS01	0.414	0.387	2.000	
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1	29.788	28.959	180.000	
Blair Fox Pty Ltd AFT Blair Fox Trust	BLAIRFOX_KARAKIN_WF 1	0.309	0.151	5.000	
Bluewaters Power 1 Pty Ltd	BW1_BLUEWATERS_G2	217.000	217.000	217.000	1/10/2030[A]
Bluewaters Power 2 Pty Ltd	BW2_BLUEWATERS_G1	217.000	217.000	217.000	1/10/2030[A]
Collgar Wind Farm	INVESTEC_COLLGAR_WF 1	25.162	24.243	218.500	
Denmark Community Windfarm Ltd	DCWL_DENMARK_WF1	0.492	0.491	1.440	
EDWF Manager Pty Ltd	EDWFMAN_WF1	11.404	10.320	80.000	
Goldfields Power	PRK_AG	59.748	0.000	68.000	
Landfill Gas & Power Pty Ltd	RED_HILL	2.603	2.497	3.750	
	TAMALA_PARK	4.018	3.835	5.550	
MEG HP1 Pty Ltd	NORTHAM_SF_PV1	0.821	0.811	9.800	
Merredin Energy	NAMKKN_MERR_SG1	82.000	82.000	82.000	
Merredin Project Company Pty Ltd ATF The Merredin	MERSOLAR_PV1	7.062	7.694	100.000	
Metro Power Company Pty Ltd	AMBRISOLAR_PV1	0.918	0.809	0.960	

[36] Anticipated reduction in Capacity Credit due to high historical force outage rates is associated with the update in the requirement in setting the Certified Reserve Capacity in accordance to clause 4.11.1A of the WEM Rules.

Market Participant	Facility	Capacity Credits 2024-25 (MW)	Capacity Credits 2025-26 (MW)	Max Capacity (MW)	Retirement
	SKYFRM_MTBARKER_WF1	0.748	0.820	2.430	
Mumbida Wind Farm Pty Ltd	MWF_MUMBIDA_WF1	7.909	6.962	55.000	
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600	330.600	342.000	
NewGen Power Kwinana Pty Ltd	NEWGEN_KWINANA_CCG1	327.800	327.800	334.800	
Perth Energy Pty Ltd	ROCKINGHAM	1.447	1.241	4.000	
	SOUTH_CARDUP	0.000	1.788	1.912	
SRV AGWF Pty Ltd as Trustee for AGWF Trust	ALBANY_WF1	6.195	6.090	21.600	
	GRASMERE_WF1	4.220	4.268	13.800	
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	3.810	4.010	40.000	
Synergy	BREMER_BAY_WF1	0.201	0.226	0.600	
	COCKBURN_CCG1	240.000	240.000	249.707	
	COLLIE_G1	317.200	317.200	318.300	1/10/2027
	KALBARRI_WF1	0.155	0.120	1.600	
	KEMERTON_GT11	155.000	155.000	171.800	
	KEMERTON_GT12	155.000	155.000	171.800	
	KWINANA_ESR1	45.250	44.250	100.000	
	KWINANA_GT2	98.500	98.500	103.940	
	KWINANA_GT3	99.200	99.200	103.940	
	MUJA_G7	211.000	211.000	212.600	1/10/2029
	MUJA_G8	211.000	211.000	212.600	1/10/2029
	PINJAR_GT1	31.000	29.301	40.350	
	PINJAR_GT10	110.500	110.500	118.200	
	PINJAR_GT11	124.000	123.700	128.200	
	PINJAR_GT2	30.500	30.800	40.35	
	PINJAR_GT3	37.000	37.000	42.000	
	PINJAR_GT4	37.000	37.000	42.000	
	PINJAR_GT5	37.000	37.000	42.000	
	PINJAR_GT7	37.000	36.395	42.000	
	PINJAR_GT9	111.000	110.500	118.200	
Tesla Corporation Management	TESLA_PICTON_G1	9.999	9.999	9.999	
Tesla Geraldton Pty Ltd	TESLA_GERALDTON_G1	9.999	9.999	9.999	
Tesla Kemerton Pty Ltd	TESLA_KEMERTON_G1	9.999	8.286	9.999	
Tesla Northam Pty Ltd	TESLA_NORTHAM_G1	9.900	9.900	9.999	
Tronox Management Pty Ltd10	TIWEST_COG1	36.000	36.000	42.100	
Waste Gas Resources Pty Ltd	HENDERSON_RENEWABLE_IG1	1.501	1.436	3.192	

Market Participant	Facility	Capacity Credits 2024-25 (MW)	Capacity Credits 2025-26 (MW)	Max Capacity (MW)	Retirement
Western Energy Pty Ltd	PERTHENERGY_KWINANA_GT1	109.000	109.000	109.000	

A. Retirement date for Bluewaters is estimated by AEMO and does not reflect any decision by Bluewaters.

Table 31 DSP capability and availability[A]

