2023 WEM ESOO Reliability Assessment Report

Australian Energy Market Operator

15 August 2023

Building a better working world

RELEASE NOTICE

Ernst & Young ("EY") was engaged on the instructions of the Australian Energy Market Operator ("AEMO") to provide the reliability assessment underpinning the 2023 Long Term Projected Assessment of System Adequacy (Long Term PASA) for the South West Interconnected System (SWIS), the results of which must be published in the annual Electricity Statement of Opportunities (ESOO) for the Wholesale Electricity Market (WEM) (the "Services").

The results of EY's work are set out in this report ("Report"), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

EY has prepared the Report for the benefit of AEMO and has considered only the interest of AEMO. EY has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, EY makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes.

Our work commenced on 9 March 2023 and was completed on 24 July 2023. Therefore, our Report does not take account of events or circumstances arising after 24 July 2023 and we have no responsibility to update the Report for such events or circumstances.

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Our conclusions are based, in part, on the initial assumptions stated and on information provided to us by AEMO by 24 July 2023. The outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. These assumptions were selected by AEMO and includes consideration of submissions to public consultations. The modelled outcomes are contingent on the collection of assumptions as agreed with AEMO and no consideration of other market events, announcements or other changing circumstances are reflected in this. The modelled scenario represents one possible future of the development and operation of the WA Wholesale Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved.

We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on your future course of action. We provide no assurance that the scenario we have modelled will be accepted by any relevant authority or third party.

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Table of contents

Executive summary

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 (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 (thermal, renewable, storage capacity) and Demand Side Management (DSM) to meet the Planning Criterion as defined in clause 4.5.9 of the WEM Rules.

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 (EUE) shortfalls to 0.002% of annual energy consumption (this report will refer to this as 'Limb B' of the Planning Criterion).

This reliability assessment has been performed using AEMO's forecasts of the 2023 WEM ESOO demand scenarios for the 2023 Long Term PASA and involves the requirements of the following four scope items (presented in further detail below and in Section 1.3):

- Scope item 1: Assessment of the extent to which the anticipated installed capacity (AIC) of the Energy Producing Systems and DSM capacity can satisfy the Planning Criterion for each year in the Long Term PASA Study Horizon (the 2023-24 to 2032-33 Capacity Years).
- Scope item 2: Based on the outcome of the assessment on Limb A and Limb B of the Planning Criterion, determine the Reserve Capacity Target (RCT) for each Capacity Year during the 2023 Long Term PASA Study Horizon (the 2023-24 to 2032-33 Capacity Years).
- Scope item 3: Determination of capacity requirements for Availability Classes 1 and 2 for each of the second and third Capacity Years of the 2023 Long Term PASA Horizon (the 2024-25 and 2025-26 Capacity Years) as required under clause 4.5.12 of WEM Rules.
- Scope item 4: Development of the Availability Curves for the second and third Capacity Years of the 2023 Long Term PASA Study Horizon (the 2024-25 and 2025-26 Capacity Years) as required under clause 4.5.10(e) of the WEM Rules.

Scope item 1 – Assessing capacity against the Planning Criterion

The main purpose of Scope item 1 is to identify, analyse and characterise capacity and reliability shortfalls under Limb A and Limb B of the Planning Criterion. This is required to be carried out for each of the demand scenarios provided by AEMO, which for this study are low, expected, and low demand scenarios, consistent with the projections in the 2023 WEM ESOO.

Limb A requirement

For each forecast year, Limb A of the Planning criterion is the sum of the forecast annual peak demand uplifted by several margins and allowances (see Section 5.2 for further details). The assessment is a deterministic calculation based on the sum of forecast Reserve Capacity (FRC) estimated to be associated with the AIC of generation, storage and DSM Facilities over the ten-year study period.[1]

Table 1 shows the Limb A requirement for the low, expected, and high scenarios as determined based on the inputs provided by AEMO, alongside forecast Reserve Capacity (MW).

In all scenarios, there is a capacity investment gap in the SWIS from 2023-24, as shown in Table 1.

Table 1: Limb A requirement (low, expected, high scenarios), forecast Reserve Capacity, and assessment

Scenario	Component (MW) / Capacity Year	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Low	Limb A requirement	5,275	5,296	5,376	5,569	5,606	5,732	5,934	6,142	6,466	6,754
	Forecast Reserve Capacity	4,668	4,467	4,467	4,467	4,149	4,149	3,727	3,293	3,293	3,293
	Capacity investment gap	608	829	910	1,102	1,456	1,582	2,206	2,848	3,173	3,460
Expected	Limb A requirement	5,364	5,430	5,543	5,716	5,806	6,061	6,422	6,821	7,140	7,425
	Forecast Reserve Capacity	4,727	4,596	4,598	4,598	4,281	4,281	3,859	3,425	3,425	3,425
	Capacity investment gap	638	833	945	1,118	1,525	1,781	2,563	3,396	3,715	4,000
High	Limb A requirement	5,398	5,577	5,917	6,370	6,677	7,169	7,595	8,038	8,676	9,134
	Forecast Reserve Capacity	4,727	5,178	5,535	5,690	5,373	5,373	5,451	5,451	5,451	5,451
	Capacity investment gap	671	398	382	680	1,304	1,796	2,144	2,587	3,226	3,683

Limb B requirement

Limb B of the Planning Criterion requires that there should be sufficient capacity available in each Capacity Year to limit EUE to 0.002% of annual energy consumption. The modelling shows that EUE is expected in all years modelled and when expressed as a percentage of forecast annual energy consumption, exceeds 0.002% from the first year of the outlook (Table 2).

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

Table 2: Modelled EUE percentage by scenario and Capacity Year

Scenario / Capacity Year	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
EUE %, Low	0.005%	0.015%	0.022%	0.041%	0.217%	0.403%	1.847%	7.124%	10.538%	13.247%
EUE %, Expected	0.007%	0.014%	0.017%	0.031%	0.177%	0.431%	2.560%	10.689%	14.345%	17.384%
EUE %, High	0.006%	0.010%	2.870%	5.500%	13.561%	16.321%	23.710%	29.863%	35.251%	37.475%

Scope item 2 - Determining the RCT for the expected scenario

Assessment against Limb A and Limb B of the Planning Criterion aims to determine the RCT by comparing the amount of Reserve Capacity needed to meet both Limb A and Limb B of the Planning Criterion, with the maximum of either Limb A or Limb B then setting the requirement.

The modelling finds that the required Reserve Capacity to meet Limb A is higher than that required to meet Limb B in every year, and as such the Limb A requirement sets the RCT in all the years as shown in Table 3.

Table 3: Forecast RCT for the 2023-24 to 2032-33 Capacity Years – expected scenario

RCT (MW) / Capacity Year	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
RCT	5,364	5,430	5,543	5,716	5,806	6,061	6,422	6,821	7,140	7,425

Scope item 3 - Determining Availability Class 1 and Availability Class 2 capacity

The WEM Rules distinguish between two Availability Classes. Availability Class 1 includes all scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals.[2] Availability Class 2 includes capacity that is not expected to be available for dispatch for all Trading Intervals such as DSM and standalone Electric Storage Resources (ESR).

Scope item 3 requires an assessment of the maximum Availability Class 2 capacity within the overall RCT that ensures EUE does not breach 0.002% in the 2024-25 and 2025-26 Capacity Years. The approach to assessing the balance between Availability Class 1 and 2 capacity involves firstly equalising the Reserve Capacity to the determined RCT.

As there was found to be a forecast capacity investment gap relative to the RCT in each year in question, generic OCGT capacity was added to the AIC in the modelling so that installed capacity and associated modelled Reserve Capacity was equal to the RCT (i.e., adding 833 MW of OCGT in 2024-25, increasing to 945 MW in 2025-26). As Availability Class 2 includes both DSM and ESR capacity, which operate quite differently to each other, the modelling determined the maximum amount of each of DSM and ESR separately, and then determined the maximum Availability Class 2

[2] Trading Interval is currently defined in the WEM Rules as a period of 30 minutes commencing on the hour or half-hour during a Trading Day.

capacity as the minimum of each of these that can contribute towards the RCT before 0.002% is breached.[3]

Based on that approach, Table 4 shows the amount of the RCT that was modelled to be provided by capacity classified as Availability Class 1 and capacity classified as Availability Class 2 for the 2024-25 and 2025-26 Capacity Years. The modelling found that the DSM scenario reached 0.002% first, and therefore sets the outcomes shown below.

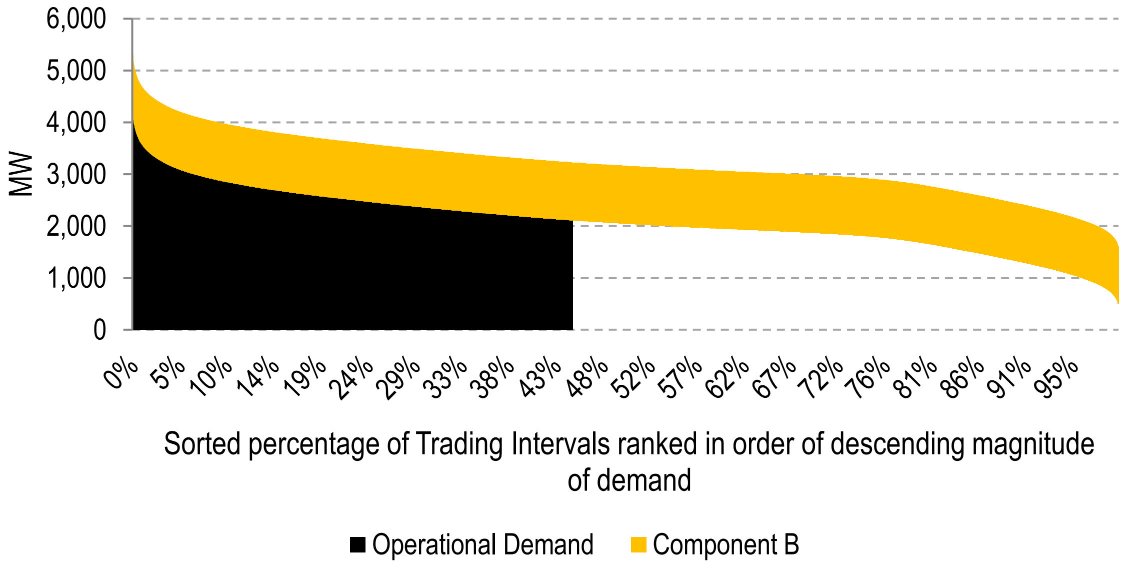
Table 4: Availability Class outcomes

Component (MW) / Capacity Year	2024-25	2025-26
Minimum Reserve Capacity required to be provided from Availability Class 1	4,430	4,510
Reserve Capacity associated with Availability Class 2	1,000	1,033
RCT	5,430	5,543

Scope item 4 – Availability curves

Following the approach set out in Section 4.4, the availability curves that consist of the operational demand curve increased by a constant reserve margin have been determined. The half-hourly data to derive these curves is based on the outcome of the process undertaken by EY to convert the annual demand data provided by AEMO into half-hourly data for each of the 12 modelled reference years. The data provided below in Figure 1 and Figure 2 is an average across each of these reference years and reflects the modelled minimum demand threshold (500 MW).[4] As the RCT is set by Limb A, the margin to add is determined as per Section 4.4.

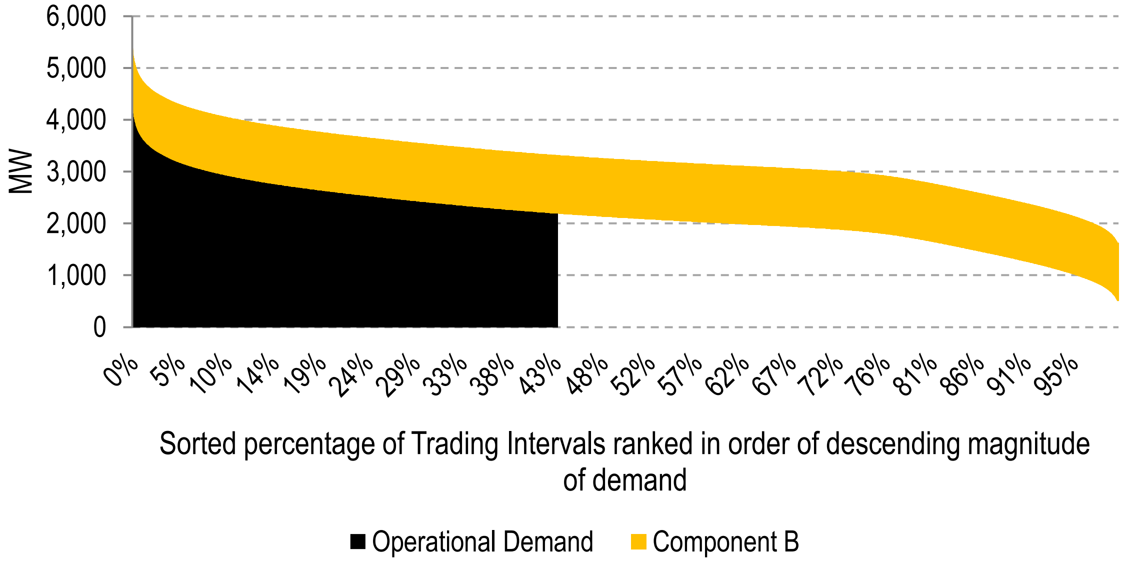
Figure 1: Availability Curve for the 2024-25 Capacity Year



[3] For example there are different requirements around when each resource must be available over the day / year, and also each has inherently different durations over which services can be provided. These are detailed further in the relevant sections of the main report.

[4] The modelling included a constraint that prevents operational demand falling below 500 MW. The constraint curtails rooftop PV in intervals where this would otherwise cause demand to fall below this level. It is important to note that in real-time operation, AEMO may be required to intervene at demand levels above 500 MW according to the specific fleet configuration and demand uncertainty at the time of intervention.

Figure 2: Availability Curve for the 2025-26 Capacity Year



1. Introduction

1.1 Background

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 electricity supply to meet demand in the South West Interconnected System (SWIS) of Western Australia (WA).

Assessing reliability of supply to meet SWIS demand (reliability assessment) informs the 10-year Long Term Projected Assessment of System Adequacy (PASA) that AEMO presents annually in the Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO). The WEM ESOO presents AEMO's forecast of the electricity demand and supply balance over the 10-year outlook period and is a key part of the WEM's Reserve Capacity Mechanism (RCM) process.

This reliability assessment has been performed using AEMO's forecasts of the 2023 WEM ESOO demand scenarios and involves the requirements of the four scope items presented in Section 1.3.

The purpose of this report is to present EY's approach, the modelling methodology, results and accompanying analysis to meet the requirements of the reliability study.

1.2 The Planning Criterion

A reliable power system has enough generation, storage, demand response and network capacity to supply customers with the energy they demand with a very high degree of confidence. The reliability of a power system is planned for through long-term projections of supply adequacy compared against the expectations of demand.

In the WEM, reliability is planned for using planning criteria that sets a target for a capacity reserve margin and a threshold for expected annual unserved energy that may result from supply shortfalls (Planning Criterion). The Planning Criterion is the basis for determining the Reserve Capacity Target (RCT) for individual years of the Long Term PASA Study Horizon (2023-24 to 2032-33). The RCT is one key input into the RCM and for the calculation of the Reserve Capacity Price (RCP).

According to clause 4.5.9 of the WEM Rules:

> *[…] There should be sufficient available capacity in each Capacity Year of the Long Term PASA Study Horizon to:*
>
> *(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:*
>
> *i. 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and*
>
> *ii. the size, in MW, of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand (including transmission losses and allowing for Intermittent Loads),*
>
> *while maintaining the SWIS frequency in accordance with the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and*

(b) *limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses and taking into account transmission network capabilities including constraints).*[5]

The Planning Criterion is comprised of two components (referred to as 'Limb A' and 'Limb B' in this assessment) as per Table 5. There needs 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).

Table 5: Components (Limbs) of the Planning Criterion

Component (Limb) of the Planning Criterion	Description
Limb A, pertaining to forecast annual peak demand uplifted by several margins and allowances	For each year, Limb A of the Planning criterion is determined as the sum of: ► Forecast annual operational sent-out peak demand, 10% POE[6] ► Intermittent Loads (IL) allowance ► A reserve margin equal to the greater of 7.6% peak demand and the size of the largest supply contingency ► Frequency regulation (FR) allowance
Limb B, pertaining to the annual expected unserved energy (EUE) standard	In each year, the annual volume of expected energy shortfalls (annual MWh) should not exceed 0.002% of annual energy consumption (annual MWh), including transmission losses and taking into account transmission network capabilities including constraints.

Limb A and Limb B of the Planning Criterion inform the setting of the annual RCT. The RCT is AEMO's estimate of the total capacity of Energy Producing Systems and DSM capacity required in the SWIS to satisfy the Planning Criterion under the 10% POE expected demand growth scenario.

The purpose of Limb A of the Planning Criterion is to ensure there is sufficient capacity from Energy Producing Systems and DSM to satisfy the forecast annual peak demand interval.

The purpose of Limb B of the Planning Criterion is to ensure that risk of unserved energy resulting from capacity shortfalls in individual dispatch intervals does not exceed 0.002% of expected annual energy consumption.

In addition to comparing Limb A and Limb B of the Planning Criterion, according to clause 4.5.12, for the second and third Capacity Years of the Long Term PASA Study Horizon, AEMO must determine the following information:

(a) *[Blank]*

(b) *The minimum capacity required to be provided by Availability Class 1 capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:*

i. *all Availability Class 2 capacity (excluding Interruptible Load used to provide Spinning Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that Capacity Year; and*

[5] Wholesale Electricity Market Rules (www.wa.gov.au)

[6] The 10% probability of exceedance (POE) peak demand forecast is expected to be exceeded for one half hour once in every 10 years.

ii. the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by clause 4.5.12(b)(i), then

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in clause 4.5.12(b)(ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed Availability Class 1 capacity, the anticipated Interruptible Load capacity available as Spinning Reserve and, to the extent that further Availability Class 1 capacity would be required, an appropriate mix of Availability Class 1 capacity to make up that shortfall; and

(c) the capacity associated with Availability Class 2, where this is equal to the Reserve Capacity Target for the Capacity Year less the minimum capacity required to be provided by Availability Class 1 capacity under clause 4.5.12(b).[7]

Availability Class 1 refers to the Availability Class assigned by AEMO to a Facility containing an Intermittent Generating System or Non-Intermittent Generating System, and any other Facility that is expected to be available to be dispatched for all Trading Intervals in a Capacity Year, under clause 4.11.4(a). Availability Class 1 thus relates to scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages.

Availability Class 2 refers to the Availability Class assigned by AEMO to Certified Reserve Capacity that is not expected to be available to be dispatched for all Trading Intervals in a Capacity Year, under clause 4.11.4(b). Availability Class 2 thus relates to capacity that is not expected to be available for dispatch for all Trading Intervals and includes DSPs and standalone ESR.[8]

1.3 Required scope items

Table 6 summarises the four scope items carried out by EY to deliver the reliability assessment to inform the Long Term PASA for the 2023 WEM ESOO. The scenarios and modelling timescales are described and are based on WEM Rules requirements.

[7] Wholesale Electricity Market Rules (www.wa.gov.au)

[8] Energy Policy WA has recently published a consultation paper recommending changes to the RCM. Amongst these recommendations is that Availability Classes be replaced with Capability Classes. These Capability Classes have not been considered within the modelling.

Table 6: Overview of scope items of the reliability study

Scope item	Description	Key objective	Assessment time period and scenario
Scope item 1	Assessment of the extent to which the anticipated installed capacity (AIC) of the Energy Producing Systems and Demand Side Management (DSM) capacity can satisfy the Planning Criterion for each Year in the Long Term PASA Study Horizon (2023-24 to 2032-33 Capacity Years), including: [9] ► identifying any capacity shortfalls for each scenario specified under clause 4.5.10(a) of the WEM Rules. ► identifying and assessing any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors as required under clause 4.5.10(c) of the WEM Rules. ► identifying any potential transmission, generation, storage, or demand side capacity augmentation options to alleviate capacity shortfalls identified in clauses 4.5.10(a) and 4.5.10(c) of the WEM Rules.	Identify, analyse and characterise capacity and reliability shortfalls under both Limbs of the Planning Criterion	► 2023-24 to 2032-33 ► Limb A: 10% probability of exceedance (POE) low, expected, high scenarios ► Limb B: 10% POE low, expected, high scenarios
Scope item 2	Forecast of the Reserve Capacity Target (RCT) for each Capacity Year during the Long Term PASA Study Horizon in accordance with clause 4.5.10(b) of the WEM Rules to meet the Planning Criterion in that year under the scenario described in clause 4.5.10(a)(iv) of the WEM Rules.	Determine whether the RCT is set by Limb A or Limb B and quantify the RCT (in MW).	► 2023-24 to 2032-33 ► 10% POE expected scenario
Scope item 3	Determination of capacity requirements for Availability Classes 1 and 2 for each of the second and third Capacity Years of the 2023 Long Term PASA Horizon (2024-25 and 2025-26 Capacity Years) as required under clause 4.5.12 of WEM Rules.	Determine the amount of Reserve Capacity between Availability Class 1 and 2.	► 2024-25 and 2025-26 ► 10% POE expected scenario
Scope item 4	Development of the Availability Curves for the second and third Capacity Years of 2023 Long Term PASA Study Horizon (2024-25 and 2025-26 Capacity Years) as required under clause 4.5. 10(e) of the WEM Rules.	Creation of supply availability curves consisting of the demand duration curve and reserve margin requirements based on scope item 2 outcomes.	► 2024-25 and 2025-26 ► 10% POE expected scenario

1.4 Industry context

To provide more context for the WA Wholesale Electricity Market for this reliability assessment, it is noted that:

- As per the WA State Government's public announcement (14 June 2022), Collie and Muja D coal-fired power plants (over 740 MW of SWIS thermal capacity) will retire by 2030, in addition to the almost 400 MW of capacity from Muja C coal-fired power station already announced to retire across 2022 and 2024, i.e., within the modelling horizon of this reliability assessment.
- The 2022 WEM ESOO (published on 17 June 2022) notes that since the RCM commenced in 2005 in the WEM, the RCT has been set by Limb A of the Planning Criterion because it has exceeded the capacity required to satisfy the Limb B component of the Planning Criterion.
- The 2022 WEM ESOO identified additional capacity is required in meeting the RCT as presented below:

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

- For the expected and low scenarios, capacity shortfalls were identified from the 2025-26 Capacity Year onwards, and for the high scenario, capacity shortfalls were identified from the 2028-29 Capacity Year onwards.

- The share of intermittent renewable capacity and instantaneous renewable output penetration on the SWIS is increasing.
- Since the release of the 2022 WEM ESOO, AEMO identified a potential requirement to secure up to 174 MW of Reserve Capacity for the period 1 December 2022 to 21 March 2023, citing the early retirement of existing generation Facilities, extended forced outages on a number of existing units and ongoing fuel supply limitations. AEMO triggered the Supplementary Reserve Capacity (SRC) in response to this projected shortfall[10].
- In June 2023, AEMO recorded the highest average MW outage within the past five years, reflecting present challenges to procure supply. This is coupled with falling average intermittent generation and higher operational demand compared to the past two years, adding further challenges to meeting demand on the SWIS.[11]
- AEMO has issued a call for Non-Co-Optimised Essential System Services (NCESS) for a Minimum Demand Service of up to 125 MW during the 2023-24 Capacity Year.[12] Further, AEMO has also identified risks which may prevent it from operating the SWIS securely and reliably at both peak and minimum demand intervals from October 2024, and issued a call for NCESS in the form of up to 830 MW of peak capacity, and 269 MW of minimum demand service.[13]

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.[14]
- The assessment of Limb B of the Planning Criterion can result in annual EUE volumes exceeding the 0.002% standard, and Limb B can be the driver of the RCT (if it is higher than Limb A in required installed MW terms).

1.5 High-level approach and report structure

The following key phases of work have been completed in the preparation of data and modelling to deliver the reliability assessment. The report is structured according to the key phases of work, and is presented on the following basis:

- Section 2 covers the assumptions and settings used for modelling in EY's 2-4-C® modelling framework. This phase involved confirming the scenario to be modelled, including identifying the necessary data, inputs, assumptions and settings to be used in the reliability assessment.
- Section 3 covers the demand forecasts used for the reliability assessment. This phase of work involved receiving AEMO's forecasts for the 2023 WEM ESOO annual peak demand (MW) and annual energy (MWh) and subsequently using EY's demand modelling framework to produce half-hourly time-sequential demand inputs for use in EY's 2-4-C® dispatch model. This includes modelling of Distributed Energy Resources (DER) and their impact on demand. This is described in Section 3.

[10] See AEMO 'Supplementary Reserve Capacity'. Available from: AEMO | Supplementary Reserve Capacity

[11] WA Electricity Consultative Forum, June 2023. Available from: waecf-43-meeting-papers.pdf (aemo.com.au)

[12] Revised to 114 MW as part of the Call for NCESS Submissions.

[13] AEMO (2023) 'Tenders and Expressions of Interest for NCESS – Reliability Services (WA)'. Available from: AEMO | Tenders and Expressions of Interest for NCESS – Reliability Services (WA)..

[14] 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.

- Section 4 describes the detailed methodology and how 2-4-C® is deployed to undertake the elements of the reliability assessment. Key aspects of how EY has derived anticipated installed capacity (AIC), expected unserved energy (EUE), comparison of Limb A and Limb B to the Planning Criterion and determination of Availability Classes is described.
- Section 5 presents the results, analysis, key simulation outputs for the reliability assessment reporting on key drivers and insights gathered throughout the modelling process.
- Appendices provide more detail as required.

2. EY's wholesale electricity market model

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

For the reliability study, EY used our 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 forthcoming WEM Dispatch Engine (WEMDE) that will be used by AEMO in operating the Real-Time Market (RTM) when it begins 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.[15]

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:[16]

- **Renewable resource variability and weather-driven demand patterns**: EY's modelling of future demand patterns bases all the inter-temporal 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 Section 3 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 DSM to ramp up or ramp down quickly.[17]

- **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. Time-sequential modelling captures the operation of storage from one interval to the

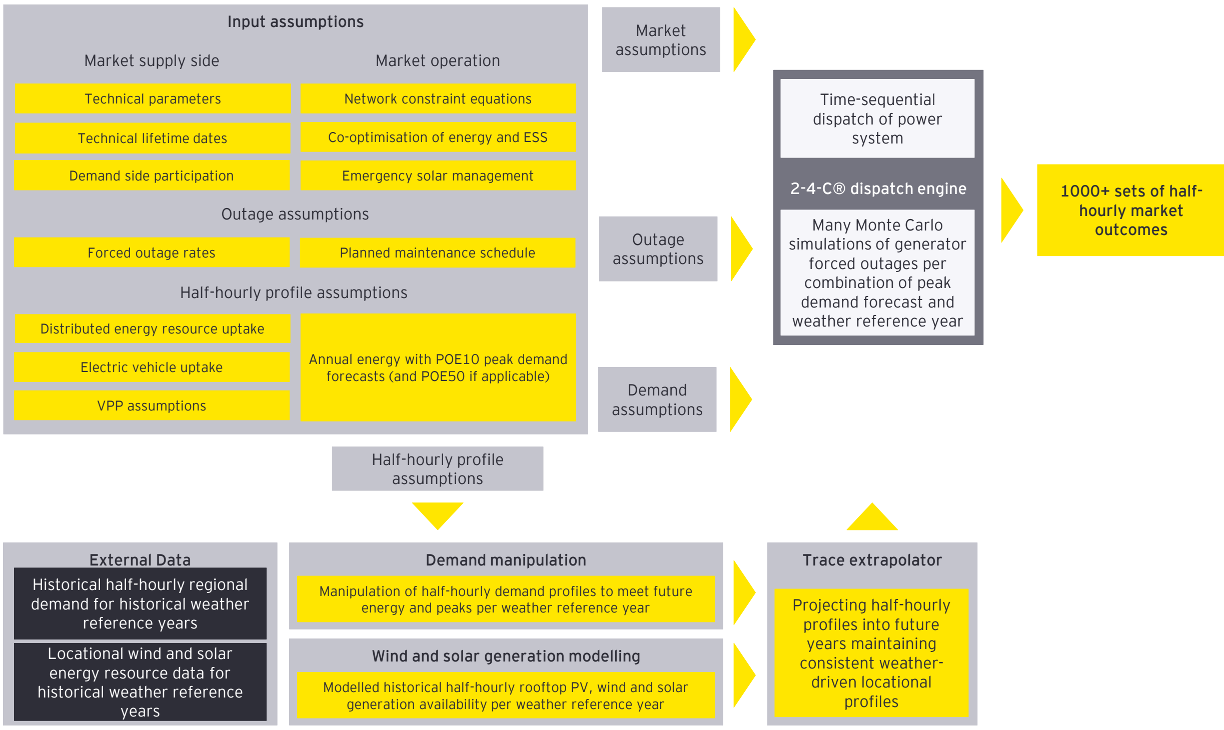
[15] As explained in Section 2.2.1, the modelling will assign bidding profiles to every Facility, however for the purposes of a reliability study, the actual values of the bids are of secondary importance (as Facilities will generate if available (subject to any constraints) as required to avoid unserved energy.
[16] 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.
[17] Generator ramping relates to generation Facilities as well as the generator side of storage facilities.

