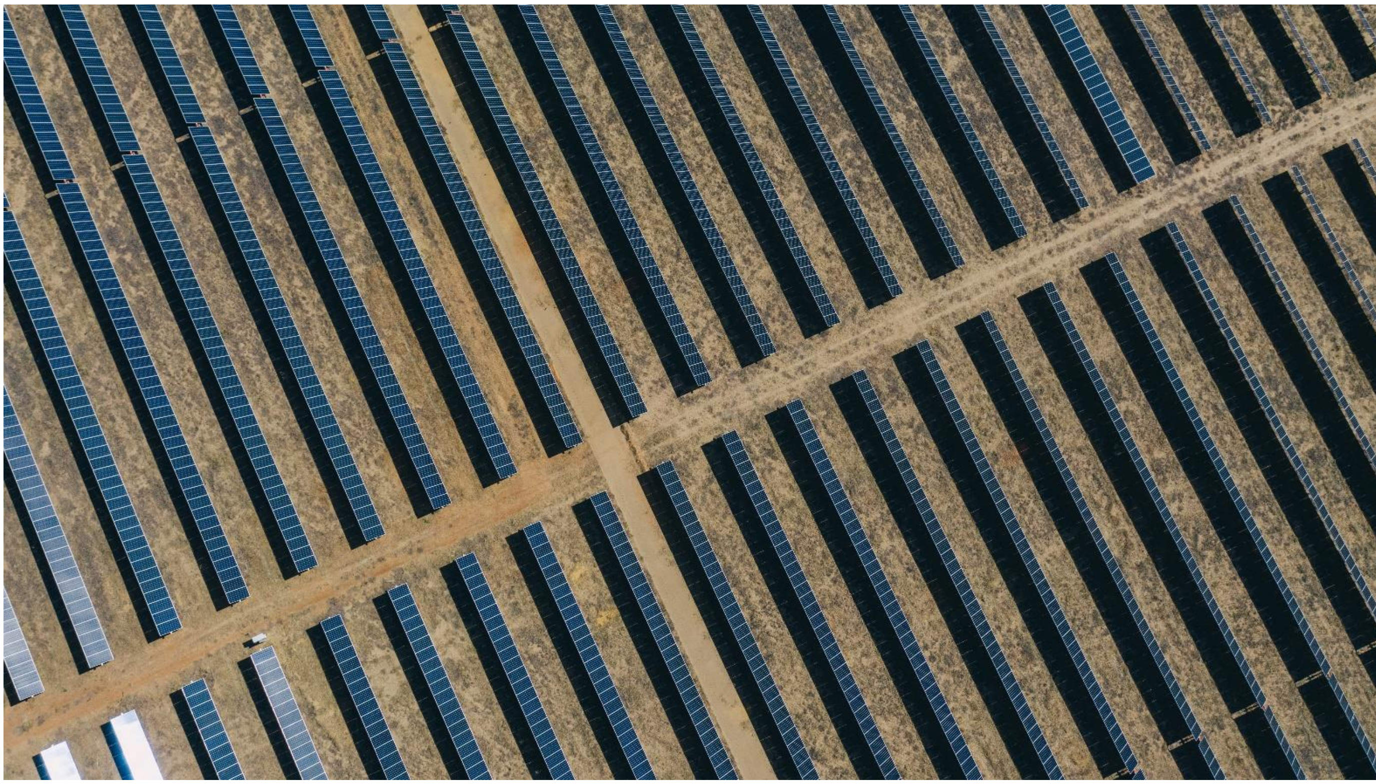
ROBINSON BOWMAKER PAUL



AUSTRALIAN ENERGY MARKET OPERATOR

Final Report - 2022 Assessment of System Reliability for the South West Interconnected System

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1 INTRODUCTION

Australian Energy Market Operator (AEMO) has engaged Robinson Bowmaker Paul (RBP) to undertake the 2022 Assessment of System Reliability for the South West Interconnected System (referred to as the 2022 Reliability Assessment for short). This report contains our modelling methodology, assumptions and results.

