2025 WEM ESOO Reliability Assessment Methodology Report

Australian Energy Market Operator

20 June 2025

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Ernst & Young ("EY") was engaged on the instructions of the Australian Energy Market Operator ("AEMO", "Client") to assist AEMO with the reliability assessment underpinning the 2025 Long Term Projected Assessment of System Adequacy (Long Term PASA) for the South West Interconnected System (SWIS) ("the "Services"), in accordance with the engagement agreement between EY and AEMO dated 28 March 2025.

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Executive summary

EY Parthenon (hereafter 'EY') has been engaged by the Australian Energy Market Operator (AEMO) to provide wholesale electricity market modelling services to assist AEMO in assessing the reliability of supply to meet electricity demand in the South West Interconnected System (SWIS) of Western Australia (WA).

Assessing reliability of supply to meet SWIS demand (the reliability assessment) informs the 10-year Long Term Projected Assessment of System Adequacy (Long Term PASA) that AEMO presents annually in the Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO).

The role of the Long Term PASA is to ensure there is sufficient capacity from Energy Producing Systems (EPS, e.g. thermal, renewable), energy storage, and Demand Side Programmes (DSPs) to meet the Planning Criterion as defined in clause 4.5.9 of the WEM Electricity System and Market Rules (ESM Rules, formerly known as the WEM Rules).[1]

The Planning Criterion sets the SWIS reliability standard and stipulates that there should be sufficient capacity in each Capacity Year to:

- Meet the forecast peak demand plus a reserve margin (this report will refer to this as 'Limb A' of the Planning Criterion)

- Limit expected unserved energy shortfalls (EUE, defined as the maximum expected energy that is not supplied to consumers), to 0.0002% of annual energy consumption (this report will refer to this as 'Limb B' of the Planning Criterion)

- Meet the highest forecast Four-Hour Demand Increase, plus a reserve margin (referred to as 'Limb C' of the Planning Criterion).[2]

The reliability assessment has been performed using AEMO's forecasts of the 2025 WEM ESOO demand growth scenarios for the 2025 Long Term PASA and EY's contribution to the broader reliability assessment involves the following scope items (presented in further detail below and in Section 3):[3]

- Scope item 1: Demand profile projections
- Scope item 2: Constraint equations development
- Scope item 3: Peak capacity reliability gap assessment
- Scope item 4: Peak Reserve Capacity Target (Peak RCT) forecasts
- Scope item 5: Minimum Capability Classes 1 and 3 capacity determination

The purpose of this report is to provide an update to the methodology and assumptions used by EY to provide the above components of the 2025 reliability assessment. EY previously provided the 2023 reliability assessment and a detailed modelling methodology report was published.[4] An update to that methodology report was published, outlining methodology or key assumption changes from

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[1] From 4 June 2025 the WEM Rules are renamed as the Electricity System and Market Rules (or ESM Rules). See - https://www.wa.gov.au/government/document-collections/electricity-system-and-market-rules.

[2] This third component is a new requirement in the WEM Rules. It is calculated by AEMO for the 2025 WEM ESOO and is not further referred to in this report, which focuses on Limb A and Limb B.

[3] For the requirements and outcomes of the broader scope of the reliability assessment please see AEMO's 2025 WEM ESOO report.

[4] EY (2023) 'AEMO Reliability Assessment 2023'. Available from: https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo

the 2023 study to the 2024 study.[5] The same modelling framework and many of the same approaches have been applied for this 2025 study, therefore the aim of this report is to highlight regulatory and modelling updates that have resulted in an updated approach. The report is set out as follows:

- **Section 1** provides further background and context for the 2025 reliability assessment, noting the updates to the ESM Rules that impact the approach to the study, as well as industry developments such as the new record peak demand recorded in the WEM and AEMO's procurement of Peak Demand Services. This section also provides further detail on the modelling scope items that comprise the 2025 reliability assessment.
- **Section 2** sets out a high-level recap of the modelling framework used for the reliability study, and a summary of the approaches that have changed since the 2024 study.
- **Section 3** provides a summary of the methodology to deliver the 2025 reliability assessment. Where this has not changed from last year, most of the detail can be found in the Appendices to this report.
- Various Appendices to this report provide further background and detail as required:
  - Appendix A: Abbreviations.
  - Appendix B: Further detail on the modelling methodology and the approach to modelling each part of the electricity market included in the study.
  - Appendix C: Further detail on producing half-hourly demand traces from AEMO's annual forecasts.
  - Appendix D: Modelling assumptions.
  - Appendix E: Glossary of Terms.

[5] EY (2024) '2024 WEM ESOO Reliability Assessment Methodology Report'. Available from: https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2024/ey---2024-wem-esoo-reliability-assessment-methodology-report.pdf?la=en

1. Introduction

1.1 Background

The results of the 2025 reliability study components prepared by EY are presented in the 2025 WEM ESOO document, with the purpose of this report to focus on assumptions and methodology. It should be noted that EY performed the reliability assessment accompanying the 2023 and 2024 WEM ESOO and provided a detailed methodology and assumptions report to accompany the reported reliability outcomes, which can be found on AEMO's website and can be referred to for further detail on approach.[6] A summary of methodology changes in the 2024 study can also be referred to in EY's 2024 methodology report.[7]

EY has used the same modelling framework (see Section 2.1), and in many instances the same methodology and approach to similar scope items as detailed in the 2023 and 2024 study. Where these assumptions and approaches remain the same, the previous report and the appendices in this report can be referred to, with the main purpose of this report to set out where new or revised assumptions and approaches have been required, either due to new market Rules requirements, or different scope items required.

This section provides the following:

- **Section 1.2** summarises the changes to the market Rules since the 2024 study and other key developments in the WEM since the previous study
- **Section 1.3** summarises the key industry developments in the year since the previous reliability assessment was carried out
- **Section 1.4** sets out the scope items that were carried out by EY to provide AEMO with the 2025 reliability assessment
- **Section 1.5** provides the high-level approach and remaining report structure.

1.2 Changes in approach from 2024 study

This section summarises any changes in assumptions or methodology since the 2024 reliability assessment, including the following:

- Half-hourly demand forecasts: Various updates to the approach including the addition of two new historical weather reference years, accounting for demand-side response activations, and accounting for large-scale battery charging in reference year traces
- The inclusion of the Electric Storage Resource (ESR) Duration Obligation Uplift in the Limb A requirement
- Introduction of battery degradation on projected Capacity Credits / Reserve Capacity
- Assessing Limb B uses Capacity Credits for ESR facilities (rather than installed capacity)
- Consideration of more dynamic line ratings for modelling of the transmission network

[6] EY (2023) 'AEMO Reliability Assessment 2023'. Available from: AEMO | WEM Electricity Statement of Opportunities

[7] EY (2024) '2024 WEM ESOO Reliability Assessment Methodology Report'. Available from: 2024 WEM ESOO Reliability Assessment Methodology Report

- Reducing the minimum demand constraint to 300 MW (from 500 MW in the 2024 study)
- Assessment of the level of commitment of transmission network augmentations
- Changes to the market Rules impacting the implications for the outcomes from Capability Class modelling and changes to remove the requirement for Availability Duration Gap Load Scenario modelling.

These revisions are described in further detail in Section 2.2.

1.3 Industry context

To provide more context for the WA Wholesale Electricity Market for this reliability assessment, the following represents key developments over the last year.

Supply developments

- The retirement of State-owned coal units, Collie and Muja D are still planned for late 2027 and late 2029 respectively) as per the WA State Government's public announcements.[8] The 400 MW Muja C coal fired power station was due to fully retire by October 2024, however the retirement of one of its units (Unit 6) was pushed back by six months to April 2025.[9,10]
- The Primary Facility List modelled includes an assumption that the Bluewaters Power Station is unavailable from 1/10/2027. An Alternative Facility List is also modelled, and based on this Facility being unavailable from a later date of 1/10/2030.
- Both the Primary and Alternative Facility list assumptions include the assumed retirements of most of Synergy's Pinjar units across 2029 to 2032 (see Table 10 in Section D.6 for further details).
- The participation from battery storage has increased over the last year, with the entry of the Collie battery (COLLIE_ESR1), the second battery in the WEM further to Synergy's 100 MW 2hr Kwinana battery (KWINANA_ESR1), as well as a second Kwinana battery (KWINANA_ESR2) and the Cunderdin hybrid solar / ESR project (SBSOLAR1_CUNDERDIN_PV1). By 2027-28, new battery capacity modelled in the reliability study is around 1.3 GW, or around 20 per cent of the modelled capacity in the WEM for that year.

  As well as participation in the energy market, the accreditation of KWINANA_ESR1 and COLLIE_ESR1 for participation in the FCESS markets, saw batteries capture an overall share of FCESS markets of 39% in Q1 2025.[11]
- The Commonwealth Government's first CIS tender for the WEM announced four successful projects on 20 March 2025 (Boddington Giga Battery, Merredin Big Battery, Muchea Battery, and Waroona Renewable Energy Project), totalling 654 MW of 4hr storage capacity. For the purposes of the reliability study, the Merredin Big Battery is assumed to be committed and included in the expected scenario.
- Amendments to the market Rules were approved on 3 June 2025 which have implications for new entrants on the supply side, as well as for market outcomes for existing Facilities. The

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[8] WA Government (2022). Available from: State-owned coal power stations to be retired by 2030 with move towards renewable energy

[9] WA Government (2023). Available from: Muja C Unit 6 in reserve mode and online for summer 2024-25

[10] Note that for the purposes of the reliability study modelling, Muja G6 is assumed to be unavailable from 1 October 2024.

[11] AEMO (2025) 'Quarterly Energy Dynamics Q1 2025'. Available from: QED Q1 2025

most impactful changes are the inclusion of an ESR Duration Obligation Uplift as a new component to the Limb A requirement and a new mechanism for AEMO to assign NAQ Facility status in the event a shortfall in capacity is identified.[12,13]

Demand developments

- 20 January 2025 saw a new maximum operational demand record in the WEM, of 4,486 MW.[14] This surpassed the forecast peak demand (Expected, 10% POE) in the 2024 ESOO (of 4,388 MW) and occurred during a severe intensity heatwave over Geater Perth between 19 and 23 January 2025, including a peak in temperature on 20 January.
- New minimum demand records have also been set in the last year – 10 November 2024 saw a record low of 511 MW for operational demand, driven by mild weather and high rooftop solar generation.
- The 2024 WEM ESOO (published June 2024) projected that the near-term supply/demand outlook had significantly improved from the 2023 WEM ESOO, with supply and demand forecast to be largely balanced between 2025 and 2027. However, the 2024 WEM ESOO found that investment in generation, storage, demand-side capacity and network transmission would be required from 2027-28 onwards.[15]
- The demand forecasts for the 2025 WEM ESOO reflect a more muted forecast of demand growth in the WEM over the next ten years (see Appendix D for further details). Operational energy is forecast to be slightly lower than in the 2024 projections up to 2028-29, and then tracks noticeably lower from 2029-30 onwards. Whereas strong growth in operational consumption was previously forecast, in the 2025 projections, consumption is almost a quarter, or around 6.5 TWh lower by 2033-34 compared to the projection made for that year in 2024 (the final year of the 2024 projections).
- Peak demand is forecast to be higher in the earlier years of the forecast period than in 2024, although, reflecting the consumption trend described above, growth remains flatter, such that peak demand from 2029-30 is projected to be lower than in the 2024 forecast for the remainder of the projection period.

In light of the above, we note that:

- Even if there is sufficient capacity to satisfy the annual peak demand interval, it may transpire that demand in other intervals is not fully satisfied by capacity available in these intervals, resulting in instances of unserved energy.[16]
- The assessment of Limb B of the Planning Criterion can result in annual EUE volumes exceeding the 0.0002% standard, and Limb B can be the driver of the Peak RCT (if it is higher than Limb A in required MW terms), particularly given the more stringent requirement of Limb

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[12] https://www.wa.gov.au/system/files/2025-03/esm_amendment_tranche_8_exposure_draft.pdf

[13] WA Government (2025) 'WEM Rules renamed ESM Rules'. Available from: Wholesale Electricity Market Rules renamed Electricity System and Market Rules

[14] Note that the demand figures presented here represent the 5-minute interval demand and differ to other reported measurements of demand that present demand or generation over a 30-minnute interval for example.

[15] AEMO (2024) '2024 WEM Electricity Statement of Opportunities (ESOO)'. Available from: AEMO | WEM Electricity Statement of Opportunities

[16] In real-time operation of the power system (especially with a high share of intermittent renewable capacity), generation capacity during the peak or other intervals may become fully or partially unavailable due to e.g., forced outages or insufficient renewable resource availability.

B in the revised market Rules to meet 0.0002% (from the previous 0.002% standard that applied at the time of the 2023 WEM ESOO).

1.4 Required scope items

Table 1 summarises the scope items carried out by EY to deliver the relevant components of the reliability assessment to inform the Long Term PASA for the 2025 WEM ESOO. The scenarios and modelling timescales are described and are based on market Rules requirements.

Table 1: Overview of EY's scope items for the 2025 reliability study

Scope item	Description	Key objective	Assessment time period and scenario
Scope item 1	Development of time-sequential, half-hourly underlying and operational demand projections for each of the required Capacity Year and demand scenarios using AEMO's peak demand and annual energy forecasts, integrating the impact of Consumer Energy Resources (CER).	Serve as an input to the reliability assessment.	▪ 2025-26 to 2034-35 ▪ 10% and 50% POE under each of the low, expected, and high demand scenarios.
Scope item 2	Development of constraint equations taking into consideration anticipated installed capacity (AIC), demand forecasts, appropriate transmission configurations and limits and anticipated network augmentations.	Required to ensure that the technical limits of the system are not exceeded.	▪ 2025-26 to 2034-35 ▪ 10% POE under expected demand scenario.
Scope item 3	Assessment of the extent to which the AIC of the Energy Producing Systems (EPS) and Demand Side Programme (DSP) capacity can satisfy the Planning Criterion (including consideration of network congestion) including:[17] ▪ identifying any Peak Capacity shortfalls for the scenario specified under clause 4.5.10(aA) of the ESM Rules. ▪ identifying and assessing any potential Peak Capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors, and which cannot be addressed by additional Peak Capacity outside the subregion, as required under clause 4.5.10(c) of the ESM Rules. ▪ identifying any potential transmission, generation, storage, or demand side capacity augmentation options to alleviate capacity shortfalls identified in clauses 4.5.10(aA) and 4.5.10(c) of the ESM Rules.	Identify, analyse and characterise capacity and reliability shortfalls under both Limbs of the Planning Criterion	▪ 2025-26 to 2034-35 ▪ 10% POE under expected demand scenario.
Scope item 4	Forecast the Peak Reserve Capacity Target (Peak RCT) for each Capacity Year during the Long Term PASA Study Horizon in accordance with clause 4.5.10(b) of the ESM Rules to meet the Planning Criterion in that year under the scenario described in clause 4.5.10(a)(iv) of the ESM Rules.	Determine whether the Peak RCT is set by Limb A or Limb B and quantify the Peak RCT (in MW).	▪ 2025-26 to 2034-35 ▪ 10% POE expected scenario
Scope item 5	Determine the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 and an appropriate mix of the additional Capability Class 1 and Capability Class 3 capacity required if any shortfall is identified for the required Capacity Year and demand scenario.	Identifying the balance of capacity between different Capability Classes.	▪ 2027-28 ▪ 10% POE peak demand under the Expected demand scenario.

[17] The AIC is determined as existing SWIS installed capacity (generation, storage, DSP) less existing capacity retirements + committed capacity, as advised by AEMO.

1.5 High-level approach and report structure

The remainder of this report is structured as follows:

- Section 2 presents a high-level overview of the modelling framework applied to carry out the 2025 reliability assessment and sets out the assumptions and approaches that have changed from the 2024 reliability assessment. All other input assumptions that remain the same are detailed further in the appendices to this report.
- Section 3 presents the methodology and how EY's electricity market model (2-4-C®) is deployed to undertake the elements of the reliability assessment. Key aspects of how EY has derived AIC EUE, comparison of Limb A and Limb B to the Planning Criterion, and the determination of Capability Classes is described.
- Appendices provide more detail as follows:
  - Appendix A provides the abbreviations list.
  - Appendix B sets out the detail behind the modelling framework.
  - Appendix C provides the detail of EY's approach to developing half-hourly demand inputs based on the annual demand inputs provided by AEMO.
  - Appendix D provides a summary of the data inputs provided by AEMO.
  - Appendix E provides the glossary of terms.

2. Modelling framework and input assumptions

2.1 High-level overview of the 2-4-C model

For the reliability study, EY used its in-house 2-4-C software suite, which consists of a co-optimised energy market and Essential System Service (ESS) dispatch engine, and several software tools that are used to develop input data and analyse output data.