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:** EY has incorporated transmission network constraint equations provided by AEMO to represent the impact that network capability has on forecast reliability in the SWIS.

Figure 3 presents a high-level overview of the range of input assumptions, and the interactions between the 2023 WEM ESOO scenarios and the 2-4-C dispatch engine.

Figure 3: High-level overview of the interactions between input assumptions, 2023 WEM ESOO demand scenarios and the 2-4-C model



Other important characteristics of the modelling framework are described below:

- The per-interval demand is based on the forecast demand scenarios provided to us by AEMO and ultimately presented in the 2023 WEM ESOO. Demand-related forecasts provided by AEMO to EY are predominantly on an annual basis, and EY has deployed its modelling framework to convert these into half-hourly inputs. These processes are described in Section 3.

- A large number of Monte Carlo iterations have been performed in the market modelling to capture the impact of forced (unplanned) generator outages. We believe that discrete generator forced outage modelling (Section 2.2.6) combined with multiple weather reference years (discussed in Section 2.2.3 and Section 3) are critically important to provide a reasonable estimate of the unserved energy that may be incurred for different operating conditions.[18]

[18] This reliability assessment has used 12 historical weather reference years which applies half-hourly weather patterns to wind availability and solar availability, and 100 iterations of Monte Carlo simulations applied to each year of the study period. This equates to 1,200 simulations applied to each year in the 10 year study period.

- The range of market participant and market operational settings has been agreed with AEMO. Key aspects of some assumptions are also described in the following section.

2.2 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)
- Intermittent generators (wind and solar)
- ESR
- DSM

Table 7 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 7: Key characteristics modelled for all Facilities

Assumption	Source	Notes
Planned maintenance	Advised by AEMO/FIR data, plus EY modelling as required.*	Further detail in Section 2.2.5
Forced outage rates	Advised by AEMO/FIR data, plus EY modelling as required.*	Further detail in Section 2.2.6
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.	
ESS capability	Advised by AEMO.	Frequency contingency raise and frequency regulation raise markets.
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 WEM Rules as part of the reliability assessment for the Long Term PASA Study Horizon.		

Further detail on the key assumptions and how these are implemented in the modelling for each technology type is provided below.

2.2.1 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.[19] 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

[19] For non-intermittent generators, 24C uses the CRC level to define the maximum dispatchable capacity when the unit is fully available.

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.[20] 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.

2.2.2 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 WEM Rules. For the 2023-24 and 2024-25 Capacity Years, AEMO has set the ESROI to commence at the 16:30 Trading Interval and conclude at the 20:00 Trading Interval for each trading day.[21]

The reliability assessment includes existing, committed and probable large-scale storage units. 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 ESROI intervals as described above.

There may well be risk of unserved energy outside of ESROI intervals, 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.

2.2.3 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.[22] The reliability study incorporates 12 historical weather reference year data from FY 2010-11 to 2021-22 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.

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.

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[20] 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 2021-22 financial year. As mentioned above however the actual value of bids are of secondary importance in a reliability study.

[21] AEMO (2021) 'Electric Storage Resource Obligation Intervals for the 2023-24 Capacity Year'. Available from: [2021-esroi-analysis.pdf (aemo.com.au)](2021-esroi-analysis.pdf).

[22] 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.

- 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, committed and probable) 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).[23]

- **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).

    - 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. [24]

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 2.2.5, 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 2.2.5, 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

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[23] 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.

[24] 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.

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).

2.2.4 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. Further detail is also provided in Section 5.7. In real-time dispatch, AEMO forecasts a need for DSM 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 WEM Rules and can be dispatched for up to 200 hours each year.[25] 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.

2.2.5 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 2032-33), 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).

[25] Reserve Capacity Mechanism Review – Information Paper Stage 1 and Consultation Paper Stage 2 - Energy Policy WA

- 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 B.7 in Appendix B).

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.[26]

It is noted that in reality, AEMO must assess Outage Plans against the criteria for evaluating Outage Plans set out in Clause 3.18.11 of the WEM Rules (which includes for example ensuring that the capacity of the generation Facilities remaining in service and AEMO's reasonable forecast of the available DSM must satisfy the Ready Reserve Standard, amongst other criteria). For modelling purposes these criteria were not 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.

2.2.6 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).

[26] 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.

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. [27]

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 outage data derived from three years of historical information (2020, 2021 and 2022).[28]

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 2.2.3, 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.

2.2.7 Ramp rates

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[29]. 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.

2.3 Assumptions relating to the operation of the WEM

2.3.1 Transmission network constraint equations

Transmission network constraint equations have been provided by AEMO for this reliability assessment and have been formulated for the purpose of forecast modelling based on AEMO's market procedures covering constraint equation formulation.

These transmission network constraint equations are 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. Distribution network limitations are not modelled in this reliability assessment.

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.

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[27] For each of the Capacity Years of the reliability assessment, we modelled a population of 1,200 Monte Carlo iterations. Assessment 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.

[28] Exceptions are for generators that had significant outages in 2022. Two years of data were applied.

[29] AEMO | Data (WEM)

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.[30]

The objective of these transmission network constraint equations is to prevent overloading of any transmission network element and to keep the power system secure. N-1 constraints are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a transmission network element). 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 will be operated in the RTM.

The constraint equations used in this study 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).

The mathematical expressions 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 (or greater than or equal) to the sum of terms on the right-hand side (RHS) of a constraint equation. Controllable generation terms are typically 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.

Post-contingent remedial actions are modelled to represent the impact of existing generator runback schemes and load shedding schemes installed on the SWIS. 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). A single SWIS demand term has been used.

For the purpose of this reliability assessment, the transmission network constraint equations have been formulated based on committed transmission network augmentations only. 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.

2.3.2 Essential system services (ESS)

2-4-C simulates the co-optimisation of the WEM balancing energy market and the following ESS markets to assess annual unserved energy against the reliability standard:

- Regulation Raise (formerly Load Following Ancillary Service (LFAS) up).[31]
- Contingency Reserve Raise (formerly Spinning Reserve Ancillary Service).[32]

Modelling ESS raise markets in this reliability study will help to identify intervals where limiting dispatch on certain generation Facilities to reserve headroom for ESS raise services may contribute to shortfalls in generation supply availability to meet demand.

It should be noted that modelling ESS markets is not the primary focus of this reliability study because unserved energy typically occurs as a result of generation supply unavailability in periods of peak electricity demand. As such the modelling has considered only the raise markets where a potential shortfall in supply capacity could be observed because of a requirement to reserve available capacity to keep the power system secure. In operational timeframes AEMO may choose

[30] Consistent with the application of seasonal ratings in the WA Whole of System Plan.
[31] Frequency regulation services assists in ensuring that system frequency stays between the range of 49.8 and 50.2 Hz for normal operating conditions
[32] Contingency Reserve Raise is designed to contain under-frequency excursions above 48.75 Hz.

to appropriately balance the risks between meeting ESS obligations or serving system demand. These decisions would be based on relevant information only available in operational timeframes including but not limited to, forecasts, volatility, contingency size and modelled frequency outcomes. For this reliability study, AEMO have advised that should a potential shortfall in supply capacity result due to the need to meet an ESS requirement, the modelling should ensure ESS obligations are not compromised and record the unserved energy reported, which is consistent with other AEMO operational and long-term planning processes.

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. Each Facility is able to offer multiple bid-quantity pairs. The bid curve for each Facility is based on a combination of SRMC-based offers and estimations of a Facilities' opportunity cost.[33] Different bid profiles are constructed depending on which ESS market is being modelled. The construction of these offers are based on 'trapezium offer profiles' as described for the National Electricity Market (NEM), which will also be relevant for the co-optimised market operation to be introduced (from 1 October 2023).[34] New storage is assumed to participate in the modelled ESS raise markets and is dispatched after existing service providers. Whilst it is possible that storage may displace existing participants in these markets, this simplified modelling implementation has minimal impact on the key outcomes of the reliability assessment as the quantity of headroom reserved is the same.

[33] SRMC stands for short-run marginal cost. Opportunity cost in this context refers to foregone energy revenue as a result of withholding available capacity from the energy market. This requires an estimation of energy market prices as an input into estimating opportunity cost from foregone energy revenue.

[34] Guide to Ancillary Services in the National Electricity Market - https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf

3. Modelling half-hourly demand

3.1 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 2023 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.

Section 3.2 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 3.3 sets out the annual forecasts provided by AEMO (most of which are typically published each year in the WEM ESOO).

Section 3.4 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.

3.2 Approach to forecast years based on historical weather reference years

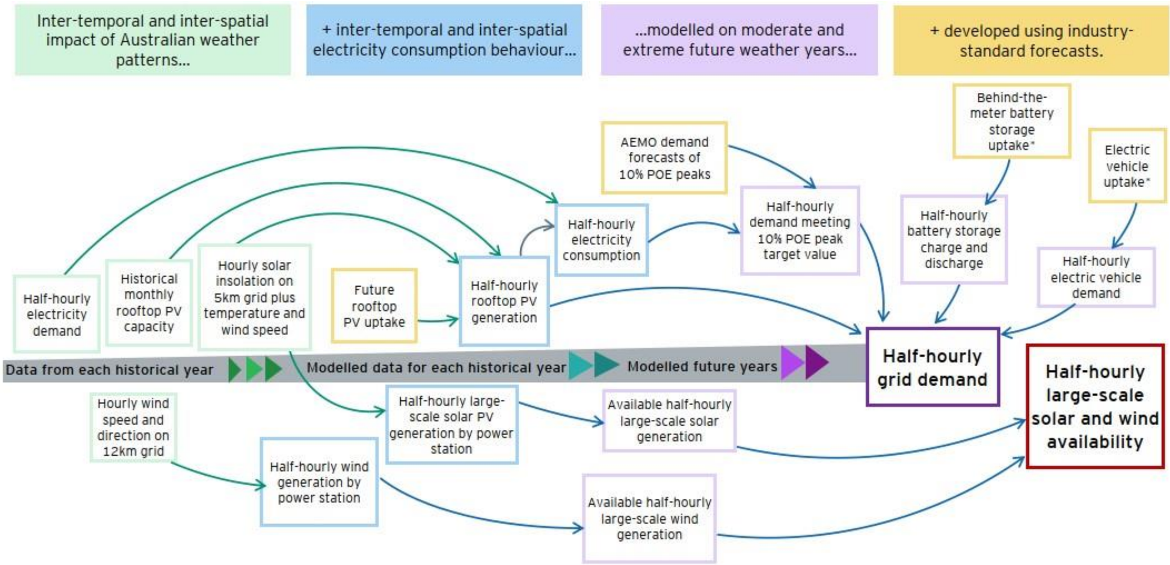
EY's approach to forward-looking half-hourly modelling is to base all the intertemporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years).

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.

Figure 4 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 4: 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



The key principles of this approach are as follows:

- The historically observed inter-temporal and inter-spatial 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 2.2.3). 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 inter-spatial (regional) electricity consumption behaviour is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO. We then add EY's historical modelled rooftop PV generation output to produce the historical electricity consumption. 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 demand scenario is used, as advised by AEMO.

- 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.

- As a final step, based on advice from AEMO, the half-hourly demand profiles across different weather years underwent a final adjustment so that overall, on average, the operational peak aligned with AEMO's estimate of operational peak in each year.

3.3 Inputs to half-hourly demand modelling

The demand scenarios modelled in the reliability assessment are consistent with the 2023 WEM ESOO scenarios. AEMO provided the demand inputs as set out in Table 8 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 8: Annual demand and DER 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 in previous years. Ultimately, we calculate/estimate the fixed-shape consumption (FSC) seasonal peak demands (see note in this table, and FSC is defined in Section 3.4) 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. We carry out any post-processing adjustment to align the average peak across the 12 weather reference years with AEMO's.
Behind-the-meter (BTM) rooftop PV	MW installed capacity and expected energy (GWh)	EY produced 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 3.4.1.1).
PVNSG (small PV non-scheduled generators)	MW installed capacity and expected energy (GWh)	As above for rooftop PV, except that these are not subject to curtailment as part of the minimum demand threshold.
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 used 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 processed this energy demand through an EV VPP tool (which essentially moves charging from peak demand times to the lowest demand times). VPP assumptions can be found in Appendix B.
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.

Item	Units/coverage	Notes
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 percent 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 percent 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. VPP assumptions can be found in Appendix B.
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	It was agreed with AEMO that demand from hydrogen production should be modelled to turn down to 10 per cent of its installed capacity at times of operational peak and to 10 percent at the time of underlying peak, or at times of otherwise unserved energy. For modelling implementation this meant hydrogen demand was input as a flat load at 10 percent of its installed capacity, so that its demand is ensured to be at 10 percent at times of peak demand and unserved energy. The reliability study outcomes do not report on outcomes outside of these intervals (i.e., where there is no unserved energy), although the full annual forecast hydrogen consumption is included in the denominator to calculate the percentage of unserved energy over the year.

3.4 High-level overview of approach to modelling demand components

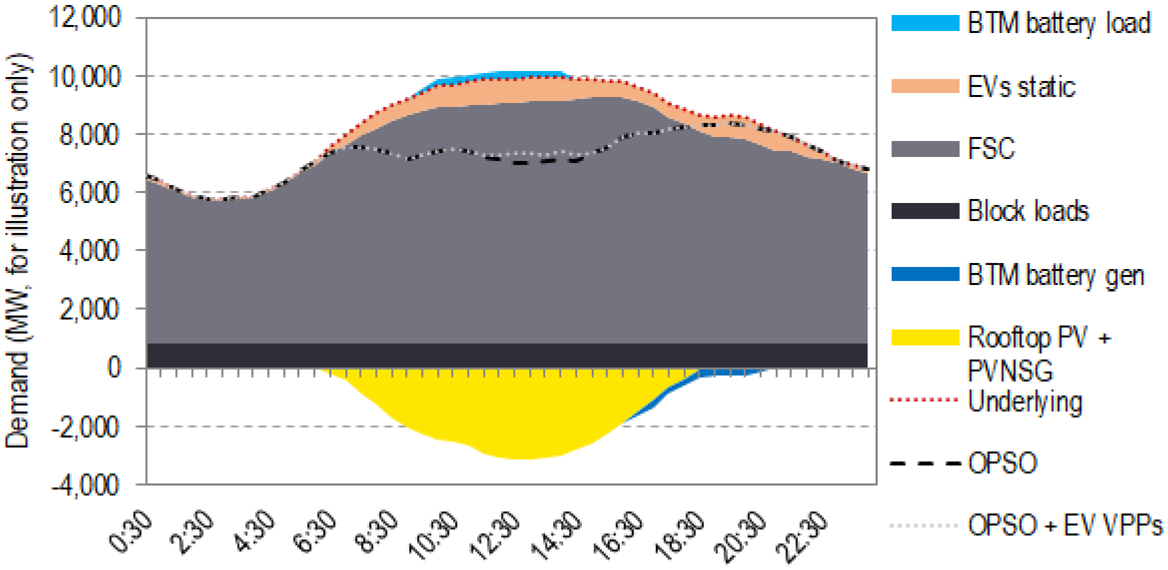
EY's demand modelling philosophy is based on splitting the operational demand into components that can be modelled separately, where each has an influence on changing the shape of the demand profile. These components include:

- 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



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 DER uptake (as outlined in Table 8 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 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. However, as noted above, the average operational peak over the 12 reference years modelled is aligned with the operational peak provided by AEMO.

3.4.1 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 2.2.3. 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 degraded MW of capacity 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.

3.4.1.1 Emergency Solar Management and DPV curtailment

The WA Government's 'Low Load Project – Stage 1 Report' identifies a minimum demand threshold (MDT) of between 550 MW and 650 MW for the SWIS. The 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 500 MW.[35]

3.4.2 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 (e.g. convenience charging, day / night charging, fast charging etc).[36]

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 reduces charging at times when demand is higher, or DPV generation has reduced for example).

Note that the default mode of the tool does not currently include vehicle-to-grid (V2G) discharging. Note also 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.

3.4.3 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 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

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[35] 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 500 MW according to the specific fleet configuration and demand uncertainty at the time of intervention.

[36] 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

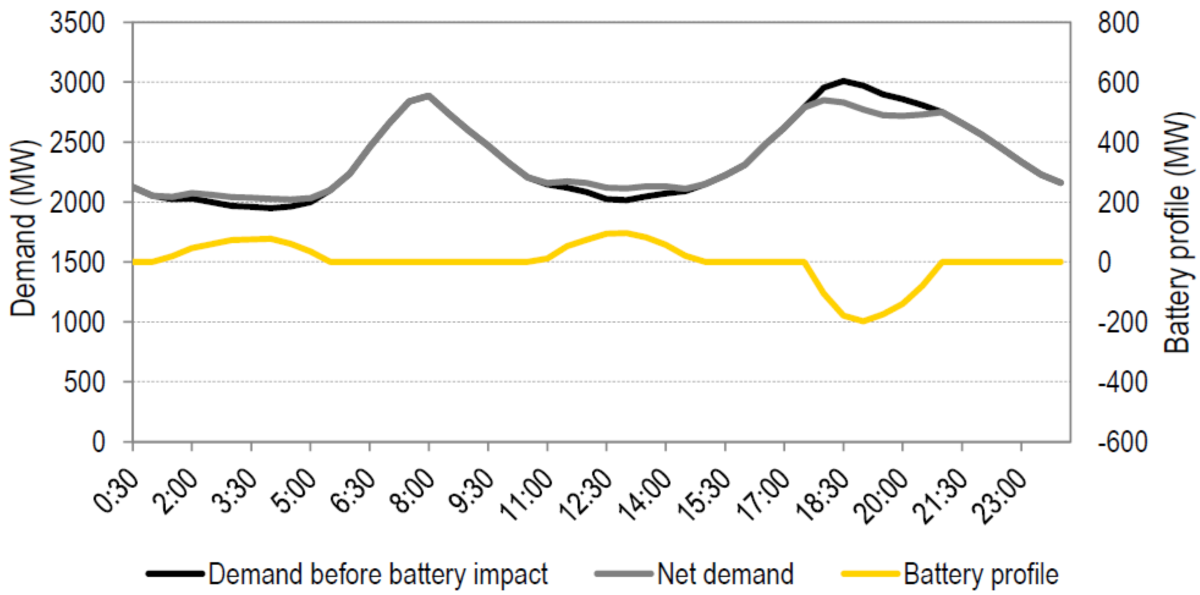
operates during the lowest periods of residual demand. This profile is produced for each historical reference year of the study.

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 in winter on how 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



3.4.4 Modelling of 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 or periods of grid emergency.
- Electrification load: This was modelled as a flat, non-flexible demand based on the MW associated with the annual energy consumption provided by AEMO.

4. Methodology

4.1 Scope item 1: Assessment against the Planning Criterion

The main objective of scope item 1 is to identify and characterise any capacity or reliability shortfalls for each modelled scenario.

The Planning Criterion is comprised of two components, referred to as Limb A and Limb B. 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 four building blocks. The building blocks are presented in Table 9.

Table 9: 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 under low, expected, or high 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: (1) 7.6% of the sum of 10% POE peak demand and IL allowance and (2) The largest contingency relating to loss of supply at the time of peak demand. AEMO has adjusted its determination under clause 4.5.9(a)(ii) of the WEM Rules reflective of rule changes made under the Tranche 6 WEM Amending Rules to consider a broader range of risks than a single generator contingency (e.g. fuel supply, delay in projects commercial operations, forced outages of Facilities and failure of network elements etc.). This change in methodology is reflective of the broader range of risks presenting as part of the energy transition. For the purposes of this WEM ESOO, AEMO has considered that the largest risk to be equivalent to the loss of the three largest generating units.
FR allowance	Accounts for the latest minimum LFAS requirement approved by the ERA for FY 2022-23 and new capacity of behind-the-meter PV and large-scale wind and solar (the future Regulation Raise Frequency Co-optimised Essential System Service under the reformed WEM due 1 Oct 2023). [37]

To assess the extent to which the AIC of the Energy Producing Systems and DSM capacity is capable of satisfying Limb A of the Planning Criterion, for each modelled scenario and each modelled year we:[38]

- 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 investment gap by comparing the annual sum of Reserve Capacity of the AIC fleet against the annual requirement set by Limb A.

[37] NOFB includes a contain band of 49.8 to 50.2 Hz (99% of the time over any rolling 30-day period) for the SWIS. NOFEB includes a contain band of 49.7 to 50.3 Hz and a stabilise band of 49.8 to 50.2 Hz within 5 minutes.

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

To assess the extent to which the AIC of the Energy Producing Systems and DSM 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 0.002% standard.
    - ► We use the annual operational energy consumption provided by AEMO as the denominator of this calculation, noting that the modelled interval demand values across each of the demand components (described in Section 3 above) are aligned with AEMO's inputs.
    - ► 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 10. Table 10 provides a summary of the four possible combinations of outcomes from the analysis in scope item 1.

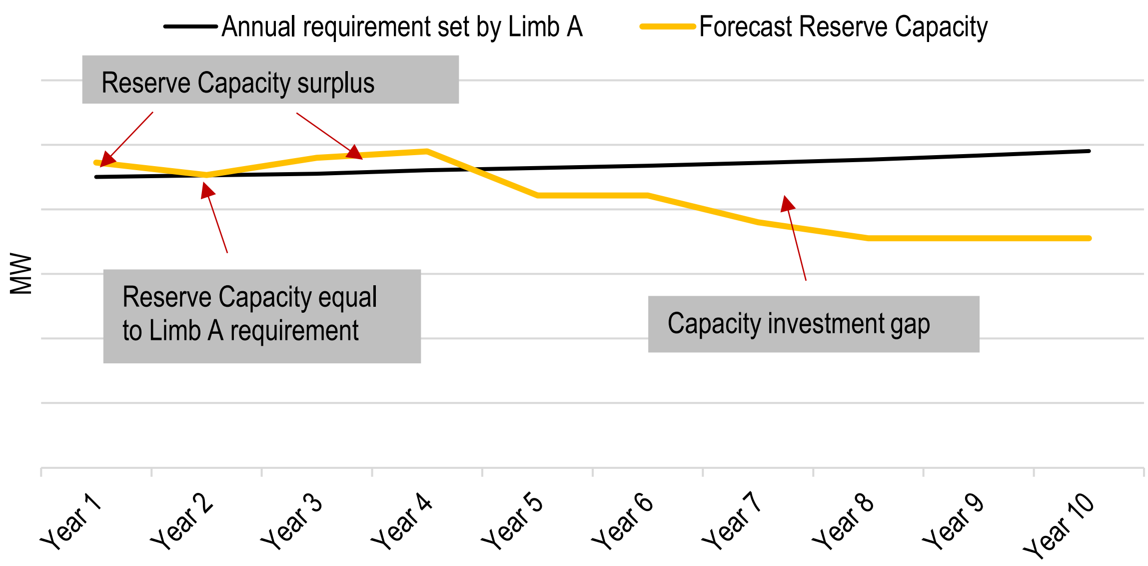
Table 10: Illustration of the logic of the assessment against Limb A and Limb B of the Planning Criterion

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 and probable units[39]	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 < 0.002%)
Case B					Capacity investment gap (annual EUE > 0.002%)
Case C		5,200	4,100	Reserve Capacity investment gap (-400 MW)	Reliability surplus (annual EUE < 0.002%)
Case D					Capacity investment gap (annual EUE > 0.002%)

For assessment against Limb A, we then report on the amount of Reserve Capacity surplus or capacity investment gap in meeting the requirement set by Limb A. Illustrative possible results of this assessment are presented in Figure 7.

[39] As applicable by scenario.

Figure 7: Illustration of possible results of the assessment against Limb A of the Planning Criterion[40]



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 investment gap.

4.1.1 Analysis of EUE

Following the assessment against Limb A and Limb B of the Planning Criterion, an analysis of EUE is performed. Based on outputs of 2-4-C modelling as above, for years with identified capacity investment gaps (i.e. modelled annual EUE % > 0.002%) we identify and analyse modelled EUE intervals to:

- Investigate EUE drivers, including capacity shortfalls isolated to a sub-region of the SWIS (through considering which power system constraints drive EUE, if any)
- Identify options to alleviate EUE.

Possible drivers of EUE in the intervals investigated include:

- A capacity investment gap driven by a forecast increase in annual energy consumption and peak demand coupled with announced capacity retirements and uncertainty around the pace and scale of investment in new supply capacity.
- Unavailability due to forced outages, planned maintenance periods
- Low availability of renewable resource
- Capacity retirements

[40] 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.

- Storage unavailability due to depleted reservoir/state of charge levels
- Unavailability of DSM (due to time of day of EUE, or DSM provision exhausted under the assumptions provided by AEMO)
- Binding or violating power system dispatch constraints (e.g. transmission network thermal constraint, ESS constraints, emissions constraints).

To understand drivers of identified EUE intervals, the timestamp of the interval and the MW quantity of the capacity investment gap is identified. The modelled prevailing demand and supply conditions in these intervals is investigated to determine factors affecting the availability of generation, storage and DSM capacity to meet the demand.

While the EUE assessment of Limb B will consider an average result across many Monte Carlo iterations and all modelled reference years, analysis of the drivers considers the individual Trading Interval outcomes to determine the extent to which EUE is driven by factors that are common to all of these simulations (e.g. a general capacity investment gap due to retirements) or if particular weather reference year patterns drive results (e.g. one or two outlier years with particularly low renewable resource at times if high demand for example). The nature of EUE intervals is considered in terms of the following:

- Contiguous duration of EUE intervals (this will inform whether particular mitigation options are favourable or not, i.e., a long duration of contiguous EUE intervals is unlikely to be addressed by short-duration storage for example).
- Time of day and monthly EUE occurrences (this will inform whether particular mitigation options are favourable or not, i.e., EUE occurring during non-solar hours, or outside the operating hours of DSM availability requirements).
- Modelled generation Facility dispatch levels compared to modelled availability (driven by forced or planned outages, renewable resource availability and its interval-to-interval fluctuations, or transmission network constraints).
- Binding or violating dispatch constraints.

To identify and assess any potential additional capacity required isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability, the modelled power system dispatch constraint results are investigated. This enables identification of when and where the modelled constraints bind or are violated. Based on the analysis, a thematic summary of identified EUE drivers and identified options to alleviate reliability shortfalls is provided in Section 5.

4.2 Scope item 2: Forecasting the 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 4.1 and is a known quantity from the calculation carried out in scope item 1.