1.1 CONTEXT

AEMO is responsible for operating a Reserve Capacity Mechanism to ensure that adequate supply is available over the long term. To assess the amount of Reserve Capacity that will be required, AEMO undertakes a Long-term Projected Assessment of System Adequacy (Long Term PASA) as required under clause 4.5 of the Wholesale Electricity Market Rules (WEM Rule 4.5). The results of the Long Term PASA feed into the AEMO's WEM Electricity Statement of Opportunities (ESOO) report which forecasts:

- The Reserve Capacity Target (RCT) for each year in the Long Term PASA Study Horizon (WEM Rule 4.5.10(b)) and the Reserve Capacity Requirement (RCR) (WEM Rule 4.6.1). The RCT is set to meet the Planning Criterion which is defined in WEM Rule 4.5.9. The Planning Criterion comprises two components:
  - A forecast peak component to ensure that adequate supply is available to meet a one in ten-year peak (WEM Rule 4.5.9(a)) plus a reserve margin.
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual energy consumption (WEM Rule 4.5.9(b)).
- Energy Producing Systems and Demand Side Management (DSM) capacity requirements in the form of the Availability Class[1] requirements which are defined by WEM Rule 4.5.12.
- The Availability Curve to determine the minimum capacity requirement for each Trading Interval in the Capacity Year, which is defined by WEM Rule 4.5.10(e).

[1] There are two Availability Classes defined in the WEM rules. Availability Class 1 is all generation capacity and any other capacity that is expected to be dispatched for all Trading Intervals in a Capacity year, while Availability Class 2 refers to Certified Reserve Capacity which is not expected to be available to be dispatched for all Trading Intervals in a Capacity Year.

The Reliability Assessment is a key component of the Long Term PASA analysis. The purpose of our modelling is to:

- Undertake an Expected Unserved Energy (EUE) assessment to ensure the RCT meets the reliability requirements set out in the Planning Criterion.
- Determine the minimum capacity required to be provided by Availability Class 1 capacity and the capacity associated with Availability Class 2.
- Develop the Availability Curve defined by WEM Rule 4.5.10(e).

1.2 Scope of modelling

Our modelling covers:

- The EUE assessment for the 2022 Long Term PASA Study Horizon covering Capacity Years 2022-23 to 2031-32
- The Availability Curve for each of the second and third Capacity Years of the 2022 Long Term PASA Study Horizon (2023-24 and 2024-25 Capacity Years).
- The Availability Classes for each of the second and third Capacity Years of the 2022 Long Term PASA Study Horizon (2023-24 and 2024-25 Capacity Years).

1.3 Structure of this report

The remainder of our report is structured as follows:

- Our modelling methodology is described in Chapter 2
- Key assumptions underpinning our modelling are summarised in Appendix A
- Our data sources are summarised in Appendix A

2 MODELLING METHODOLOGY

2.1 INTRODUCTION AND BACKGROUND

RBP has undertaken the Reliability Assessment since 2012. Since 2019, we have used a bespoke model (CAPSIM), which simulates the capacity gap (a simple arithmetic calculation subtracting load from available generation capacity) for every hour of every year given a specific generation mix, load profile, planned outage schedule and random forced outages. This model was developed specifically for the context of the Reliability Assessment and delivers a large amount of statistical power while maintaining the chronological approach necessary to capture the increasing role of intermittent generation and Electric Storage Resources (ESRs) in the WEM.

The remainder of this chapter is structured as follows:

- In Section 2.2, we provide an overview of the modelling stages that will be required to undertake the Expected Unserved Energy (EUE) assessment (WEM Rule 4.5.9(b)), determine the Availability Class requirements (WEM Rules 4.5.12(b) and 4.5.12(c)) and develop the Availability Curve (WEM Rule 4.5.10(e)).
- In Sections 2.3 to 2.6 we describe each modelling stage in further detail.

2.2 OVERVIEW OF MODELLING APPROACH

Our modelling approach consists of four phases:

- **Phase 1: Hourly Load Forecasting.** Forecasting five hourly operational[2] load traces over the Long Term PASA study horizon, taking into account the annual 10% or 50% Probability of Exceedance (POE) summer peak forecast, expected and high annual energy consumption forecasts and hourly distributed energy resources (DER) contribution.

[2] AEMO distinguishes between operational demand and underlying demand. Operational demand refers to network demand that is met by sent-out electricity supply of all market registered energy producing systems and includes losses incurred from the transmission and distribution and distribution of electricity and electricity demand of electric vehicles (EV) but excludes electricity demand met by distributed Photovoltaics (DPV). Underlying demand refers to the amount of electricity 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. It is equal to operational demand plus an estimate of DPV generation and the impacts of battery storage.