The 2-4-C dispatch engine replicates key aspects of electricity market dispatch engines such as the WEM Dispatch Engine (WEMDE) that is used by AEMO in operating the Real-Time Market (RTM) which began operation on 1 October 2023.

The 2-4-C model is designed to represent the key characteristics of the WEM and the generation, energy storage and demand side response providers that participate in the RTM. Each Facility is modelled explicitly and is dispatched in response to the demand forecast, power system security requirements, transmission network capability and Facility availability for each half hour according to modelled bidding assumptions which are a representation of RTM Submissions.[18]

The 2-4-C dispatch engine has been applied in this engagement at a half-hourly resolution to perform time-sequential dispatch modelling over the study horizon. Modelling on a time-sequential basis helps to capture a range of important market aspects that can impact reliability outcomes:[19]

- **Renewable resource variability and weather-driven demand patterns:** EY's modelling of future demand patterns bases all the intertemporal and interspatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years). This reference year approach is described in more detail in Appendix C and is applied on a time-sequential basis. This means that the same weather factors that drive variability in demand from one Trading Interval to the next are also captured in the resource availability of wind and solar generation (large-scale and behind-the-meter in the case of solar) in future modelled years. In this way, the correlation between when renewable resources are available and when customers use energy is captured in the datasets.

- **Generator and storage forced outages:** Using time-sequential modelling captures the duration (and thus impact) of generator and storage outages throughout contiguous intervals in a year, as opposed to modelling based on data 'blocks', i.e., only selected representative days or other periods of a year.

- **Ramp rate limitations:** The ability of a modelled Facility (generation, storage, demand side response provider, or a combination thereof) to contribute to meeting energy demand (or provide ESS) can depend on how quickly it can increase or decrease its output from one Trading Interval to another. Ramp rates may not bind often but in the context of a reliability study where EUE can result because of discrete step changes to supply availability, it is important to capture the ability of generators or DSP to ramp up or ramp down quickly.[20]

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[18] As explained in **Error! Reference source not found.**, the modelling will assign bidding profiles to every Facility, however for the purposes of a reliability study, the actual values of the bids are of secondary importance (as Facilities will generate if available (subject to any constraints) as required to avoid unserved energy.

[19] By time-sequential data we mean time series of 17,520 (or 17,568 for leap years) consecutive 30-minute interval datapoints for each modelled year, with outcomes in the previous interval being relevant for the currently modelled interval.

[20] Generator ramping relates to generation Facilities as well as the generator side of storage facilities.

- **Modelling of storage**: The ability of storage to provide energy in a given interval depends on its state of charge (or reservoir level for pumped hydro). For the purpose of this reliability study, it is assumed that storage in the market will be deployed to avoid unserved energy as a priority.[21] Time-sequential modelling captures the operation of storage from one interval to the next and take account of the level of the storage remaining in each particular interval. It also allows the storage to flex between charge and discharge from one interval to the next in response to changing demand and supply conditions.

- **Transmission network limitations**: Constraint equations in trading interval are evaluated by using the generation dispatch from the previous trading interval period t-1, to calculate terms in the right-hand side of the equation and to enable the left-hand side of the equation to be solved. EY's 2-4-C model is time-sequential, dispatched for every half-hour and has the required functionality.

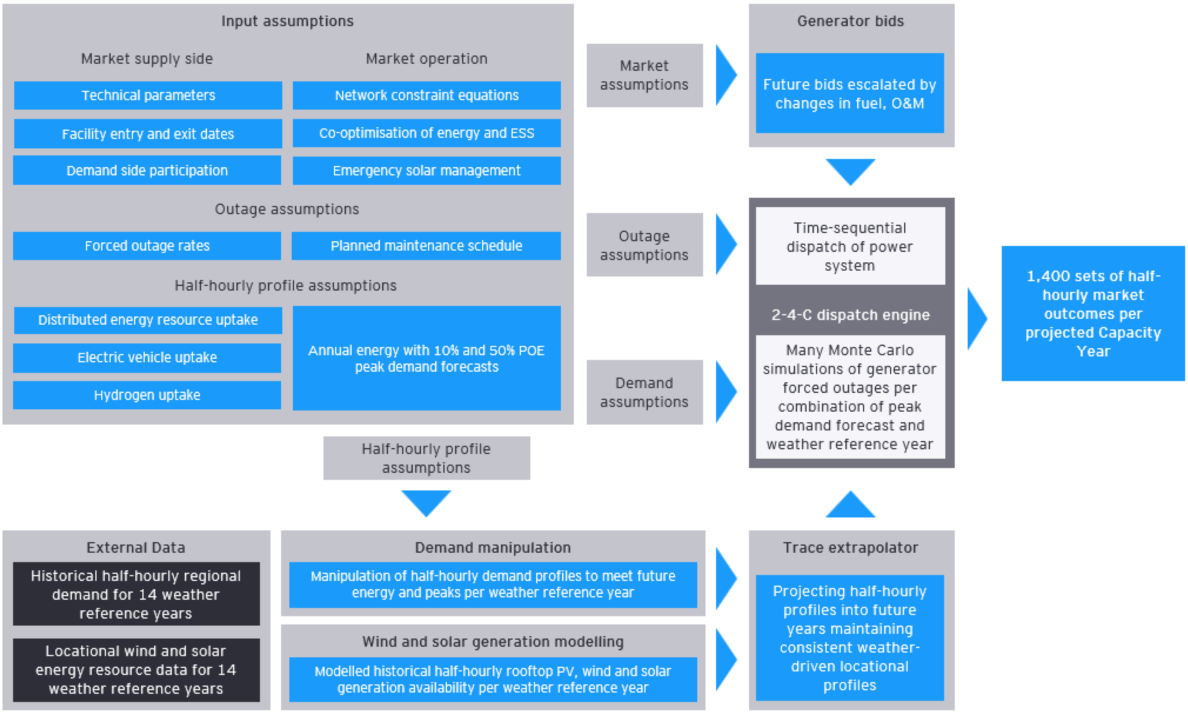
As well as modelling as many possible weather reference years to capture the uncertainty in future weather outcomes, a large number of Monte Carlo iterations have been performed in the market modelling to capture the impact of forced (unplanned) generator outages. By modelling a very large number of combinations of these two factors that are all equally likely, we capture these two critically important uncertain factors to produce a reasonable estimate of unserved energy. [22]

It should be noted that a further uncertain factor is network outages, however these are not included in the current modelling for several reasons. Firstly, it is difficult to derive a sufficiently robust estimate of different network outages. Notwithstanding estimates being available, the number of potential combinations involved with different constraint sets and the number of simulations required would be computationally excessive.

Figure 1 presents a high-level overview of the range of input assumptions, and the interactions between the 2025 WEM ESOO scenarios and the 2-4-C dispatch engine.

[21] This is the approach taken for large-scale storage projects and behind-the-meter virtual power plant (VPP) battery storage. A different approach is used for disaggregated behind-the-meter battery charging and discharging, as set out in Appendix C.

Figure 1: High-level overview of the interactions between input assumptions, 2025 WEM ESOO demand scenarios and the 2-4-C model



Source: EY

The approach to each of the modelling elements is described in further detail in Appendix B, Appendix C, and Appendix D. Key changes that were implemented in this year's modelling are described in the following section.

2.2 Modelling assumptions and approaches updated from the 2024 reliability assessment

Key changes that were implemented this year, and are described further below, include:

- Updates to half-hourly demand traces
- Changes to the market Rules impacting the implications for the outcomes from Capability Class modelling
- The inclusion of the ESR Duration Obligation Uplift in the Limb A requirement
- Introduction of battery degradation on Capacity Credits
- Using Reserve Capacity instead of installed capacity for modelling of ESR facilities in assessing any gap against Limb B
- Consideration of more dynamic line ratings for modelling of the transmission network
- Reducing the minimum demand constraint to 300 MW from the 500 MW applied in previous reliability studies
- Assessment of the level of commitment of transmission network augmentations

2.2.1 Updates to the production of half-hourly weather reference year traces

In the previous reliability studies, historical weather reference year data was modelled for 2010-11 to 2021-22. This year, EY developed an additional two weather reference years, for 2022-23 and 2023-24. Putting reference years together involves collecting the historical operational demand and estimating the contribution from rooftop PV and small non-scheduled PV (PVNSG) to determine the underlying demand. For the two new reference years, market conditions and the changing nature of the generation mix required two additional adjustments:

- **Demand-side response activations**: These new reference years feature demand-side response activations data, provided by AEMO. Data provided on Supplementary Capacity, DSP and NCESS responses activated by AEMO was added to the operational demand trace to ensure the underlying demand captures the demand that would have occurred had the demand response not taken place.[23]

- **Large-scale battery charging**: Given that large-scale battery charging is modelled in dispatch in EY's electricity market modelling, we do not want to include the impact of battery charging in the historical reference year trace (as this is projected forward to create half-hourly profiles of future demand). Therefore, AEMO provided data (from National Metering Identifier (NMI)) on battery charging which was subtracted from the historical reference year data.

2.2.2 Half-hourly projected demand traces

Once the historical weather reference year traces are produced for each year in question, these profiles are used to create future half-hourly traces. These traces reflect demand characteristics and the prevailing weather and renewable resource at that time. Adjustments are made to capture the changing nature of demand (due to EVs, electrification, increasing CER etc), as well as AEMO's forecast annual energy consumption and peak demand.

In previous WEM ESOO reliability studies EY set a fixed target for underlying demand at the given demand probability (e.g., 10% POE) and then modelled individual components of demand such that when these are put together, an operational peak for each individual weather reference year can be calculated (and will differ in each reference year predominantly due to the rooftop solar profile on the day of the underlying peak). As a final step, a post-modelling adjustment was made such that on average, the operational peaks across all reference years aligned with AEMO's forecast 10% POE operational peak.

This year, the demand traces were created to achieve the *underlying* 10% POE peak in every weather reference year and the operational peak is an outcome determined by the combination of the shape of demand and rooftop PV resource on the day of the underlying peak. The result is that the operational peaks better capture a one in ten operational peak level, where the 10% POE operational peak would be expected to be exceeded in one out of ten weather reference years. This revised approach maintains consistency of the underlying 10% POE peak across all reference years, which is considered independent of weather reference years.

2.2.3 Capability Class modelling

Tranche 8 of amendments to the WEM Rules (including a change to renaming to the 'Electricity System and Market (ESM) Rules') proposed new implications from the outcomes of the Capability Class modelling. The amending rules flagged that under the previous Rules, if additional Capability

[23] Supplementary Capacity (SC) is procured by AEMO if, at any time after the day that is six months before the start of a Capacity Year, it determines that insufficient capacity is available to satisfy demand. NCESS refers to the Peak Demand Service 'Non-Co-optimised Essential System Services' contracts entered into between AEMO and participants to provide capacity during peak times.

Class 1 and 3 capacity is required to make up a shortfall against the Peak Reserve Capacity Target, there was no specific incentive to fill that shortfall.

In a move to address that, Tranche 8 proposed that in the event of a shortfall against the assessed requirements, any Capability Class 1 and 3 capacity that has not been assigned a Network Access Quantity (NAQ) in any previous Reserve Capacity Cycle will be treated as 'Network Augmentation Funding Facility' for the purposes of NAQ prioritisation under new clause 4.5.12A of the ESM Rules. Given that *any* shortfall (i.e. 1 MW and above) will trigger this update, the methodology to determine the absolute minimum amount of Capability Class 1 and 3 capacity has been updated in this year's reliability study. Section 3.5 provides further details.

These amendments also removed the requirement that the Capability Class modelling be carried out on the 'Availability Duration Gap Load Scenario' (and instead modelling is carried out using the unadjusted half-hourly traces produced by EY to align with AEMO's annual ESOO forecasts).

It is also noted that the Rule changes resulted in a different methodology to determine the ESR Duration Requirement (ESR Duration Requirement) for Peak Capacity Credits in the 2025 Reserve Capacity Cycle. The 2025 cycle procures capacity for 2027-28 and therefore impacts the modelling of Capability Classes for 2027-28. The duration requirement for 2027-28 is increased from four hours to six hours, and therefore the ESR modelling for Capability Classes used generic six-hour storage in the Capability Class assessment. For DSP, the requirement has also changed for 2027-28 from 50 hours per Capacity Year to 23.75 hours, however the assumption input for the modelling applied the previous 50-hour requirement (with no impact on outcomes).

2.2.4 ESR Duration Obligation Uplift

The aforementioned 2025 amendments to the market Rules also include changes to the Planning Criterion. These changes include the requirement for AEMO to determine an ESR Duration Obligation Uplift as a new component for inclusion in the Limb A requirement. This uplift, expressed in MW, accounts for a gap between the actual capacity available to meet the Peak Reserve Capacity Target and the capacity which is assigned Capacity Credits. This gap is expected to arise due to a proposed extension to the five-year protection for Capacity Credits assigned to ESR units.

2.2.5 Battery degradation and use of Reserve Capacity for ESR modelling of Limb B

This year, AEMO have provided estimates of the MW and MWh degradation for each individual grid-scale battery in the WEM. This has been included in EY's model and impacts both the Reserve Capacity available to meet Limb A, as well as the capacity modelled to meet Limb B.

2.2.6 Dynamic line ratings

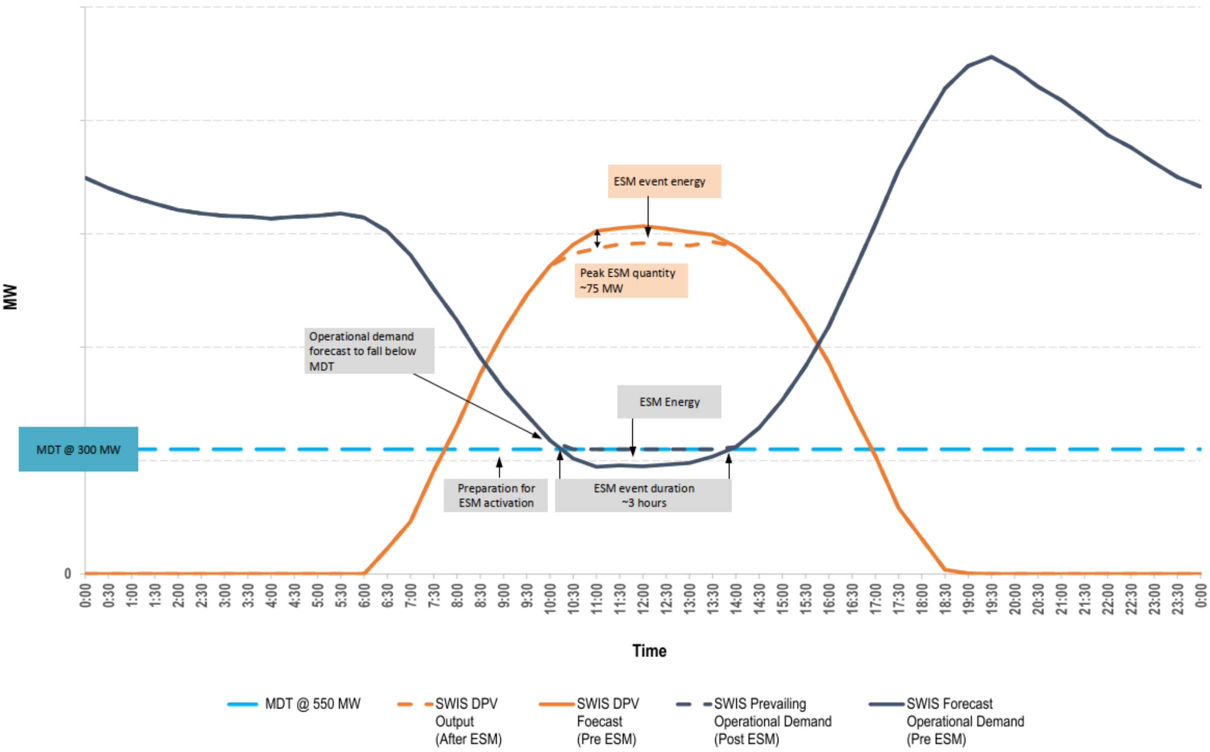
Several regions in the SWIS are set to commence operation with dynamic line ratings (DLR) and EY has implemented DLR on these transmission circuits. These ratings are used as an input into the formulation of transmission network constraint equations and represent thermal capability. DLR allows for a greater range of ratings to be applied to transmission corridors, increasing the utilisation of transmission circuits.

2.2.7 Minimum demand constraint

For the 2025 reliability study, a minimum demand threshold (MDT) in the WEM for the purposes of modelling was set at 300 MW, from the 500 MW previously modelled in 2024. The MDT refers to the minimum operational level below which the SWIS is no longer secure, and emergency actions are required.