The capacity required to meet Limb B at this stage of the analysis is an unknown quantity, i.e. the modelling in scope item 1 will result in annual EUE being either above or below 0.002% but not exactly at this threshold. Therefore, there is a need to derive the level of AIC and associated Reserve Capacity where EUE just meets the 0.002% threshold and then compare it with the Limb A requirement. The process to do this will be informed by outcomes of scope item 1, i.e., whether our starting point is a capacity mix resulting in EUE above or below 0.002%.

Changes to the AIC aimed at approaching the 0.002% standard will be based on removing existing generation Facilities in the order of retirement date (which currently implies starting with coal, based on announced retirements) or adding new generic OCGT units. The approach to use OCGT units as the new entrant technology is based on their use for setting the Benchmark Reserve Capacity Price for the RCM and is deemed to be the lowest cost-of-new-entrant (CONE) option to address where additional capacity is required in the SWIS. [41]

Forecasting the RCT for scope item 2 is informed by results of the assessment and analysis performed in scope item 1, and will also account for the dual nature of the Planning Criterion (i.e. both Limb A and Limb B must be met).

Table 10 provided a summary of the four possible combinations of outcomes from the analysis in scope item 1, and how these inform the starting point for scope item 2. There are two possible approaches based on that assessed starting point – these are described in more detail below.

4.2.1 Forecasting the RCT for years with a reliability surplus

For years with observed reliability surpluses (i.e. modelled annual EUE % < 0.002%), this would result in the following steps:

- ► Decrease the starting-point AIC (as per scope item 1) by removing existing coal units (or part thereof), and simultaneously decreasing the amount of associated Reserve Capacity by removing Reserve Capacity associated with the removed units
- ► Determine scope item 2 AIC and scope item 2 Reserve Capacity as a result of the above
- ► Run the 2-4-C model to dispatch scope item 2 AIC
- ► Observe the resulting EUE %.

The RCT for each year can then be determined as the greater of:

- ► The Limb A requirement and
- ► The quantum of scope item 2 Reserve Capacity determined as above.

4.2.2 Forecasting the RCT for years with a capacity investment gap

For years with observed capacity investment gaps (i.e. modelled annual EUE % > 0.002%), the following steps apply:

- ► Increase the starting point AIC (as per scope item 1) by adding new generic OCGT units, and simultaneously increase the amount of assumed Reserve Capacity by adding Reserve Capacity assumed to be associated with the new generic OCGT units. Assumed assignment of generic new entrants Reserve Capacity has been agreed with AEMO.[42] The logic is illustrated in Figure 8.
- ► Determine scope item 2 AIC and scope item 2 Reserve Capacity as a result of the above
- ► Run the 2-4-C model to dispatch scope item 2 AIC
- ► Observe the resulting EUE %.

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[41] To the extent possible, removal of existing OCGT units will be informed by analysis of dispatch results (including dispatch constraints) and size of facilities relative to the quantum of capacity surplus. Additions of new generic OCGTs will assume that these facilities are modelled at the regional reference node (i.e. not affected by transmission network thermal constraints or NAQ de-rating).

[42] Generic OCGTs are assumed to receive Capacity Credits equivalent to their installed capacity.

The RCT for each year can then be determined as the greater of:

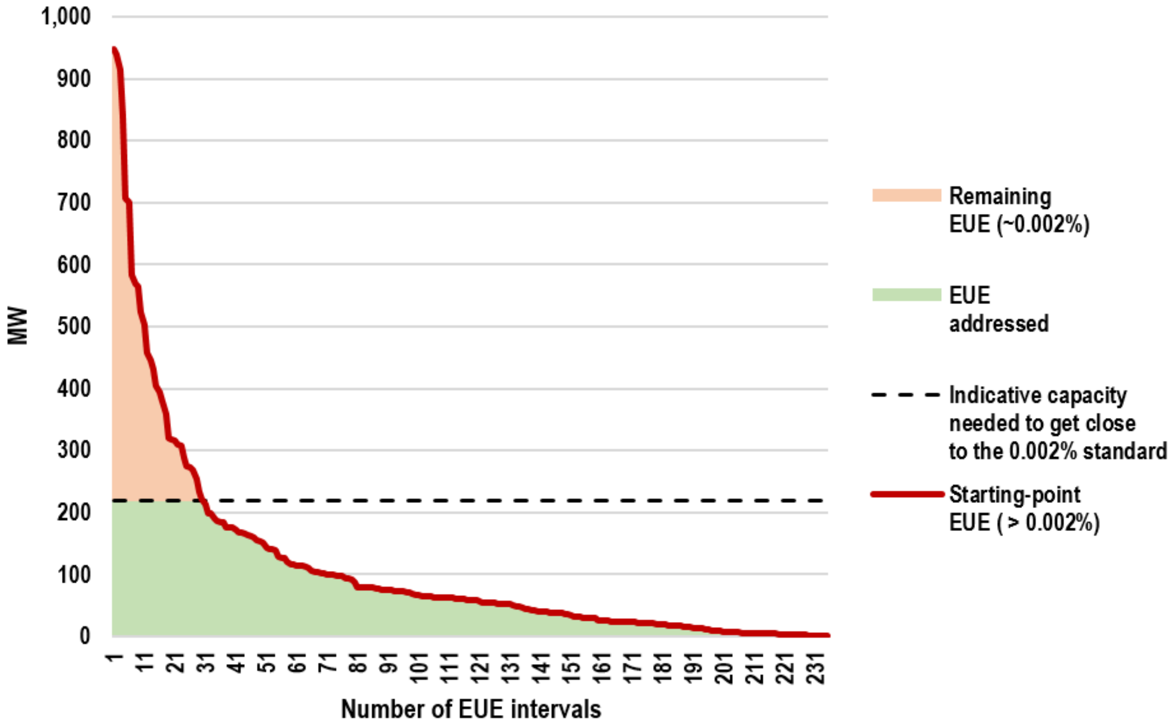
- The Limb A requirement and
- The quantum of scope item 2 Reserve Capacity determined as above.

The logic of the RCT forecasting process is illustrated in Table 11.

Table 11: Illustration of the logic to forecast the RCT, informed by results of scope item 1 (numbers are illustrative only)

Case	Key inputs			Scope item 1		Scope item 2			
	Limb A requirement (MW)	AIC (MW)	Reserve Capacity (MW)	Limb A assessment: possible results	Limb B assessment: possible results	Limb B re-modelling	AIC delta and associated Reserve Capacity (MW)	Scope Item 2 AIC, Scope Item 2 Reserve Capacity (MW)	Forecast RCT
	Based on building blocks	Existing units less retirements of existing units + committed and probable units	Advised by AEMO	Reserve Capacity minus Limb A requirement	2-4-C modelling (dispatch AIC, assess EUE)	2-4-C modelling (dispatch AIC with regard for AIC delta, observe EUE)	Additions / removals to AIC	[2] + [7] [3] + [7]	Outcome of Scope item 2
	[1]	[2]	[3]	[4] = [3] – [1]	[5]	[6]	[7]	[8]	[9]
Case A	4,500	5,800	4,700	Reserve Capacity surplus (+200 MW)	Reliability surplus (annual EUE < 0.002%)	• Based on Scope item 1 modelling results, decrease AIC by removing capacity based on order of retirement date (implying starting with coal as per age and announcements) • Run model, observe EUE %, re-iterate (if needed)	• Existing OCGT capacity (and Reserve Capacity) removed or • Generic OCGT capacity (and Reserve Capacity) added	Scope Item 2 AIC: • AIC [2] less existing capacity removed [7] or • AIC [2] plus generic OCGT capacity added [7] Scope Item 2 Reserve Capacity: • Reserve Capacity associated with AIC [3] less Reserve Capacity associated with removed capacity [7] or • Reserve Capacity associated with AIC [3] plus Reserve Capacity associated with new generic OCGTs added [7]	Greater of: • Limb A requirement [1] or • Scope item 2 Reserve Capacity [8]
Case B					Capacity investment gap (annual EUE > 0.002%)	• Based on Scope item 1 modelling results, increase AIC by adding new generic OCGT units (see below) • Run model, observe EUE %, re-iterate (if needed)			
Case C		5,200	4,100	Capacity investment gap (-400 MW)	Reliability surplus (annual EUE < 0.002%)	Same as per Case A			
Case D					Capacity investment gap (annual EUE > 0.002%)	Same as per Case B			

Figure 8: Illustration of the starting-point, theoretical capacity needed to address a reliability shortfall



4.3 Scope item 3: Availability Classes

The key objective of scope item 3 is to determine how much of the RCT should be provided by capacity classified as Availability Class 1 and capacity classified as Availability Class 2. For this year's WEM ESOO and Long Term PASA, this is determined for the 2024-25 and 2025-26 Capacity Years.

The WEM Rules distinguish between the two Availability Classes:

- Availability Class 1: The Availability Class assigned by AEMO to a Facility containing an Intermittent Generating System or Non-Intermittent Generating System, and any other Facility that is expected to be available to be dispatched for all Trading Intervals in a Capacity Year, under clause 4.11.4(a).[43] Availability Class 1 thus relates to scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages.[44]

- Availability Class 2: The Availability Class assigned by AEMO to Certified Reserve Capacity that is not expected to be available to be dispatched for all Trading Intervals in a Capacity Year, under clause 4.11.4(b).[43] Availability Class 2 thus relates to capacity that is not expected to be available for dispatch for all Trading Intervals and includes DSPs and standalone ESR.[44]

The technologies that contribute to Availability Class 1 and Availability Cass 2 are presented in Table 12. [44]

[43] As per WEM Rules Glossary.

[44] Definitions from 2022-wholesale-electricity-market-esoo.pdf (aemo.com.au)

Table 12: Availability Class 1 and Availability Class 2

Item	Comments
Availability Class 1	This includes thermal generators (coal, CCGT, cogeneration, diesel, OCGT, waste-to-energy), renewable generators (wind and large-scale solar PV) and hybrid Facilities (generator + ESR).
Availability Class 2	This includes DSPs and standalone (not hybrid) ESR.

4.3.1 Determining Availability Class 1 and Availability Class 2

As described above, Availability Class 2 capacity is comprised of DSM and standalone ESR. Within this Availability Class, these two technology types have different operating characteristics and availability over the day and year. Reflecting this, the approach agreed with AEMO involves modelling each of these technologies separately to determine the maximum amount of capacity of each individually that can be within the RCT Reserve Capacity allocation before breaching the 0.002% standard. The minimum of these is then taken to set the Availability Class 2 capacity.

To determine the maximum amount of capacity within Availability Class 2, an approach is applied similar to that taken to address reliability surpluses in scope item 2 (Section 4.2). This involves for DSM and ESR separately in turn:

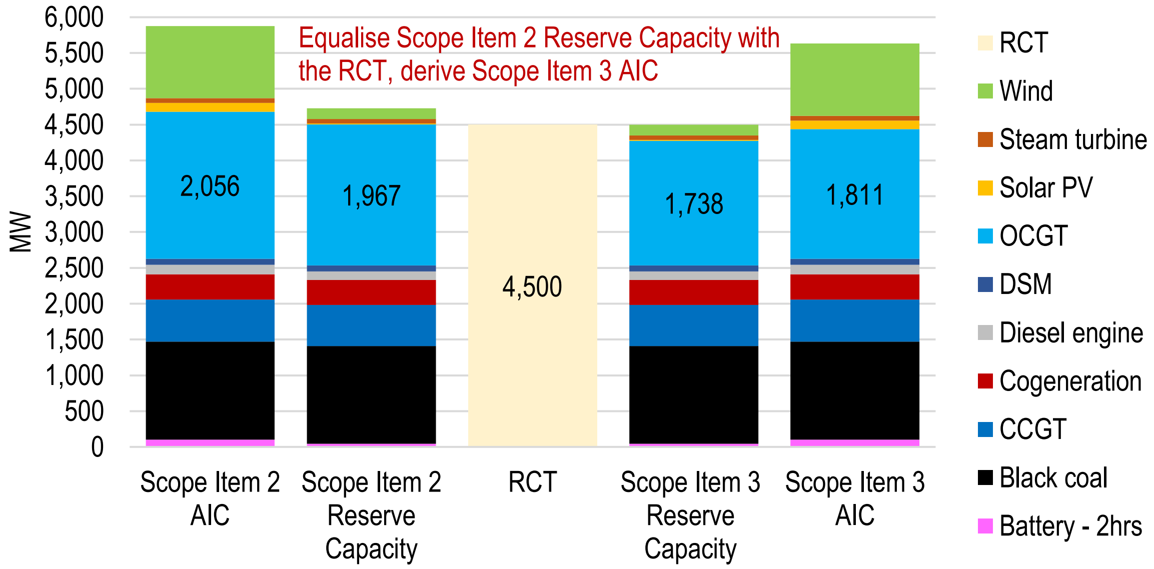
- Decreasing capacity classified as Availability Class 1
- Simultaneously increasing the amount of capacity in Availability Class 2
- Running the 2-4-C model until the observed annual EUE % has just breached the 0.002% standard.

The approach to scope item 3 is described in step 1 – step 4 below.

The amount of total capacity modelled is required to be aligned with the Reserve Capacity required to meet the RCT in the years in question. Therefore, step 1 of our process involves determining the scope item 3 AIC for the dispatch modelling. The approach to deriving scope item 3 AIC will depend on whether the RCT in scope item 2 was set by Limb A or Limb B of the Planning Criterion. If the RCT in scope item 2 was set by Limb B, the Reserve Capacity and AIC will be known. The approach below thus only applies to a case when the RCT in scope item 2 has been set by Limb A (and there was a capacity investment gap or surplus).

The magnitude of Reserve Capacity determined in scope item 2 (scope item 2 Reserve Capacity, as per column [8] in Table 11) is equalised with the RCT determined for a relevant Capacity Year and adjusting the AIC respectively. This is done by adding OCGT or removing coal units in retirement order and their associated Reserve Capacity (depending on whether there is a forecast Reserve Capacity shortfall or surplus respectively relative to the RCT) and will produce scope item 3 AIC and associated estimated Reserve Capacity. This is illustrated in Figure 9 for a reliability surplus case where in this instance coal is removed in order of retirement dates until Reserve Capacity matches the RCT. In the case of a capacity investment gap, OCGT capacity and respective assumed Reserve Capacity are added. This step is required because the total quantum of assumed Reserve Capacity from Availability Class 1 and 2 must equal the RCT (as required by the WEM Rules).

Figure 9: Illustration of the approach to equalise assumed Reserve Capacity associated with Item 2 AIC with the RCT for a relevant year (numbers are illustrative only)



In Step 2, the 2-4-C model is run to dispatch scope item 3 AIC across all demand intervals for the 10% POE expected scenario in the relevant year. The modelled annual EUE % over an average of the reference years is observed, and, given the Limb A and Limb B determination above, should be below 0.002%.

In Step 3, we iteratively increase the capacity with the RCT that is allocated to Availability Class 2 (modelling DSM and ESR separately) while decreasing Availability Class 1 capacity by the Reserve Capacity equivalent. The 2-4-C model is simulated to dispatch revised AIC across all demand intervals for the 10% POE expected scenario (average of reference years) for the required Capacity Years (2024-25 and 2025-26). The annual EUE % is observed and the process is iterated through until the modelled annual EUE % just breaches the 0.002% standard for the amounts of DSM and ESR separately.

Based on the above, we can determine the maximum amount of Availability Class 2 capacity before the modelled annual EUE % breaches the 0.002% standard, based on the lower of the resulting DSM and ESR capacity.

For the purposes of this scope item, generic DSM capacity is added to the model with the following parameters:

- DSM can be provided for 200 hours per year. This is provided as it is required in the time-sequential modelling, with no imposed optimisation over the year.
- DSM is provided between 8:30am and 8:30pm.
- It is assumed there are no ramp rate restrictions within the 30-minute interval.
- All available DSM is called upon and dispatched simultaneously in the event there would otherwise be unserved energy (with the assumption that tie-breaking would share the provided MW across providers).
- DSM is provided as a last resort after all existing capacity is utilised to its full availability in either providing energy or ESS.

Storage is modelled with the following parameters:

- ► The generic ESR capacity added is assumed to be four-hour storage duration (in line with receiving 100% Reserve Capacity allocation).
- ► Large-scale storage is operated to ensure unserved energy is avoided where possible (and not just in the ESROI intervals).

4.4 Scope item 4: Availability Curves

The key objective of scope item 4 is to create demand duration curves increased by a margin (Availability Curves) for the 2024-25 and 2025-26 Capacity Years.

As per clause 4.5.10(e), the Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirements over a Capacity Year for each of the second and third Capacity Years of the Long Term PASA Study Horizon. The forecast minimum capacity requirement for each interval in the Capacity Year must be determined as the sum of:

- ► The forecast demand (including transmission losses and allowing for Intermittent Loads) for that Trading Interval under the scenario described in clause 4.5.10(a)(iv)
- ► The difference between the Reserve Capacity Target for the Capacity Year and the maximum of the quantities determined under clause 4.5.10(e)(i) for the Trading Intervals in the Capacity Year.[45]

Based on the above, for each interval of a Capacity Year the Availability Curve is determined as the sum of the following two Items:

(a) The forecast demand for the 10% POE expected Growth Scenario

(b) A constant margin applicable to all demand intervals in a Capacity Year being the difference between the RCT and the forecast peak demand for the 10% POE expected Growth Scenario.

We note that historically the RCT was set by Limb A of the Planning Criterion. In this case, Item (b) of the Availability Curve was equal to the sum of:

- ► The IL allowance
- ► The Reserve margin
- ► The Frequency regulation allowance.

However, if the RCT were to be set by Limb B of the Planning Criterion, Item (b) would be derived as the difference between:

- ► The RCT (as set by Limb B and)
- ► The forecast 10% POE expected peak interval demand, i.e. Item (a).

[45] We note that in the past where the RCT was set by Limb A of the Planning Criterion this component was equal to the sum of the IL allowance, the Reserve margin and the FR allowance (being the building blocks of Limb A other than the forecast 10% POE Expected peak demand). If the RCT were to be set by Limb B of the Planning Criterion, this component will be the difference between the RCT (determined as per section 4.2) and the forecast 10% POE Expected peak interval demand (i.e. the first building block of Limb A of the Planning Criterion).

The approach to determining the value of Item (b) is presented in Table 13.

Table 13: Illustration of the approach to determine the value of Item (b) (numbers are illustrative only)

Item	RCT set by Limb A	RCT set by Limb B
RCT	4,588 MW	4,800 MW
Forecast 10% POE expected peak interval demand	4,100 MW	4,100 MW
Item (b)	4,580 – 4,100 = 488 MW, equivalent to the sum of: • IL allowance (3 MW) • Reserve margin (335 MW) • FR allowance (150 MW)	4,800 MW – 4,100 MW = 700 MW

Based on the above, for each of the 2024-25 and 2025-26 Capacity Years modelled, we develop an Availability Curve as follows:

- Rank demand intervals for the 10% POE expected scenario (average of reference years) in order of descending magnitude of demand
- Increase each demand data point by adding a constant margin (Item (b) above) being the difference between:
  - The value of the RCT determined as per section 4.2 and
  - The value of the forecast 10% POE expected peak demand.

5. Results and analysis

This section presents the outcomes of the reliability assessment, based on the methodology and approach set out in previous sections. Firstly Section 5.1 provides the anticipated installed capacity and associated forecast Reserve Capacity that is included in the modelling for each scenario. Section 5.2 provides the Limb A outcomes resulting from the building blocks described in Section 4.1.

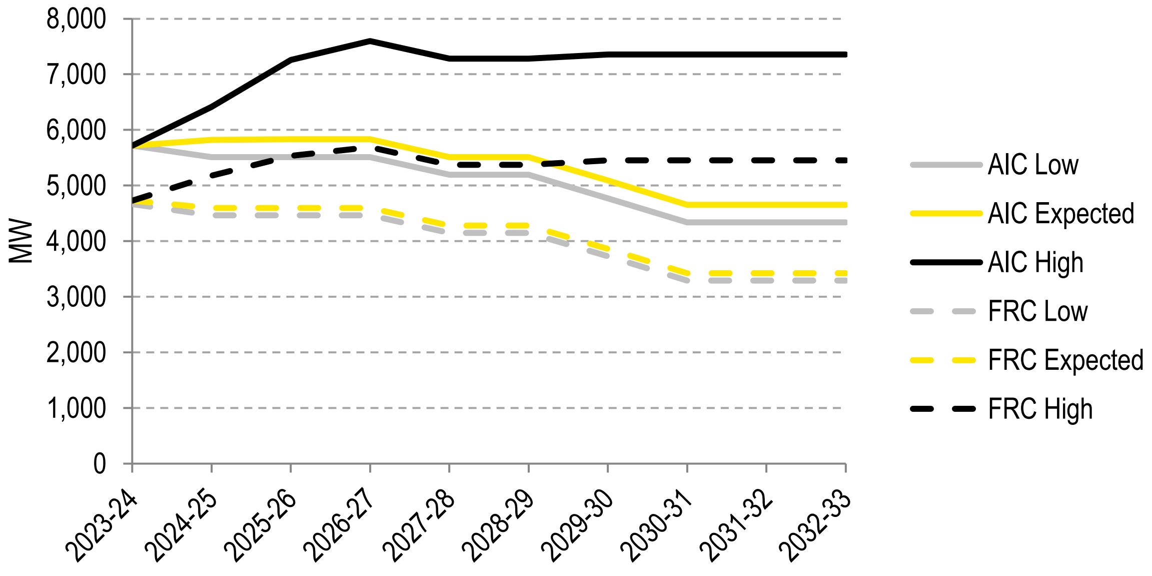
5.3 provides the outcome of comparing forecast Reserve Capacity against the Limb A requirements, while Section 5.4 sets out the results of the dispatch modelling of AIC, the EUE outcomes, and the capacity required to maintain annual EUE below the 0.002% standard. Based on the outcomes of the Limb A and Limb B analysis, 5.5 determines the Reserve Capacity Target for the expected scenario.

Section 5.6 provides further detail on the EUE outcomes from the reliability assessment while Sections 5.7 and 5.8 provide the Availability Class and Availability Curve outcomes respectively. Section 5.9 and 5.10 consider the impact of transmission network constraints and options to alleviate capacity investment gaps respectively.

5.1 Anticipated installed capacity and Reserve Capacity

Figure 10 summarises the forecast AIC and the forecast Reserve Capacity across AEMO's low, expected and high scenarios.

Figure 10: Forecast AIC and the forecast Reserve Capacity in the low, expected and high scenarios



Changes to the AIC and forecast Reserve Capacity are the result of the announced retirements of Synergy coal generators and a number of new entrant Facilities anticipated to enter the WEM. Although there is a net increase in AIC to 2026-27 in the expected scenario (as new entrant installed capacity more than offsets the reduction from the exit of Muja G6), these new entrants are expected to have a lower Certified Reserve Capacity (CRC) as a proportion of their installed capacity (in comparison to the retiring units).[46] CRC for each Facility for the first year of the study (the 2023-24 Capacity Year) is based on 2021 Reserve Capacity Cycle (RCC) assignment and then

[46] This is based on observations that the historical Capacity Credits awarded to intermittent generators are a smaller proportion of their total installed capacity compared to the retiring coal Facilities that are retiring. The Capacity Credits awarded to intermittent generators are an outworking of the Relevant Level methodology.

CRC for each Facility is assumed flat from the 2024-25 Capacity Year (based on the 2022 RCC assignment.

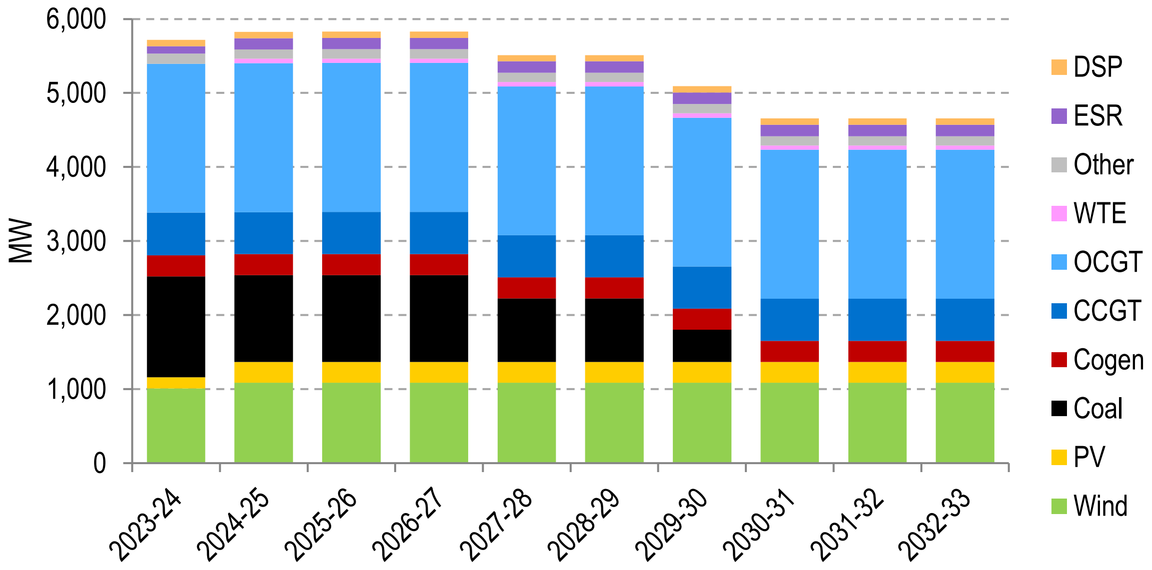
Beyond 2027-28, there is less certainty with respect to capacity that is anticipated to enter the WEM and no further new entrant Facilities are assumed beyond this point. As such, the announced retirements of coal units result in both AIC and forecast Reserve Capacity reducing over the study period in the expected and low scenario.

The high scenario has assumed the connection of a number of supply Facilities by 2026-27, which are additional to the expected and low scenarios. This offsets the retirement of non-State-owned coal generation units, which are assumed to exit the market in the high scenario by 2025-26. These additional Facilities in the high scenario results in AIC increasing to a high of around7,500 MW in 2026-27.[47]

The Reserve Capacity outlook presented includes the impact that Network Access Quantities (NAQ) have on Reserve Capacity. AEMO have advised that NAQs have no impact on Reserve Capacity assigned for the AIC Facilities in the 2024-25 Capacity Year.

Figure 11 and Figure 12 summarise AIC and forecast Reserve Capacity by technology type from 2023-24 to 2032-33 for the expected scenario. All coal capacity is anticipated to exit the WEM by 2030-31 in the expected scenario as shown below.[48]

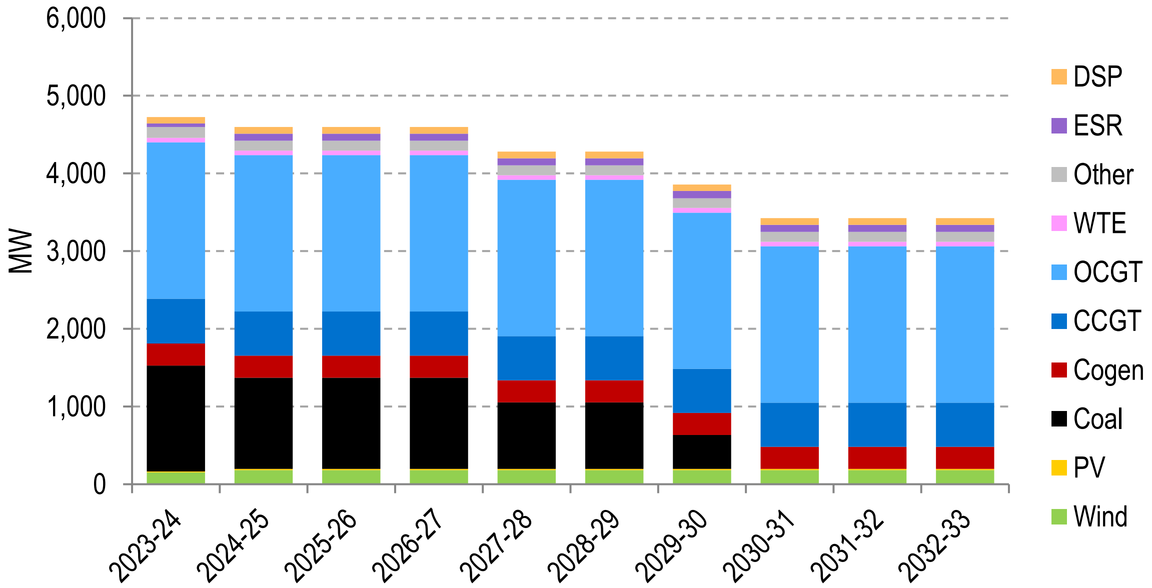
Figure 11: Forecast AIC over the study period (expected scenario)



[47] Although there are two ESR Facilities assumed to commence operation in 2029-30, due to the assumed coal retirements in 2027 and 2029, overall AIC peaks in 2026-27.