- **Phase 2: EUE Assessment.** Simulating expected unserved energy (EUE) over the Long Term PASA Study Horizon to apply the second component of the Planning Criterion (WEM Rule 4.5.9(b)) and determine the amount of Reserve Capacity required to limit expected energy shortfalls to 0.002% of forecast annual energy consumption. This will enable AEMO to determine the RCT for each year in the Long Term PASA Study Horizon.
- **Phase 3: Availability Class Requirements.** Determining the Availability Class requirements contemplated by WEM Rules 4.5.12(b)[3] and 4.5.12(c)[4] and
- **Phase 4: Availability Curves.** Developing the two-dimensional duration curves required under WEM Rule 4.5.10(e)

Each of these phases is discussed in more detail in Sections 2.3 - 2.6 below.

2.3 Phase 1: Hourly load forecasting

In recent years, we have seen significant changes in load profiles, with lower off-peak loads and peak demand occurring later in the day. These changes have been driven by the increasing penetration of DER[5]. This trend is expected to continue across the modelling horizon, and we would expect changes to the load profile in future years.

Reflecting this, our load forecasting methodology in the 2021 Reliability Assessment explicitly forecasted the load profile for each individual Capacity Year (allowing year-on-year variation), based on AEMO's forecasts of future DER growth and underlying demand. This preserved the cross-correlations between DER, utility-scale generation and the weather conditions which drive underlying demand. The Photovoltaics (PV) and battery capacity factors for a modelled hour were the historical capacity factor for that hour in each reference year, while the underlying load profile was based off the profile for that reference year. This produced five, hourly operational load forecasts. We have utilised this approach again in the 2022 Reliability Assessment.

Our approach to forecasting the load profile has five steps:

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[3] The capacity associated with Availability Class 1.

[4] The capacity associated with Availability Class 2.

[5] This includes DPV and distributed battery storage, but for the purposes of this report (in contrast to the WEM ESOO) not EV.

1. **Create the underlying load profile:** The underlying load shape was developed using historical sent out generation data (adding historical DPV) generation to get underlying load) to derive a load shape for each of five historical reference years[6], this is applied to the load chronology implied by the most recently available Capacity Year to create the underlying load profile[7] [8].
2. **Scale the underlying load profile to forecasted values:** Hourly underlying load forecasts for each year in the Long Term PASA Study Horizon were developed by scaling up the underlying load profile for each reference year to match the underlying 50% POE peak demand forecast[9], and the expected annual consumption forecasts for the respective Capacity Year.
3. **Forecast hourly DER contribution:** Using DER data provided by AEMO, we forecasted five series (one for each reference year) of hourly DPV generation and distributed battery charge/discharge over the modelling horizon.
4. **Create the preliminary operational load profiles (chronology and load shape):** The hourly underlying load forecasts and hourly DER contribution forecasts for each reference year were combined and adjusted for losses to create five hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year in each of the five reference years.
5. **Scale the operational load to forecasted values:** To ensure that our hourly operational load forecasts align with the operational peak and annual energy consumption forecasts provided by AEMO, we scaled the five operational load profiles to forecasted peak demand and annual consumption values, producing five final hourly operational load forecasts to be used in the modelling.

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[6] The historical reference years are 2016/17, 2017/18, 2018/19, 2019/20 and 2020/21.

[7] Hence, we would use the load chronology from the 2020-21 Capacity Year to create the underlying reference profile, such that the hour with the largest underlying load in 2020-21 is the hour with the largest underlying load in our forecasts and likewise for the 2nd, 3rd - 8760th hour

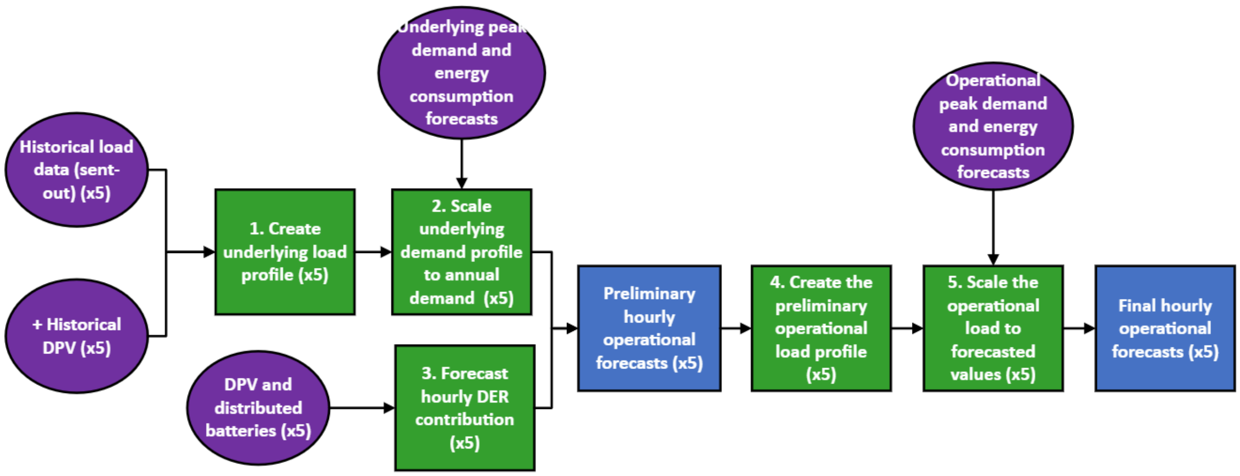
[8] This approach is used for the EUE assessment only. The Availability Class modelling (see Section 2.5) requires an iterative approach which makes the use of multiple reference load shapes problematic. For this reason, the Availability Class modelling uses an average load shape that is derived by averaging the five historical load profiles and the chronology from the most recent Capacity Year (i.e. 2020/21).