The threshold, and the emergency response is implemented in EY's dispatch model through a constraint that curtails rooftop PV generation when demand would otherwise fall below this level. In this process, we exclude the impact that large-scale storage charging has on increasing operational demand. Figure 2 illustrates the impact of this constraint on demand.

Figure 2: Illustration of the minimum demand constraint



Source: EY

2.2.8 Assessment of transmission network augmentations

AEMO has introduced a framework for assessing whether transmission network augmentations are considered 'committed' in the 2025 reliability assessment. Based on this framework, AEMO has advised of potential delays to network augmentations such as CEL North.

3. Methodology to deliver the 2025 reliability assessment

3.1 Scope item 1: Demand profile projections

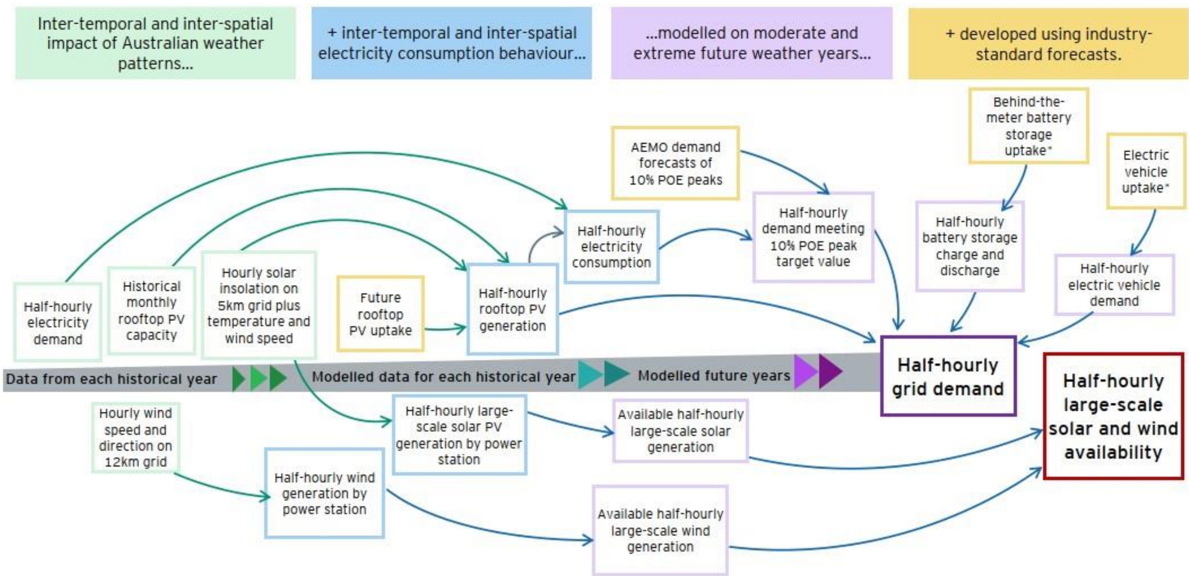
EY's approach to forward-looking half-hourly modelling is to base all the intertemporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical weather reference years.

This helps to retain the relationships between time of day, consumption behaviour and renewable resources. We consider this an essential aspect of modelling supply reliability, and allows our model to capture high impact, low probability (HILP) events induced by weather conditions and demand variability.

We believe that having demand and renewable profiles based on internally consistent weather patterns is fundamental to assessing the reliability / operability of power systems, particularly with increasing penetration of wind and solar generation.

Figure 3 depicts EY's methodology to modelling future half-hourly electricity demand, rooftop PV available generation as well as large scale wind and solar PV available generation.

Figure 3: Flow diagram showing EY's use of a historical year of electricity demand and weather conditions data to produce a time-sequential, half-hourly, forward-looking dataset for dispatch modelling



Source: EY

EY's approach to creating the half-hourly demand inputs for the dispatch model is based on disaggregating demand into the various components that influence its shape across each day and year. Once we take account of these components, the remaining demand profile is considered to be a 'fixed shape consumption' (FSC), which is driven by consumer energy use patterns in response to weather on working and non-working days. We consider these patterns fixed across future years, modified for future energy and peak demand projections.

Putting together the half-hourly demand inputs for the dispatch model involves the following key steps:

- Develop historical half-hourly operational demand profiles (based on data published by AEMO).

- Derive half-hourly profiles for historical rooftop PV and small non-scheduled PV (PVNSG) based on historical capacity and data collected by EY on historical solar resource.
- Derive half-hourly historical FSC traces for each weather reference year to be modelled. This involves adding on the historical modelled rooftop PV and PVNSG to the operational demand profiles and subtracting off other demand components modelled separately such as flat loads.
- Implement EY's load forecasting methodology, which creates future FSC profiles by targeting the same underlying annual peak for each historical weather reference year (as provided by AEMO for the reliability study).
- Derive projections of each individual component of demand (see Appendix B) which when added to (or subtracted from) the FSC profiles represent the half-hourly operational demand required to be met from WEM Facilities (and also match the annual energy consumption provided by AEMO over each forecast year).
- In previous reliability studies a final step previously involved checking the operational peak outcomes and adjusting if necessary to align with AEMO's provided projections of operational peak demand. However, this year this step has been omitted so that the reference year forecasts target the underlying peak rather than operational peak (see Section 2.2.2).

Further detail of EY's overall approach and approach to individual demand components can be found in Appendix C.

3.2 Scope item 2: Development of Constraint Equations

For the 2025 reliability assessment it was agreed with AEMO to utilise the constraint equations EY developed for the 2024 reliability study, given no significant changes to network topology assumed between the two studies.[24] The constraint equations are used to identify capacity shortfalls in sub-regions of the SWIS that may arise due to transmission network limitations.

Transmission network constraint equations are linearised mathematical expressions that represent thermal limits that the SWIS must operate within. They model the maximum power transfer that can flow on transmission network elements before a limitation is reached.[25] Distribution network limitations are not modelled in this reliability assessment.

The objective of these transmission network constraint equations is to ensure supply is dispatched in a manner that prevents overloading any transmission network elements and to keep the power system secure. The constraints take two forms:

- **N-0 constraints**: These are formulated to avoid the overloading of a transmission network element during system normal operation. This ensures the system is operating in a satisfactory operating state.
- **N-1 constraints**: These are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a different transmission network element). This ensures the system is operating in a secure operating state.

[24] Modifications were made to the constraint equations to incorporate new supply facilities, DLR and delays to CEL North.
[25] Constraint equations are constructed for network elements operating at 330 kV and 132 kV. Limitations on zone substation transformers are not considered.

In our 2-4-C modelling, N-1 constraints are enforced pre-contingently, that is, at all times. This ensures compliance with limit advice provided by Western Power and is consistent with how the SWIS and the WEM are operated in the RTM.[26]

The constraint equations are formulated based on a set of detailed power system load flow studies to derive a flow equation (representing the active power flow on a transmission network element) and the limit equation (representing the limit of that transmission network element).

Thermal constraint equations are typically formulated such that the sum of terms on the left-hand side (LHS) of a constraint equation must be less than or equal to the sum of terms on the right-hand side (RHS) of a constraint equation. Controllable generation terms are assigned to the LHS and a system demand term and a constant term associated with any post contingent remedial actions are assigned to the RHS. Constraint equations may be simplified by a combination of scaling and removal of terms considered immaterial as per AEMO constraint formulation guidelines.

3.2.1 Circuit ratings

Where a transmission network constraint is related to the thermal loading of a transmission network element, the limit has been set applying a 'summer' and 'not-summer' seasonal rating. Summer ratings are applied to all periods in the months from November to March inclusive whilst not-summer ratings are applied to all periods in other months.

Several regions in the SWIS are set to commence operation with DLR. DLR is an online monitoring system that computes ratings for network elements based on local operating conditions for use in market and operational dispatch decisions. This is different from static ratings whereby the rating of a transmission circuit is based on (typically) more conservative ambient conditions. Ratings determined by DLR may differ to the design rating, owing to different assumptions used in deriving the design rating at the time of design and commissioning.

The impact of DLR is that it will increase the RHS limit of a constraint equation during the time period where DLR is applied. This enables the SWIS to be operated with additional transmission network capacity at certain periods of time. EY has implemented DLR based on information provided by Western Power and AEMO.

3.2.2 Network reinforcement schemes

Network Reinforcement Schemes that are currently operational in the SWIS are modelled based on information provided by Western Power. These schemes can materially impact transmission network congestion modelling in different SWIS regions and include generator runback/curtailment schemes, load runback/curtailment schemes and operational measures such as opening circuit breakers to reconfigure the network.[27] These schemes allow the transmission network to be operated with higher network utilisation levels and have been factored into the constraint equations through offsets to the limit equation (the RHS), or by modifying coefficients in the flow equation (the LHS).

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[26] There are parts of the network that are designed to the N-0 planning criterion, as per the Western Power Technical Rules (https://www.westernpower.com.au/resources-education/technical-documentation/distribution-network-documentation/technical-rules/. These networks will experience the loss of power transfer capability following the loss of a transmission element. These types of considerations are factored into quantification of EUE.

[27] In certain regions, customers have had to accept a lower level of reliability to connect. For example, customers in the Eastern Goldfields have been connected under the Eastern Goldfields Load Permissive Scheme (ELPS). These customers are curtailed by Western Power when there are very high loadings on the 220 kV line. Whilst individual customer connections are not modelled, quantification of EUE consider that some customers are on ELPS and different planning criterion apply to certain parts of the network.

3.2.3 Network states

For the purpose of this reliability assessment, the transmission network constraint equations have been formulated based on a number of projected network 'states', based on information provided by Western Power:[28]

- **2025-26**: Existing network
- **2026-27**: Ratings upgrade associated with the East Region Stage 1 project, also known as East Regional Energy Project (EREP)[29]
- **2028-29**: Clean Energy Link – North Region project.[30]

3.2.4 Other considerations

Other power system security constraints have been modelled to account for minimum demand thresholds (MDT) and to limit the dispatch from multiple Facilities that may be connected behind a single connection point exceeding declared sent out capacities. This may impact hybrid facilities that have multiple technologies behind a connection point.

3.3 Scope item 3: Assessment against the Planning Criterion

The main objective of scope item 3 is to identify and characterise any capacity or reliability shortfalls for each modelled scenario (which for this year's study is the 10% POE peak demand under the expected demand scenario).

As set out in Section 1, the Planning Criterion is comprised of three components, of which 'Limb A' and 'Limb B' are applicable to the reliability study. The reliability standard requires there to be sufficient capacity available in the SWIS in each Capacity Year to meet **both** requirements (i.e. both Limb A and Limb B need to be satisfied).

Limb A of the Planning Criterion is made up of five building blocks. The building blocks are presented in Table 2.

Table 2: Building blocks of Limb A of the Planning Criterion

Building block of Limb A	Description
Annual peak demand	Forecast annual operational sent-out peak demand for 10% POE the expected demand growth scenario.
IL allowance	Estimate of the capacity required to cover the forecast requirements of Intermittent Loads (ILs), which are excluded from the 10% POE peak demand forecast.
Reserve margin	Determined as the greater of: ▪ peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages and

[28] The earliest date for commissioning the Clean Energy Link project (previously known and referred to as the North Region Energy Project [NREP]) is summer 2027-28. This has been modelled in two states – for 2026-27 and for 2027-28.

[29] See https://www.westernpower.com.au/siteassets/documents/transmission-system-plan-2023-20230929.pdf.

[30] CEL North is modelled in two stages, consistent with the approach undertaken for the 2024 WEM ESOO, but with a 1-year delay applied to each stage. The first stage of CEL North involves reconfiguring and establishing 132 kV line assets in the north metropolitan region. The second stage of CEL North involves establishment of a second 330 kV circuit and associated 330 kV infrastructure between the Midwest into the Perth Metropolitan area, along with further 132 kV reconfiguration works.

Building block of Limb A	Description
	▪ The largest contingency relating to loss of supply at the time of peak demand. For the purposes of this WEM ESOO, AEMO has considered that the largest risk to be equivalent to the loss of the three largest energy producing units.
FR allowance	Accounts for Regulation Raise quantities, escalated to account for the impact of new DPV and large-scale wind and solar capacity.
ESR Obligation Duration Uplift	Expressed in MW, this uplift accounts for a forecast gap between the actual capacity available to meet the Peak Reserve Capacity Target and the capacity which is assigned Capacity Credits. This gap is expected to arise due to a proposed extension to the five-year protection for capacity credits assigned to ESR units (to ten years).

To assess the extent to which the AIC of the Energy Producing Systems, storage, and DSP capacity is capable of satisfying Limb A of the Planning Criterion, for each modelled scenario and each modelled year we: [31]

- Quantify the Limb A requirement by determining its building blocks.
- Identify AIC as well as associated forecast Reserve Capacity, advised by AEMO.
- Identify years where there is a capacity shortfall by comparing the annual sum of Reserve Capacity of the AIC fleet against the annual requirement set by Limb A.

To assess the extent to which the AIC of the existing and committed capacity is capable of satisfying Limb B of the Planning Criterion, for each modelled scenario and each modelled year we:

- Run the 2-4-C model to dispatch the AIC under each scenario and agreed assumptions.
- Identify if there are any years where the Limb B requirement is not met. To do this, we derive the annual EUE percentage indicator (annual EUE %) by dividing modelled annual EUE volumes (MWh) by annual energy consumption (MWh) and compare the results against the 0.0002% standard.
    - We use the annual operational energy consumption provided by AEMO as the denominator of this calculation.
    - Calculate the EUE % based on averaged results of the multiple reference years and Monte Carlo iterations.

The logic of the assessment against Limb A and Limb B of the Planning Criterion is illustrated below in Table 3. Table 3 provides a summary of the four possible combinations of outcomes from the analysis in scope item 3.

Table 3: Illustration of the logic of the assessment against Limb A and Limb B of the Planning Criterion

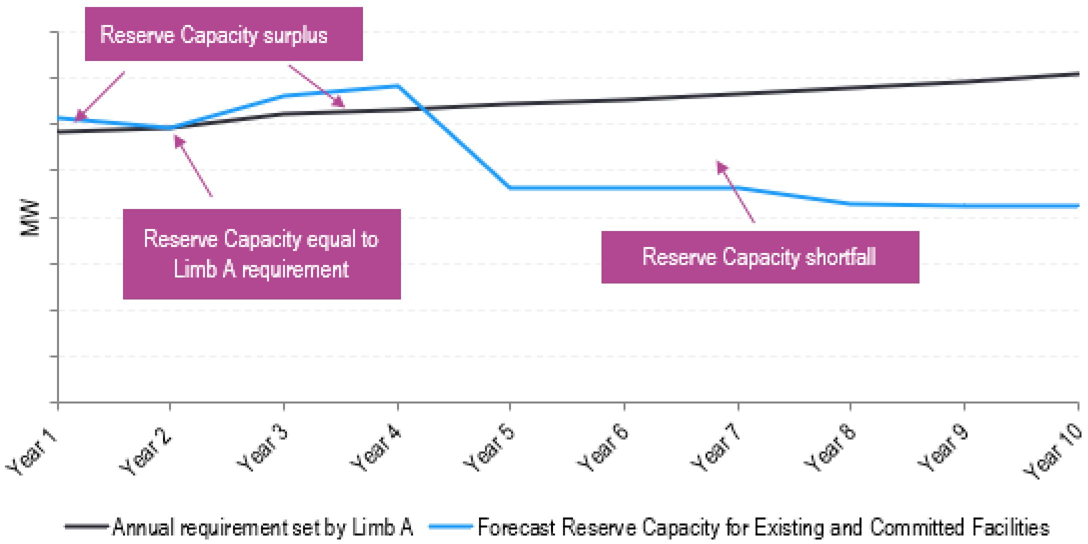
Case	Limb A requirement (MW)	AIC (MW)	Reserve Capacity (MW)	Limb A assessment: possible results	Limb B assessment: possible results
	Based on building blocks	**Existing units less retirements + committed units**	**Advised by AEMO**	**Reserve Capacity minus Limb A requirement**	**2-4-C modelling (dispatch AIC, assess EUE)**
	[1]	[2]	[3]	[4] = [3] - [1]	[5]
Case A	4,500	5,800	4,700	Reserve Capacity surplus (+200 MW)	Reliability surplus (annual EUE < 0.0002%)
Case B					Capacity investment gap (annual EUE > 0.0002%)

[31] AIC will be determined as existing SWIS installed capacity (generation, storage, DSP) less existing capacity retirements + committed capacity, and will be advised by AEMO.