[48] Coal Facilities exit the market by 2030-31 in the Expected scenario and 2025-26 in the high scenario.

Figure 12: Forecast Reserve Capacity over the study period (expected scenario)



5.2 Limb A determination

Figure 13 summarises the determination of Limb A for the expected scenario and Table 14 provides the values that make up the calculation. All scenarios are presented in Table 14.

Figure 13: Limb A calculation (expected scenario)

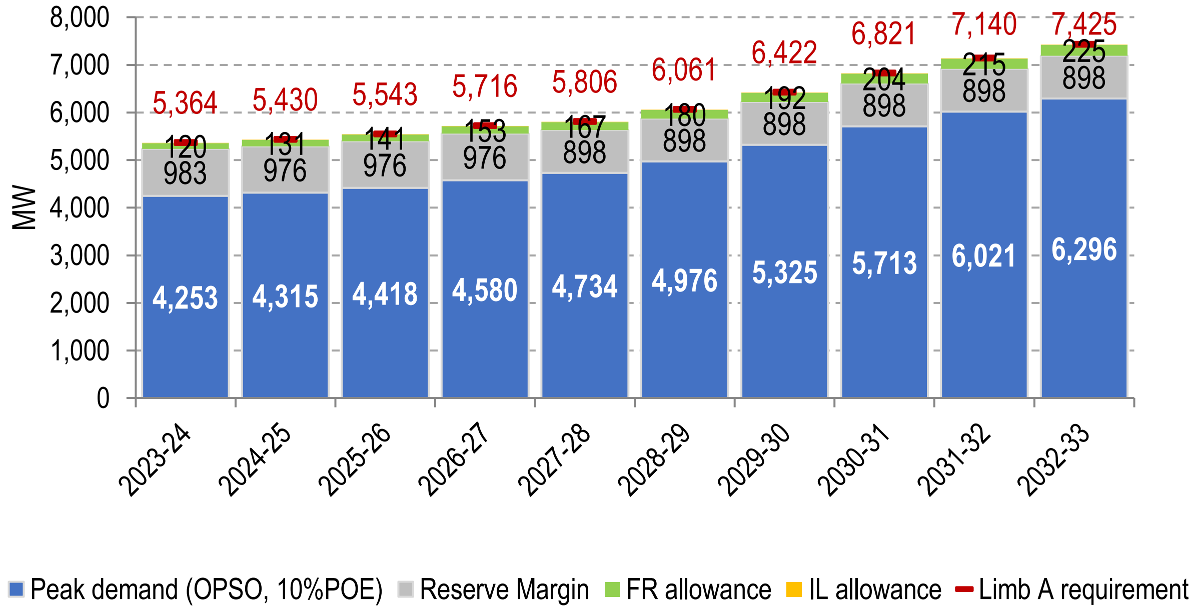


Table 14: Building blocks for Limb A calculation by Capacity Year and scenario (low, expected, high scenarios)

Component (MW)	Scenario	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak operational demand Sent Out 10% POE	Low	4,169	4,191	4,267	4,453	4,560	4,679	4,874	5,076	5,394	5,676
	Expected	4,253	4,315	4,418	4,580	4,734	4,976	5,325	5,713	6,021	6,296
	High	4,286	4,461	4,789	5,227	5,584	6,058	6,467	6,895	7,520	7,967
IL allowance	Low	8	8	8	8	7	7	7	6	6	6
	Expected	8	8	8	8	7	7	6	6	6	5
	High	8	8	7	7	6	6	5	5	5	4
Reserve Margin	Low	983	976	976	976	898	898	898	898	898	898
	Expected	983	976	976	976	898	898	898	898	898	898
	High	983	976	976	976	908	908	908	908	908	908
FR allowance	Low	115	121	126	132	140	147	155	161	168	174
	Expected	120	131	141	153	167	180	192	204	215	225
	High	121	132	145	161	178	197	215	229	243	255
Limb A requirement	Low	5,275	5,296	5,376	5,569	5,606	5,732	5,934	6,142	6,466	6,754
	Expected	5,364	5,430	5,543	5,716	5,806	6,061	6,422	6,821	7,140	7,425
	High	5,398	5,577	5,917	6,370	6,677	7,169	7,595	8,038	8,676	9,134

5.3 Assessment against Limb A of the Planning Criterion

Table 15 summarises the Limb A requirement against forecast Reserve Capacity for the low, expected and high scenario. In all scenarios, there is a capacity investment gap in the SWIS from 2023-24, shown in Table 15.

Table 15: Capacity investment gap by Capacity Year and scenario (low, expected, high)[49]

Scenario	Component (MW)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Low	Limb A requirement	5,275	5,296	5,376	5,569	5,606	5,732	5,934	6,142	6,466	6,754
	Forecast Reserve Capacity	4,668	4,467	4,467	4,467	4,149	4,149	3,727	3,293	3,293	3,293
	Capacity investment gap	608	829	910	1,102	1,456	1,582	2,206	2,848	3,173	3,460
Expected	Limb A requirement Expected	5,364	5,430	5,543	5,716	5,806	6,061	6,422	6,821	7,140	7,425
	Forecast Reserve Capacity	4,727	4,596	4,598	4,598	4,281	4,281	3,859	3,425	3,425	3,425

49 MW values may not sum due to rounding

Scenario	Component (MW)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
	Capacity investment gap	638	833	945	1,118	1,525	1,781	2,563	3,396	3,715	4,000
High	Limb A requirement	5,398	5,577	5,917	6,370	6,677	7,169	7,595	8,038	8,676	9,134
	Forecast Reserve Capacity	4,727	5,178	5,535	5,690	5,373	5,373	5,451	5,451	5,451	5,451
	Capacity investment gap	671	398	382	680	1,304	1,796	2,144	2,587	3,226	3,683

5.4 Assessment against Limb B of the Planning Criterion

Limb B of the Planning Criterion requires that there should be sufficient capacity available in each Capacity Year to limit EUE to 0.002% of annual energy consumption. Dispatch modelling underpinning the assessment against Limb B was undertaken using the AIC for each scenario (as set out in Section 5.1).

EUE refers to the expected amount of customer demand that cannot be supplied in the SWIS due to a shortage of generation, storage or demand side response which may be impacted by planned or forced outages, renewable resource availability patterns or requirements to operate the SWIS securely and within a technical envelope (e.g., ESS requirements or thermal network limits).

Events of unserved energy would be experienced by customers as loss of supply in one or more parts of the network for a variable duration of time. It is noted that loss of supply to customers due to local distribution network issues do not contribute to EUE for the purpose of this reliability assessment and are not captured in this modelling.

Table 16 presents the results of the dispatch modelling. The modelling shows that EUE is expected in all years modelled and exceeds 0.002% from the first year of the outlook when taking AIC only in to account. There is also therefore a forecast capacity investment gap in the Limb B assessment (as well as against Limb A).

The magnitude of modelled EUE in the high scenario is comparable to the low and expected scenarios in the first two Capacity Years and grows considerably from the 2025-26 Capacity Year. This is primarily driven by the fact that starting from the 2025-26 Capacity Year, the forecast annual energy consumption in the high scenario is greater than in the low and expected scenarios, where both of the latter follow a similar trajectory and comparable magnitude in those earlier years (see Section B.1 in Appendix B).

In the 2025-26 Capacity Year, forecast annual energy consumption in the high scenario is around 7.9 TWh (42%) higher than in the expected scenario. In the 2025-26 Capacity Year, forecast peak demand in the high scenario is 371 MW higher than in the expected scenario, with the difference increasing to 1,671 MW in the 2032-33 Capacity Year (compare section B.2 in Appendix B)

On the supply side, AIC in the 2025-26 Capacity Year in the expected scenario is around 5.8 GW and around 7.3 GW in the high scenario (around 1.4 GW difference). The 1.4 GW difference in AIC is comprised of 0.6 GW intermittent generation capacity, 1.1 GW of ESR capacity and 0.1 GW of DSP capacity, net of 0.4 GW of retired coal capacity.[50]

[50] Intermittent generation capacity is comprised of 0.3 GW more wind capacity and 0.3 GW more large-scale solar PV capacity.

Table 16: Modelled EUE and EUE percentage by Capacity Year based on AIC for each scenario

Scenario	Component	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Low	Annual energy consumption, GWh (OPSO, 10% POE)	16,969	17,128	17,506	18,541	18,962	19,465	20,90	21,585	23,390	24,910
	Simulated annual EUE (GWh)	0.838	2.489	3.802	7.558	41.069	78.453	382.104	1537.7	2464.7	3299.96
	EUE %	0.005%	0.015%	0.022%	0.041%	0.217%	0.403%	1.847%	7.124%	10.538%	13.247%
Expected	Annual energy consumption, GWh (OPSO, 10% POE)	18,010	18,237	18,607	19,509	20,375	21,825	24,251	26,482	28,368	30,306
	Simulated annual EUE (GWh)	1.214	2.519	3.184	6.019	36.135	94.104	620.739	2830.60	4069.50	5268.30
	EUE %	0.007%	0.014%	0.017%	0.031%	0.177%	0.431%	2.560%	10.689%	14.345%	17.384%
High	Annual energy consumption, GWh (OPSO, 10% POE)	18,984	20,816	26,510	33,127	38,676	44,987	48,639	51,438	55,579	58,884
	Simulated annual EUE (GWh)	1.225	2.117	760.784	1822.10	5245.03	7342.25	11532.4	15361.2	19592.3	22067.1
	EUE %,[51]	0.006%	0.010%	2.870%	5.500%	13.561%	16.321%	23.710%	29.863%	35.251%	37.475%

5.5 Determining the RCT for the expected scenario

Assessment against Limb A and Limb B of the Planning Criterion aims to determine the RCT by comparing the amount of Reserve Capacity needed to meet both Limb A and Limb B of the Planning Criterion, with the maximum of either Limb A or Limb B then setting the requirement. This section presents the outcomes of each assessment and the determination of the RCT.

The amount of Reserve Capacity required to meet Limb A of the Planning Criterion was determined as per Section 5.2. To determine the amount of AIC and associated forecast Reserve Capacity to meet Limb B of the Planning Criterion, we modelled the capacity required to limit EUE to less than 0.002%. Following the methodology described in Section 4, we added the amount of generic OCGT capacity for reliability (CFR) which resulted in modelled EUE being less than 0.002%.

Table 17 presents the results of the dispatch modelling for the expected scenario with the OCGT CFR capacity added. The modelling shows that adding the amount of OCGT CFR shown below reduces modelled EUE in all years to less than 0.002% from the first year of the outlook.

[51] The high scenario shows less EUE as more supply capacity enters the market. This includes additional renewable capacity and additional ESR capacity.

Table 17: Modelled EUE and EUE percentage by Capacity Year for the expected scenario with OCGT CFR capacity included

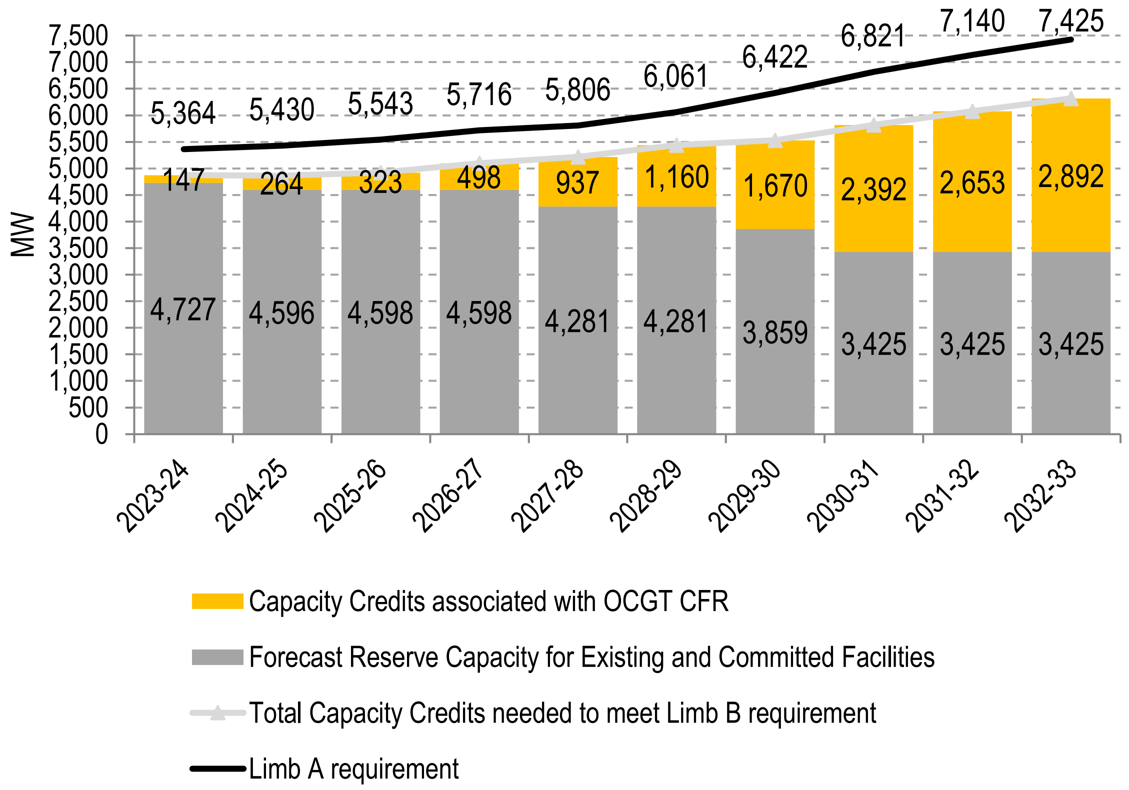
Component	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Capacity for reliability (MW)	147	264	323	498	937	1,160	1,670	2,392	2,653	2,892
Annual energy consumption (GWh, OPSO)	18,010	18,237	18,607	19,509	20,375	21,825	24,251	26,482	28,368	30,306
Simulated annual EUE (GWh)	0.348	0.365	0.364	0.390	0.405	0.423	0.466	0.519	0.561	0.606
EUE %	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%

The modelled generic OCGT CFR as well as the comparison of the assessment against Limb A and Limb B of the Planning Criterion is presented in Figure 14. As shown in Figure 14, the required Reserve Capacity to meet Limb A is higher than that required to meet Limb B in every year, therefore the Limb A requirement sets the RCT.

It should be noted that for the Limb B assessment, the capacity presented in each year to meet Limb B additional to Reserve Capacity for existing, committed and probable Facilities is modelled as completely additional to the operation of the existing capacity in the scenario (it is bid very last in the model merit order, after DSM, to achieve this). If this capacity was instead modelled as available and generating at a lower bidding price, there is an additional interaction with storage in the model which results in lower unserved energy (below the 0.002% standard) or conversely a lower Limb B MW requirement that would be required to just avoid breaching the 0.002% standard.

The interaction with storage arises in intervals where unserved energy was previously occurring over long periods where storage was unable to charge due to lack of available generating capacity. With the addition of generic OCGT in these intervals, this allows more charging of storage and increases availability in unserved energy intervals. The capacities have been provided below as a conservative measure that does not assume any further interaction with storage, though it is noted in reality that storage and / or the operation of this generic OCGT (or of any capacity entering the market) could be operated to achieve lower unserved energy outcomes overall, or reduce the amount of generic new entrant capacity required.

Figure 14: Assessment against Limb A and Limb B of the Planning Criterion and determination of the RCT (expected scenario)



5.6 EUE snapshots and analysis

This section provides further insights to the EUE results presented above. The results of the Limb A and Limb B analysis show a capacity investment gap in each year and each demand scenario when comparing the requirements of the Planning Criterion against AIC and forecast Reserve Capacity. For example, by 2032-33 in the expected scenario, the Limb B modelling suggested that a capacity investment gap of almost 3 GW exists between forecast Reserve Capacity and the capacity required to limit EUE to less than 0.002%. These capacity investment gaps are the fundamental driver of the observed EUE across the study period.

However, the shape, duration, and magnitude of EUE across time of day, months/seasons and years is also driven by the interaction of a range of different factors, including the shape of demand, Facility availability, the ability of the network to transfer available energy to load and technical envelope constraints related to secure operation of the system (ESS requirements, thermal limits of conductors, etc).

The sections below present EUE on a more detailed basis using the 2025-26 Capacity Year as an illustration of how EUE can vary by month/season, and by time of day, and considers the following suite of EUE drivers impacting the ability of the supply capacity to meet SWIS demand:

- Projected capacity investment gap driven by a forecast increase in annual energy consumption and peak demand coupled with announced capacity retirements
- Unavailability due to planned maintenance
- Unavailability due to unplanned forced outages
- Unavailability of DSM due to temporal constraints
- Low wind and solar availability due to the variable nature of weather-dependent renewable resources

- ESS requirements resulting in withholding a portion of capacity from dispatch in the energy market
- Dispatch curtailment due to thermal network limitations
- Ramp rate limitations.

Modelled EUE was found to be caused by a combination of the above drivers, which impacted the 'depth' (MW), duration (hrs) and magnitude (MWh) of EUE. The drivers are grouped in Table 18 and discussed in more detail throughout the following section. These are based on analysis of the 2025-26 Capacity Year for illustration, but the way these factors impact EUE is applicable to all study years.

5.6.1 EUE by month and time of day

Figure 15 provides a snapshot of the EUE metrics for the 2025-26 Capacity Year on a monthly basis for the expected, low and high scenarios. Figure 16 provides a snapshot of the EUE metrics for the analysed year on a time-of-day basis for the modelled expected, low and high scenarios.[52]

For the expected and low scenarios, Figure 15 indicates that EUE events were mostly concentrated in January, February and March. Based on the metrics considered, the months of July to September as well as December shared similar EUE patterns, and were of lesser quantity (MWh, MW and duration) than the period of January to March. October and November, and April and March shared the lowest intensity (MWh, MW and duration) of EUE.

In the expected scenario, modelled EUE volumes in the July to September period are lower than in the low scenario. This is because the increase in demand from the low to expected scenario is largely offset by additional generation capacity modelled in the expected scenario and not included in the AIC of the low scenario.[53]

For the high scenario, Figure 15 indicates that September was the modelled month with the highest volume of EUE (MWh), while March and the months of July to September had the highest numbers of EUE occurrences. Highest values of maximum EUE were observed in January, February and March, as well as August.

For the high scenario, September has relatively large amounts of modelled planned maintenance compared to July and August. Modelled planned outages include Newgen Kwinana, Collie, Muja G7 and Muja G8 (combined 1.1 GW of capacity), ranging from 5 to 20 days. This translates into around 294 GWh of energy not dispatched and is partially offset by an increase in modelled wind availability in September compared to August (compare Figure 19).[54,55]

[52] The EUE snapshots presented in Figure 15 and Figure 16 are based on averaged results across the modelled 12 reference years and 100 Monte Carlo iterations per reference year.

[53] Made up of 59 MW of waste to energy capacity, 130 MW of solar PV capacity, 75 MW of wind capacity and 54 MW of ESR capacity.

[54] For comparison, the quantity of energy not dispatched due to modelled planned maintenance in July is around 113 GWh and around 86 GWh in August.

[55] Noting that as described in Section 4, although there is relatively large amount of maintenance taking place in September, there may not be a more optimal time to schedule maintenance and if it was to be scheduled in a different month, EUE results may appear higher for that month instead of September.

Figure 15: Snapshot of EUE metrics (monthly basis) for the 2025-26 Capacity Year

EXPECTED

Item	Unit of measure	Annual value	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
EUE volume in a period	MWh	3,184.1	0.3	0.3	91.3	722.9	1,487.2	515.9	2.0	0.1	54.9	142.9	105.0	61.5
EUE occurences	# intervals when EUE was a non-zero value	888	2	1	72	155	220	96	9	-	72	118	76	67
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	4	0.2	0.2	2.5	9.3	13.5	10.7	0.4	-	1.5	2.4	2.8	1.8
Maximum magnitude of an EUE interval	MW	63	0.2	0.2	19.5	63.1	53.9	62.8	0.7	-	11.3	19.2	23.6	19.9

LOW

Item	Unit of measure	Annual value	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
EUE volume in a period	MWh	3,802.0	0.0	5.2	93.6	686.7	1,458.9	537.4	0.1	0.3	94.2	401.1	387.7	136.8
EUE occurences	# intervals when EUE was a non-zero value	979	-	23	97	148	224	105	-	2	72	126	117	65
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	5	0.2	0.4	1.9	9.3	13.0	10.2	0.4	0.3	2.6	6.4	6.6	4.2
Maximum magnitude of an EUE interval	MW	65	-	1.6	20.6	65.4	65.3	58.0	-	0.4	19.5	46.3	58.3	46.0

HIGH

Item	Unit of measure	Annual value	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
EUE volume in a period	MWh	760,784.4	25,199.7	8,417.9	21,056.5	39,995.4	62,130.6	37,008.3	16,197.5	27,569.8	61,832.2	108,360.7	83,551.2	269,464.5
EUE occurences	# intervals when EUE was a non-zero value	14,722	1,079	906	1,026	1,267	1,249	1,329	1,231	1,278	1,335	1,376	1,305	1,341
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	94	46.7	18.6	41.0	63.1	98.5	55.7	26.3	43.1	91.8	151.9	125.5	363.8
Maximum magnitude of an EUE interval	MW	1,306	234.9	207.0	295.5	477.0	650.8	475.0	206.6	381.1	636.3	903.0	892.5	1,306.4

Figure 16: Snapshot of EUE metrics (time-of-day basis) for the 2025-26 Capacity Year

EXPECTED

Item	Unit of measure	Annual value	0:00	0:30	1:00	1:30	2:00	2:30	3:00	3:30	4:00	4:30	5:00	5:30	6:00	6:30	7:00	7:30	8:00	8:30	9:00	9:30	10:00	10:30	11:00	11:30
EUE volume in a period	MWh	3,184	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EUE occurences	# intervals when EUE was a non-zero value	888	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maximum magnitude of an EUE interval	MW	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Item	Unit of measure	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30
EUE volume in a period	MWh	0	0	1	1	3	2	6	16	32	66	161	321	520	569	476	416	375	177	36	5	1	0	0	0
EUE occurences	# intervals when EUE was a non-zero value	0	1	2	2	2	3	5	8	18	28	47	91	123	131	115	98	96	63	37	13	3	1	0	0
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	0	0	1	1	3	2	2	4	4	5	7	7	8	9	8	9	8	6	2	1	0	0	0	0
Maximum magnitude of an EUE interval	MW	0	0	1	2	5	4	7	21	19	21	35	49	54	63	59	61	63	43	14	3	1	0	0	0

LOW

Item	Unit of measure	Annual value	0:00	0:30	1:00	1:30	2:00	2:30	3:00	3:30	4:00	4:30	5:00	5:30	6:00	6:30	7:00	7:30	8:00	8:30	9:00	9:30	10:00	10:30	11:00	11:30
EUE volume in a period	MWh	3,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
EUE occurences	# intervals when EUE was a non-zero value	979	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	2	1	0	0	0	0	0	0	0
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maximum magnitude of an EUE interval	MW	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0

Item	Unit of measure	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30
EUE volume in a period	MWh	0	0	0	1	2	3	7	17	43	83	191	391	683	736	562	485	421	145	29	3	0	0	0	0
EUE occurences	# intervals when EUE was a non-zero value	0	0	2	2	3	4	5	14	25	35	58	99	133	138	123	110	110	66	31	14	1	0	0	0
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	0	0	0	1	1	2	3	2	3	5	7	8	10	11	9	9	8	4	2	0	0	0	0	0
Maximum magnitude of an EUE interval	MW	0	0	0	1	3	4	7	19	22	27	42	56	61	65	61	64	65	43	17	2	0	0	0	0

HIGH

Item	Unit of measure	Annual value	0:00	0:30	1:00	1:30	2:00	2:30	3:00	3:30	4:00	4:30	5:00	5:30	6:00	6:30	7:00	7:30	8:00	8:30	9:00	9:30	10:00	10:30	11:00	11:30
EUE volume in a period	MWh	760,784	14,574	11,940	10,279	9,110	8,462	7,922	7,802	7,679	8,194	9,057	12,186	15,198	19,868	22,256	22,845	19,759	10,180	5,931	3,495	2,644	2,027	1,547	1,317	1,305
EUE occurences	# intervals when EUE was a non-zero value	14,722	355	353	352	349	345	342	337	340	345	342	345	337	333	332	319	312	294	282	271	256	232	214	199	197
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	90	80	68	58	52	48	46	46	44	47	53	71	89	114	130	140	123	69	42	26	21	17	14	13	13
Maximum magnitude of an EUE interval	MW	1,306	865	807	766	733	710	686	701	703	737	795	932	1,023	1,068	1,070	983	837	496	337	265	240	211	193	166	144

Item	Unit of measure	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30
EUE volume in a period	MWh	1,241	1,294	1,445	1,653	1,986	2,279	2,706	3,965	6,320	9,356	15,249	24,144	33,006	38,572	40,275	40,695	48,038	46,828	48,216	46,129	39,269	30,601	23,563	18,377
EUE occurences	# intervals when EUE was a non-zero value	196	191	197	204	223	242	260	286	302	324	334	342	344	351	348	349	356	353	351	355	356	360	358	357
Average magnitude of an EUE interval	MW, average across non-zero intervals in a month	13	14	15	16	18	19	21	28	42	58	91	139	177	213	208	212	255	248	246	244	213	165	129	100
Maximum magnitude of an EUE interval	MW	130	110	114	142	164	166	173	207	265	321	539	841	1,092	1,242	1,278	1,245	1,306	1,251	1,256	1,203	1,150	1,046	951	866

Figure 16 indicates that simulated EUE was concentrated in the periods of the day between 17:00 and 20:00. This period of the day is when operational demand on the SWIS is typically the highest due to the decline of behind the meter rooftop PV occurring with an increase in underlying electricity consumption from residential premises. This peak operational demand period also coincides with decreasing utility scale solar. When EUE was present at this time, this was driven by the modelled coincident occurrence of decreasing solar PV availability and dispatch, relatively low wind availability and dispatch compared to the installed capacity on the SWIS, unavailability of dispatchable generation (due to planned maintenance, forced outages or reserving headroom for ESS), or the impact of thermal network constraints (section 5.9).

The low and expected scenario demonstrate comparable time-of-day patterns (EUE occurring predominantly in the afternoon and evening) and magnitudes (number of occurrences, MWh and MW) of modelled EUE. The high scenario exhibits greater magnitudes of modelled EUE, and also sees a considerable intensity of modelled EUE in the night-time and morning hours.

The difference in the high scenario is driven by demand and supply-related factors described in section 5.4 (i.e. 7.9 TWh higher annual energy consumption, qualitative change in the AIC to include more intermittent capacity). Compared to the low and expected scenarios, higher annual consumption translates into modelled demand levels which are consistently higher in the time-of-day granularity across most of the intervals. This consistent difference in demand translates into more numerous EUE occurrences of greater MW magnitude across more time-of-day intervals (including night and morning) than in the low and expected scenarios. Lower magnitudes of EUE in the high scenario in the daylight hours results from the impact of rooftop PV on decreasing time-of-day demand.