[9] The EUE assessment and Availability Class modelling is undertaken assuming 50% POE peak demand and expected annual consumption.

Each of the bullets above are described in more detail in the sections below.

Figure 1 provides an overview of the load forecasting process. Purple circles reference inputs, boxes in green reference each step in the process (described in more detail in Sections 2.3.1 - 2.3.5), while blue boxes refer to outputs.

Figure 1: Overview of the forecasting process



The hourly load forecasts are key inputs into both Phases 2 and 3. Specifically:

- They are used as the hourly load across the modelling horizon for each reference year for the EUE assessment.
- They are also used to derive the two-dimensional duration curve defined in WEM Rule 4.5.10(e), which is developed into the Availability Curves by adjusting further the scaled profiles (in Section 2.3.5) to incorporate the requirements of WEM Rule 4.5.10(e). This is addressed in further detail in Section 2.6.

2.3.1 Creating the underlying load profile

We first develop an underlying load profile by constructing underlying historical load duration curves (LDCs)[10] for each of the last five full Capacity Years (2016-17 to 2020-21), these are used to

[10] A load curve ordered in order of descending demand magnitude.

construct a load shape and chronology for each reference year[11]. As the historical total sent-out generation from AEMO reflects operational consumption and excludes demand met by DPV generation, we have added historical DPV generation[12] from each reference year (provided by AEMO) to the historical operational load data[13] before conducting the above analysis.

2.3.2 Scaling the underlying load profile to forecasted values

The next step in our load forecasting methodology involves scaling the reference underlying load profiles for each reference year to match the underlying 50% peak forecast and annual energy consumption forecast in any given modelled year.

For each scenario, each year of the Long Term PASA forecast horizon and each reference year we produce a forecast underlying load profile with a shape such that:

- The peak of the load profile equals the underlying 50% POE forecast.
- The load allocated across all hours sums to the expected underlying annual energy consumption forecast.
- The shape of the profile is "close" to the reference year underlying load profile developed above.

We define a function F(h) (h ∈ hours of the year) to achieve this, such that the shape of underlying profile for a given year t ($\widehat{PROF}(h)$) can be derived by multiplying the average load shape ($\overline{PROF}(h)$) by this function. That is:

- $\widehat{PROF}(h) = F(h) \times \overline{PROF}(h)$ such that:
  - $Max\left(\widehat{PROF}(h)\right)$ = 50% or 10% underlying POE peak forecast in year t and
  - $\sum_{h=1}^{8760} \widehat{PROF}(h) =$ underlying expected (or high) energy consumption forecast in year t.

The function is defined to ensure that the shape of the profile varies with differing peak/energy ratios in a way that is consistent with the historical load shapes of the last five years. F(h) is defined as follows:

[11] See footnote 8. This approach is used for the EUE assessment, while the Availability Class modelling uses an average load shape based on LDCs from the last five Capacity Years.

[12] DPV generation will cause total sent generation to be lower than underlying demand.

[13] This is based on the Total Sent Out Generation data provided by AEMO.

$$F(h) = \begin{cases} \dfrac{p-z}{m^2}(m-h)^2 + z \; if \; h \le m \\ \dfrac{e-z}{(n-m)^2}(h-m)^2 + z \; if \; h > m. \end{cases}$$

Where:

- p denotes the ratio of the underlying peak forecast to the underlying peak demand in that reference year
- e denotes the ratio of the underlying expected (or high) energy consumption forecast to the underlying hourly energy consumption
- m denotes the position in the profile in which the curve flattens
- n denotes the total number of hours in a year and
- z represents a curvature constant that is adjusted to achieve the expected (or high) demand forecast in the profile's resulting load shape.