Market Participant	DSP Name	Capacity Credits 2024-25 (MW)	Capacity Credits 2025-26 (MW)	Maximum MW available to provide Reserve Capacity
Bluewaters Power 1 Pty Ltd	GRIFFINP_DSP_01	20.000	20.000	20.000
Synergy	SYNERGY_DSP_04	42.000	33.136	42.000
Wesfarmers Kleenheat Gas Pty Ltd	PREMPWR_DSP_02	23.000	18.689	24.000

A.DSPs must be available to provide at least 200 hours' Reserve Capacity during a Capacity Year for 2024-25 and 2025-26. From 2026-27 and onward, DSPs must be available to provide at least 50 hours of Reserve Capacity during a Capacity year. This availability must cover no less than 12 hours per Business Day between 08:00 and 20:00.

A9.2 Capabilities of committed capacity

Projects that received Capacity Credits for the first time in 2024-25 or 2025-26 are modelled to be in operation from the respective years as committed capacity. Additionally, capacities procured under 2024-26 Peak Demand NCESS are modelled as committed projects starting from 2024-25. These projects are detailed in **Table 32**.

Table 32 Capacities of committed projects received Capacity Credits or contracted for NCESS for peak demand, 2024-26[A]

Market Participant	Facility	Capacity 2024-25 (MW)	Capacity 2025-26 (MW)	Maximum Capacity (MW)
Neoen Australia Pty Ltd[A]	COLLIE_ESR1	196.725	196.700[B]	200.000
Cunderdin Development Pty Ltd	SBSOLAR1_CUNDERDIN_PV1	48.677	47.981	179.187
East Rockingham RRF Project	ERRRF_WTE_G1	25.134	25.134	29.000
Kwinana WTE Project Co	PHOENIX_KWINANA_WTE_G1	33.909	33.909	36.000
Moonies Hill Energy	FLATROCKS_WF1	20.358	22.561	75.600
PRD SWIS OPS PTY LTD	PRDSO_WALPOLE_HG1	1.500	1.500	1.500
Alinta Sales Pty Ltd	ALINTA_WGP_ESR1	50.000	48.265	50.000
Alinta Sales Pty Ltd[C]	ALINTA_WGP_GT	10.000	10.000	10.000
Alinta Sales Pty Ltd[C]	ALINTA_WGP_U2	10.000	10.000	10.000
ENELX DSP[D]	ENELX DSP	120.000	120.000	120.000
Synergy	KWINANA_ESR2	200.000	200.000	200.000

A. ESR Capacity is modelled to depreciate over the outlook period.
B. COLLIE_ESR1 received a 200MW Capacity Credit for 2025-26 and it is procured under 2024-26 NCESS for Peak Demand NCESS. Modelled capacity is taken as the minimum of the two values.
C. The projects are upgrade to the existing Facilities to increase capacity by 10MW.
D. Capacity is expected to be available for 2024-26 NCESS contract period only.

Projects that scored 80% or higher in the new project status evaluation are modelled as committed capacity commencing operation in 2026-27. Projects under contract negotiation for 2025-27 Peak Demand NCESS are modelled to begin operation in 2025-26. The combined capacities of these projects are listed in **Table 33**.

Table 33 Capacities of committed projects from the Facilities submitted a valid EOI or under contract negotiation for NCESS, 2025-27

Generator Type	Capacity Credits (MW)									Installed Nameplate (MW)
	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	
ESR[A]	312.340	823.502	815.352	809.172	803.194	797.542	793.032	788.598	783.497	834.338
DSP	112.300	62.300	3.800	3.800	3.800	3.800	3.800	3.800	3.800	112.300

A. ESR group includes standalone batteries, the battery components of project, and the hydro projects.

A9.3 Capabilities of probable capacity

Projects that scored between 50% and 80% in the new project status evaluation were included in the committed capacity and modelled to commence operation in 2026-27.

Table 34 Capacities of probable Facilities by Generator Type

Generator Type	Capacity Credits (MW)								Installed Nameplate (MW)
	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	
Wind Generation	87.200	87.200	87.200	87.200	87.200	87.200	87.200	87.200	476.000
ESR[A]	384.995	371.639	362.533	355.557	348.680	342.197	337.095	331.988	394.995
Solar Farm	22.000	22.000	22.000	22.000	22.000	22.000	22.000	22.000	110.000
Distillate Generation	19.998	19.998	19.998	19.998	19.998	19.998	19.998	19.998	19.998

A. ESR grouping includes standalone batteries, the battery components of project, and the hydro projects.

Glossary, measures, and abbreviations

Glossary

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

Term	Definition
10-year outlook period	2024-25 to 2033-34 Capacity Years, inclusive.
anticipated installed capacity (AIC)	The anticipated quantity of Reserve Capacity available from existing, committed, or probable capacity.
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).
capability at 41°C	Sent out capacity calculated at air temperature of 41°C. This accounts for efficiency loss at high temperatures, which are typical during peak demand periods.
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 A1.7 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[37]) unless otherwise stated.
daytime hours	Trading Intervals commencing 08:00 to 16:30.
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 DPV) 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 photovoltaics (DPV), distributed battery storage, and electric vehicles (EVs).
distributed energy storage systems (DESS)	These are small distributed behind-the-meter battery storage systems installed for residential, commercial, and large commercial customers, that do not hold Capacity Credits in the WEM.
distributed photovoltaics (DVP)	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.