5.6.2 Drivers of EUE

As explained above, the forecast capacity investment gaps identified in the assessment against the Planning Criterion are the fundamental driver of observed EUE in every year of the reliability study horizon. Within that, there are various drivers of EUE outcomes that influence the nature of those EUE outcomes.

These drivers of modelled EUE (with illustrative data for the 2025-26 Capacity Year) in the expected scenario are listed in Table 18. A more detailed exploration of modelled EUE occurrences and drivers for the 2025-26 Capacity Year, expected scenario is provided in Sections 5.6.3, 5.6.4 and 5.6.5.

Table 18: Drivers of modelled EUE (data for 2025-26 Capacity Year, expected scenario)

EUE driver	Comment
Operational demand	Modelled operational demand was generally higher in the summer months (January-March) compared to the July-September period. Lowest operational demand levels were observed for the October-November and April-June periods. Figure 17 presents operational demand duration curves for February, July and October modelled for the 2025-26 Capacity Year in the expected scenario. The top 20% of daily peak demand intervals in February were between 50 MW to 468 MW higher than in July, and between 837 MW to 1,592 MW higher than in October. These peak demand intervals (usually between 4 pm and 9 pm) were when the most EUE occurrences (MWh, MW and duration) in the 2025-26 Capacity Year were observed (see Figure 16).
Capacity investment gap	The primary driver of EUE was found to be the projected cpacity investment gap. For example, for the expected Scenario, Figure 14 shows a capacity investment gap of almost 3 GW by 2032-33.
ESS requirements	The modelled ESS requirements were found to be a consistent driver contributing to EUE, regardless of season (winter or summer) or time of day. The modelling methodology to satisfy ESS reserves before dispatching Facilities for energy was found to limit the dispatch of ESS-capable Facilities (coal, gas and ESR) into the energy market.

EUE driver	Comment
Forced and planned outages (availability of thermal plant)	Planned outages were modelled for not-summer periods which results in lower availability of coal and gas Facilities than in summer months. Hence, planned thermal plant availability is generally higher in summer. However, forced outages were modelled to occur randomly, which might lead to situations where - on certain days and in certain intervals - summer availability is decreased and can even be lower than during winter months (for example as is the case for gas on a few days in January and February in the sample iteration shown in Figure 18. This impact of forced outages contributes to EUE occurrences in summer when demand is generally higher than in winter.
Wind availability	Modelled wind availability was generally higher in the summer months than in the winter months and also displayed variability by SWIS region (North, East and South of the SWIS) and time of day (Figure 19). In general, the northern region of the SWIS displayed the highest levels of availability on a monthly basis, with the southern region having the lowest availability (except June and July). Across all regions, the summer wind availability increases towards late afternoon. The northern and eastern regions experience greater variability on a daily basis, with a mid-day valley between 10 am and 2 pm, after which the availability increases almost 1.5-2 times around 6-7 pm. The winter time-of-day profile in the south is stable throughout the day. In summer, the profile increases from midday and peaks around 4-6 pm, followed by a decline into the evening. Most of the wind capacity modelled is in the northern region of the SWIS. Despite higher availability levels in summer, operational demand is also higher in these months (Figure 17) which altogether may lead to EUE events of greater magnitude (MW, MWh or duration) than in winter.
Solar PV availability	Modelled solar PV availability was lower in winter months than in summer months. Solar availability was less varied per location than wind availability. Due to the natural daily insolation cycle, solar PV availability was either low or zero in intervals when EUE was observed (4pm – 9 pm).
Thermal network constraints	Thermal network constraints were found to bind or violate (see Section 5.6.6 and Section 5.9), which at times limited the dispatch of certain Facilities.

Figure 17: Operational demand duration curves for February (summer month), July and October (not-summer months) in the 2025-26 Capacity Year, expected scenario

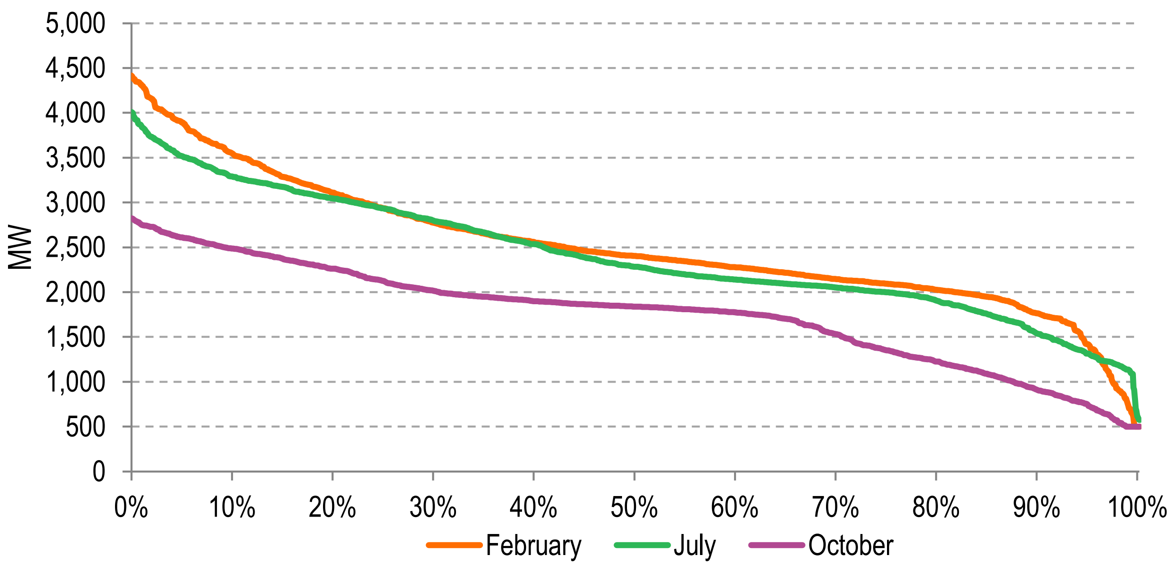
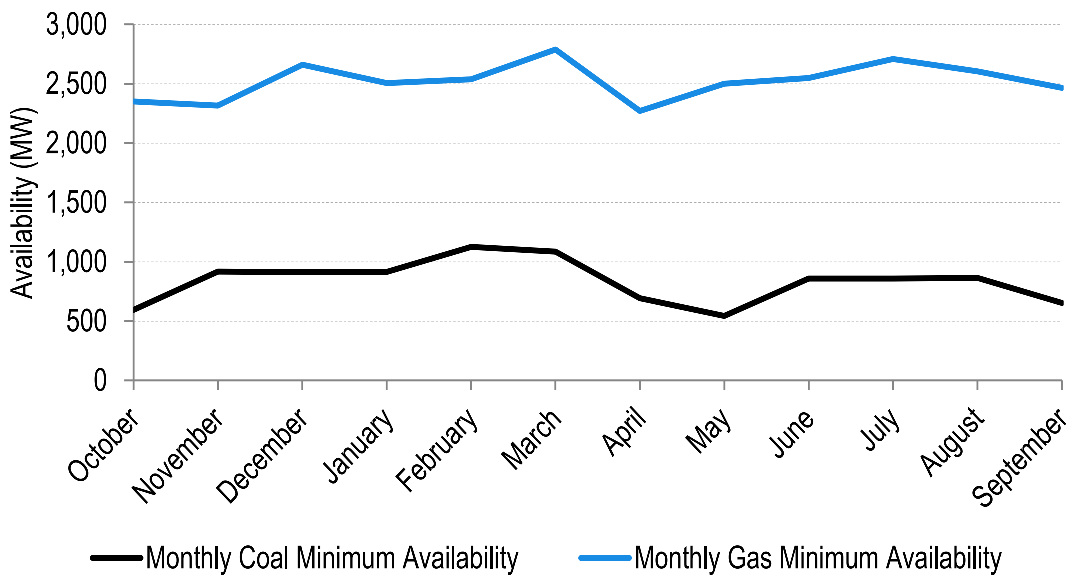


Figure 18: Coal and gas availability profiles in the 2025-26 Capacity Year, expected scenario, single Monte Carlo iteration

Coal and gas availability - monthly minimum



Coal and gas availability - daily minimum

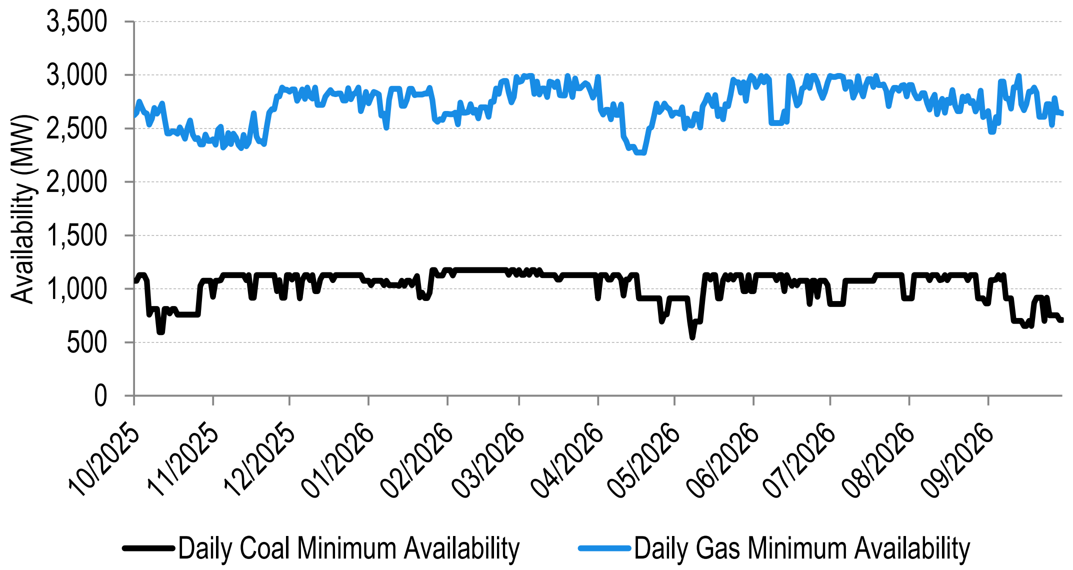
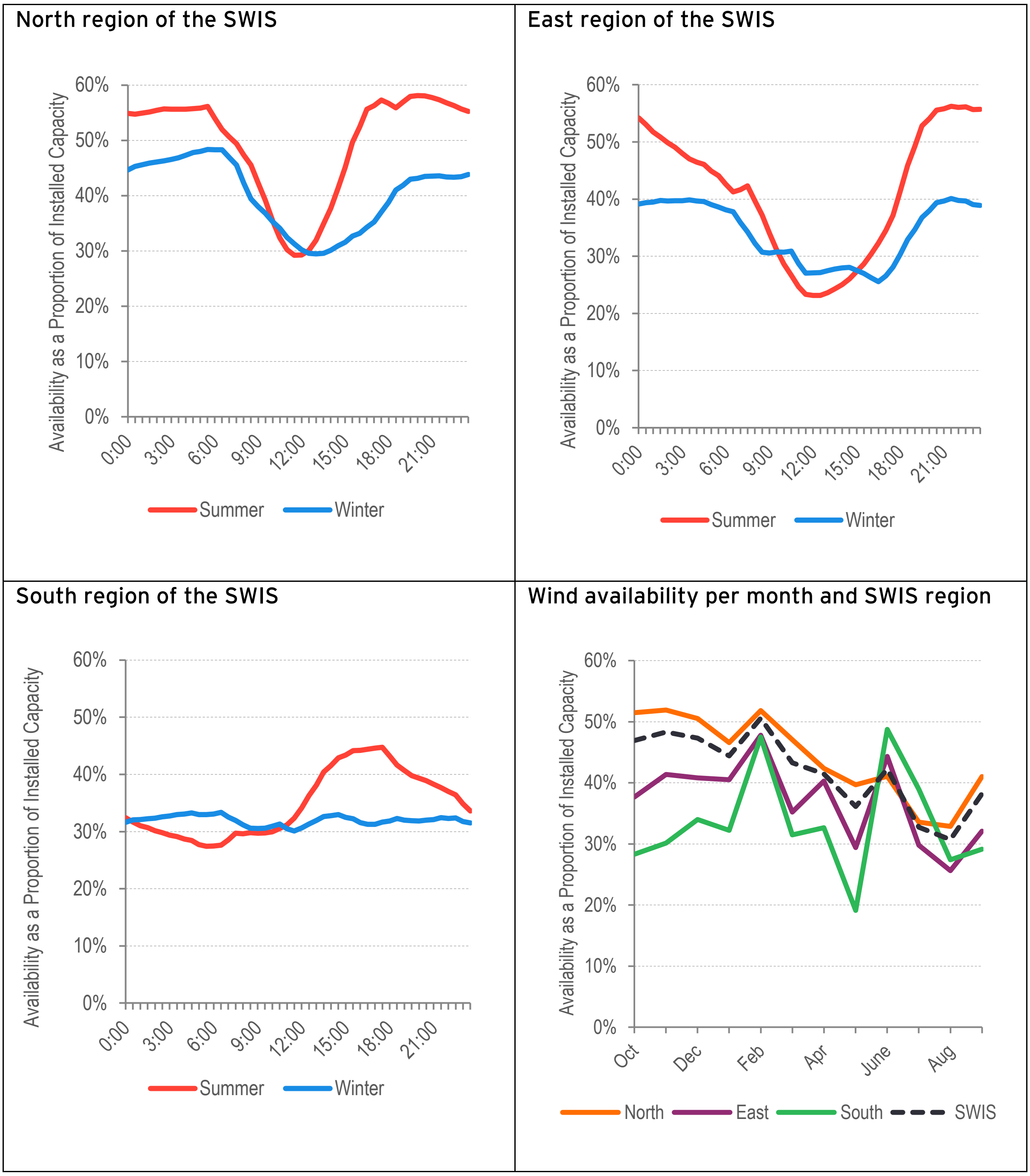


Figure 19: Representative wind availability profiles for summer months (November to March inclusive) and not-summer months (April to October inclusive) in the 2025-26 Capacity Year, expected scenario[56]



For the high scenario, Figure 16 indicates that modelled EUE of greatest magnitudes were occurring in the afternoon and evening hours. Compared to the expected and low scenarios, for the high scenario occurrences of EUE were also observed in the night-time and morning hours. EUE intensity was observed to drop in the daytime (solar hours), associated with time-of-day increase in solar PV generation during these intervals.

[56] The modelled AIC of wind farms in the North, East and South regions of the SWIS is approximately 750, 300 and 40 MW respectively.

Figure 20 presents a heat map illustrating the count of contiguous EUE events modelled for the expected scenario.[57] This heat map is based on analysing the entire population of modelled EUE intervals in each of the 12 reference years (2010-11 to 2021-22) and 100 Monte Carlo iterations per each reference year. The above population was grouped into 8,911 days when EUE was observed and 9,225 EUE events.[58]

The heat map indicates that most modelled EUE events were of shorter duration and starting in late afternoon. Longer duration EUE events were less frequent and tended to start earlier in the afternoon.

Out of the entire population of 9,225 EUE events observed for the Capacity Year 2025-26 in the expected scenario, 86% of the events (regardless of duration) concentrated between 17:00 and 20:00. This was driven by the fact that highest values of operational demand prevailed in the above-mentioned time window, consistent with typical peak operational demand hours currently in the SWIS.

Out of 648 longer-duration EUE events (meaning 10 or more contiguous intervals for this discussion), 646 were observed in January, February and March, which coincided with highest levels of operational demand prevailing longer than in other months of the year. Out of the remaining two, one was observed for July (starting at 17:00), and one for September (starting at 17:30). The longest-duration EUE event (19 contiguous intervals) was observed on a Friday in January when high levels of operational demand (3.7 GW and more, as per the demand heat map in Figure 20) were modelled as early as 12:00 and coincided with insufficient supply availability.

Shorter-duration EUE events (meaning 9 or fewer contiguous intervals for this discussion) generally occurred in the time window between 16:00 and 20:00 (when daily and monthly operational demand was modelled to be the highest) and coincided with insufficient supply availability.

[57] Contiguous EUE events are defined as a sequence half-hourly intervals when non-zero EUE values was observed in each of the intervals. # of intervals means number of half-hour trading intervals.

[58] The count of EUE events is greater than the count of days. This is because for certain days more than one EUE event was observed.

Figure 20: Heat map illustrating the count of contiguous EUE events for the 2025-26 Capacity Year, expected scenario

EUE event starting at...

Duration of a contiguous EUE event (# of half-hourly intervals)	06_00	06_30	07_00	07_30	12_00	12_30	13_00	13_30	14_00	14_30	15_00	15_30	16_00	16_30	17_00	17_30	18_00	18_30	19_00	19_30	20_00	20_30	21_00	21_30	22_00	22_30
1 interval	-	-	5	-	-	-	-	2	24	-	-	4	3	16	19	48	474	689	34	55	187	4	4	-	-	-
2 intervals	-	-	1	-	-	-	-	6	1	-	4	-	12	4	3	83	896	241	30	43	9	-	-	-	-	-
3 intervals	1	-	-	-	-	-	1	-	-	-	-	-	5	-	17	511	538	33	83	6	-	-	-	-	-	-
4 intervals	-	-	-	-	-	-	3	-	7	-	-	-	-	1	128	345	156	75	4	-	-	-	-	-	-	-
5 intervals	-	-	-	-	-	-	-	-	-	-	-	-	-	28	96	362	442	79	2	-	-	-	-	-	-	-
6 intervals	-	-	-	-	-	-	-	-	-	-	-	-	-	6	82	620	198	22	-	-	-	-	-	-	-	-
7 intervals	-	-	-	-	-	2	-	-	-	-	-	1	-	8	170	397	105	1	-	-	-	-	-	-	-	-
8 intervals	-	-	-	-	-	-	-	-	-	-	1	-	-	135	402	98	6	-	-	-	-	-	-	-	-	-
9 intervals	-	-	-	-	-	-	-	-	-	-	1	-	89	214	183	12	-	-	-	-	-	-	-	-	-	-
10 intervals	-	-	-	-	-	-	-	-	3	-	-	14	152	134	23	1	-	-	-	-	-	-	-	-	-	-
11 intervals	-	-	-	-	-	-	-	2	8	-	70	15	105	35	-	-	-	-	-	-	-	-	-	-	-	-
12 intervals	-	-	-	-	-	-	-	9	-	1	14	8	14	2	-	-	-	-	-	-	-	-	-	-	-	-
13 intervals	-	-	-	-	-	-	2	-	-	10	4	7	4	-	-	-	-	-	-	-	-	-	-	-	-	-
14 intervals	-	-	-	-	-	-	-	-	-	-	-	1	2	-	-	-	-	-	-	-	-	-	-	-	-	-
15 intervals	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 intervals	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17 intervals	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18 intervals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19 intervals	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Operational demand (GW, average across Reference Years) prevailing at time when non-zero EUE was observed

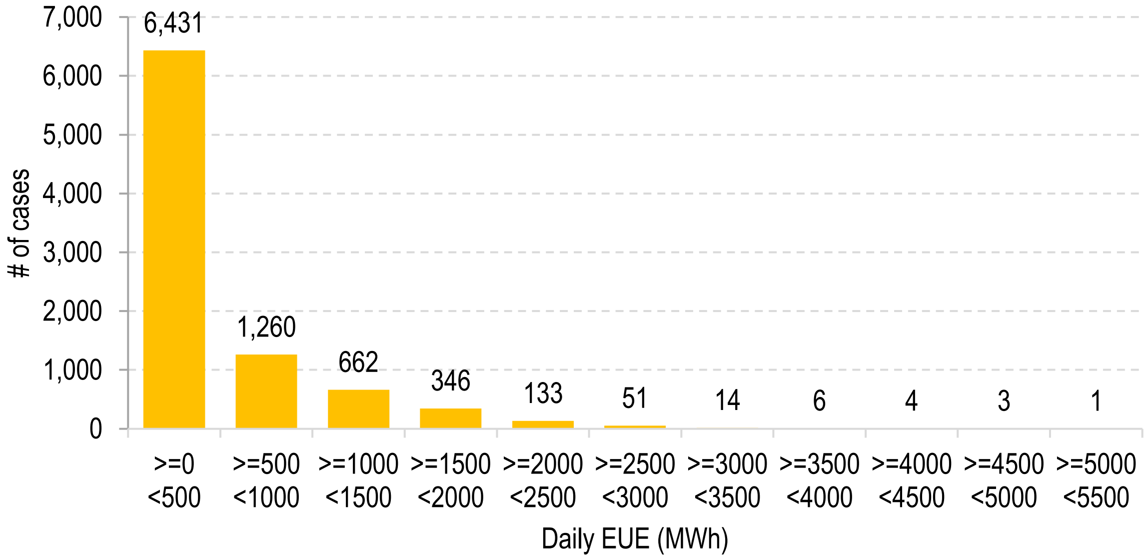
	06_00	06_30	07_00	07_30	12_00	12_30	13_00	13_30	14_00	14_30	15_00	15_30	16_00	16_30	17_00	17_30	18_00	18_30	19_00	19_30	20_00	20_30	21_00	21_30	22_00	22_30
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.9	2.9	2.8	2.9	2.8	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.5	3.5	3.5	3.4	3.4	3.3	-	-	-	-	-
Dec	-	-	-	-	-	3.6	3.7	3.8	3.8	3.7	3.6	3.6	3.7	3.9	4.1	4.1	4.1	4.1	4.0	4.0	3.9	3.8	3.9	3.9	-	-
Jan	-	-	-	-	3.7	3.7	3.9	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.2	4.2	4.0	3.8	-	-
Feb	-	-	-	-	-	-	-	-	3.5	3.8	4.0	4.2	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.1	4.1	4.0	3.9	3.6	3.5
Mar	-	-	-	-	-	-	-	-	-	-	3.7	3.8	4.1	4.2	4.2	4.3	4.2	4.2	4.3	4.3	4.2	4.1	4.0	3.8	3.6	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	3.3	3.2	3.3	3.3	3.3	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.2	-	-	-	-	-	-	-	-	-
Jun	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	3.3	3.6	3.7	3.7	3.7	3.6	3.5	3.4	3.4	-	-	-
Jul	-	-	3.3	3.3	-	-	-	-	-	-	-	-	-	-	3.4	3.8	3.8	3.8	3.8	3.7	3.6	3.5	3.4	3.2	-	-
Aug	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	3.6	3.8	3.8	3.8	3.8	3.7	3.6	3.6	3.6	3.4	-	-
Sep	2.9	3.0	3.1	-	-	-	-	-	-	-	-	-	-	-	-	3.3	3.5	3.6	3.6	3.5	3.4	3.3	3.2	3.1	2.9	-

Figure 21 presents a frequency distribution of the daily EUE (MWh) across all reference years and MC iterations when EUE was non-zero.

This frequency distribution is based on analysing the entire population of modelled EUE intervals in each of the 12 reference years (2010-11 to 2021-22) and 100 Monte Carlo iterations per each reference year.

This distribution indicates that most daily EUE events were below 500 MWh per day. EUE events of magnitude greater than or equal to 500 MWh per day made up 28% of the entire population of modelled EUE events.

Figure 21: Frequency of the daily EUE (MWh) across all reference years and MC iterations when EUE was non-zero



As mentioned in Table 18, the primary driver of EUE was found to be the projected capacity investment gap.

Most events with modelled daily EUE greater than or equal to 500 MWh were recorded for January (649 events), February (1,221 events) and March (348 events). Other months included June-September as well as December (no more than 75 events each). On average, on days with EUE equal to or above 500 MWh, modelled wind availability and dispatch between 17:00 and 20:00 was found to be between 20 MW and 170 MW lower than on days with EUE below 500 MWh. This, together with the assumed ESS modelling methodology, was found to be the main driver of these events. On days with EUE equal to or above 500 MWh modelled average solar PV availability and dispatch was around 25 MW lower than on days with EUE below 500 MWh.

Modelled average coal and gas availability was respectively ~10 MW and ~25 MW lower on days with EUE equal to or above 500 MWh. Modelled ESR availability was the same on both types of days (i.e. both the days with EUE below 500 MWh, as well as on days with EUE equal to or above 500 MWh). On both types of days gas dispatch was on average 18 to 21 per cent lower than modelled availability, which was driven by the modelled withholding of capacity for the purpose of meeting ESS requirements. In the case of ESR, dispatch on both types of days was around 61 to 72 per cent lower than on days with EUE below 500 MWh, driven by the same modelling approach for ESS.

Also, as described in Table 18, the primary driver of EUE was found to be the projected capacity investment gap. In parallel, the assumed modelling methodology for ESS was a consistent driver contributing to EUE, regardless of season (winter or summer) or time of day.

Figure 22 presents a frequency distribution of the daily maximum EUE (MW) across all reference years and MC iterations when EUE was non-zero.

This frequency distribution is based on analysing the entire population of modelled EUE intervals in each of the 12 reference years (2010-11 to 2021-22) and 100 Monte Carlo iterations per each reference year.

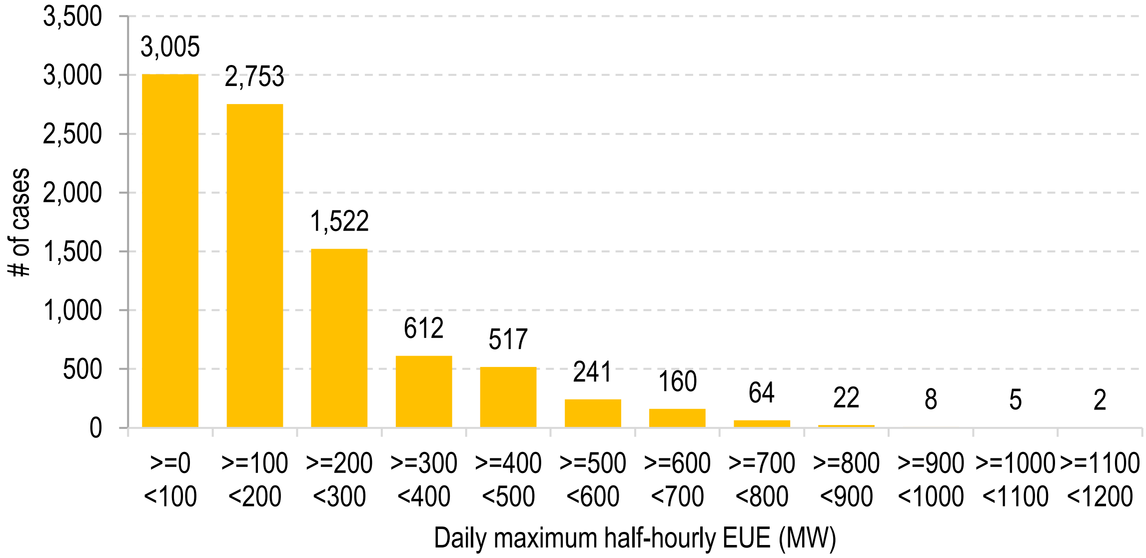
This distribution indicates that maximum EUE was below 600 MW in 97 per cent of modelled cases. EUE greater than or equal to 600 MW of made up 3 per cent of the entire population of modelled EUE events.

Events with observed daily maximum EUE greater than or equal to 600 MW were recorded for January (22 events), February (103 events), March (132 events) and July (4 events). On average on these days, modelled wind availability and dispatch between 17:00 and 20:00 was found to be between 80 MW and 130 MW lower than on days with maximum EUE below 600 MW. This, together with the assumed ESS modelling methodology, was found to be the main driver of these events. Modelled average solar PV availability and dispatch was around 10 MW lower.

Modelled average coal and gas availability was respectively around 15 MW and 40 MW lower. Modelled ESR availability was the same on both days. On both types of days, gas dispatch was on average 17 to 20 per cent lower than modelled availability, which was driven by the modelled withholding of capacity for the purpose of meeting ESS requirements. In the case of ESR, dispatch was 71 to 81 per cent lower, driven by the same modelling approach for ESS.