Applying this function to the each of the five underlying load profiles gives us five hourly underlying demand forecasts across the modelling horizon.

2.3.3 Forecasting hourly DER contribution:

Our DER forecasts consist of the following data:

- DPV generation
- Distributed battery charge and discharge

Each component has a separate methodology which is discussed below. These methodologies produce hourly forecasts which are aggregated together to produce an hourly DER contribution for each Capacity Year over the modelling horizon. Note that as EVs are already included in the underlying demand forecasts from AEMO, we do not model these separately.

DPV generation

For each of the five reference years, we apply the hourly (hour of the year) DPV capacity factor for each of the historical reference years to each given hour within a modelled year. This is multiplied by the yearly/monthly DPV forecasts provided by AEMO to get an hourly DPV generation sequence across the modelling horizon for each reference year.

Distributed battery storage

Distributed battery storage includes installations in domestic and commercial properties, but does not include grid-connected storage facilities.

For distributed battery storage, we apply the same approach as for DPV generation, applying the historical hourly net charge profile in each reference year to each year over the modelling horizon and multiplying these by the capacity forecasts provided by AEMO.

2.3.4 Creating the preliminary operational load profile

To create the preliminary operational load profile, we first aggregate our hourly underlying load forecasts with our hourly DER contribution forecasts for each reference year to create hourly delivered (loss adjusted) load forecasts, as follows:

$$DL_{h(y),r} = UL_{h(y)} - DER_{h(y),r}$$

Where:

- $DL_{h(y),r}$ refers to the (loss adjusted) delivered load (or demand) in hour h of the year y (h(y)) for reference year r,
- $UL_{h(y)}$ refers to the (loss adjusted) underlying load (or demand) forecast in h(y) and
- $DER_{h(y),r}$ refers to the (loss adjusted) hourly DER contribution in h(y) for r.

To convert the delivered load into operational load (or demand) that is non-loss adjusted, we loss-adjust the delivered loads by a weighted loss factor to include network losses. The weighted loss factor is calculated from a residential loss factor and a business loss factor provided by AEMO, and the relative proportion of forecasted underlying residential to business annual energy consumption, such that:

$$OL_{h(y),r} = DL_{h(y),r} \times \left(\left(LF^{RES} \times \frac{L^{RES}}{L^{RES} + L^{BUS}} \right) + \left(LF^{RES} \times \frac{L^{BUS}}{L^{RES} + L^{BUS}} \right) \right)$$

Where:

- $OL_{h(y),r}$ refers to the (non-loss adjusted) operational load in h(y) for reference year r,
- LF^{RES},LF^{RES}refer to the residential and business loss factors (respectively), and
- L^{RES},L^{BUS} refer to total forecast underlying residential and business load for a given Capacity Year.

These preliminary operational load hourly forecasts are then aggregated into the operational load profile for each Capacity Year and reference year by:

1. Converting the load values into a load shape by expressing each load value as a percentage of maximum demand, ranking these in descending order (largest to smallest)
2. Indexing the load shape by its associated date in the hourly forecasts to create a load chronology.

This gives us a preliminary operational load profile for each forecast Capacity Year, for each reference year.

2.3.5 Scaling the operational load profile to forecasted values

Given that the peak forecasts provided by AEMO set the RCT and consequently forms the basis of the Reliability Assessment, it is important that the peaks we use for our modelling match those provided by AEMO. To ensure this, we re-scale the five operational load profiles created in Section 2.3.4 using the function described in Section 2.3.2. This gives us five hourly load forecasts (one for each reference year) that capture year-on-year variation in load shape and chronology, while maintaining alignment with the 50% POE operational peak demand and expected annual operational consumption forecasts provided by AEMO.

2.4 PHASE 2: EUE ASSESSMENT

We use our bespoke model, CAPSIM[14] to conduct the EUE assessment. CAPSIM simulates the capacity gap (a simple arithmetic calculation subtracting load from available generation capacity) for every hour[15] of every year, sequentially, given a specific generation mix, load profile, planned outage schedule and random forced outages. This assessment is conducted for the five reference years with intermittent profiles and DER forecasts varying by reference year. Both GIA constraints (in the 2022-23 Capacity Year) and a full set of network constraints (from the 2023-24 Capacity Year onwards) is modelled.

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[14] CAPSIM is developed in Python, utilising the open-source packages Pandas and NumPy for tabular processing and vectorised operations.