Case	Limb A requirement (MW)	AIC (MW)	Reserve Capacity (MW)	Limb A assessment: possible results	Limb B assessment: possible results
	Based on building blocks	**Existing units less retirements + committed units**	**Advised by AEMO**	**Reserve Capacity minus Limb A requirement**	**2-4-C modelling (dispatch AIC, assess EUE)**
	[1]	[2]	[3]	[4] = [3] - [1]	[5]
Case C		5,200	4,100	Reserve Capacity shortfall (-400 MW)	Reliability surplus (annual EUE < 0.0002%)
Case D					Capacity investment gap (annual EUE > 0.0002%)

For assessment against Limb A, we then report on the amount of Reserve Capacity surplus or shortfall in meeting the requirement set by Limb A. Illustrative possible results of this assessment are presented in Figure 4.

Figure 4: Illustration of possible results of the assessment against Limb A of the Planning Criterion[32]



Source: EY

For assessment against Limb B, the following key metrics are provided:

- Modelled annual EUE (MWh)
- Annual operational consumption as provided by AEMO
- Modelled annual EUE % and any identified capacity shortfall.

The assessment against Limb B for the purposes of setting the Peak RCT does not include network constraints, but the analysis on sub-regional shortfalls does add network constraints to the modelling.

The results reported in the 2025 WEM ESOO reflect the addition of network constraints to the modelling as well as the outcomes of adding generic unconstrained generators to various locations

[32] Figure has no y-axis numbers deliberately as it is for the purpose of illustrating possible outcomes of the comparison between the Limb A requirement and forecast Reserve Capacity only.

around the SWIS to examine the extent of EUE that occurs in particular regions (that cannot be addressed by generation located elsewhere).

3.3.1 Identifying sub-regional capacity shortfalls

As well as determining the Peak RCT, the reliability assessment identifies sub-regional capacity shortfalls and reports on EUE outcomes isolated to these regions of the SWIS. This is identified through a set of 'EUE Generators' that are located at selected transmission connection points. They are included in a set of simulations which combine the 2-4-C reliability model with transmission network constraint equations. Apart from the constraint equations, all other elements of the reliability study are the same (i.e. same MC simulations of thermal generator outages, same weather reference years, same AIC, etc).

The EUE generators are specifically setup to be dispatched only in the case of a supply shortage and/or to relieve transmission network constraints and placed at the lowest priority of the bid merit order. They are provided an energy bid profile to ensure they are dispatched only after all existing generation, DSP and storage has been exhausted and are included as terms within the transmission network constraint equations. The generators are modelled as perfectly reliable (no forced outage rates) and do not have limits on ramp rate or the amount of MW that can be dispatched.

Where the EUE Generators are dispatched, this reflects a possible EUE risk or capacity shortfall. It reflects locations on the SWIS where customer demand can only be served by dispatching fictitious generators that are the most expensive in the BMO indicating there is inadequate sub-regional supply and insufficient import power transfer capability from the transmission network.
Sub-regional shortfalls are reported across two metrics:

- Annual EUE, which represents the annual customer demand in MWh that is observed across a capacity year, based on equally weighted likelihoods for different weather reference year conditions and iterations of MC outages; and
- Capacity shortfalls, which represents the maximum shortfall in each node of the SWIS, quantified by observing the maximum dispatch of unserved energy generators located at different parts of the SWIS. Each EUE Generator is assigned to a region and subregion. The sum of dispatch and shortfall is observed by summing up all generators in each region and subregion.

The ESOO report also provides an assessment of the potential network augmentations to relieve some of these shortfalls based on the outcomes of the sub-regional analysis, and the constraint equations that bind in the model. The ESOO report also contains the outcomes of a high-level assessment by EY of the different technologies that may contribute to addressing capacity shortfalls, based on the outcomes and learnings from other long term planning studies of the WEM.

3.4 Scope item 4: Forecasting the Peak RCT

The key objective of this scope item is to determine which component of the Planning Criterion (Limb A or Limb B) will set the RCT, where the maximum of either Limb A or Limb B will be the determining factor. Limb A is a mathematically derived requirement based on the building blocks set out in Section 3.3 and is a known quantity from the calculation carried out in scope item 3.

The capacity required to meet Limb B at this stage of the analysis is an unknown quantity, i.e. the modelling in scope item 3 will result in annual EUE being either above or below 0.0002% but not exactly at this threshold (or at least is unlikely to be at exactly 0.0002% in every forecast Capacity Year). Determining Limb B and whether Limb A or Limb B would set the Peak RCT means iteratively re-running the dispatch model to determine the required capacity that would result in EUE not breaching 0.0002%. The process is set out in the following steps.

- **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 re-run is required for each Capacity Year based on the conditions outlined in the table below.

Table 4: Limb B calculation conditions

Case	EUE	Limb B modelled AIC compared to Limb A	Re-run is required	Why?
1	Less than 0.0002%	Limb B modelled AIC<Limb A requirement	No	We know that Limb A sets the RCT because Limb B can be met at a lower level than the Limb A requirement (EUE is below the standard at a lower MW than Limb A).
2	Less than 0.0002%	Limb B modelled AIC>Limb A requirement	Yes	We don't know at the first stage if Limb A or Limb B will set the Peak RCT. The model needs to be re-ran by removing capacity to determine if the level at which EUE is reduced to no more than 0.0002% is higher or lower than Limb A.
3	Greater than 0.0002%	Limb B modelled AIC > Limb A requirement	Yes	We know Limb B sets the Peak RCT as Limb B's AIC > Limb A requirement and EUE is greater the standard. The model needs to be re-ran to iteratively add capacity until EUE is no more than 0.0002% to determine the MW value of Limb B.
4	Greater than 0.0002%	Limb B modelled AIC<Limb A requirement	Yes	We don't know at the first stage if Limb A or Limb B will set the Peak RCT. The model needs to be re-ran, adding capacity to bring EUE down to no more than 0.0002% and comparing that level of capacity with the Limb A requirement.

- **Step 3**: If a re-run is required and capacity is required to be added (depending on the case outcome described above) this is done by adding 'capacity for reliability' which is modelled as fully available dispatchable capacity which is operated to be available for instances of EUE but also provides additional benefits by being available for storage to charge from and to preserve the limited running hours of DSP. If capacity is required to be reduced, then capacity is removed from existing Facilities in order of assumed retirement.

  - Case 2: In this case, Limb B AIC Reserve Capacity is greater than the Limb A requirement but EUE is below 0.0002% therefore Reserve Capacity must be removed from the modelling to determine if the value at which EUE is increased to 0.0002% is higher or lower than Limb A. In this case capacity is reduced to 1 MW less than Limb A. If EUE is still less than 0.0002% then Limb A can be determined to set the Peak RCT for that year. If EUE is >0.0002% then Limb B Reserve Capacity would need to be increased incrementally until EUE was brought back within the standard and that value of Limb B would set the Peak RCT.

  - Case 3 and Case 4: In each of these cases a re-run is required for the relevant Capacity Year. As a first indicative step, this is done by setting Limb B capacity to just under the Limb A requirement (by 1MW). If EUE is below the 0.0002% reliability standard, then Limb A sets the Peak RCT. If EUE exceeds the standard, further modelling is required to establish the Limb B requirement.

The 2025 ESOO report provides the outcomes of each step in the process, illustrated by the results of each step for the 2025 reliability assessment

3.5 Scope item 5: Capability Classes

The assessment for this scope item must determine the minimum capacity required to be provided by Capability Class 1 (CC1) and Capability Class 3 (CC3) capacity, as required by the ESM Rules and described further in Section 2.2.3. This involves finding an appropriate mix of additional CC1 and CC3 capacity required if any shortfall is identified for the year in question, which for the 2025 ESOO is 2027-28 (in the 10% POE expected demand scenario), as the third year of the Long Term PASA Study Horizon. This modelling is required to ascertain the minimum capacity to be provided by Capability Class 1 and Capability Class 3 while ensuring that EUE does not exceed 0.0002% of annual energy consumption.

Table 5: Definition of Capability Classes

Capability Class 1	Capability Class 2	Capability Class 3
Firm capacity that is not energy limited, such as a gas-fired Facility that meets the fuel availability requirements.	Firm capacity with energy or availability limitations, such as battery / ESR, pumped hydro storage or a DSP.	Non-firm capacity, such as a wind or solar farm with no associated firming capability.

To provide this, the modelling takes the following approach, which has undergone a number of revisions to last year's approach:

- In last year's reliability study, the Capability Class modelling was required to be modelled using the 'Availability Duration Gap Load Scenario (ADGLS)'. However, the ESM Rules produced in June 2025 no longer require this. This year, the analysis takes the half-hourly demand traces developed by EY as the load scenario.
- On the supply side, the first step is to equalise the modelled capacity and associated Reserve Capacity with the Peak RCT for 2027-28. As Reserve Capacity is 932 MW below the Peak RCT in this year, the first step is to add this level of Reserve Capacity to the model. In previous reliability studies, the approach was to initially fill this gap with firm Capability Class 1 capacity (termed in the reliability study as 'capacity for reliability', or CFR) which was modelled to be fully available unconstrained capacity.

  From that point previously the next step was to iteratively add Capability Class 2 ESR and DSP capacity separately, and reduce CFR by an equal amount (in Reserve Capacity terms) until no more could be added without breaching 0.0002%. The technology that reached that point first was deemed to set the limit to the amount of Capability Class 2 capacity, and determine the minimum amount of Capability Class 1 and 3 capacity.

  However, given the new Rules referring to the outcome of the Capability Class modelling and implications for NAQ Facilities (see Section 2.2.3), the approach was revised this year to take the following steps:

  - Firstly, equalise Reserve Capacity with the Peak RCT using ESR capacity only to test if Capability Class 2 capacity alone can meet Limb B requirements. ESR is selected on the basis that it is more representative than DSP (the other Capability Class 2 type) of the forthcoming pipeline of projects, and as it has greater potential energy contribution over the year than DSP (which in the modelling for 2027-28 was only required to run for 100

Trading Intervals over the whole Capacity Year, compared to storage which is required to be available every day).[33]

- As the assessment is done for 2027-28, the modelling used the ESR Duration Requirement which applies for that Capacity Year, which was provided by AEMO as six hours duration. Therefore 932 MW of six-hour storage was added to the Reserve Capacity projected for 2027-28 to equalise total Reserve Capacity with the Peak RCT (which was set by Limb A at 6,328 MW).[34]

- If EUE is found to be less than 0.0002% then the modelling would need to be iterated to reduce existing Capability Class 1 and 3 capacity to find the minimum at which EUE would not breach 0.0002%. On this occasion, EUE was above 0.0002%, therefore the next step involved adding Capability Class 1 capacity and reducing Class 2 by an equal amount (in Reserve Capacity terms) until EUE was brought back within the standard.[35]

- A further new modelling step undertaken this year relates to the question of the appropriate mix of Capability Class 1 and Capability Class 3 capacity. This year additional modelling was undertaken to explore the impact of different combinations of CC1 and CC3, using a mix of wind and solar capacity for the latter. In this case CC1 capacity was reduced while wind and solar capacity was increased in different combinations to test the outcome on Limb B. In each case, CC1 capacity was reduced by the Reserve Capacity equivalent of the modelled wind and solar (using estimates from representative wind and solar projects, as determined by the Relevant Level Method).[36]

- The outcome of this modelling and implications is discussed in AEMO's 2025 WEM ESOO report.

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[33] For the modelling, the dispatch requirement for DSP was assumed to be the same as 2026-27, although it is noted there is a new requirement for 2027-28. This is a lower requirement than modelled and does not change any of the outcomes.

[34] Six-hour storage is used as AEMO has determined an Availability Duration Gap of 4 Trading Intervals (2 hours), which is added to the 2026-27 ESDR of 8 Trading Intervals (4 Hours) to set the ESRDR for the 2027-28 Capacity Year as 12 Trading Intervals (6 hours).

[35] In this instance 1 MW of firm Capability Class capacity is equal to 1 MW of 6-hour battery storage.

[36] Relevant Level Method as per Appendix 9 on the ESM Rules for assigning Capacity Credits to intermittent generators.

Appendix A List of abbreviations

Abbreviation	Explanation
AC	alternating current
AEMO	Australian Energy Market Operator
AIC	anticipated installed capacity
BTM	behind-the-meter
CC	Capacity Credits
CC1	Capability Class 1
CC2	Capability Class 2
CC3	Capability Class 3
CCGT	combined cycle gas turbine
CER	Clean Energy Regulator
CER	Consumer Energy Resources
CFR	Capacity for Reliability
CONE	cost of new entrant
CRC	Certified Reserve Capacity
DC	direct current
DPV	distributed PV
DSP	Demand Side Programme
EREP	East Region Energy Project
ESM	Emergency Solar Management
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resources
ESROI	Electric Storage Resource Obligation Intervals
ESS	Essential System Services
EUE	Expected unserved energy
EV	electric vehicle
FIR	Formal Information Request
FR	Frequency Regulation
FRC	Forecast Reserve Capacity
FSC	fixed shape consumption
HILP	high impact, low probability
Hz	hertz
IL	Intermittent Load
kW	kilowatt
LFAS	Load Following Ancillary Service
LHS	left hand side (of constraint equation)
LIL	Large Industrial Load
LMT	EY's Load Modelling Tool
LRR	Load Rejection Reserve
Long Term PASA	Long Term Projected Assessment of System Adequacy
MDT	Minimum Demand Threshold
MW	megawatt
MWh	megawatt hour
NAQ	Network Access Quantity

Abbreviation	Explanation
NCESS	Non-Co-optimised Essential System Service
NEM	National Electricity Market (Australia's East Coast)
NOFB	Normal Operating Frequency Band
NOFEB	Normal Operating Frequency Excursion Band
NREL	National Renewable Energy Laboratory
NREP	North Region Energy Project
OCGT	open cycle gas turbine
OPSO	operational sent out
POE	Probability of Exceedance
PVNSG	photovoltaic non-scheduled generator
RCM	Reserve Capacity Mechanism
Peak RCT	Peak Reserve Capacity Target
RHS	right hand side (of constraint equation)
SAM	System Advisory Model
SC	Supplementary Capacity
SEST	EY's Solar Energy Simulation Tool
SRAS	Spinning Reserve Ancillary Service
SRMC	short-run marginal cost
SWIS	South West Interconnected System
V2G	vehicle-to-grid
VPP	virtual power plant
WA	Western Australia
WEM	Wholesale Electricity Market (Western Australia)
WEMDE	WEM Dispatch Engine
WEST	EY's Wind Energy Simulation Tool

Appendix B Modelling methodology

This appendix provides an overview of the modelling approaches that are unchanged from the 2024 reliability assessment.

B.1 Assumptions relating to generation, storage and demand side response providers

AEMO has provided EY with the generation, storage and demand side capacity that is expected to be participating in the WEM over the study period. This includes assumptions around which Facilities may enter the market and those that have been announced or are assumed to exit the market. For the purposes of modelling, and categorising how the modelling treats each of these Facilities, the various types of Facilities modelled are described as follows:

- Thermal generators (coal, gas, diesel, waste-to-energy, landfill gas)
- Intermittent generators (wind and solar)
- ESR
- DSP

Table 6 sets out the key characteristics that impact a Facility's interval-to-interval availability to meet the demand for energy in the SWIS, captured within EY's modelling. Additional assumptions that are specific to each Facility type are discussed in each section below as relevant.

Table 6: Key characteristics modelled for all Facilities

Assumption	Source	Notes
Planned maintenance	Advised by AEMO/FIR data, plus EY modelling as required.*	Further detail in B.1.6,
Forced outage rates	Advised by AEMO/FIR data, plus EY modelling as required.*	Further detail in Section B.1.7.
Fuel type	AEMO market data/advised by AEMO for new Facilities.	The capacity of gas pipeline infrastructure is not modelled.
Maximum sent out capacity	Advised by AEMO/FIR data.*	
Ramp rates by Facility (up/down)	AEMO market data/advised by AEMO for new Facilities.	Defined as MW/minute, up/down capability.
Capacity Credits and forecast Reserve Capacity by Facility	Advised by AEMO.	
Battery Degradation	Advised by AEMO.	Applied to the determination of AIC and Limb B modelling.
ESS capability	Advised by AEMO.	Contingency Reserve Raise and Regulation Raise services.
Energy market bids	Merit order agreed with AEMO	For the reliability study the precise bids of each unit are of secondary importance, as at times of high demand all available Facilities will be dispatched regardless of their market bid. The order of bids however and the times of the day during which particular capacity bids in the model is important for energy-limited resources – for example DSP is bid last as it has the most limited annual availability (50 hours per year from 2026-27). Also note that Facilities with NCESS contracts with AEMO are only required to be available over an agreed set of intervals each day, and are bid in the model to reflect this – see further details below.

Note: AEMO market data for the WEM can be found here: AEMO | Market data.

**FIR (formal information request) data refers to the data collected by AEMO from Rule Participants as provided for in the ESM Rules as part of the reliability assessment for the Long Term PASA Study Horizon.*

B.1.1 Thermal generators

The key assumptions relating to thermal generators for the purposes of the reliability study refer to their maximum sent out capacities, ramp rates, planned maintenance schedules and unplanned / forced outage characteristics.[37] Each Facility is modelled individually and is dispatched fully as required to meet projected demand in each interval, subject to its maximum sent out capacity in that interval, maintenance and forced outages and any network or other constraints (e.g., ramp rates) on its output.