Also, as described in Table 18, the primary driver of EUE was found to be the projected capacity investment gap. In parallel, the assumed modelling methodology for ESS was a consistent driver contributing to EUE, regardless of season (winter or summer) or time of day.

Figure 22: Frequency of the daily maximum EUE (MW) across all reference years and MC iterations when EUE was non-zero



Based on the underlying dataset for all reference years and Monte Carlo Simulations for the expected scenario and the 2025-26 Capacity Year, we identified modelled illustrative days with:

- the highest observed daily EUE (MWh),
- the highest EUE in any half-hourly interval (MW).
- the longest-duration contiguous EUE event.[59]

The above are characterised in Table 19.

[59] Contiguous EUE events are defined as a sequence half-hourly intervals when non-zero EUE values was observed in each of the intervals. # of intervals means number of half-hour trading intervals.

Table 19: Selected EUE illustrative days modelled for the 2025-26 Capacity Year

Component	Observed value	Modelled day	Daily EUE (MWh)	Maximum half-hourly EUE (MW)	Duration (# of intervals with non-zero EUE)	Daily EUE as % of annual EUE
Modelled day with the highest observed daily EUE volume	5,196 MWh	Monday in March 2026	**5,196**	1,080	15	0.000028%
Modelled day with the highest observed half-hourly EUE quantum	1,165 MW	Tuesday in March 2026	4,691	**1,165**	13	0.000006%
Modelled day with the observed longest-duration contiguous EUE event	19 intervals	Friday in January 2026	1,813	294	**19**	**0.000010%**

Summaries of the three identified days are presented in each of Sections 5.6.3 , 5.6.4, and 5.6.5 respectively, and a summary comparison can be found in 5.6.6.

5.6.3 Modelled day in the 2025-26 Capacity Year with the highest observed daily EUE volume (MWh)

Results for the modelled day with the highest observed daily EUE volume are presented in Figure 23. Across intervals when EUE was observed on this day, modelled demand was between 3.6 GW and 4.6 GW. On the supply side, despite total AIC of SWIS generators of 5.8 GW, their available capacity during EUE intervals was between 4.1 GW and 4.3 GW. [60]

Estimated available capacity was driven by a combination of modelled outages (planned and forced) as well as low availability of wind and solar resource compared to wind and solar AIC (Figure 24).

Another factor was the modelled ESS requirement, which effectively decreased the amount of capacity available for dispatch in the energy market from ESS-capable units (notionally, the impact of the ESS requirement is represented by the AVAIL_less_ESS_req line in Figure 23). ESS on this day was mostly being provided by gas and ESR (with coal providing the least), which was a factor limiting their dispatch in the energy market.[61] In the case of gas, availability was below AIC, which indicates it was also impacted by outages (Figure 25).

Modelled availability of coal units was impacted by a modelled outage and hence lower than AIC. All coal units were dispatched at their prevailing availability level, indicating there were no transmission network constraints curtailing their ability to be dispatched. Dispatch of DSM was impacted by a modelled ramp rate limitation as well as the temporal availability as per WEM Rules, i.e. available only on business days between 8:00 AM and 8:00 PM (Figure 26). Ramp rate limitations for each DSM Facility has been provided to EY through AEMO's FIR process and relates to the capability of the Facility to respond flexibly to control signals issued.

The drivers identified above have collectively resulted in dispatch into the energy market (DISP) being below prevailing operational demand (DEMAND_oper), resulting in observed EUE intervals.

[60] Includes thermal generators, renewable generators (excluding rooftop PV) and ESR generators.

[61] Which in the case of batteries is illustrated by dropping reservoir of the batteries with no dispatch occurring in the energy market.

Figure 23: Modelled SWIS dispatch conditions for the period with the highest observed daily EUE volume in 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Monday in March)

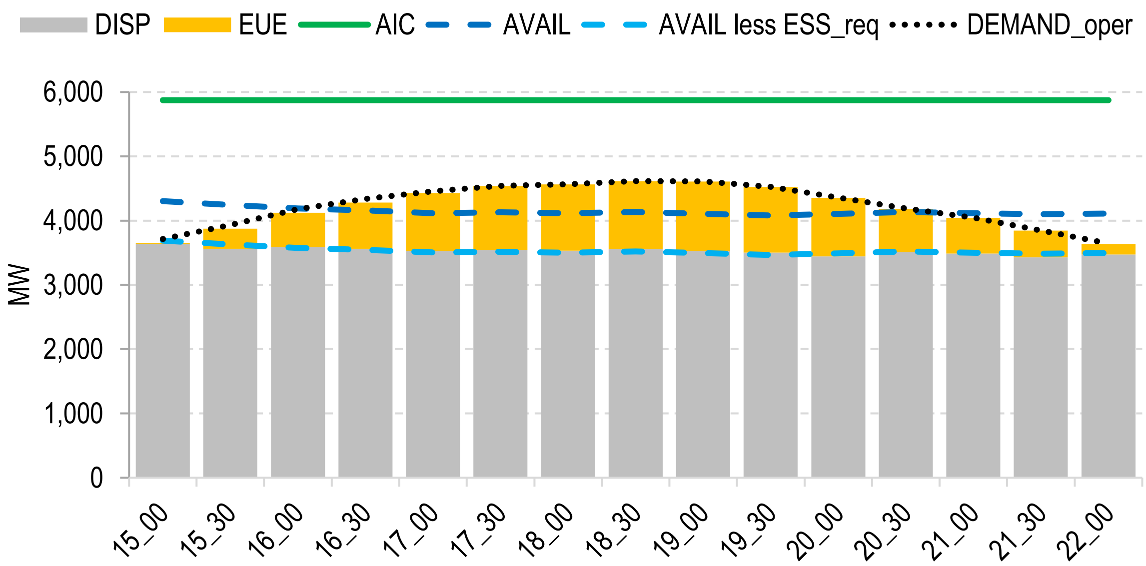


Figure 24: Modelled wind and solar dispatch conditions for the period with the highest observed daily EUE volume in the 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Monday in March)

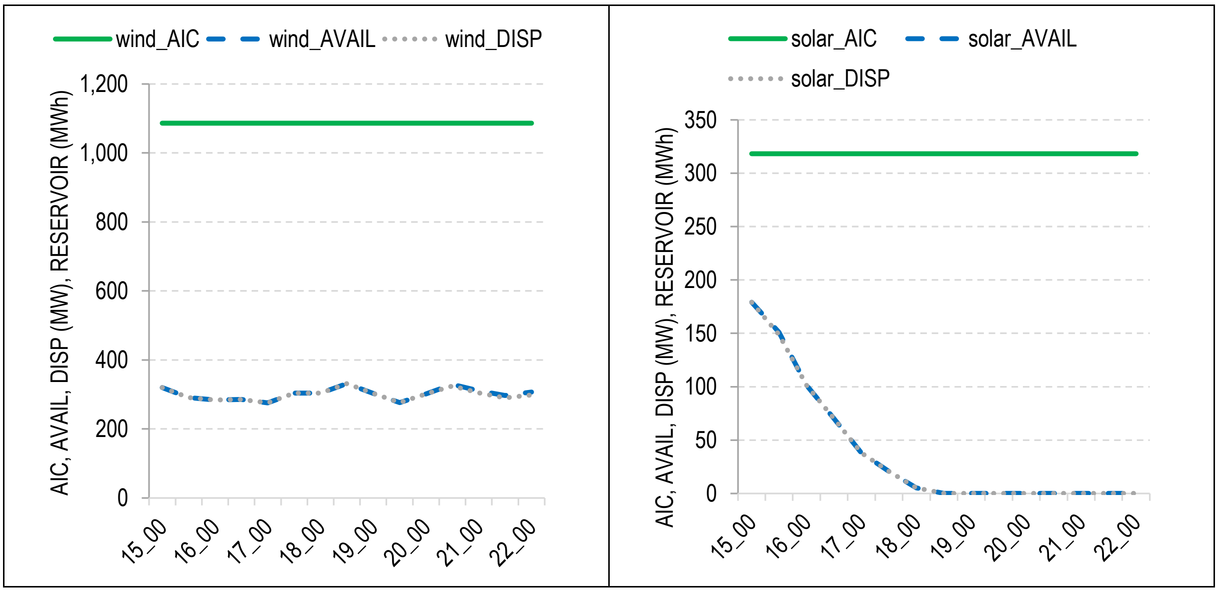


Figure 25: Modelled ESR and gas dispatch conditions for the period with the highest observed daily EUE volume in the 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Monday in March)

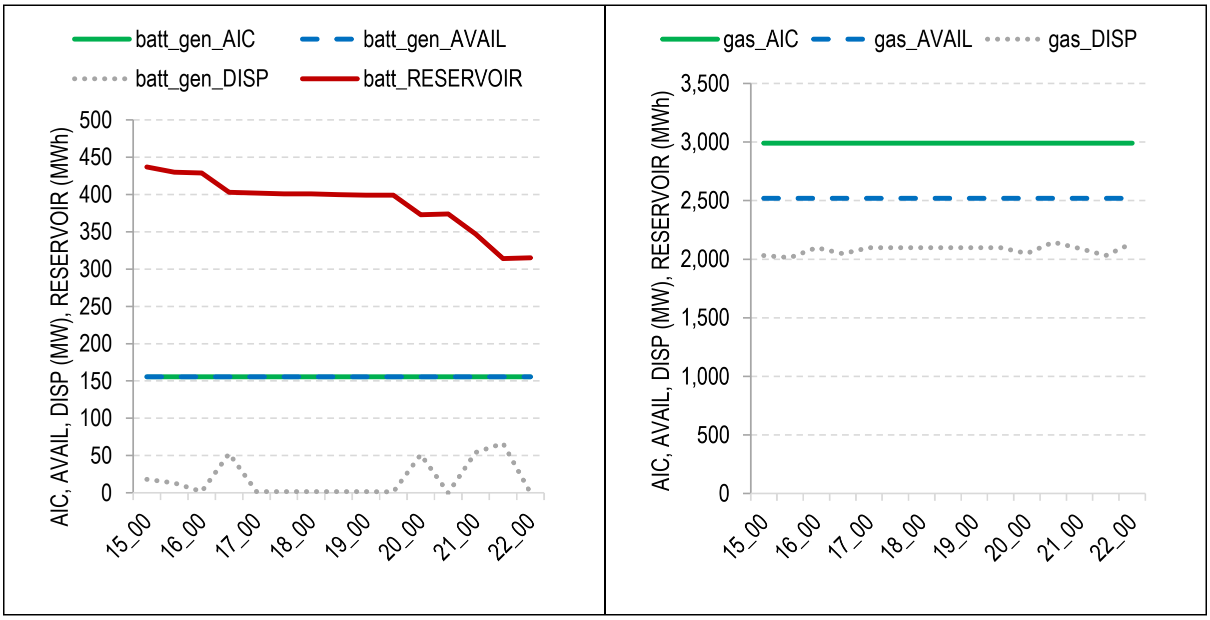
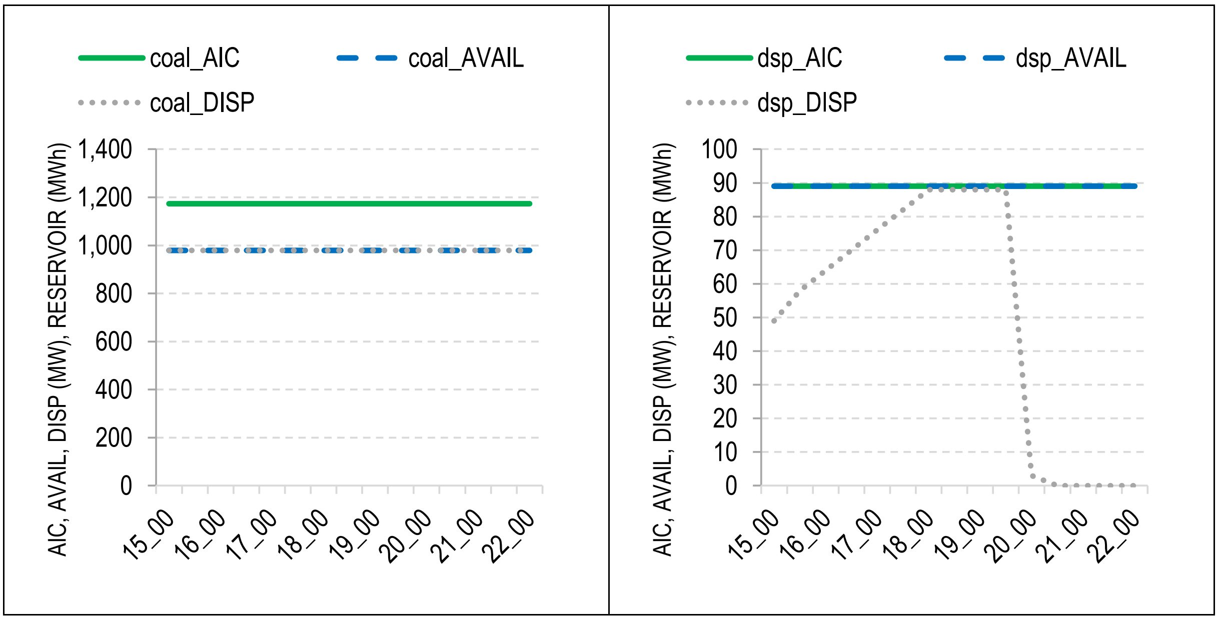


Figure 26: Modelled coal and DSM dispatch conditions for the period with the highest observed daily EUE volume in 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Monday in March)



5.6.4 Modelled day in the 2025-26 Capacity Year with the highest observed half-hourly EUE quantum (MW)

Results for the modelled day with the highest observed half-hourly EUE (observed in interval starting at 18:30) are presented in Figure 27. Across intervals when EUE was observed on this day, modelled demand was between 3.6 GW and 4.6 GW. On the supply side, despite total AIC of SWIS generators of 5.8 GW, available capacity (AVAIL) during EUE intervals was between 4.1 GW and 4.3 GW.[60]

Available capacity was driven by a combination of modelled outages (planned and forced) as well as low availability of wind and solar resource compared to wind and solar AIC (Figure 28). Besides low resource availability, dispatch of solar PV was below prevailing availability on this day, which indicates it was being limited by modelled transmission network thermal constraints.

Another factor impacting availability was the modelled ESS requirement, which effectively decreased the amount of capacity available for dispatch in the energy market from ESS-capable units (notionally, the impact of the ESS requirement is represented by the AVAIL_less_ESS_req line in Figure 27). ESS on this day was being provided by gas and ESR (with coal providing the least), which was a factor limiting their dispatch in the energy market (Figure 29). In the case of gas and coal, availability was below AIC, which indicates it was also impacted by outages (Figure 30).

Availability of coal units was impacted by a modelled outage and hence lower than AIC. All coal units were dispatched at their prevailing availability level, indicating there were no transmission network constraints curtailing their ability to be dispatched.

Dispatch of DSM was impacted by a modelled ramp rate limitation as well as the temporal availability as per WEM Rules, i.e. available only on business days between 8:00 AM and 8:00 PM (Figure 30).

The drivers identified above have collectively resulted in dispatch into the energy market (DISP) being below prevailing operational demand (DEMAND_oper), resulting in observed EUE intervals.

Figure 27: Modelled SWIS dispatch conditions for the period with the highest observed half-hourly EUE quantum in 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Tuesday in March)

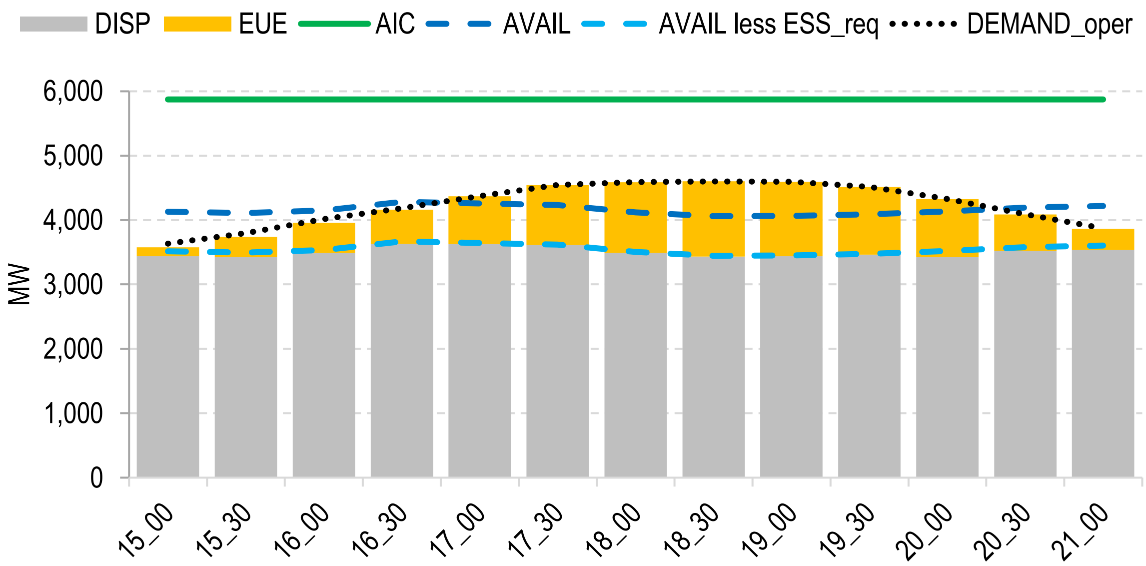


Figure 28: Modelled wind and solar dispatch conditions for the period with the highest observed half-hourly EUE volume in 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Tuesday in March)

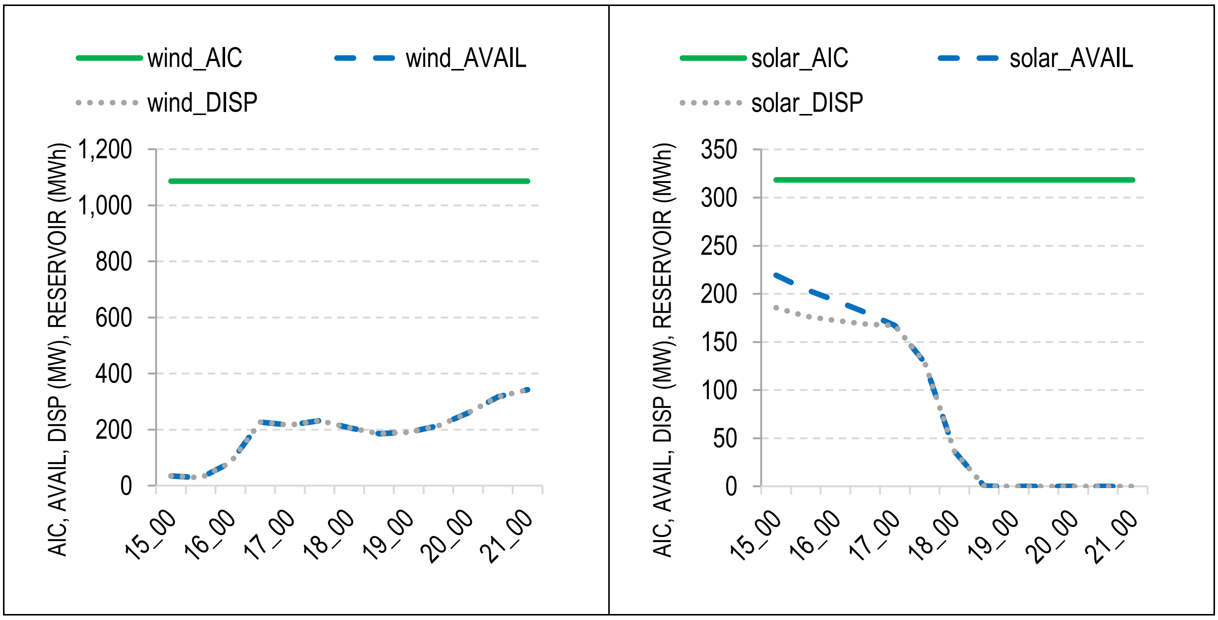


Figure 29: Modelled ESR and gas dispatch conditions for the period with the highest observed half-hourly EUE volume in the 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Tuesday in March)

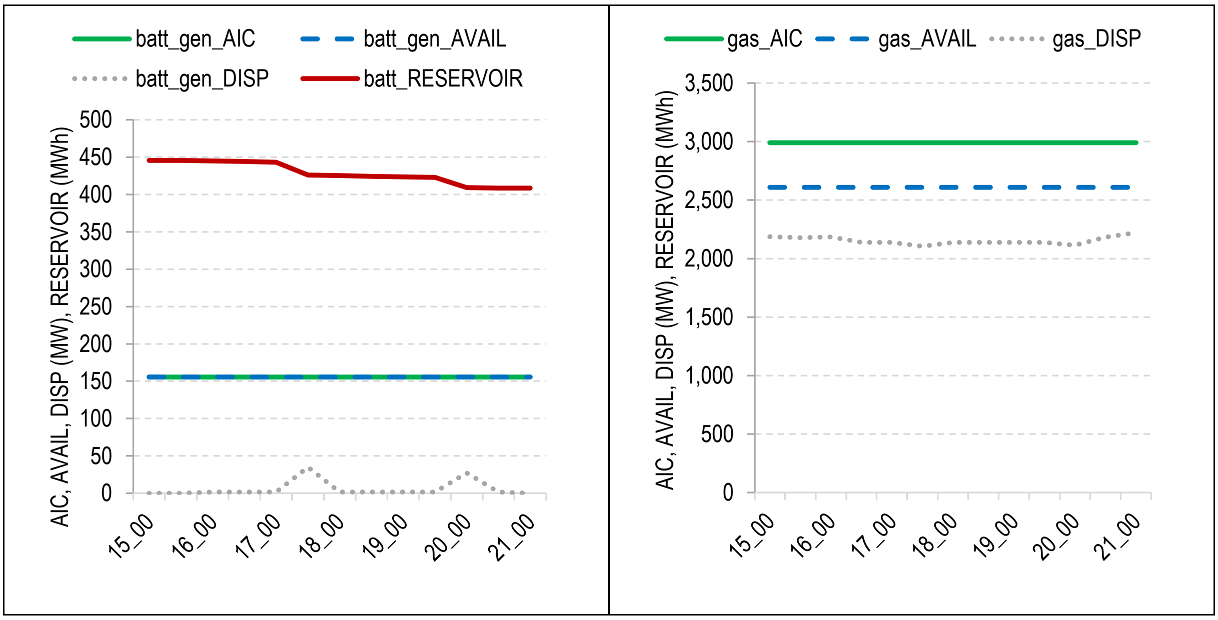
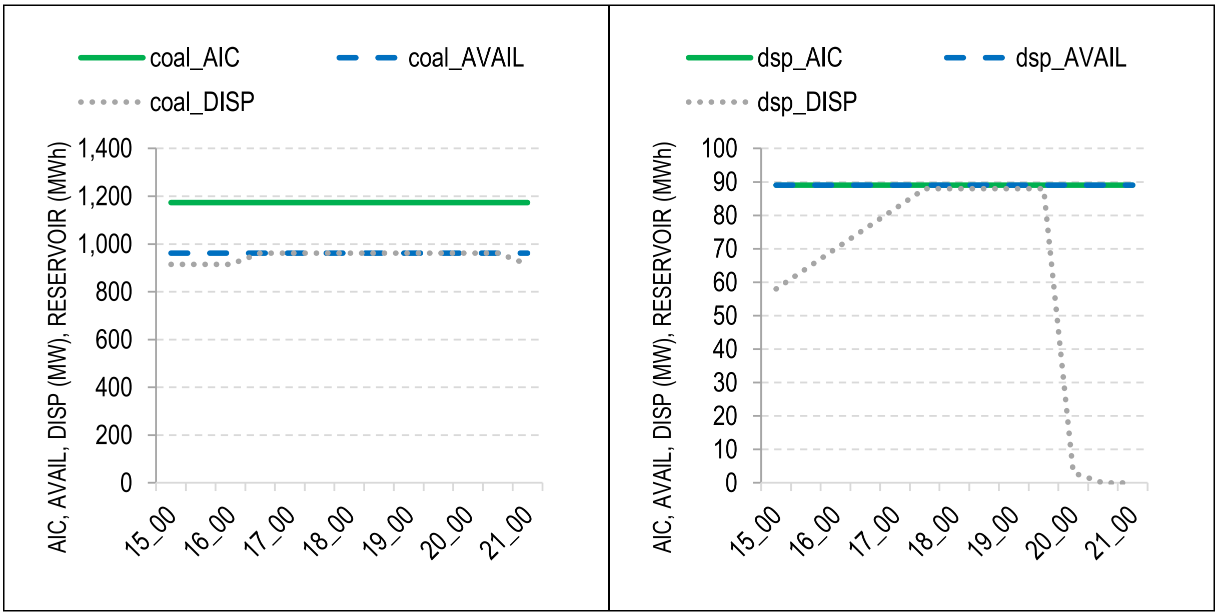


Figure 30: Modelled coal and DSM dispatch conditions for the period with the highest observed half-hourly EUE volume in the 2025-26 Capacity Year, expected scenario (EUE event starting at 15:00 on a Tuesday in March)



5.6.5 Modelled day in the 2025-26 Capacity Year with the observed longest-duration contiguous EUE event

Results for the modelled day with the observed longest duration contiguous EUE event (19 contiguous half-hour intervals) are presented in Figure 31. Across intervals when EUE was observed on this day, modelled demand was between around 3.7 GW and 4.2 GW. On the supply side, despite total AIC of SWIS generators of 5.8 GW, available capacity (AVAIL) during EUE intervals was between around 4.1 GW and 4.9 GW.[60]

Modelled available capacity was driven by a combination of modelled outages (planned and forced) as well as low availability of wind and solar resource compared to wind and solar AIC. However, from 17:00 wind availability increased (from around 300 MW to between around 600 to 800 MW) which translated into an overall increase in availability of the generation fleet and contributed to decreasing the volumes of USE in the late afternoon and evening hours (Figure 32).

Another factor impacting availability was the modelled ESS requirement, which effectively decreased the amount of capacity available for dispatch in the energy market from ESS-capable units (notionally, the impact of the ESS requirement is represented by the AVAIL_less_ESS_req line in Figure 31). ESS on this day was being provided by gas and ESR (with coal providing the least), which was a factor limiting their dispatch in the energy market (Figure 33). In the case of gas and coal, availability was below AIC, which indicates it was also impacted by outages (Figure 34). Gas availability increased after two intervals (form 2504 MW to 2663 MW) due to an end of a modelled forced outage. Modelled coal availability increased after 3 intervals (from 979 MW to 1128 MW), due to the ending of a modelled forced outage.

Availability of coal units was impacted by a modelled forced outage and hence lower than AIC. All coal units were dispatched at their prevailing availability level, indicating there were no transmission network constraints curtailing their ability to be dispatched.

On the analysed day, AVAIL_less_ESS_req exceeded demand (Figure 31) which was not the case on the two other days analysed (section 5.6.3 and 5.6.4). This indicates that on the day in question, modelled dispatch was being limited by network constraints and not ESS constraints.

On this day, dispatch of gas into the energy market from 17:30 was on average lower by around 150 MW (compared to earlier intervals), despite no change to ESS provision by gas (Frequency Contingency Raise was being provided consistently at around 320 MW, Frequency Regulation Raise was being provided consistently at around 160 MW).

This occurrence indicates that dispatch of gas into the energy market was being limited by modelled transmission network constraints.

Dispatch of DSM was impacted by a modelled ramp rate limitation as well as the temporal availability as per WEM Rules, i.e. available only on business days between 8:00 AM and 8:00 PM (Figure 34).