[37] 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[38] (or demand)[39]	Electricity consumption (or demand) that is met by sent-out electricity supply of all market registered energy producing units[40]. 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 DPV 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)[41]	Operational consumption/demand that excludes any consumption/demand associated with scheduled loads (such as utility-scale storage 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, coordinated EV charging and demand response). Only non-coordinated, 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.
expression/s of interest	An annual call out for expressions of interest from new generation or DSM Facilities that may seek CRC and Capacity Credits for the relevant Capacity Year.
installed capacity	The generating capacity (in MW) of a single or multiple generating units.
large industrial loads (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.
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	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[42]), winter (June to August), or shoulder months (April, May, September to November).
outlook period	2024-25 to 2033-34 Capacity Years, inclusive.
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: are a candidate for registration and have submitted a valid Expression of Interest for the 2024 Reserve Capacity Cycle (2024 EOI)[43],

[38] 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.

[39] 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.

[40] Includes market generators and utility-scale energy storage systems.

[41] 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.

[42] These months are aligned with the Hot Season defined in the WEM Rules.

[43] The information that a 2024 EOI must include to be deemed valid is outlined in clause 4.4.1 of the WEM Rules.

Term	Definition
	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.
rooftop photovoltaics	Photovoltaics installed on a residential building (less than 15 kW) or business premises (less than 100 kW).
reliability standard	The Planning Criterion defined in clause 4.5.9 of the WEM Rules.
residential sector	Includes non-contestable[44] residential customers (supplied by Synergy) only.
shoulder season	The period including Trading Months of April, May, August, and September.
summer	The Hot Season as defined in the WEM Rules.
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 utility-scale storage 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 (DPV) and battery storage.
virtual power plant (VPP)[45]	An aggregation or grouping of DER that is actively controlled and coordinated via an Orchestration System[46] by an operator. VPPs can operate in a coordinated 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
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
TWh	Terawatt hour

[44] 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.

[45] As defined in AEMO's VPP Visibility Guideline (p8), see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/wa_wem_consultation_documents/2022/proposed-design-for-a-visibility-framework/vpp-visibility-guideline.pdf.

[46] Orchestration System means, without limitation, the technologies, technology platform(s), algorithms, process and systems used to coordinate the Injection and Withdrawal of energy from the DER within an Aggregation of DER. See AEMO's VPP Visibility Guideline.

Abbreviations

Term	Definition
ADGLS	Availability Duration Gap Load Scenario
AEMO	Australian Energy Market Operator
AIC	Anticipated Installed Capacity
BESS	Battery energy storage system
BITRE	Bureau of Infrastructure and Transport Research Economics
BMM	Business mass market
BRCP	Benchmark Reserve Capacity Price
CBD	Commercial Building Disclosure
CER	Clean Energy Regulator
Coordinator	Coordinator of Energy
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWC	ClimateWorks Centre
DER	Distributed energy resources
DESS	Distributed energy storage systems
DPV	Distributed photovoltaics
DSP	Demand Side Programme
ELPS	Eastern Goldfields Load Permissive Scheme
EOI	Expressions of Interest
EPA	Environmental Protection Authority
EPWA	Energy Policy Western Australia
ERA	Economic Regulation Authority
EREP	East Regional Energy Project
ESM	Emergency solar management
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resources
ESROI	Electric Storage Resource Obligation Intervals
ETS	Energy Transformation Strategy
EUE	Expected unserved energy
EV	Electric vehicle
EY	Ernst & Young
FCESS	Frequency Control Essential System Services
FID	Final Investment Decision
FRG	Forecasting Reference Group
FSC	Fixed shape consumption
GEM	Green Energy Market
GEV	Generalised extreme value
GSP	Gross state product
IASR	Inputs, Assumptions and Scenarios report

Term	Definition
IGS	Intermittent Generating Systems
LDC	Linearly Derating Capacity
LFAS	Load following ancillary service
LIL	Large industrial load
NABER	National Australian Built Environment Rating System
NAQ	Network Access Quantity
NCC	National Construction Code
NCESS	Non-Co-optimised Essential System Services
NEM	National Electricity Market
NIGS	Non-Intermittent Generating Systems
NMI	National Metering Identifiers
NSF	Non-scheduled Facilities
NVES	New Vehicle Efficiency Standard
OCGT	open-cycle gas turbines
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generator
QED	Quarterly Energy Dynamics
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
RLM	Relevant Level Methodology
SCADA	Supervisory Control and Data Acquisition
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
WA	Western Australia
WEM	Wholesale Electricity Market

List of tables and figures

Tables

Figures