Thermal generators are bid into the market model based on a set of input bids constructed in price quantity pairs that are benchmarked by EY to recent WEM price and generation outcomes.[38] We note that at times where unserved energy may present, we expect every available Facility to be generating at its maximum available capacity (subject to outages, ramp rates, ESS headroom, impact of network constraints) to avoid unserved energy, which means that the bids and the position of a Facility in the bid merit order (BMO) will be of secondary importance.

B.1.2 Large-scale energy storage modelling

In the WEM, large scale storage that is assigned Capacity Credits is required to be available for a set of eight contiguous 30-minute Trading Intervals. These are set by AEMO and make up the Electric Storage Resource Obligation Intervals (ESROI) in the ESM Rules.

The reliability assessment includes existing and committed large scale storage units. For the main scope items of the reliability study, EY has modelled storage with priority on generating during periods where there is a heightened risk of unserved energy. This requires prioritising charging the storage unit at all other times. We note that this does not automatically align exactly with the ESROIs as described above.

There may well be risk of unserved energy outside of ESROIs, e.g., 15:00 to 16:00 on a cloudy, low-wind afternoon with low thermal generator availability during the spring season. Considering this example, for the purpose of the reliability assessment we have modelled the operation of large-scale storage to ensure unserved energy is avoided whenever possible. This means that storage units may operate outside of the ESROI intervals and not be at a full state of charge at the beginning of the ESROI interval. This approach was agreed with AEMO on the basis that if risk of unserved energy was known in advance the ESROI intervals may be revised on an operational timeframe in consultation with ESR providers.

B.1.3 Modelling of intermittent generators

To model large scale wind and solar Facilities, EY models future half-hourly generation availability profiles based on historical wind and solar resource data for various locations. These availability profiles reflect potential renewable energy output (in MW) before the impact of network curtailment (due to thermal limits of network equipment) or economic spill.[39] The reliability study incorporates 14 historical weather reference year data from FY 2010-11 to 2023-24 to ensure a spread of different weather patterns are considered when forecasting supply reliability. This is particularly important as the WEM transitions to increasing proportions of intermittent generation sources.

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[37] For non-intermittent generators, 2-4-C uses the CRC level to define the maximum dispatchable capacity when the generator is fully available.
[38] The benchmarking process is carried out every 6-12 months and creates a range of input bids that are set up in price quantity pairs that aim to yield outcomes that align with the latest market outcomes The most recent bids are aligned with a full benchmark carried out on the 2022-23 financial year. As mentioned above however the actual value of bids are of secondary importance in a reliability study.
[39] Economic spill relates to the scenario where interval demand is such that available wind and solar resource is not fully utilised. In such cases, generation bidding into the market at lower (or equal) prices than the unused wind and solar availability is sufficient to meet demand, and the unused availability of wind or solar is "spilled", i.e., not dispatched.

An overview of our methodology for wind and solar modelling is as follows:

- **Wind**: EY's half-hourly wind generation modelling is based on location-specific historical wind resource data.
  - The first step involves collection of historical hourly short-term wind forecast data (wind speed and direction forecasts from a few hours ahead) from the Bureau of Meteorology (the Bureau) for a 12 km grid across the relevant areas of WA.
  - EY's Wind Energy Simulation Tool (WEST) is then used to develop half-hourly, time sequential, locational wind availability profiles for existing and potential wind farms used in the modelling. WEST does this by scaling the wind speed data for each site and processing through a typical wind farm power curve to target a specific annual capacity factor. The scaling is usually required to convert the modelled wind speed to the representative wind speed received by the wind farm.
  - The capacity factor target for each wind farm (existing and committed) is based on market observations and estimations (noting that published data on wind farm availability is not available for the WEM – the published data on wind farm output is actual dispatched generation which will be availability net of economic spill and/or generation curtailed due to constraints and/or operational actions used by AEMO to manage power system security).[40]
- **Solar PV**: Similar to wind modelling, the large-scale PV half-hourly availability profiles produced by EY are based on historical data collected from the Australian Bureau of Meteorology, processed by EY to convert the resource to develop half-hourly, time-sequential, locational solar PV generation availability profiles.
  - The data collected is historical satellite derived solar insolation data, with hourly data on a 5 km grid for 2010-11 to 2015-16 and 10-minute data on a 1 km grid for 2016-17 onwards. The solar insolation data is combined with weather station data of temperature and wind speed from the Bureau to account for impacts of those variables on solar cell efficiency.
  - EY applies its Solar Energy Simulation Tool (SEST), which uses the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to convert the resource data to generation availability profiles for each Facility (targeting an annual capacity factor or using EY's calibrated settings to predict the capacity factor for a given solar farm design).

[40] Annual capacity factor targets to inform creation of half-hourly wind resource availability profiles were obtained through EY's analysis of the Global Wind Atlas data as well as observed half-hourly generation output data for WEM wind farms throughout historical weather reference years. EY has also considered industry feedback received through planning processes such as the WA Whole of System Plan and the SWIS Demand Assessment to estimate the capacity factors for new entrants.

- Modelled annual available capacity factors may vary from site to site as a result of calibration to the performance of existing solar farms and the locational resource data as well as assumed design characteristics such as solar position tracking and the DC capacity to AC capacity ratio.[41]

For both wind and solar, the capacity factor may vary between historical weather reference years based on inter-annual differences in the underlying locational resource data.

As noted in Section B.1.6, where information is available on planned maintenance periods for intermittent generators, we have included this in the modelling (i.e., modelled it as unavailable during the stated Trading Intervals in future). As noted in B.1.6, the nature of outages for wind and solar generators is different from large thermal generating units due to the modular nature of wind turbines or solar panels within a Facility. The capacity factors modelled for wind and solar farms are based on observed and/or expected output of the wind and solar farms modelled, and as such implicitly include the impact of planned and forced outages (which are expected to impact only a subset of turbines or panels at any given time).

B.1.4 Demand side providers

Demand side response providers have been included in the dispatch modelling based on information provided by AEMO. These providers typically operate as last-resort capacity suppliers to the energy market and as such, have been bid to be dispatched last in the BMO. The modelling applies the same bid to each of these units meaning that all will be dispatched simultaneously in the model if required (up to their annual availability as described below), with tie breaking enabled in the model to share dispatch across each provider. In real time dispatch, AEMO forecasts a need for DSP and activates DSP Facilities ahead of the relevant Dispatch Interval (which would be expected to be at Maximum STEM Price but might not be). As such, all DSP Facilities have the same merit.

Demand side response providers in the WEM are required to satisfy minimum availability requirements according to the ESM Rules. Each demand-side response provider has been modelled according to the parameters provided on:

- Maximum annual available hours of demand-side response.
- Maximum MW demand side response provided per event.
- Maximum number of response events per year and maximum number of hours per day duration.
- Minimum number of hours response provided.
- Availability for demand side response, including business / non business day and time of day.
- Ramp rates.
- Any other availability constraints as advised by AEMO.

B.1.5 NCESS Facilities

The capacity procurement undertaken by AEMO as described in Section 1.3, has resulted in a number of Facilities in the WEM with contracts with AEMO to provide the NCESS Peak Demand service. Under these contracts, these Facilities, or the capacity of those Facilities associated with the contract is required to be available every day during the ESROI periods.

For the 2025 reliability study, indicative ESROI intervals were applied as follows:

[41] Annual capacity factor targets to inform creation of half-hourly wind resource availability profiles were obtained from observed half-hourly generation output data for WEM solar PV farms throughout historical weather reference years. EY has also considered industry feedback received through planning processes such as the WA Whole of System Plan and the SWIS Demand Assessment to estimate the capacity factors for new entrants.

- All seasons: 17.00 to 21.00

NCESS Facilities are bid into the model only during the ESROI intervals and are bid very last in the merit order, reflecting that these Facilities would be called upon as a last resort.

B.1.6 Planned maintenance

AEMO has provided EY with data collected through its formal information request (FIR) process which includes the planned outage data provided by market participants, including the start and end intervals of the outage and MW of capacity on outage (i.e., either full or partial outages).

As noted in the FIR file from AEMO, not all Facilities provided planned outage information where schedules are not yet available. In some instances, we noted that maintenance is planned up to a certain point in time (e.g., to 2026-27) but not for the full modelling period required for scope items 1 and 2 of this reliability assessment.

The following approach has been undertaken to model planned maintenance:

- Where maintenance schedules are provided for the full modelling period (i.e., up to 2034-35), EY has implemented these directly into the dispatch model.
- Where maintenance schedules are provided only up to a certain point, EY has used its maintenance scheduling tool (the Maintenance Creator) to schedule maintenance for the years where data is not available (further detail below).
- Where maintenance schedules are not available but guidance has been provided in the FIR (e.g. number of hours planned per year), this information has been incorporated into EY's Maintenance Creator and used to schedule maintenance (e.g. for the indicated number of hours per year).
- Where no data is available (i.e., neither dates nor length of maintenance), we have agreed technology specific maintenance parameters that are applied to each Facility with AEMO (i.e., on number of hours / days of maintenance per year) and have applied these through our Maintenance Creator to schedule maintenance for these units (see Section D.7).
- As an additional step, any maintenance that was indicated through the FIR responses to be planned over the Hot Season (December to March) was moved to an alternative non-Hot Season month.

EY's Maintenance Creator tool schedules maintenance for each Facility in the 2-4-C model during periods estimated to typically have low demand for a given number of days each year generally depending on technology (or Facility specific) assumptions. The tool starts with the largest Facility and the largest number of maintenance days blocks first and continues to identify the next lowest demand periods to schedule maintenance days for the next Facility in order of their MW capacity.

The Maintenance Creator has been provided with scheduled maintenance dates as submitted to AEMO via the FIR data. The tool has taken those planned periods into account and scheduled maintenance for other units around those periods. By allocating planned maintenance to the largest units first, the tool has ensured they are put on maintenance during the lowest demand periods, considering the number of days they are required to be on maintenance. The ultimate date chosen is the date which has the lowest demand period throughout the maintenance duration, not necessarily the lowest demand day.

The Maintenance Creator tool iterates through all Facilities from largest to smallest, checking if there is a planned maintenance already input for that year, checking if other units in that Facility are already on maintenance (and if so, skip to the next Facility) and checking if any other restrictions have been added (e.g., it can be set to not allow maintenance over a set of defined months such as the summer months). This process continues until all Facilities have been assigned planned maintenance schedules for each year of the study.[42]

It is noted that in reality, AEMO must assess Outage Plans against the criteria for evaluating Outage Plans set out in Clause 3.18E.8 of the ESM Rules (the Outage Evaluation Criteria are met when in AEMO's opinion there will be sufficient Network in service and capacity, including DSP capacity to maintain Power System Security and Power System Reliability). For modelling purposes these criteria were not specifically applied to the maintenance scheduling, however due to the way in which the tool schedules maintenance (by allocating the largest units to the lowest demand periods and iterating through units by size) there is likely not a more optimal time to arrange maintenance from a supply demand balance perspective.

B.1.7 Forced outages

The modelling of each future year of this reliability assessment includes multiple iterations of forced outages to capture a range of potential outage outcomes that may occur at the half-hourly level for the same modelled interval. One of the key drivers of uncertainty of outcomes is the probabilistic nature of forced outages (they are unplanned and can occur randomly at any time due to a whole range of potential causes).

For this reliability study, 2-4-C was applied to simulate a large number of Monte Carlo iterations to capture the impact of forced (unplanned) outages on the availability of the supply side to meet prevailing interval demand.[43]

Each Monte Carlo iteration assigns random outages to each generating or storage Facility, based on assumed outage statistics. These statistics have been provided by AEMO and are based on an assessment of recent actual outage data.

A 'mean time to repair' and a 'mean time to fail' value of hours is assigned to each Facility in the simulation. A Facility on a forced outage is excluded from the BMO and is unable to be dispatched to meet demand in that interval (or in the case of a partial outage, a proportion of the Facility's capacity is modelled as unavailable).

As noted in Section B.1.3, the nature of forced outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a Facility. The capacity factors modelled for wind and solar Facilities are based on observed and expected output of the wind and solar Facilities included in the modelling, and as such implicitly include the overall impact of outages on a Facility's availability.

B.1.8 Ramp rates

[42] EY has assessed whether scheduled maintenance across the fleet contributes to the EUE. In a power system with insufficient supply capacity across the majority of the year rescheduling maintenance has negligible impact except for moving the observed EUE to another period of time.

[43] For each of the Capacity Years of the reliability assessment, EY modelled a population of 1,200 Monte Carlo iterations. An assessment in the 2023 study on the basis of the coefficient of variation for the 2025-26 Capacity Year indicated that the modelling achieved convergence (i.e. a stable value of the coefficient of variation) meaning that increasing the population of Monte Carlo simulations would not significantly change the modelled EUE outcomes. Such assessment is e.g., exercised by the European Network of Transmission System Operators for Electricity (ENTSO-E) in the European Resource Adequacy Assessment for the European Union interconnected electricity system. The selected number of Monte Carlo also maintained simulation speed (model runtime) within reasonable timeframes.

The ability of a Facility to contribute to meeting energy demand (or provide ESS) can depend on how quickly it can increase or decrease its output. For 30-minute modelling ramp rates may not bind often but for the purpose of a reliability study it is particularly important to capture the ability of generators (and demand-side response providers) to ramp up (or down) to the required level from one interval to the next.

Data on generator ramp rates is sourced from the publicly available data on WEM Facilities on AEMO's website.[44] These are input into the 2-4-C database and the assumed rate of MW/min for ramping up and down will be taken into account in the modelled dispatch of each Facility.

B.1.9 ESS bidding

The Regulation Raise and Contingency Reserve Raise have been modelled with Facilities cleared for each of these markets based on bid profiles into these markets. Facilities are cleared based on a co- optimised merit order considering bids across all ESS markets and the energy market.

An ESS bid curve was produced for each Facility that is eligible to participate in the different ESS markets. For the purposes of the reliability assessment, these bid curves were simplified to ensure that facilities eligible for ESS would meet ESS requirements ahead of participating in the energy market.

[44] AEMO | Data (WEM)

Appendix C Modelling half-hourly demand

C.1 Introduction

This section describes the principles and steps used by EY to produce half-hourly demand data inputs based on AEMO's forecasts of peak demand (MW) and annual energy (MWh) for the 2025 WEM ESOO. Half-hourly demand data was used as inputs to the 2-4-C model used in the reliability assessment for each future year and scenario as applicable.

- **Section C.2** describes the use of historical weather reference years, which is EY's approach to capturing the potential future variation in time-sequential, per-interval demand as well as renewable resource availability.
- **Section C.3** sets out the annual forecasts provided by AEMO (most of which are typically published each year in the WEM ESOO).
- **Section C.4** describes the steps EY has taken to convert the annual (or monthly) forecast data provided by AEMO into half-hourly demand profiles and renewable resource availability profiles used in the modelling.

C.2 Approach to forecast years based on historical weather reference years

EY's approach to forward-looking half-hourly modelling is to base all the intertemporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical weather reference years.

This helps to retain the relationships between time of day, consumption behaviour and renewable resources. We consider this an essential aspect of modelling supply reliability, and allows our model to capture high impact, low probability (HILP) events induced by weather conditions and demand variability.

We believe that retaining correlation (or temporal synchronisation) between demand and renewable resource data is fundamental to assessing the reliability / operability of power systems, particularly with increasing penetration of wind and solar generation.

The key principles of this approach are as follows:

- The historically observed intertemporal and interspatial impact of weather patterns are maintained in the forward-looking dataset. Historical hourly locational wind and solar resource data is used by EY to model half-hourly generation from rooftop PV, large-scale solar PV and wind generation (see also Section B.1.3). All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns.
- Intertemporal and interspatial (regional) electricity consumption behaviour is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO. We then add historical modelled rooftop PV generation output and generation from small non-scheduled PV units ('PVNSG') to produce the historical electricity consumption. If applicable, depending on the market operation in the relevant reference year, we also take account of any load shedding and large-scale battery charging on the demand profile.

  By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation and how that is changing the half hour to half hour shape of grid demand during each day. EY also separately models behind-the-meter storage profiles and electric vehicle charging profiles to capture their impact on the shape of grid demand.

- The historical years used in the modelling consist of various types of weather, which may or may not be considered typical or average. For the purposes of this reliability study, the 10% POE expected demand scenario is used to deliver the reliability study scope items although demand traces for all scenarios (the 10% POE and 50% POE for low, expected and high demand) have been developed as part of EY's scope.