On the day in question, the EUE event begins at 12:00 and sees DSM activation from that interval (limited in the first intervals by the modelled ramp rate constraint). On the other two days, EUE events start later, i.e., at 15:00, and so does the dispatch of DSM (similarly, limited in the first intervals by the modelled ramp rate constraint). In each case, DSM is only usable until 20:00. The drivers identified above have collectively resulted in dispatch into the energy market (DISP) being below prevailing operational demand (DEMAND_oper), resulting in observed EUE intervals.

Figure 31: Modelled dispatch conditions for the day with the observed longest-duration contiguous EUE event in the 2025-26 Capacity Year, expected scenario (EUE event starting at 12:00 on a Friday in January)

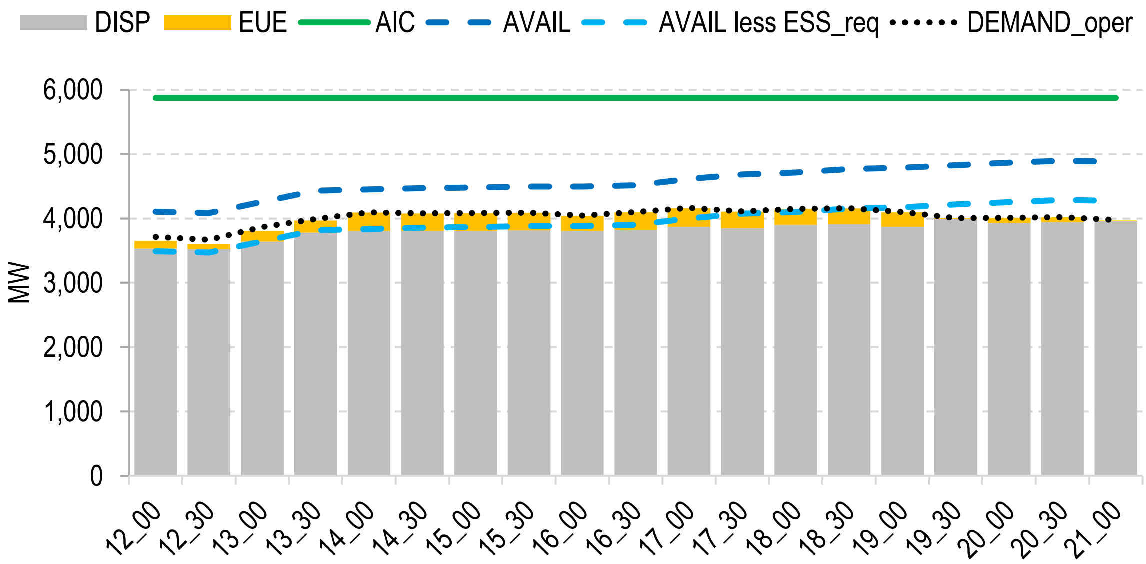


Figure 32: Modelled wind and solar dispatch conditions for the period with the observed longest-duration contiguous EUE event in the 2025-26 Capacity Year, expected scenario (EUE event starting at 12:00 on a Friday in January)

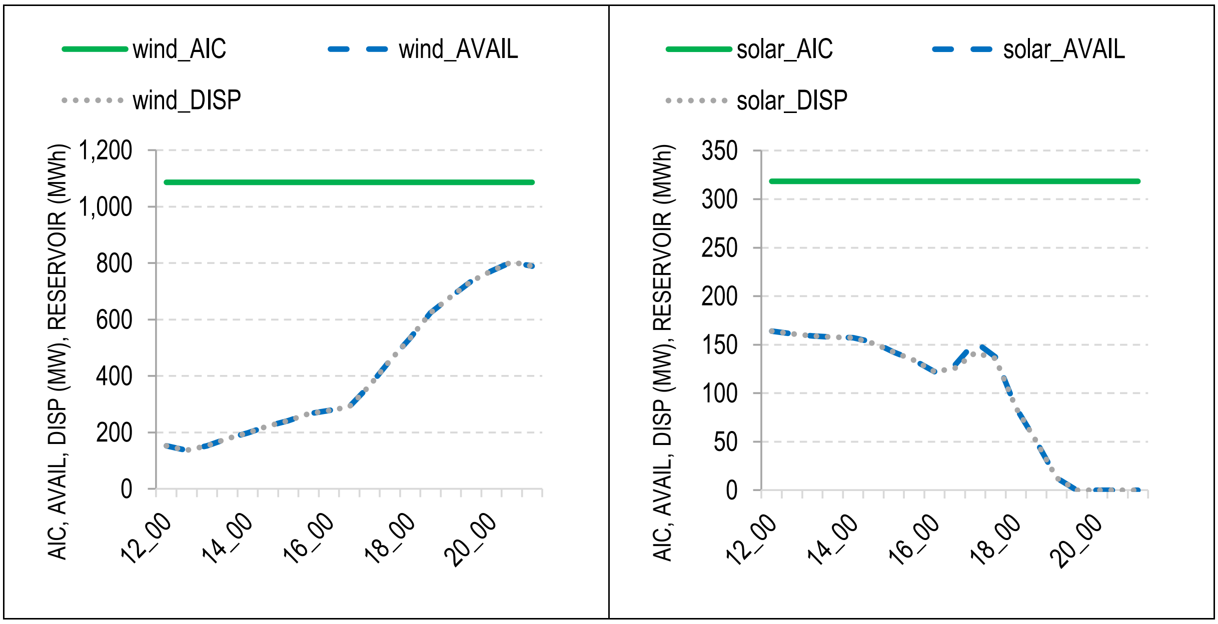


Figure 33: Modelled ESR and gas dispatch conditions for the period with the highest observed longest-duration contiguous EUE event in the 2025-26 Capacity Year, expected scenario (EUE event starting at 12:00 on a Friday in January)

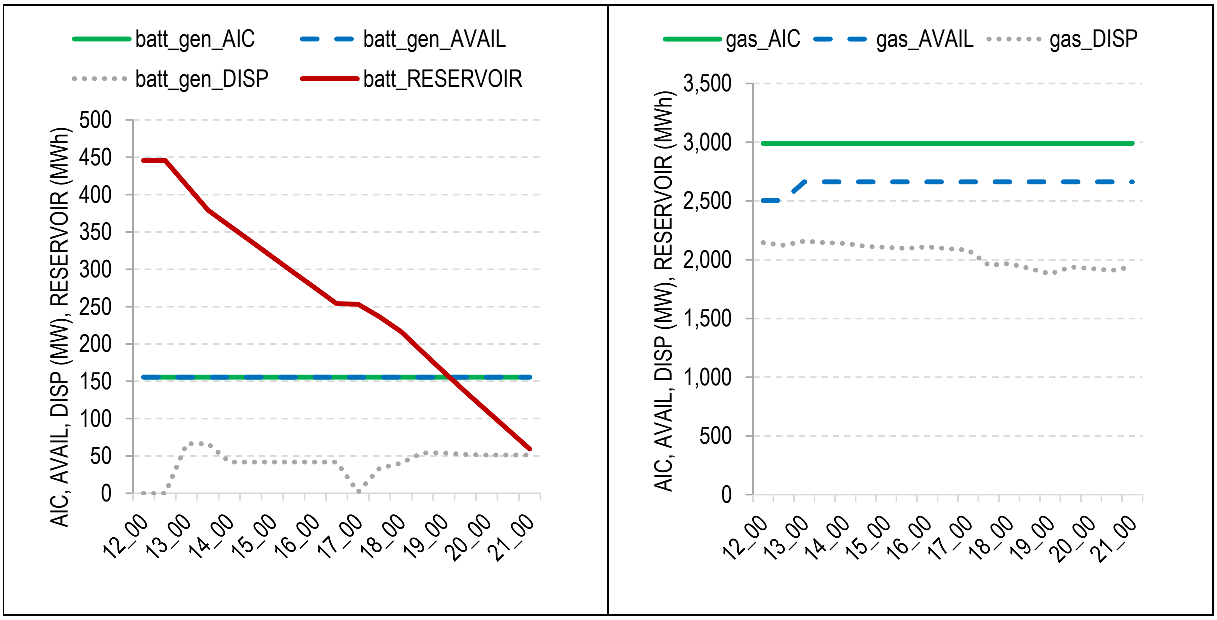
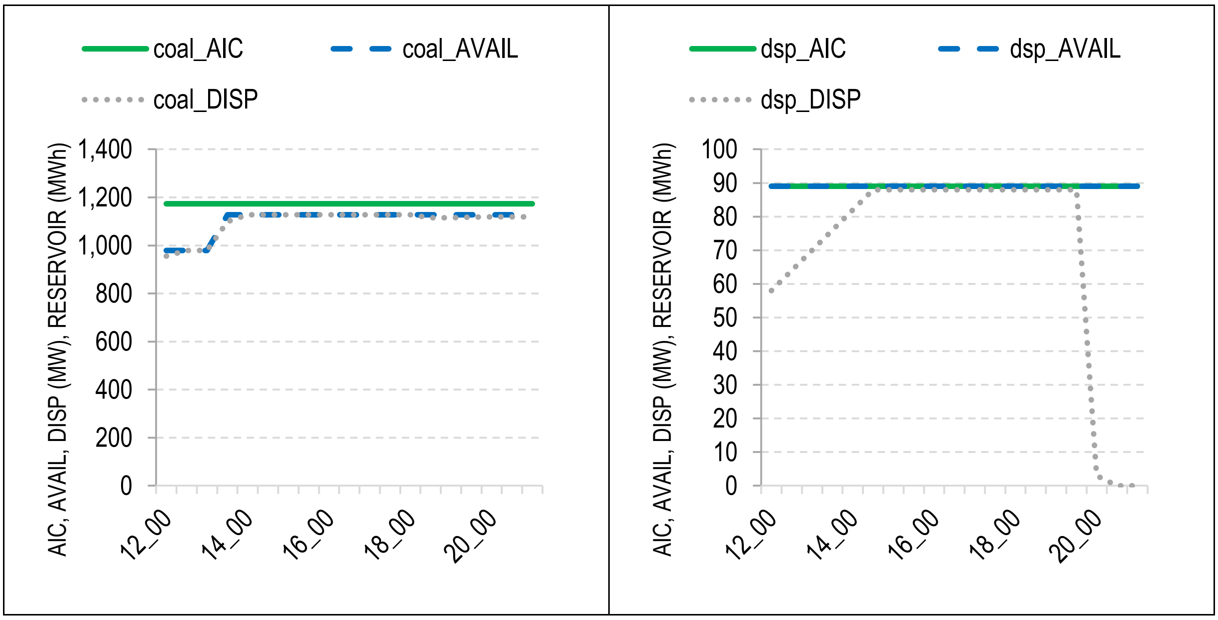


Figure 34: Modelled coal and DSM dispatch conditions for the period with the highest observed longest-duration contiguous EUE event in the 2025-26 Capacity Year, expected scenario (EUE event starting at 12:00 on a Friday in January)



5.6.6 Summary of insights from illustrative EUE days analysis

The analysis of illustrative EUE days presented in sections 5.6.3, 5.6.4 and 5.6.5 is summarised in Table 20 below.

Table 20: Summary of drivers of modelled EUE on three illustrative days (data for 2025-26 Capacity Year, expected scenario)

<table>
<tr><th>Modelling component</th><th>Modelled day with the highest observed daily EUE volume</th><th>Modelled day with the highest observed half-hourly EUE quantum</th><th>Modelled day with the observed longest-duration contiguous EUE event</th></tr>
<tr><td>Modelled operational demand and available capacity across intervals when EUE was observed</td><td>• Demand: between 3.6 GW and 4.6 GW.
• Available capacity: between 4.1 GW and 4.3 GW.
• AIC of SWIS Facilities: 5.8 GW.</td><td>• Demand: between 3.6 GW and 4.6 GW.
• Available capacity: between 4.1 GW and 4.3 GW.
• AIC of SWIS Facilities: 5.8 GW.</td><td>• Demand: between around 3.7 GW and 4.2 GW.
• Available capacity: between 4.1 GW and 4.9 GW.
• AIC of SWIS Facilities: 5.8 GW.</td></tr>
<tr><td>Modelled rivers impacting dispatch of renewable capacity</td><td colspan="3">On all days in question, dispatch of wind and solar capacity was found to be impacted by prevailing low availability of natural resource compared to the AIC of wind and solar.

Notes:
• On the day with the highest observed half-hourly EUE quantum, dispatch of solar PV capacity was below prevailing availability. This indicates that dispatch was being limited by modelled transmission network thermal constraints.
• The day with the longest-duration contiguous EUE event (starting at 12:00) experienced an increase in wind availability and dispatch from 17:00 (from around 300 MW to between around 600 to 800 MW). This contributed to decreasing the volumes of USE in the late afternoon and evening hours on this day.</td></tr>
</table>

Modelling component	Modelled day with the highest observed daily EUE volume	Modelled day with the highest observed half-hourly EUE quantum	Modelled day with the observed longest-duration contiguous EUE event
Drivers impacting dispatch of thermal capacity	On all days in question, dispatch of thermal capacity was found to be impacted by a combination of modelled outages (planned and forced) as well as the assumed modelling methodology for ESS, i.e., to reserve a portion of capacity from ESS-capable Facilities (coal, gas and ESR) to satisfy ESS reserves before dispatching them into the energy market. *Notes:* • On the day with the highest longest-duration contiguous EUE event, dispatch of gas into the energy market from 17:30 was on average lower by around 150 MW (compared to earlier intervals), despite no change to ESS provision by gas. This occurrence indicates that dispatch of gas into the energy market was being limited by modelled transmission network constraints.		
Drivers impacting dispatch of ESR capacity	On all days in question, dispatch of thermal capacity was found to be impacted by the assumed modelling methodology for ESS (see above). On the days in question, outages were not found to impact the dispatch of ESR capacity.		
Drivers impacting dispatch of DSM	On all days in question, dispatch of DSM was found to be impacted by a modelled ramp rate limitation as well as the temporal availability as per WEM Rules (i.e., available only on business days between 8:00 AM and 8:00 PM).		

5.7 Determining Availability Class 1 and Availability Class 2 capacity

Following the approach set out in Section 4.3, the modelling has determined the amount of the RCT that can be provided by capacity classified as Availability Class 1 and capacity classified as Availability Class 2. The assessment is required to be carried out for the 2024-25 and 2025-26 Capacity Years. The RCT for these years along with the forecast Reserve Capacity from anticipated installed capacity is shown in Table 21.

Table 21: RCT and forecast Reserve Capacity for the 2024-25 and 2025-26 Capacity Years[62]

Component	2024-25	2025-26
RCT	5,430	5,543
Reserve Capacity from AIC	4,596	4,598
Difference between RCT and Reserve Capacity from AIC to be modelled	-833	-945

As there is a capacity investment gap in each year in question, the approach followed for this scenario was as set out in Section 4.4, and adds generic OCGT capacity to the model so that installed capacity and associated assumed Reserve Capacity is equal to the RCT (i.e. adding 833 MW of OCGT in 2024-25, increasing to 945 MW in 2025-26).

The modelling then separately runs an ESR scenario and a DSM scenario, increasing the MW capacity of each and reducing the new OCGT capacity by the same amount, until the 0.002% standard is just short of being breached.[63] The DSM scenario reached this point more quickly, therefore it is the DSM capacity that sets the Availability Class 2 capacity, in line with the approach set out above.

[62] May not sum due to rounding.

[63] Noting that if the DSM or ESR increased to the point all the new OCGT had been removed, the approach involves then removing existing capacity in order of retirement date.

The modelling finds that the 0.002% standard is reached first by DSM (i.e. at the point where DSM capacity would breach 0.002%, an equivalent MW capacity of ESR results in EUE below 0.002%). This is due to the modelled DSM being more energy limited over the year than ESR, noting that DSM is modelled to be called upon and dispatched simultaneously in the event there would otherwise be unserved energy (with the assumption that tie-breaking would share MW dispatch across providers), up to a maximum of 200 hours per year. This is in contrast to ESR which can operate every day of the year, and can continue to contribute towards avoiding EUE after the 200 hours of DSM is exhausted. ESROIs were not implemented for this modelling (ESR is modelled to respond to avoid EUE at any time of the day) but noting that the ESROIs can be adjusted to different times of the day it is anticipated that even with enforcing ESROIs, DSM as modelled, would still reach the 0.002% standard first.

In the DSM scenario, the modelling was able to add 823 MW of DSM in 2024-25 and 855 MW in 2025-26 before the 0.002% was reached. Adding in the Reserve Capacity already included in the modelling for Availability Class 2 for these years results in the minimum Availability Class 1 capacity, and associated Availability Class 2 capacity as shown in Table 22.

Table 22: Availability Class outcomes for the 2024-25 and 2025-26 Capacity Years

Component (MW)	2024-25	2025-26
Minimum capacity required to be provided from Availability Class 1	4,430	4,510
Capacity associated with Availability Class 2	1,000	1,033
RCT	5,430	5,543

5.8 Availability Curves for the 2024-25 and 2025-26 Capacity Years

Following the approach set out in Section 4.4, the modelling has determined the availability curves that consist of the operational demand curve increased by a constant reserve margin. The half-hourly data to derive these curves is based on the outcome of the process undertaken by EY to convert the annual demand data provided by AEMO into half-hourly data for each of the 12 modelled reference years.[64]

The data provided below is an average across each of these reference years and also reflects the modelled minimum demand threshold (500 MW). As the RCT was set by Limb A, the margin to add is determined as per Section 5.2.

[64] The demand modelling process applied by EY targeted AEMO's operational peak demand forecasts. However, due to the application of 12 weather reference years, each year resulted in slight deviations from AEMO's target values, driven by the different impact of rooftop PV (based on various weather reference years) on operational demand. Given this, operational demand values deviate slightly from AEMO's forecasts, which has been discussed with and consented to by AEMO.

Figure 35: Availability Curve for the 2024-25 Capacity Year

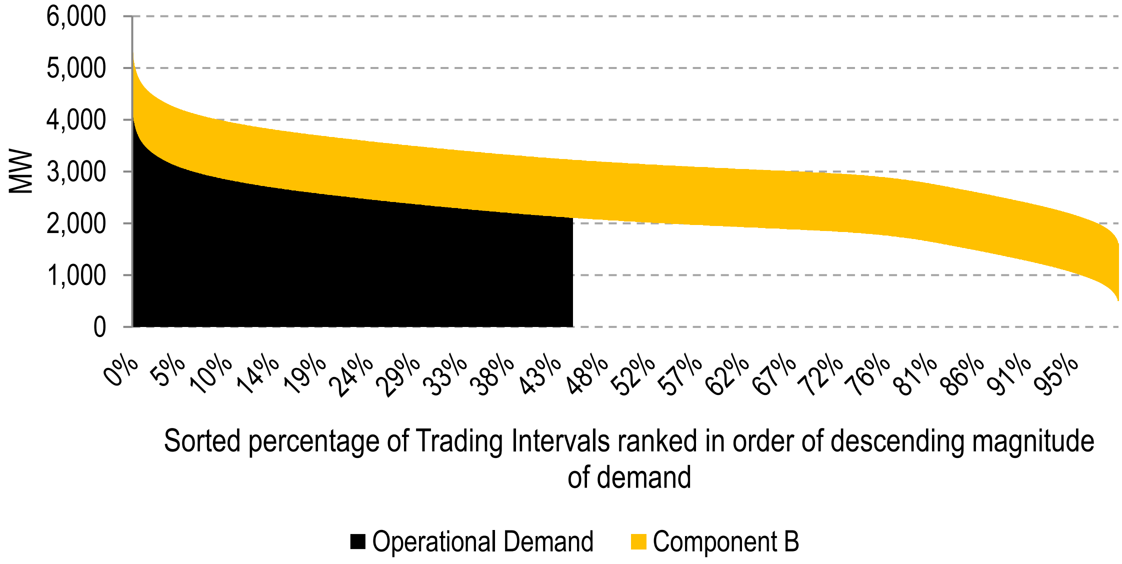
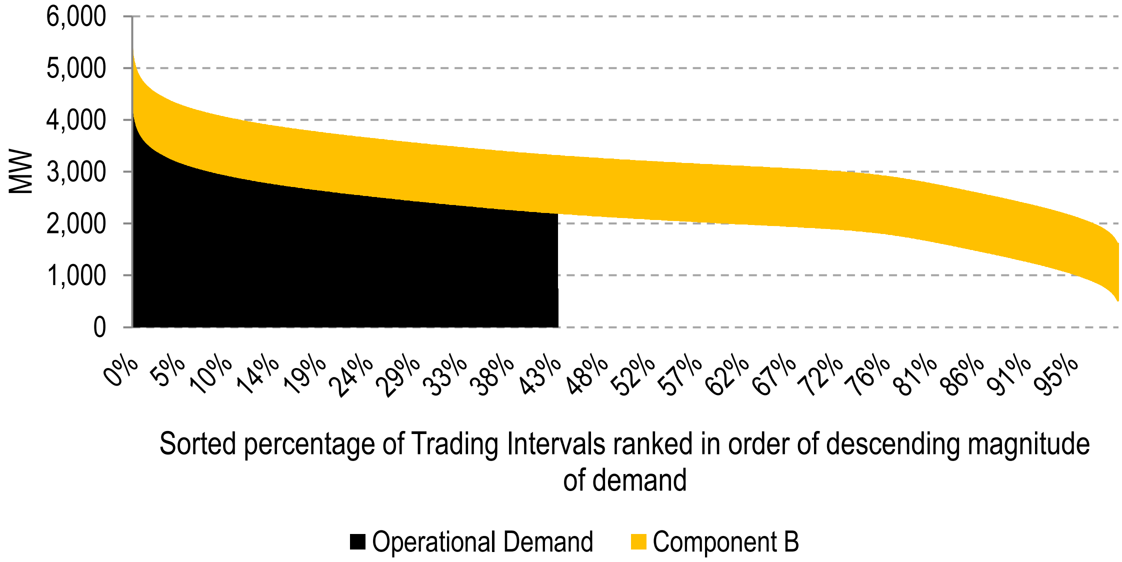


Figure 36: Availability Curve for the 2025-26 Capacity Year



5.9 Impact of transmission network constraints

The electricity market modelling framework used for parts of this Reliability Assessment includes transmission network constraint equations to represent the capability of the existing transmission network in the SWIS. Implementing constraint equations enables the identification of where restrictions on transmission capability may contribute to potential capacity shortfalls on the SWIS. Section 2.3.1 provides further details on transmission network constraint equations.

This section makes a distinction between the constraint equations that are found to be binding and constraint equations that are found to be violating:

- A binding constraint equation indicates where transmission network capability may impact on the dispatch of generation facilities but not result in a system security issue. Binding constraint equations are an outworking of the implementation of SCED in the WEM RTM and highlight parts of the transmission network where generation dispatch may need to be modified, but a dispatch solution can be found that does not involve load shedding.

- A violating constraint equation indicates where transmission network capability may impact on power system security. These constraint equations highlight parts of the transmission network where load shedding may be required to maintain power system security as a generation dispatch solution cannot be found otherwise.

The modelling undertaken in this Reliability Assessment focuses on assessing generation supply adequacy and does not consider the full range of network options and operational mechanisms that may be available to AEMO to resolve violating or binding constraints. This assessment does not consider the impact of planned network augmentations which are expected to relieve constraints in the later years of the study horizon or different access standards that may be negotiated with large load customers.

5.9.1 Binding constraints

Table 23 summarises the top 10 most binding constraint equations on the SWIS by 2025-26, based on the number of intervals binding in that year. A binding constraint equation indicates that a part of the power system is modelled as being operated near or very close to a design limit. Where the power system element is a part of the transmission network, a binding constraint equation indicates where transmission network capability may impact on the dispatch of generation facilities in the electricity market.

It should be noted that the metric reported here does not imply generator facilities near the constraint would experience curtailment at these levels nor does it imply that unserved energy is caused specifically by these constraints. The magnitude of curtailment experienced by a facility will depend on prevailing market and network conditions that will be influenced by many factors including, but not limited to, facility bidding profiles, renewable resource availability, dynamic network ratings and whether special protection schemes exist. Operational mechanisms and planned network augmentations may be used to alleviate some of these binding constraints.

Table 23: Top 10 binding constraint equations by 2025-26, expected scenario

Constraint ID	2023-24	2024-25	2025-26
MBRALB81 >> FLATROCKS_WF1_KOJ81_599		6.5%	7.9%
TS_BUSBAR_542	7.1%	7.0%	6.6%
KOJMBRFLATROCKS_WF2 >> FLATROCKS_WF1_KOJ81_598		4.8%	5.8%
MRTT1 >> MRT_NOR_81_NOR_381		5.4%	5.8%
MUBTT2INTERTRIP >> NT_NOR_81_NOR_382	0.4%	3.9%	3.9%
PJRCTB81 >> PJR_RGN_81_RGN_413	4.0%	3.8%	3.6%
MSRWMOFE81 >> KW_81_KCM_KW_147	1.5%	2.2%	2.3%
MRTNORCNS81 >> MU_NGS_X1_NGS_260	0.1%	2.3%	2.3%
ROWAI81 >> PNJ_APJ_81_APJ_440	1.4%	1.9%	2.0%
BGACTBEMD81 >> CTB_ENB_81_ENB_47	1.9%	1.5%	1.7%

The results highlight parts of transmission network flow paths where thermal ratings may impact on the wholesale market dispatch in the SWIS. This includes (but is not limited to):

- The 132 kV transmission network between Merredin Terminal Station, Northam Zone Substation and Northern Terminal Station, impacting on generators connected to the 220 kV network.
- The 132 kV transmission network around Kwinana Terminal Station, Rockingham Zone Substation and Waikiki Zone Substation, impacting on 132 kV connected generators in the Kwinana region.
- The 132 kV transmission network north of Three Springs Zone Substation including the Three Springs 132 kV busbar, impacting on 132 kV connected generators north of Three Springs Zone Substation.
- The 132 kV transmission network south of Three Springs Zone Substations towards Regans Zone Substation and Pinjar Terminal Station, impacting on 132 kV connected generators south of Three Springs Zone Substations.
- The 132 kV transmission network between Kojonup Terminal Station and Albany Zone Substation, impacting on 132 kV generators south of Kojonup Terminal Station

5.9.2 Violating constraints

Table 24 summarises the top 10 most violating constraint equations on the SWIS by 2025-26, based on the number of violating intervals in that year. A violating constraint equation indicates a potentially insecure power system and where load shedding may be necessary to keep the power system secure. Violating constraints indicates those parts of the network that may need to be reinforced to maintain power system security, as a generation dispatch solution was not found in the dispatch simulations.

It should be noted that whilst the presence of violating constraints may indicate where power system security issues on the SWIS may present, this does not mean EUE will occur. The modelling of EUE is a probabilistic modelling assessment and in practice, operational decisions regarding load shedding considers a risk assessment of the forecast and prevailing conditions that may occur in the planning timeframes and will consider the use of operational mechanisms and planned network augmentations to address system security issues. [65]

Table 24: Top 10 violating constraint equations by 2025-26, expected scenario.

Constraint ID	2023-24	2024-25	2025-26
KWCCMED81 >> WM_81_MWO_WM_544	0.065%	0.106%	0.141%
ROWAI81 >> PNJ_APJ_81_APJ_440	0.021%	0.077%	0.101%
KWCCMED81 >> RO_81_RWA_RO_444	0.003%	0.054%	0.100%
MSRWMOFE81 >> KW_81_KCM_KW_147	0.013%	0.069%	0.100%
PJRYP81 >> NBT_WNO_81_NBT_321	0.010%	0.041%	0.095%
CTMSSPNJ81 >> MH_PNJ_81_PNJ_166	0.021%	0.028%	0.075%
KWST81 >> ST_SF_81_ST_466	0.005%	0.037%	0.074%
PICPNJBSNKEM81 >> PNJ_APJ_81_APJ_427	0.003%	0.033%	0.068%
KEMMRR82 >> KEM_MRR_81_KEM_139	0.047%	0.032%	0.059%
KWCCMED81 >> WM_81_RWA_WM_528	0.001%	0.008%	0.057%

[65] The demand forecast used for this assessment is based on an unconstrained view and may not consider operational limitations that may negotiated with large customers (apart from hydrogen loads) as part of their connections framework.