- Overall, the half-hourly modelling methodology ensures that the underlying weather patterns and atmospheric conditions are projected in the forecast, capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in a historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The availability of renewable generation which is assumed to be operational within a given period is a function of the atmospheric conditions specific to each plant location and as would have been experienced across the whole SWIS during the same weather event.

C.3 Inputs to half-hourly demand modelling

The demand scenarios modelled in the reliability assessment are consistent with the 2025 WEM ESOO scenarios. AEMO provided the demand inputs as set out in Table 7 on an annual (or in some cases seasonal or monthly) basis. Based on AEMO's forecasts, EY developed half-hourly projections covering every Trading Interval in the forecast period and used these half-hourly projections in dispatch modelling.

Table 7: Annual demand and CER inputs from AEMO

Item	Units/coverage	Notes
Annual underlying peak demand	▪ Summer and winter, MW	Not published as part of WEM ESOO, received separately from AEMO. Ultimately, we calculate/estimate the fixed-shape consumption (FSC) seasonal peak demands and other components separately. These then sum to operational demand (which is an outcome of the demand process).
Annual operational energy	▪ GWh	We calculate the FSC annual energy demand but use this information to check the final operational demand produced by EY after accounting for each of the various demand components aligns with AEMO's projections.
Behind-the-meter (BTM) rooftop PV	▪ MW installed capacity ▪ Expected energy (GWh)	EY produces rooftop PV profiles that meet the projected energy in each future year before any potential rooftop PV curtailment is applied to meeting minimum operational demand threshold requirements (see Section C.5).
PVNSG (small PV non-scheduled generators)	▪ MW installed capacity ▪ Expected energy (GWh)	As above for rooftop PV, except that these are not subject to curtailment as part of the minimum demand threshold. See Section C.5.
Electric vehicles (EVs)	▪ GWh annual consumption from EVs, broken down by EV types with static demand profiles ▪ EV virtual power plant (VPP) proportion of total EV demand	EY uses data provided by AEMO on monthly uptake of EVs by charging type, vehicle type and typical charging half-hourly profiles and used these to produce aggregate half-hourly profiles for the EV fleet for each year of the study. AEMO provided the proportion of EV VPP (which applied in the expected and high scenarios and represents the charging that is participating in an aggregated virtual power plant arrangement) and EY processes this energy demand through an EV VPP tool (which essentially moves charging from peak demand times to the lowest demand times in each day in each reference year). Vehicle-to-grid modelling was included based on an uptake trajectory provided by AEMO. To reflect the capability of these EVs to both charge and discharge, these EVs were modelled as 5-hr batteries. The

Item	Units/coverage	Notes
		dispatch of these batteries was modelled dynamically in the supply side of the model, similarly to other large-scale batteries.
EV contribution to peak	▪ MW, summer and winter	The interval time-stamp of peaks for each year and scenario were used to derive this from the half-hourly profiles created as described above.
BTM battery storage	▪ MW/MWh capacity by year ▪ Assumptions on coincident generation, charging and storage capacity utilised ▪ VPP proportion of total BTM storage capacity	Based on the annual uptake provided by AEMO, EY created a set of 'static' behind-the-meter storage charge and discharge profiles (for summer and not-summer). These profiles are developed based on an assumption that tariffs are in place that incentivise a reduction in peak demand and charging during low demand intervals during the day. To incorporate imperfection into the aggregated profile of the batteries, the following factors are applied: ▪ **Total energy charge discount:** To account for the likelihood that battery owners won't fully charge their batteries every day the daily charge is limited to 50 per cent of the total installed energy capacity. ▪ **Co-incident charge/discharge factor:** This factor accounts for faults, co-ordination and the potential for different tariff signals to lead to batteries never being charged or discharged all the same time. The maximum charge or discharge is limited to 25 per cent of the total charge/discharge capacity in MW. Additionally, AEMO provided annual estimates of the proportion of storage that is forecast to participate in a VPP. As it is assumed this capacity is operating as an aggregated and co-ordinated resource, it is operated in the model with the same methodology as applied to large-scale storage.
Block loads	▪ GWh / MW at peak	Modelled with the contribution to peak demand as advised by AEMO and energy aligned with AEMO's projections over the year as a whole.
Electrification	▪ GWh	Electrification was modelled as a flat, non-flexible 'baseload' demand, based on the MW associated with the projected annual GWh energy demand.
Hydrogen load	▪ GWh / MW at peak	The operational demand peaks provided by AEMO for the reliability study reflect hydrogen load turning down to ten per cent of its installed capacity at peak times. As a simplified approach, the modelling for the reliability study included hydrogen load at this ten per cent over 4.30 to 9.30pm, and at a higher level nearer its full installed capacity over the year such that the full annual energy consumption is included in the modelling.

C.4 High-level overview of approach to modelling demand components

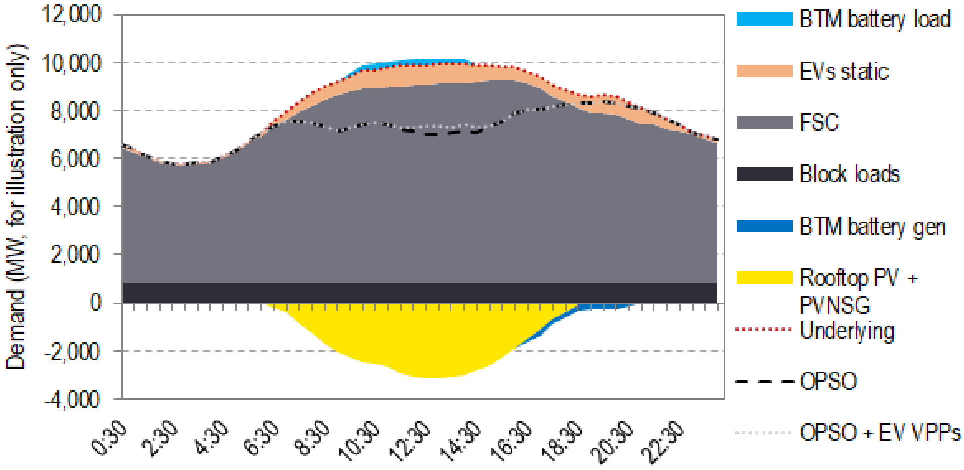
EY's demand modelling philosophy is based on splitting the operational demand into components that can be modelled separately, where each has an influence on changing the shape of the demand profile. These components include:

- BTM rooftop PV generation and small non-scheduled PV generation (PVNSG).
- Electric vehicles (EVs).
- BTM batteries (can have a positive and negative demand at different times).
- Block loads (large flat loads or large industrial loads), hydrogen production loads, and electrification load.

After separating these components in the demand modelling, we consider the remaining demand profile to be of a fixed shape (named 'fixed shape consumption', or FSC), with the shape driven by residential and business energy use behaviour patterns in response to the weather from half hour to half hour. We consider these patterns to be fixed across future years, modified for future energy and demand forecasts. We assume that the same temperature and weather conditions in a forward-looking year based on a particular reference year elicits the same demand behaviour as in the corresponding reference year (further detail below).

Figure 5 presents the various demand components that EY models separately, and illustrates how these result in the sent out operational demand that SWIS Facilities will be dispatched to meet in the half-hourly dispatch modelling.

Figure 5: Illustrative profile of demand components[45]



Notes: FSC – fixed shape consumption, OPSO – operational demand sent-out, VPP – virtual power plant

At a high level, the approach to producing each of the half-hourly profiles for each component of demand involves the following steps:

- Determine the half-hourly historical operational demand (from market data published by AEMO)
- Determine the historical rooftop PV and PVNSG capacity factors based on monthly data on installed capacity and generation from AEMO and produce half-hourly historical profiles using EY's SEST tool
- Create a historical half-hourly FSC profile for each historical weather reference year.

To create an FSC profile for each forecast year, the annual underlying and operational peak demands (summer and winter, as provided by AEMO) as well as annual operational consumption are processed by EY's Load Modelling Tool (LMT), along with other annual inputs on demand components and CER uptake (as outlined in Figure 6 above).

By projecting forward consumption (derived as per the above steps) instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day.

EY also separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO.

This approach considers that the underlying consumption / FSC peak demand is consistent across different weather reference years (i.e., it is about how high electricity consumption will go in a given

[45] Note that this chart is illustrative only, intended to show how 'Fixed Shape Consumption' is modelled relative to other demand components – the modelling for the reliability study (or any other modelling) may include additional demand components or exclude certain of these (i.e. the low demand scenario did not include EV VPP take-up for example).

year, and is independent of the intra and inter day weather patterns that we get from the reference year data). Therefore, based on the underlying peak demand provided by AEMO we have derived a target for the FSC peak demand that is also the same in each reference year for each future year. Due to the varying weather pattern in each reference year we observe differences in the shape of rooftop PV and PVNSG output in different reference years, resulting in different operational peak demands depending on the weather reference year.

C.5 Behind-the-meter rooftop PV and PVNSG (DPV)

For each scenario of the reliability study, AEMO provided EY with monthly uptake (MW) of distributed PV (DPV), comprising:

- Business and residential behind the meter rooftop PV
- PV non-scheduled generators (PVNSG, systems that are greater than 100 kW but smaller than 10 MW generators).

To model BTM rooftop PV and PVNSG, EY uses a similar approach to that for large scale solar described in Section B.1.3. We use historical data on solar resource at selected locations of the SWIS to estimate historical reference year PV generation and use this to produce half-hourly reference year availability traces for behind the meter rooftop PV and PVNSG.

We used the data on projected energy provided by AEMO, and capacity factors based on historical monthly data on PV generation and installed capacity provided by AEMO to align with the future PV annual energy forecast provided by AEMO. This historical capacity factor can be used in modelling projections in two ways:

- The same annual capacity factor can be targeted for every reference year profile, or
- The annual capacity factor can be allowed to vary from year to year, but average to the target capacity when considered over all reference years (with the latter allowing more of the natural variability in different weather reference years to be captured within the reliability study).

It was agreed with AEMO to apply the second approach described above (varying capacity factors each year). The half-hourly PV profiles for each year are input into 2-4-C, with generation impacting the operational demand to be met from large scale generators, storage and demand-side response providers units in each interval. In most intervals, modelled generation of DPV will equal its resource availability profile, however in certain instances DPV may be subject to Emergency Solar Management (ESM) where it will be dispatched below its availability.

C.5.1 Emergency Solar Management and DPV curtailment

The minimum demand threshold (MDT) refers to the minimum operational demand level below which the SWIS is no longer secure, and emergency actions are required.

As part of the response to managing low load conditions in the SWIS, new measures were introduced in February 2022 requiring all new and upgraded behind-the-meter solar PV and battery installations with inverter capacity of 5 kW or less to be capable of being remotely turned down or switched off in emergency situations.

To reflect the above, our modelling implements a constraint that curtails DPV generation if SWIS operational demand were to fall below a particular threshold. For the purposes of this study, AEMO has advised an MDT of 300 MW, which AEMO has identified as the level required to maintain system security, including local region (both North and South) reactive power management requirements.[46]

C.6 Electric vehicles (EVs)

AEMO provided EY with detailed information that allowed EY to calculate an aggregate interval by interval charging profile for the fleet of vehicles that will charge from the grid, for each scenario and each year of the reliability study.

This information includes a monthly uptake of electric vehicles by vehicle type (10 vehicle types) as well as sample weekday and weekend charging profile for each of these vehicle types by charging profile type (unscheduled / incentivised by time of use tariffs / public and fast charging for example).[47]

Based on the proportion of vehicle numbers undertaking each charging behaviour, we used the monthly uptake to multiply the sample weekday and weekend charging profiles to create an aggregated half-hourly MW electricity demand for the entire fleet.

AEMO also provided the proportion each charging profile assumed to participate in a virtual power plant (VPP) arrangement. Based on that assumption EY modelled the associated energy consumption using its EV VPP tool.

For the VPP component of EVs, rather than applying a 'static' approach to charging, the VPP tool considers demand across each day in the modelled year and selects periods of charging at times which fill in the deepest troughs in demand (and in effect reduces charging at times when demand is higher, or DPV generation has reduced for example).

Note that while the 'static' EV profile is assumed to be the same in each reference year (i.e. it is not driven by differences in weather conditions), the VPP outcomes are determined separately for each weather reference year, depending on the shape of demand in each day of the forecast.

Vehicle-to-grid modelling was included based on an uptake trajectory provided by AEMO. To reflect the capability of these EVs to both charge and discharge, these EVs were modelled as 5-hr batteries. The dispatch of these batteries was modelled dynamically in the supply side of the model (similar to other large-scale batteries) and operated to reduce unserved energy. Effectively, the charging profile of the V2G EVs uplifts the operational load curve during lower demand times and reduces operational peaks.

C.7 Behind-the-meter battery storage

AEMO provided EY with MW and MWh (degraded) by commercial, large commercial and residential categories of BTM battery storage Facilities.

EY's approach is to run our behind-the-meter storage tool which takes the annual MW and MWh uptake and converts this to a half-hourly charge and discharge profile for each day of the forecast period. The tool assumes that charging and discharging behaviour will be incentivised via tariffs that reflect higher peak demand usage tariffs (to incentivise BTM battery discharging) and lower priced

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[46] The calculation of the operational demand value in the constraint equation does not include the demand from utility-scale battery charging. It is also important to note that in real-time operation, AEMO may be required to intervene at demand levels above 300 MW according to the specific fleet configuration and demand uncertainty at the time of intervention.

[47] Note that the 10 vehicle types provided are as follows: 1. Articulated Truck, 2. Bus, 3. Large Light Commercial, 4. Medium Light Commercial, 5. Small Light Commercial, 6. Rigid Truck, 7. Motorcycle, 8. Large Residential, 9. Medium Residential, 10. Small Residential.

daytime effective tariffs (to incentivise BTM battery charging, due to battery owners being assumed to also own rooftop PV systems).

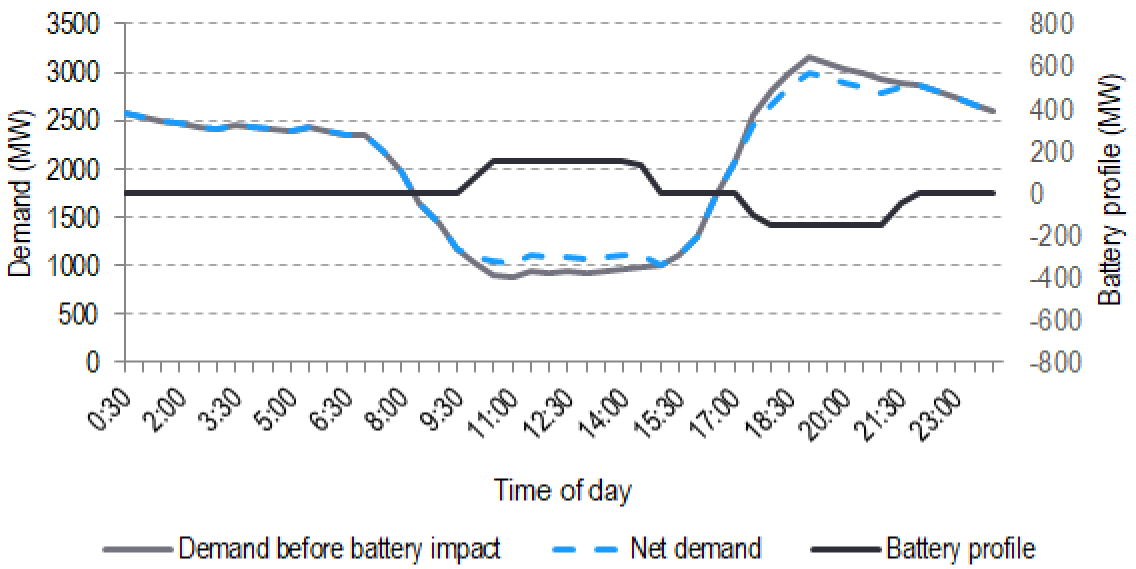
Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network, i.e. consumption minus rooftop PV generation. This is based on the rationale that future tariffs will be structured to incentivise battery owners to reduce the difference between the daily minimum and maximum demand as this provides a more optimal network usage. As a result, the tool produces a fixed time of day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand. This profile is produced for each historical reference year of the study.

There are two ways in which the tool introduces imperfection to the aggregated profile of the batteries:

- Total energy charge discount factor (50%): To account for the likelihood that battery owners will not fully charge their batteries every day (due to faults, performance degradation, etc.), the daily charge is limited to the selected percentage of the total installed energy capacity of the battery.
- Coincident charge/discharge discount factor (25%): This factor accounts for faults, coordination and the potential for different tariff signals to lead to batteries never being charged or discharged all the same time. The maximum charge or discharge is limited to the selected percentage of the total charge/discharge capacity in MW.

Figure 6 illustrates an example day where the aggregate battery charge and discharge cycle alters the operational demand profile.

Figure 6: Illustrative day showing impact of BTM battery storage on operational demand



C.8 Modelling block loads/large-industrial loads

EY's default approach is to model large known loads separately from other demand components as outlined above, particularly where these loads have implications for the modelling of network constraints. For this modelling we do not require block loads or large industrial loads to be modelled as separate entities, but did include the collective MW / MWh of these loads to ensure their contribution to peak and overall energy demand in the modelling is aligned with AEMO's annual peak and energy forecasts. Specifically, the demand forecasts and the EY translation of these into half-hourly profiles covered three main large / industrial load components:

- Large industrial loads (LILs): These are modelled with their specific contribution to peak as provided by AEMO, and their energy over the year aligned with the energy consumption provided by AEMO.

- Hydrogen production load: These were modelling assuming that the demand reduced to 10 per cent of installed capacity during peak demand intervals, which for the purposes of this study were assumed to be across 4.30pm to 9.30pm. For the reliability assessment modelling of the expected 10% POE scenario, the remainder of hydrogen load was modelled at a MW value for the other hours of the day each day of the year such that the annual energy consumption aligned with AEMO's annual energy forecast.

- Electrification load: This was modelled as a flat, non-flexible demand based on the MW associated with the annual energy consumption provided by AEMO.

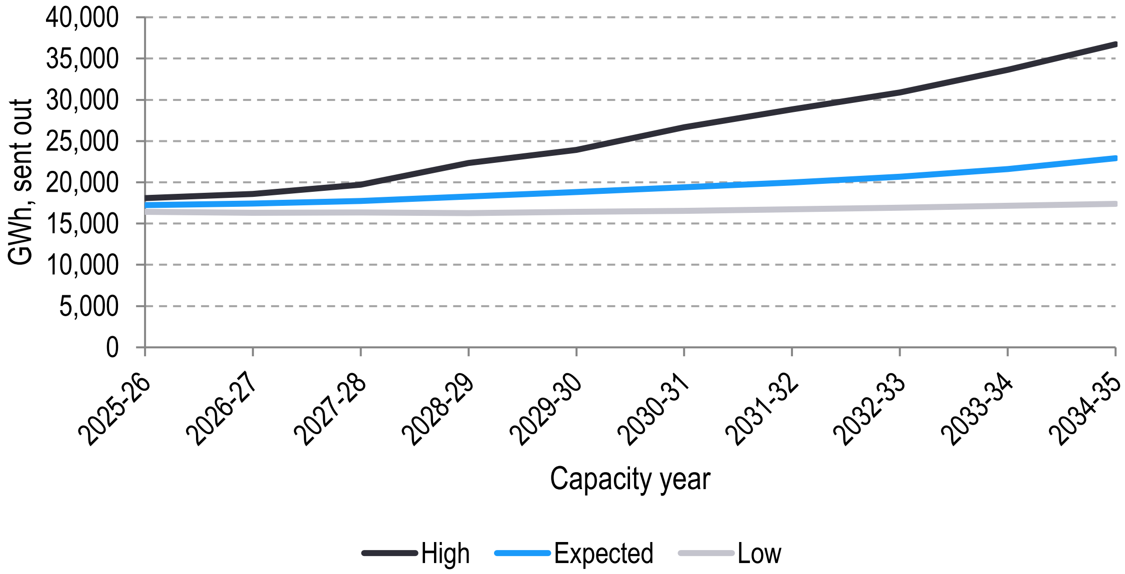
For the assessment of sub-regional capacity shortfalls, a number of loads were explicitly modelled in transmission network constraint equations as a flat, non-flexible demand, based on information provided within network power flow models. Where large industrial loads have embedded generation, these demand terms were modelled within the relevant constraint equations to reflect the net impact at the transmission connection point.

Appendix D Modelling assumptions

D.1 Energy demand

The modelling for the reliability study incorporates AEMO's WEM ESOO 2025 energy consumption forecasts for the expected scenario. Figure 7 presents the annual operational energy consumption in the WEM used in this reliability study. The annual inputs provided by AEMO are converted into half-hourly input data for EY's electricity market model through the process outlined in Appendix C.

Figure 7: AEMO's 2025 WEM ESOO forecast of annual operational energy consumption in the WEM for the low, expected and high scenarios



D.2 Peak demand

The peak demand for electricity is influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The future operational peak demand, to be met by large-scale generators, also depends on the rooftop PV generation, behind-the-meter battery operation and electric vehicle load during the peak periods.

AEMO provides peak demand forecasts for summer and winter in the WEM and for each of these a 10% POE peak demand level. The 10% POE peak demand represents a high demand outcome with a one in ten chance of the peak demand forecast being exceeded in at least one half hour of the year. EY simulates half-hourly demand profiles achieving each of these summer and winter peaks.

Figure 8 and Figure 9 show the annual peak demand in the WEM for the summer and winter 10% POE projections respectively, consistent with AEMO's 2025 WEM ESOO scenarios.

Figure 8: AEMO's 2025 ESOO forecast of annual summer peak operational demand in the WEM for the low, expected, and high scenarios

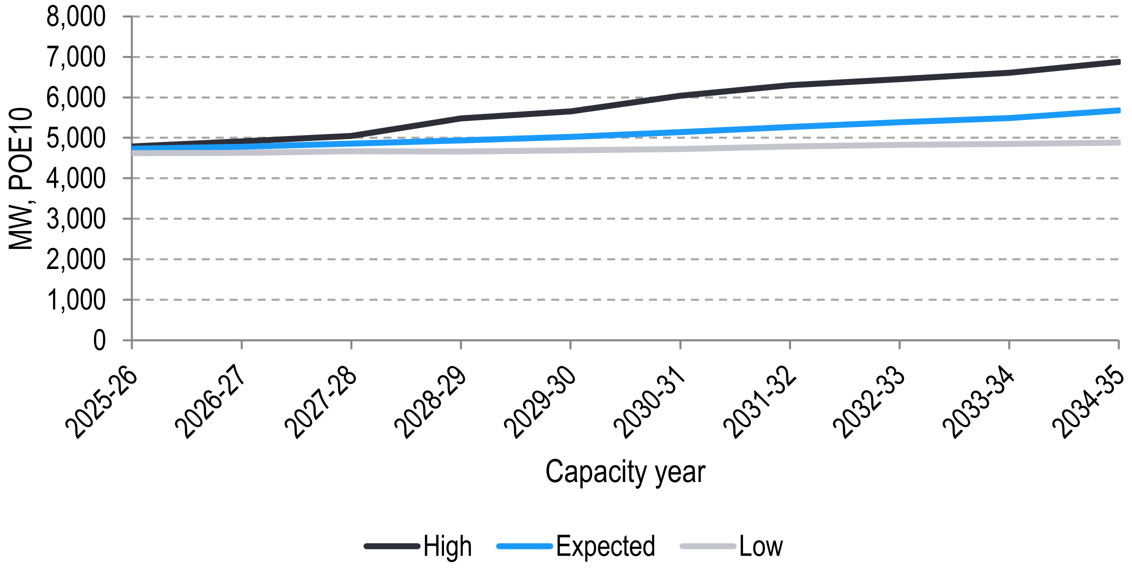
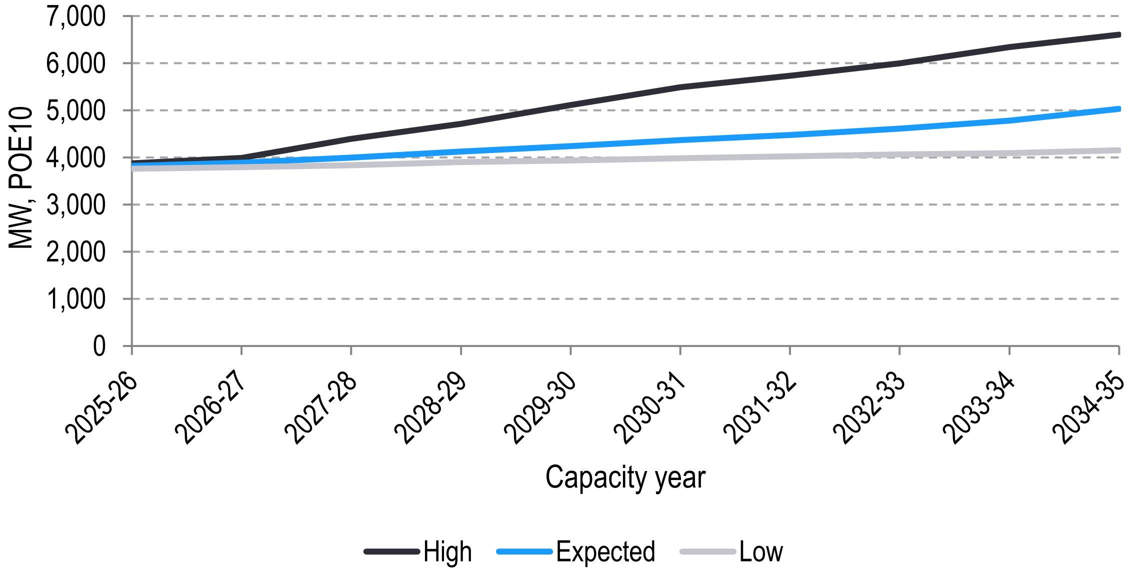


Figure 9: AEMO's 2025 ESOO forecast of annual winter peak operational demand in the WEM for the low, expected, and high scenarios



D.3 Distributed PV

Figure 10 and Figure 11 show the distributed PV assumptions consistent with AEMO's low, expected and high demand scenarios presented above and including in the modelling, for rooftop PV and small PV non-scheduled generators (PVNSG) respectively.

Figure 10 : Residential and business behind-the-meter rooftop PV forecast available generation for low, expected and high demand scenarios[48]

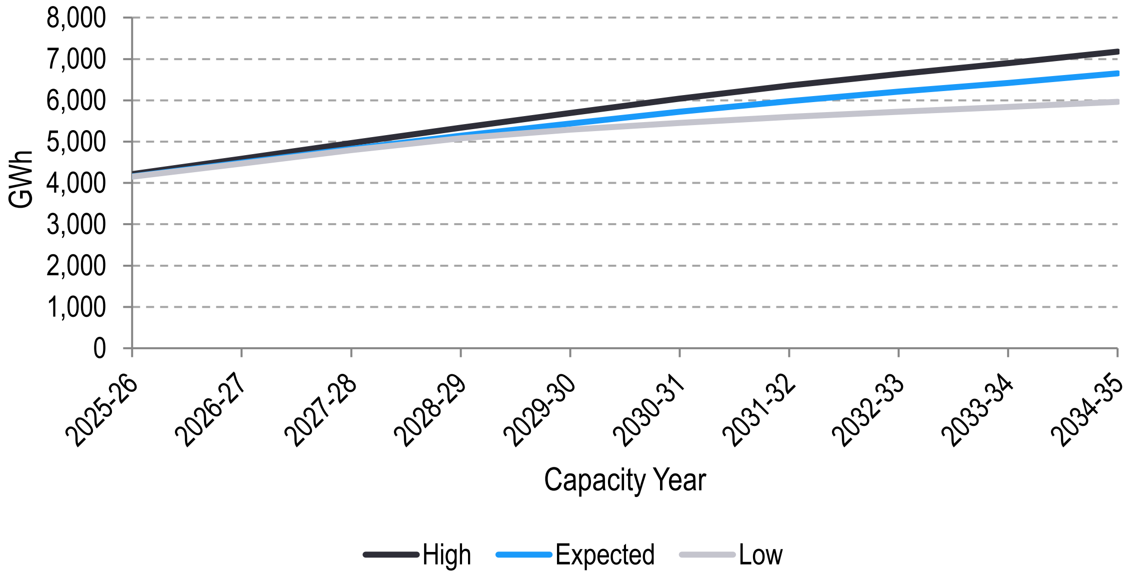
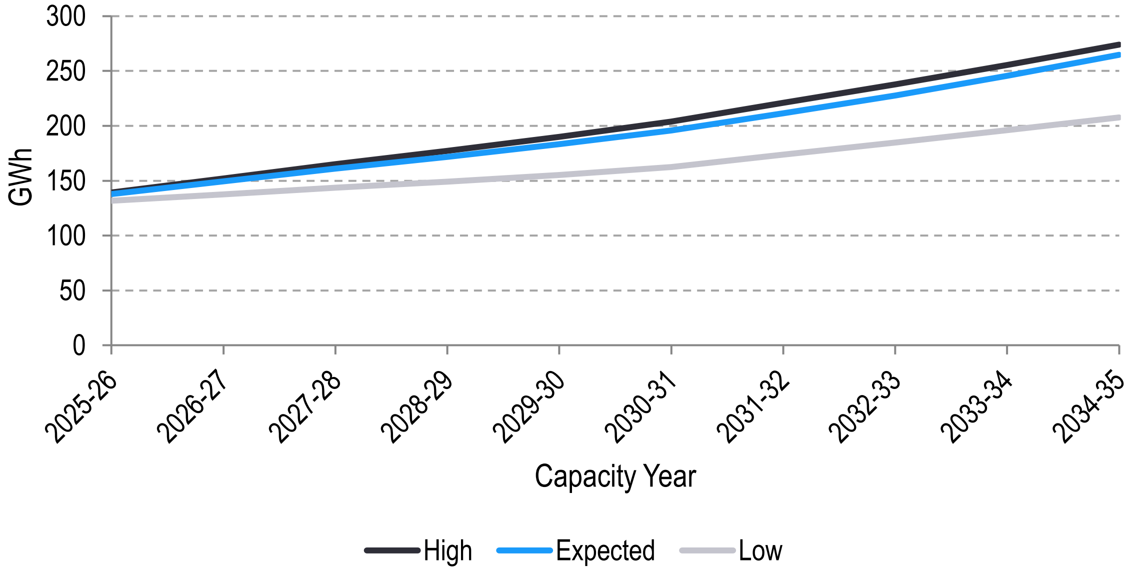


Figure 11: PVNSG generation for low, expected and high demand scenarios



[48] Note, this does not include the impact of any emergency solar management measures to curtail rooftop PV generation and times where demand would otherwise drop below the minimum demand threshold.

D.4 Electric vehicles

Figure 12 provides the annual energy consumption associated with EVs in each of the demand scenarios modelled, while Table 8 sets out the VPP assumptions for EVs. The proportion of EVs by charging profile assumed to participate in co-ordinated charging (through a VPP) is the same in the expected and high scenarios, noting that no co-ordinated charging was assumed for the low scenario. Table 9 provides the daily available MW and MWh for the EV vehicle to grid (EV V2G) charge and discharge, noting that no EV V2G was assumed for the low demand scenario.

Figure 12: Energy consumption from electric vehicles consistent with the low, expected and high demand scenarios (non-VPP)

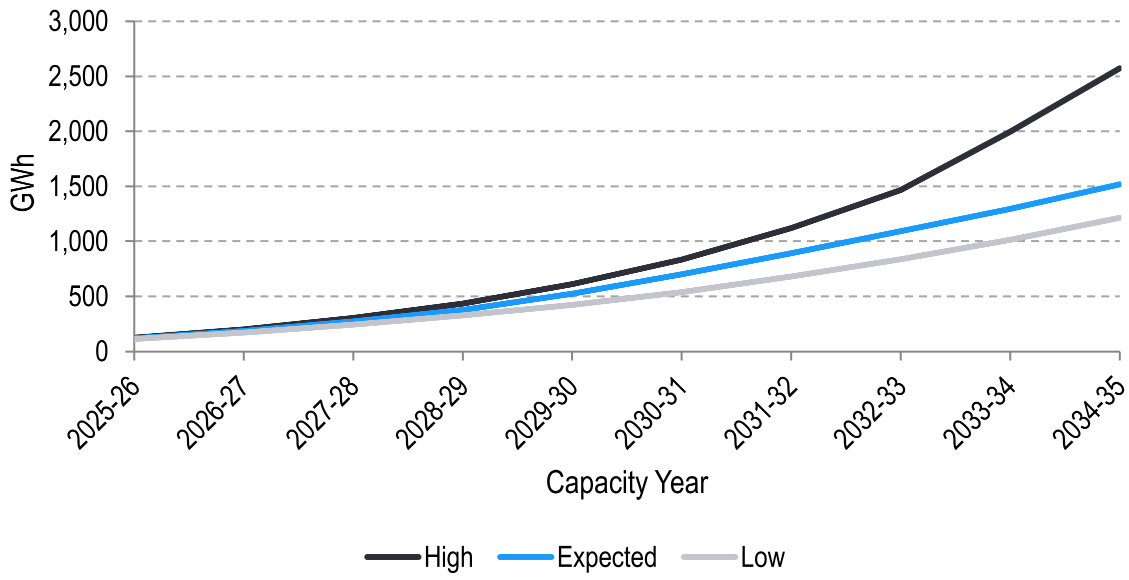


Table 8: EV consumption assumed to be part of co-ordinated charging in the expected and high scenarios, annual GWh

Capacity Year / Demand scenario	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2043-35
Low	-	-	-	-	-	-	-	-	-	-
Expected	0.3	1	2	4	11	32	66	112	172	249
High	0.3	1	2	5	12	35	75	142	255	408

Table 9: EV V2G assumptions for low, expected and high scenarios, daily MWh

Capacity Year / Demand scenario	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2043-35
Low	-	-	-	-	-	27	66	116	179	253
Expected	-	-	-	-	-	41	100	177	273	389
High	-	-	16	57	123	218	343	503	760	1067

D.5 Behind the meter storage

Figure 13 presents the assumed uptake of behind the meter batteries (residential and commercial uptake) in terms of the total MWh installed capacity (degraded) while Figure 14 presents the proportion of that battery energy by scenario that is assumed to participate in co-ordinated operation through a VPP.