The results highlight parts of the transmission network whereby forecast demand increases may result in EUE to keep the power system secure. These constraints are centred on two main areas:

- The 132 kV transmission network in and around Kwinana/Peel metro area, where the majority of the identified constraint equations were modelled to violate

- The 132 kV transmission network in the northern metropolitan 132 kV network, in and around the Pinjar region.

5.10 Alleviating capacity investment gaps

The ESOO sits alongside other planning publications such as Western Power's Transmission System Plan and Energy Policy WA's Whole of System Plan and the SWIS Demand Assessment. These collectively provide a view of the generation and transmission network capacity needed on the SWIS across the next 10 years.

The ESOO is primarily an assessment of the long-term supply adequacy on the SWIS to meet the projected peak demand forecast identifying additional supply capacity needed on the SWIS.

The delivery of additional transmission network capacity is a key enabler for additional supply capacity to alleviate these capacity investment gaps. Existing and potential new supply capacity may benefit from an increase in the transfer capability across key regions of the SWIS. Where areas of the SWIS may also have system security concerns, there may be benefits in technologies that are able to provide both peaking capacity, thermal limit management and ESS reserves.

The results highlight key areas of the SWIS whereby increased transfer capability and additional supply capacity may be of benefit in the modelled scenarios. [66] These include (but are not limited to):

- Network augmentation to increase the thermal transfer capability in and around the Kwinana area and flexible demand services from existing and new market participants in the region.

- Network augmentation to increase the thermal transfer capability in and around the South-West and South-East region of the SWIS, additional supply capacity and flexible demand services from existing and new market participants in the South-West part.

- Network augmentation to increase the thermal transfer capability in and around the North Metropolitan region, and towards the Mid-West region, including considering providing for additional network redundancy on the existing 330 kV line to management reserve requirements noting the potential impact of multiple generator losses.

- Network augmentation to increase the thermal transfer capability around the 220 kV Merredin Terminal and flexible demand services from existing and new market participants in the eastern region of the SWIS.

- Network augmentation to increase the thermal transfer capability of the corridor north of Three Springs including addressing busbar limitations at Three Springs Zone Substation.

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[66] EY has not undertaken a market benefit assessment of options listed. The options discussed here are based on a high-level review of constraint outcomes.

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
CCGT	combined cycle gas turbine
CER	Clean Energy Regulator
CFR	Capacity for Reliability
CONE	cost of new entrant
CRC	Certified Reserve Capacity
DC	direct current
DER	distributed energy resources
DPV	distributed PV
DSP	Demand Side Programme
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
NEM	National Electricity Market (Australia's East Coast)
NOFB	Normal Operating Frequency Band

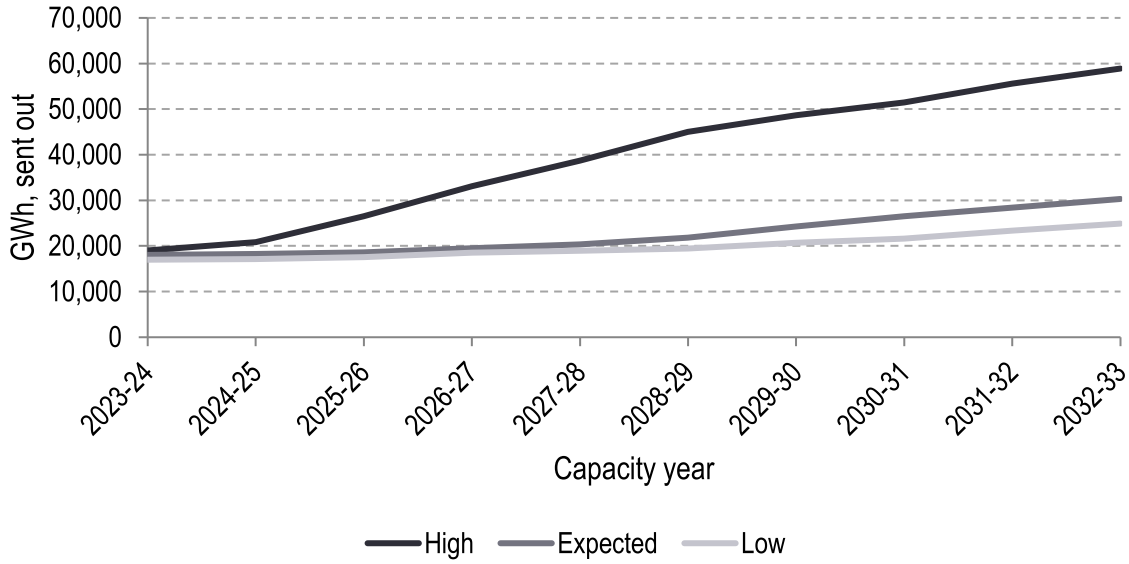
Abbreviation	Explanation
NOFEB	Normal Operating Frequency Excursion Band
NREL	National Renewable Energy Laboratory
OCGT	open cycle gas turbine
OPSO	operational sent out
POE	Probability of Exceedance
PVNSG	photovoltaic non-scheduled generator
RCM	Reserve Capacity Mechanism
RCT	Reserve Capacity Target
RHS	right hand side (of constraint equation)
SAM	System Advisory Model
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 assumptions

B.1 Energy demand

The modelling for the reliability study incorporates AEMO's WEM ESOO 2023 energy consumption forecasts for the low, expected and high scenarios. Figure 37 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 Section 3.

Figure 37: AEMO's 2023 WEM ESOO forecast of annual operational energy consumption in the WEM for the low, expected and high scenarios



B.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 38 and Figure 39 show the annual peak demand in the WEM for the summer and winter 10% POE projections respectively, consistent with AEMO's 2023 WEM ESOO scenarios.

Figure 38: AEMO's 2023 ESOO forecast of annual summer peak operational demand in the WEM for the low, expected, and high scenarios

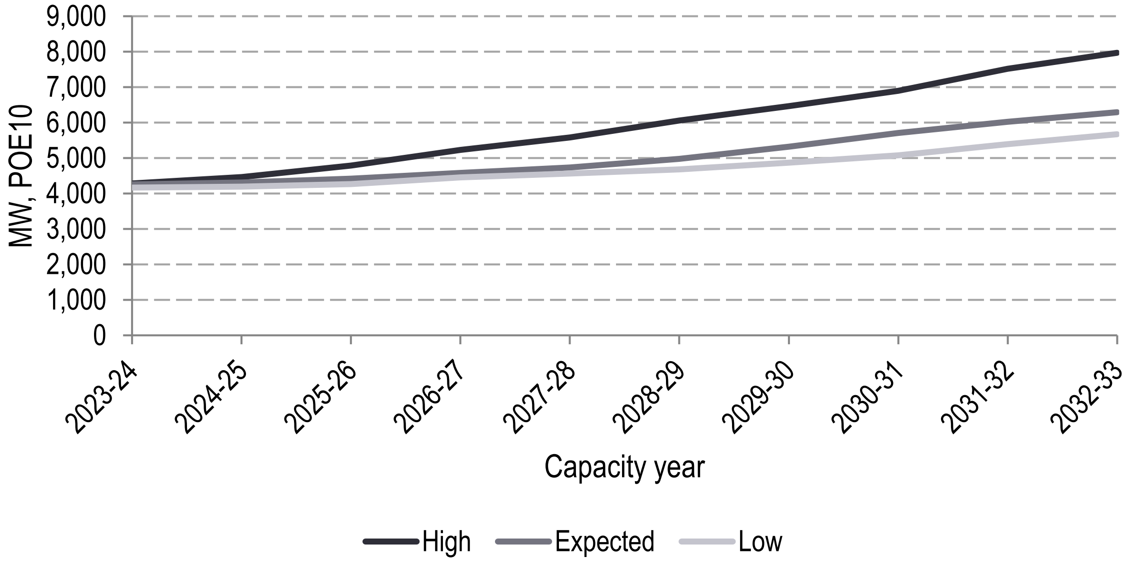
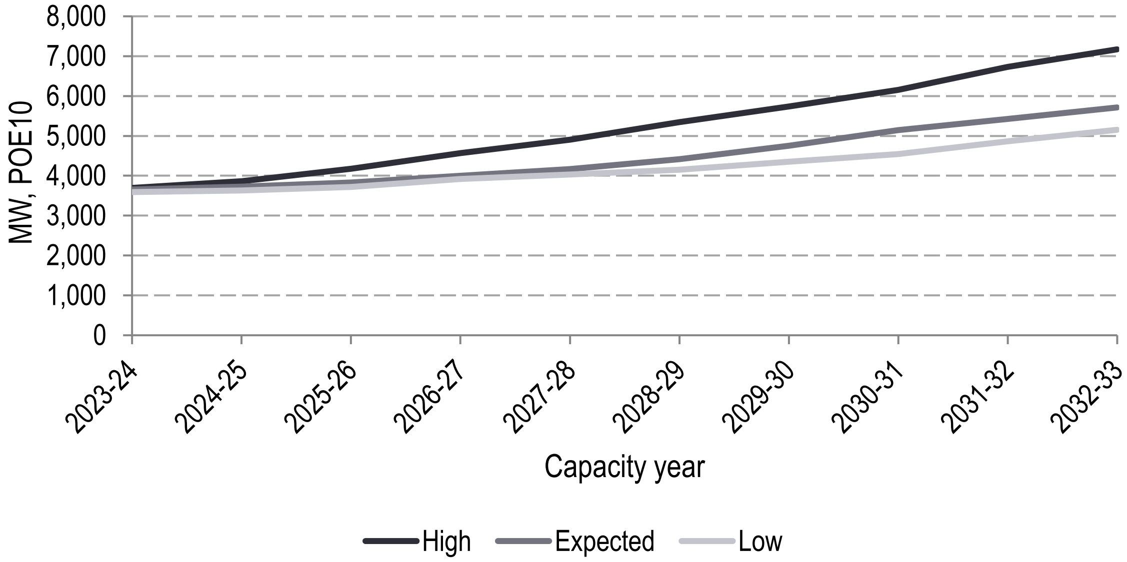


Figure 39: AEMO's 2023 ESOO forecast of annual winter peak operational demand in the WEM for the low, expected, and high scenarios



B.3 Distributed PV

Figure 40 and Figure 41 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 40: Residential and business behind-the-meter rooftop PV capacity consistent with the low, expected and high demand scenarios

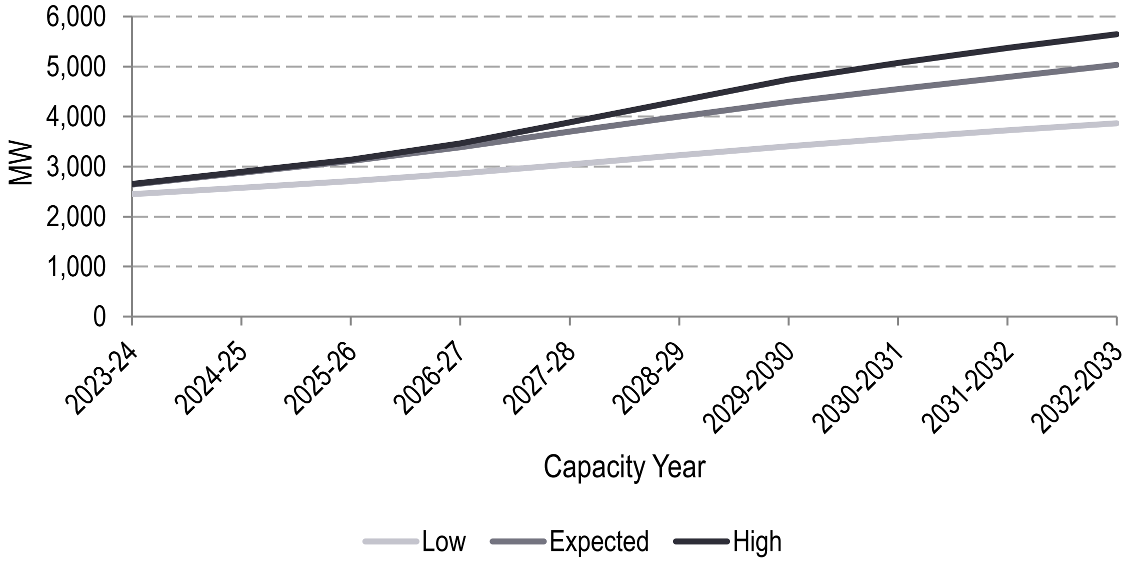
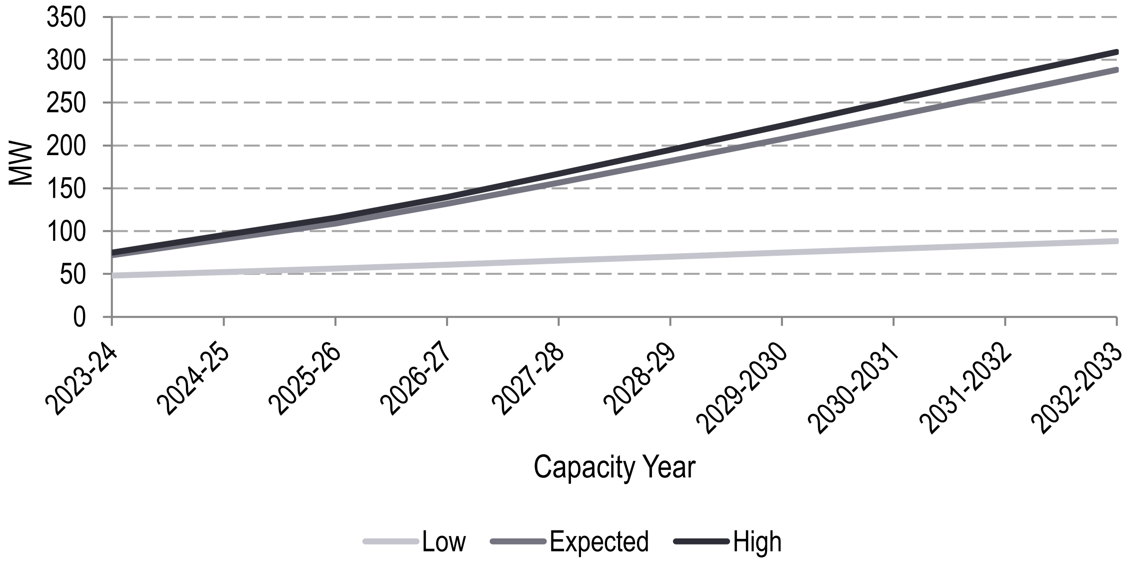


Figure 41: PVNSG capacity consistent with the low, expected and High demand scenarios



B.4 Electric vehicles

Figure 42 provides the annual energy consumption associated with EVs in each of the demand scenarios modelled, while Table 25 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.

Figure 42: Energy consumption from electric vehicles consistent with the low, expected and high demand scenarios

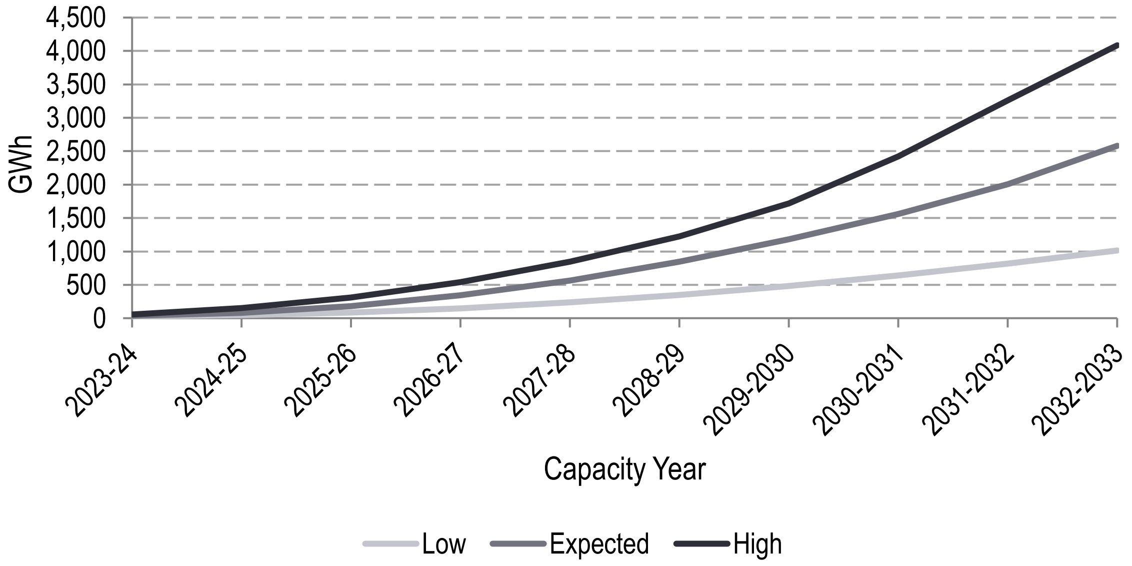


Table 25: Proportion of EVs with co-ordinated charging by charging profile in the expected and high scenarios

Financial year	Convenience	Fast-charge	Day-flex	Night-flex	Vehicle To Grid	Vehicle To Home
2023-24	-	-	-	-	-	-
2024-25	-	-	-	-	-	-
2025-26	-	-	4%	-	-	-
2026-27	-	-	8%	-	-	-
2027-28	-	-	12%	-	-	-
2028-29	-	-	16%	-	-	-
2029-30	-	-	20%	-	-	-
2030-31	-	-	24%	5%	-	-
2031-32	-	-	28%	10%	-	-
2032-33	-	-	32%	15%	-	-

B.5 Behind-the-meter storage

Figure 43 presents the assumed uptake of behind-the-meter batteries (residential and commercial uptake) in terms of the total MWh installed capacity (degraded) while Figure 44 presents the proportion of batteries by scenario that are assumed to participate in co-ordinated operation through a VPP.

Figure 43: Behind-the-meter battery capacity in the low, expected and high demand scenarios

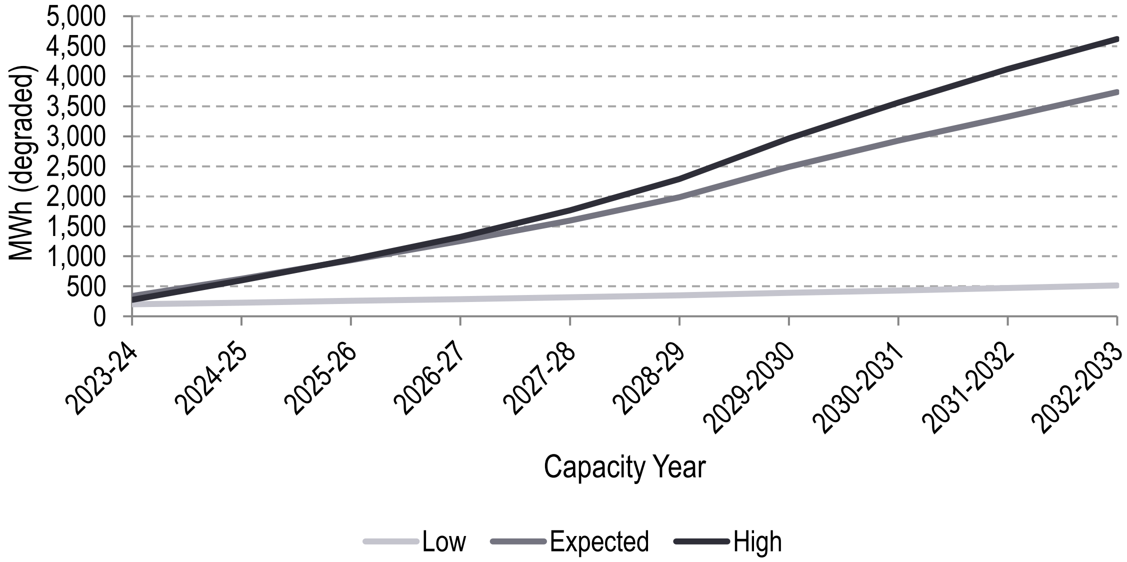
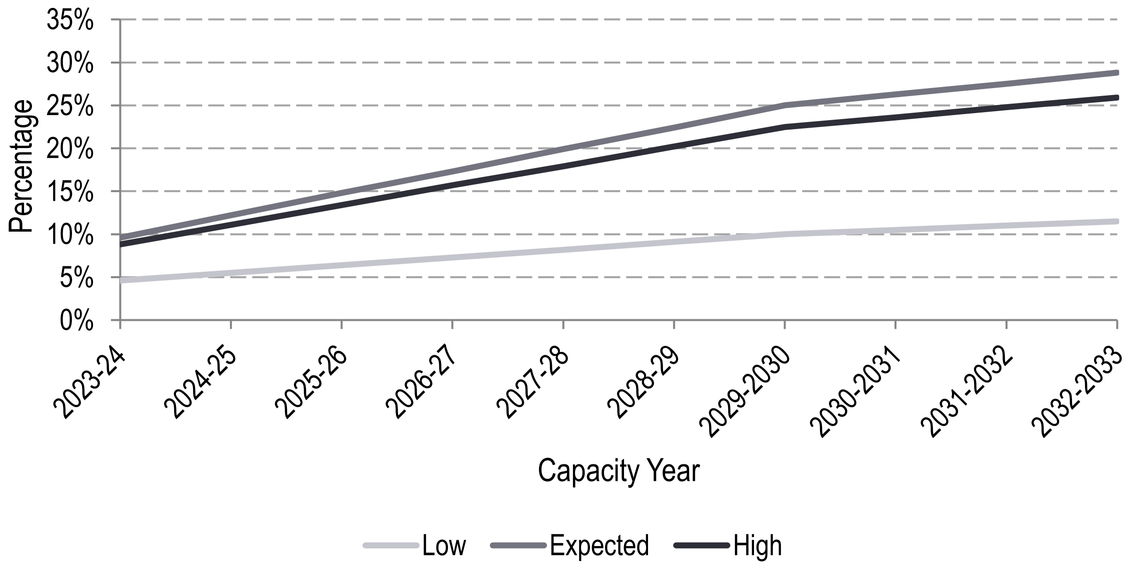


Figure 44: Proportion of batteries assumed to participate in a VPP in the low, expected and high scenarios



B.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 and probable) were provided to EY and are as published by AEMO alongside the ESOO. Assumed retirements from the WEM were also provided by AEMO and are as set out in Table 26.

Table 26: Assumed generator retirements for the reliability study modelling

Power station	Technology	Maximum capacity (MW sent out)	Low scenario retirement date	Expected scenario retirement date	High scenario retirement date
MUJA_G6	Black coal	193.6	1/10/2024	1/10/2024	1/10/2024
COLLIE_G1	Black coal	318.3	1/10/2027	1/10/2027	1/10/2027
MUJA_G7	Black coal	212.6	1/10/2029	1/10/2029	1/10/2029
MUJA_G8	Black coal	212.6	1/10/2029	1/10/2029	1/10/2029

Power station	Technology	Maximum capacity (MW sent out)	Low scenario retirement date	Expected scenario retirement date	High scenario retirement date
Bluewaters Power Station	Black coal	434	1/10/2030	1/10/2030	1/10/2025

B.7 Planned maintenance

Planned maintenance was applied to units in line with the methodology set out in Section 2.2.5. 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 27: 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	30
Battery gen	0

B.8 Forced outages

AEMO provided EY with forced outage rate statistics based on an assessment of published outage data (see Table 28). These rates were applied in the modelling where available, otherwise generic rates by technology were applied as set out in Table 29 (for example for new and probable Facilities).

Table 28: Forced outage rates by Facility

Facility Code	Full outage rate	Full outage – mean time to repair	Partial outage rate	Partial outage - mean time to repair	Partial outage derating factor
ALCOA_WGP	2.3%	42.09	7.5%	32.98	57.5%
ALINTA_PNJ_U1	1.1%	25.47	1.0%	1.63	16.2%
ALINTA_PNJ_U2	3.5%	130.42	0.8%	3.30	33.6%
ALINTA_WGP_GT	0.1%	1.01	0.8%	1.73	53.5%
ALINTA_WGP_U2	0.4%	1.99	0.5%	0.76	52.6%
BW1_BLUEWATERS_G2	0.4%	10.44	2.2%	3.38	21.8%
BW2_BLUEWATERS_G1	3.4%	69.13	3.4%	3.27	19.4%
COCKBURN_CCG1	1.0%	40.63	0.8%	9.76	43.2%
COLLIE_G1	0.4%	76.50	3.0%	24.62	47.1%
KEMERTON_GT11	0.7%	98.00	0.1%	1.32	51.4%
KEMERTON_GT12	0.8%	51.00	0.1%	1.55	60.3%
KWINANA_GT2	1.4%	53.94	2.0%	23.46	54.7%
KWINANA_GT3	1.4%	32.50	0.3%	2.19	57.7%
MUJA_G6	6.0%	75.77	2.5%	20.82	31.9%
MUJA_G7	0.2%	30.25	73.8%	3,305.17	21.4%
MUJA_G8	3.9%	132.40	3.3%	79.96	25.2%

Facility Code	Full outage rate	Full outage – mean time to repair	Partial outage rate	Partial outage - mean time to repair	Partial outage derating factor
NAMKKN_MERR_SG1	0.6%	35.12	0.0%	1.08	56.6%
NEWGEN_KWINANA_CCG1	1.1%	196.50	1.4%	4.03	36.4%
NEWGEN_NEERABUP_GT1	0.0%	1.50	2.4%	41.45	48.0%
PERTHENERGY_KWINANA_GT1	0.0%	0.50	9.8%	12.26	50.2%
PINJAR_GT1	0.4%	24.63	0.0%	0.88	38.9%
PINJAR_GT10	5.2%	84.08	0.3%	5.78	82.9%
PINJAR_GT11	1.1%	21.75	0.3%	6.15	74.8%
PINJAR_GT2	0.5%	26.00	0.1%	3.50	68.6%
PINJAR_GT3	0.4%	15.89	0.0%	0.92	45.0%
PINJAR_GT4	10.4%	812.37	0.1%	1.15	44.6%
PINJAR_GT5	2.6%	46.13	1.0%	9.85	61.0%
PINJAR_GT7	0.5%	15.46	0.2%	3.63	74.5%
PINJAR_GT9	3.2%	94.75	0.9%	19.28	52.6%
PRK_AG	0.7%	0.91	6.6%	11.12	80.4%
STHRNCRS_EG	0.3%	5.83	83.7%	222.37	48.9%
TESLA_GERALDTON_G1	0.3%	38.75	0.0%	N/A	N/A
TESLA_KEMERTON_G1	0.0%	3.00	0.0%	N/A	N/A
TESLA_NORTHAM_G1	0.2%	21.18	0.0%	N/A	N/A
TESLA_PICTON_G1	0.4%	21.80	0.0%	N/A	N/A
TIWEST_COG1	0.2%	12.70	1.6%	18.63	55.3%
TESLA_GERALDTON_G1	0.3%	38.75	0.0%	N/A	N/A

Table 29: 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%
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%

Appendix C 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, DSM) less existing capacity retirements + committed capacity + probable facilities (as applicable by scenario settings).
Availability class 1	Scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages.
Availability class 2	Capacity that is not expected to be available for dispatch for all Trading Intervals and includes DSPs and standalone ESR.
Availability Curve	The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year.
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.
distributed energy resource (DER)	DER 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

Term	Meaning
	expectation of a future state; an average across a range of future outcomes, weighted for probability.
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 WEM 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 0.002% of annual energy consumption.
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 WEM Rules.
Reserve Capacity Cycle	A period covering the cycle of events described in clause 4.1 of the WEM Rules.
Reserve Capacity Mechanism	Set out in Chapter 4 of the WEM 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.
Reserve Capacity Target (RCT)	AEMO's estimate of the total quantity of generation or DSM 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 WEM 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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