Figure 13: Behind the meter battery capacity in the low, expected and high demand scenarios

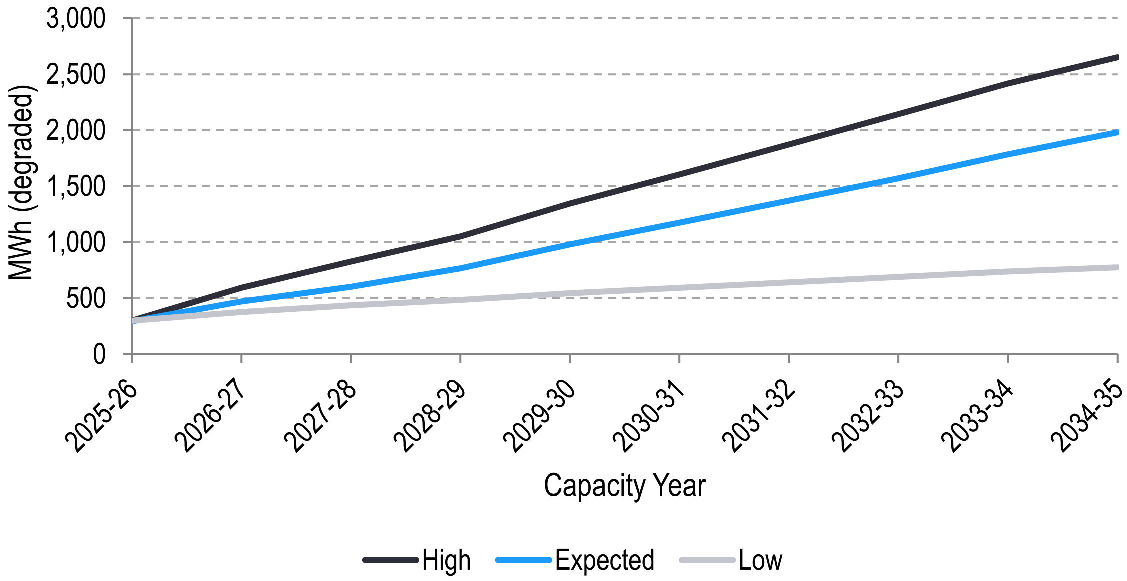
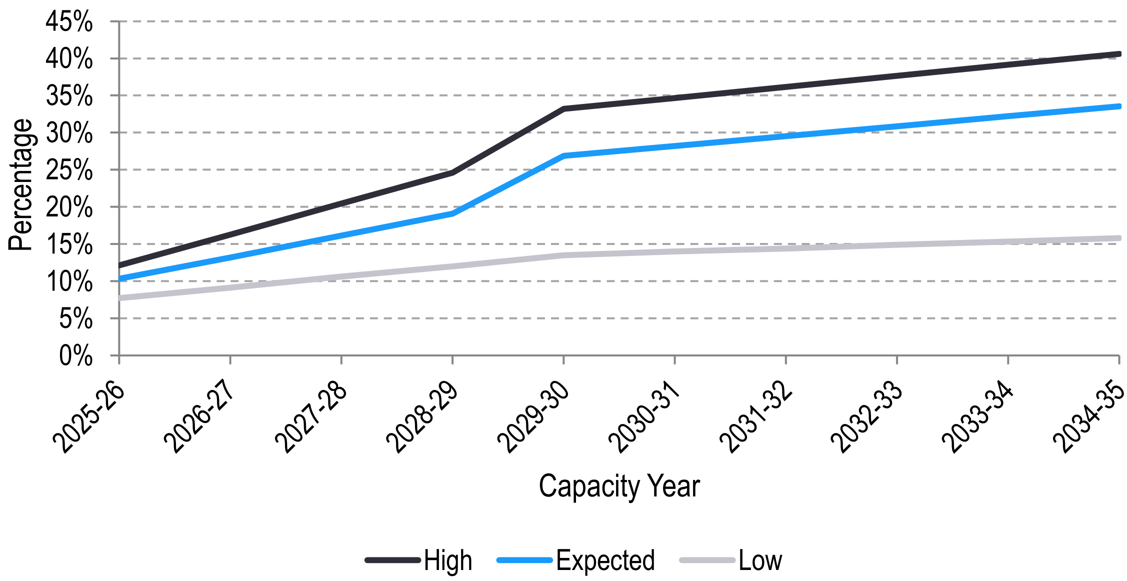


Figure 14: Proportion of batteries assumed to participate in a VPP in the low, expected and high scenarios



D.6 Generation developments

The generation supply side (covering generation, storage and demand side capacity) in the model is based on anticipated installed capacity provided by AEMO. Details of new Facilities entering the WEM (committed) were provided to EY and are as published by AEMO alongside the ESOO. Assumed retirement or unavailability dates from the WEM were also provided by AEMO and are as set out in Table 10.

Table 10: Assumed generator retirements or unavailability dates for the reliability study modelling

Power station	Technology	Maximum capacity (MW sent out)	Expected scenario retirement or unavailability date	Alternative scenario retirement or unavailability date
BLUEWATERS PS	Black coal	434	1/10/2027	1/10/2030
COLLIE_G1	Black coal	318.3	1/10/2027	1/10/2027
MUJA_G7	Black coal	212.6	1/10/2029	1/10/2029
MUJA_G8	Black coal	212.6	1/10/2029	1/10/2029
PINJAR_GT2	OCGT	38.5	1/10/2029	1/10/2029
PINJAR_GT3	OCGT	39.3	1/10/2029	1/10/2029
PINJAR_GT4	OCGT	42.0	1/10/2029	1/10/2029
PINJAR_GT5	OCGT	39.3	1/10/2029	1/10/2029
PINJAR_GT7	OCGT	42.0	1/10/2029	1/10/2029
PINJAR_GT9	OCGT	118.2	1/10/2032	1/10/2032
PINJAR_GT10	OCGT	118.2	1/10/2032	1/10/2032
PINJAR_GT11	OCGT	128.2	1/10/2032	1/10/2032

D.7 Planned maintenance

Planned maintenance was applied to units in line with the methodology set out in Section B.1.6. Where maintenance data was available from AEMO's FIR process, this was applied in the modelling, otherwise assumed maintenance periods were applied to technologies as set out below in Table 11.

Table 11: Assumed planned maintenance periods applied to Facilities and / or years FIR data not available

Technology	Equivalent average days per year on planned maintenance
Black coal	20
CCGT	20
OCGT	5
Diesel	6
Cogeneration	20
Waste to energy	23
Battery gen	0

Note: *Waste to energy uses biomass assumption. Cogeneration applied CCGT rates.*
Source: *AEMO 2025 Draft IASR (Inputs and Assumptions Workbook v7.1)*

D.8 Forced outages

AEMO provided EY with forced outage rate statistics based on an assessment of published outages. These rates were applied in the modelling where available, otherwise generic rates by technology were applied as set out in Table 12 (for example for new Facilities).

Table 12: Outage rates by technology applied where outage statistics not otherwise available

Facility Code	Full outage rate	Full outage - mean time to repair	Partial outage rate	Partial outage - mean time to repair	Partial outage derating factor
Black coal	4.3%	104	23.8%	17	17.51%
CCGT	1.7%	23	0.2%	29	36.52%
OCGT	1.3%	7	0.4%	40	11.96%

Facility Code	Full outage rate	Full outage - mean time to repair	Partial outage rate	Partial outage - mean time to repair	Partial outage derating factor
Diesel	3.5%	16	0.4%	35	7.18%
Cogeneration	1.7%	23	0.2%	29	36.52%
Waste to energy	3.0%	40	2.0%	7	30.00%
Battery gen	1.5%	48	3.0%	96	20.00%

Source: AEMO 2025 Draft IASR (Inputs and Assumptions Workbook v7.1), apart from coal, which is based on WA Whole of System Plan 2020.

Appendix E Glossary of terms

Term	Meaning
2-4-C®	EY's in-house time-sequential market dispatch modelling suite.
Anticipated Installed Capacity	Existing SWIS installed capacity (generation, storage, DSP) less existing capacity retirements + committed capacity Facilities (as applicable by scenario settings).
Capability Class 1	Firm capacity that is not energy limited, such as a gas-fired Facility that meets the fuel availability requirements.
Capability Class 2	Firm capacity with energy or availability limitations, such as battery / ESR, pumped hydro storage or a DSP.
Capability Class 3	Non-firm capacity, such as a wind or solar farm with no associated firming capability.
business	Includes industrial and commercial users.
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equal to 1 MW of capacity.
capacity factor	Actual energy output over a given period of time as a proportion of the theoretical maximum output over that period.
Capacity Year	"A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year."
Consumption	The amount of power used over a period of time, conventionally reported as megawatt hours (MWh) or gigawatt hours (GWh) depending on the magnitude of power consumed. It is reported on a "sent-out" basis (excluding electricity used by a generator) unless otherwise stated.
Demand	The amount of power consumed at any time. Peak and minimum demand is measured in 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.
demand side management (DSM)	A type of capacity held in respect of a Facility connected to the SWIS; specifically, the capability of a Facility connected to the SWIS to reduce its consumption of electricity through the SWIS, as measured at the connection point of the Facility to the SWIS
demand side programme (DSP)	Facility comprising one or more Non-Dispatchable Loads that can be curtailed on request by AEMO, registered in accordance with clause 2.29.5A.
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.
Consumer energy resource (CER)	CER includes distributed PV, distributed battery storage, and electric vehicles.
distributed photovoltaics (DPV)	DPV includes both behind-the-meter rooftop PV and PVNSG.
economic spill	Relates to the scenario where interval demand is such that available wind and solar resource is not fully utilised.
Electric Storage Resource (ESR)	One or more energy storage assets that are electrically connected to the SWIS at the same connection point.
Electric Storage Resource Obligation Intervals (ESROIs)	The Electric Storage Resource Obligation Intervals (ESROI) are a set of 8 contiguous Trading Intervals during which an Electric Storage Resource (ESR) is obligated to be available under the Reserve Capacity Mechanism (RCM).
electric vehicle	Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
emergency solar management	Refers to the capability to remotely reduce the generation from small-scale distributed rooftop solar PV systems as a last resort measure, assisting AEMO to protect the power system during extreme low load events.
energy producing system	Generation capacity in the SWIS consisting of thermal, renewable, storage capacity
expected unserved energy	Unserved energy means the amount of customer demand that cannot be supplied in a region of the national electricity market due to a shortage of generation or interconnector capacity. It is calculated in megawatt or gigawatt hours (MWh or GWh) and is typically expressed in terms of a percentage of customer demand. The term expected unserved energy means a statistical expectation of a future state; an average across a range of future outcomes, weighted for probability.

Term	Meaning
Facility	The following are Facilities in the WEM: (a) a distribution system; (b) a transmission system; (c) a generation system; (d) a connection point at which electricity is delivered from a distribution system or transmission system to a Rule Participant ("Load"); and (e) a Demand Side Programme.
forced and partial outage	Unplanned shut down of a generating Facility. In the case of a partial outage, a proportion of the Facility's capacity is modelled as unavailable. Each Facility has a probability of experiencing a forced (unplanned) outage at any one time. Monte Carlo simulations of forced outages assign full and partial forced outages to each generating unit based on the assumed probabilities.
Intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g., wind speed).
Interruptible Load	A load through which electricity is consumed, where such consumption can be curtailed automatically in response to a change in system frequency and registered as such in accordance with clause 2.29.5 of the ESM Rules.
iteration	Half-hourly modelling of a single possible outcome for a future set of years.
Large Industrial Loads	Users that consume, or are forecast to consume, at least 10 MW for at least 10% of the time (around 875 hours a year).
Limb A	Term attributed to the requirement of the Planning Criterion that stipulates that there should be sufficient available capacity in each Capacity Year to meet the forecast peak demand plus a reserve margin.
Limb B	Term attributed to the requirement of the Planning Criterion that stipulates there should be sufficient available capacity in the SWIS to limit expected unserved energy (EUE) shortfalls to 0.0002% of annual energy consumption.
Limb C	Term attributed to the requirement of the Planning Criterion that stipulates that there should be enough capacity available in the SWIS to meet the highest forecast Four-Hour Demand Increase, plus a reserve margin, in each Capacity Year.
load shedding	The controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure.
maximum capacity	The net sent-out generation or installed capacity of a Facility, as detailed on AEMO's Market Data website.
Not-summer seasonal rating	Seasonal rating applied to months outside of November to March.
operational	Electricity consumption (demand) that is met by sent -out electricity supply of all market-registered energy.
operational consumption	Electricity consumption (demand) that is met by sent-out electricity supply of all market registered energy producing systems. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (demand) of EVs but excludes electricity consumption (demand) met by DPV generation.
peak demand	MW value for maximum demand supplied through the SWIS (operational peak demand) for a single 30-minute interval in a Capacity Year. Peak demand refers to operational peak demand unless otherwise stated.
peaking capacity	Facilities that generally operate less than 10% of the time.
probability of exceedance (POE)	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded on average once in every 10 years.
Projected Assessment of System Adequacy (Long Term PASA)	Forecasting study undertaken by AEMO on an annual basis, as part of the publishing of the Electricity Statement of Opportunities (ESOO) for the Wholesale Electricity Market. It takes into consideration a 10-year planning horizon for generation, demand side programs, and network capacity.
ramp rates	Speed at which a Facility can increase (ramp up) or decrease (ramp down) generation or demand.
Reference year	Future half-hourly demand, wind and solar PV generation is modelled based on several historical reference years to capture a variety of Australian weather patterns.
Reliability Standard	The Planning Criterion defined in clause 4.5.9 of the ESM Rules.
Reserve Capacity Cycle	A period covering the cycle of events described in clause 4.1 of the ESM Rules.
Reserve Capacity Mechanism	Set out in Chapter 4 of the ESM Rules, it is aimed at ensuring that there is sufficient capacity in the South West interconnected system (SWIS).

Term	Meaning
Reserve Capacity Price (RCP)	In respect of a Reserve Capacity Cycle, the price for Reserve Capacity determined in accordance with clause 4.29.1, where this price is expressed in units of dollars per Capacity Credit per year.
Peak Reserve Capacity Target (Peak RCT)	AEMO's estimate of the total quantity of generation or DSP capacity required in the SWIS to satisfy the Planning Criterion.
residential	Includes residential customers only.
rooftop photovoltaics	Systems comprising of one or more photovoltaic panels, installed on a residential building (less than 15 [kW]) or business premises (less than 100 kW) to convert sunlight into electricity.
Solar Energy Simulation Tool (SEST)	EY's in-house tool used to develop half-hourly PV availability profiles for existing and potential solar farms used in the modelling.
Summer seasonal rating	Seasonal rating applied to all periods in the months from November to March inclusive.
Supplementary Reserve Capacity	Supplementary Reserve Capacity (SRC) will be procured by AEMO if, at any time after the day that is six months before the start of a Capacity Year, it determines that insufficient capacity is available to satisfy demand.
Time-sequential data	Mean time series of 17,520 (or 17,568 for leap years) consecutive 30-minute interval datapoints for each modelled year, with outcomes in the previous interval being relevant for the currently modelled interval.
Trading Interval	Defined in the ESM Rules as a period of 30 minutes commencing on the hour or half-hour during a Trading Day
transmission network constraint equations	Linearised mathematical expressions that represent the technical envelope that the SWIS must operate within. They model the maximum power transfer that can flow on transmission network elements before a limitation is reached.
underlying consumption/demand	The total amount of electricity consumption (demand) by electricity users from their power points regardless, if it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation.
virtual power plant	An aggregation of resources (such as decentralised generation, storage, and controllable loads) co-ordinated to deliver services for power system operations and electricity markets.
Wind Energy Simulation Tool (WEST)	EY's in-house tool used to develop half-hourly, time sequential, locational wind availability profiles for existing and potential wind farms used in the modelling.

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