[15] Note that CAPSIM does not consider intra-hour demand variability as very short-term fluctuations in demand will be covered by the dispatch of Ancillary Services.

The purpose of this phase is to assess the amount of Reserve Capacity required to limit expected energy shortfalls to the Planning Criterion set by WEM Rule 4.5.9(b) (0.002% of annual energy), in doing this we follow the subsequent steps:

1. For each year of the Long Term PASA Study Horizon, we assume Reserve Capacity (generating and storage capacity and DSM) equals the forecast peak quantity plus the reserve margin, Intermittent Load (IML) allowance and Load Following Ancillary Services (LFAS) quantity determined by WEM Rule 4.5.9(a).
2. For each of the five reference years, using the associated hourly load forecast (see Section 2.3) intermittent generation profile (see Section 2.4.4) and randomised forced outages (see Section 2.4.6); and using assumptions (common to all reference years) around Electric Storage Resources (see 2.4.3), and planned outages (see Section 2.4.5), we simulate the capacity gap (the difference between available capacity and load) in CAPSIM. Each iteration yields an estimate of unserved energy.
3. We then use N=50 iterations and R=5 reference years above to estimate Expected Unserved Energy (EUE) for each modelled year as follows:

$$\mathrm{EUE(y)} = \frac{1}{R}\frac{1}{N}\sum_{r=1}^{R}\sum_{n=1}^{N}\sum_{h=1}^{H}\mathrm{Unserved\ Energy\ (r,n,h)}$$

- EUE(y) is the EUE in year y, where y is one of ten Capacity Years in the Long Term PASA horizon
- UnservedEnergy(r,n,h) is the unserved energy in hour h of Capacity Year y as simulated under iteration n of Reference Year r.

4. We then divide EUE(y) by forecast annual energy consumption in year y to express EUE as a percentage.
5. If the percentage in Step 4 is less than or equal to 0.002% then we stop; the RCT will be set by the first component of the Planning Criterion (WEM Rule 4.5.9(a)).
6. If the percentage is greater than 0.002%, then:
   a. We incrementally increase the Reserve Capacity (over and above the forecast peak quantity determined by WEM Rule 4.5.9(a)) and
   b. Repeat steps 1 to 6 until the percentage in Step 4 is less than or equal to 0.002%.

CAPSIM is be run over 50 forced outage iterations for each of the five reference years (250 iterations in total) to generate a probability distribution of unserved energy and to estimate EUE over the modelling horizon.

The EUE assessment has been undertaken assuming a 50% POE demand peak under an expected demand growth scenario.

The above steps are a high-level summary of our modelling methodology for the EUE assessment. In the remainder of this section, we provide a more detailed description of the modelling. Specifically, the following sections outline how Steps 2 and 3 have been implemented in practice.

The rest of this section is structured as follows:

- We first provide an overview of CAPSIM in Section 2.4.1
- We then give an overview of our new approach to modelling network constraints (including both the GIA and full network constraints) in Section 2.4.2
- We then discuss our proposed approach for the treatment of ESR in Section 2.4.3
- We then discuss how intermittent generation is be modelled in CAPSIM in Section 2.4.4
- We then explain our methodology for developing a planned outage schedule in Section 2.4.5
- Finally, we describe our approach to modelling forced outages in Section 2.4.6

2.4.1 Overview of CAPSIM

In 2019, we developed a bespoke model (CAPSIM) in Python to complete the Reliability Assessment. This model compares the total available capacity in each hour across the Long Term PASA modelling horizon and compares it to the corresponding load.

Total available capacity takes into account planned outages, intermittent generation, network constraints and randomly sampled forced outages. Unserved energy occurs whenever load is greater than total available capacity in a period.

CAPSIM is run over multiple iterations with varying random number seeds for forced outages to generate a probability distribution of unserved energy, which is used to estimate EUE.

2.4.2 Application of network constraints

As part of the WEM reforms, Security Constrained Economic Dispatch (SCED) will be introduced from 1 October 2023 under the gazetted WEM Rules. While historically (with the exception of the GIA generators), the SWIS has operated under an unconstrained network access regime, the introduction of SCED means that dispatch in the WEM will explicitly take network constraints into account.

AEMO has requested that we model the full set of network constraints for the 2022 Reliability Assessment from the 2023-24 Capacity Year onwards, in addition to modelling the GIA constraints in the 2022-23 Capacity Year.

For both the GIA and the full network constraints, we have created a constraint optimisation model to take into account the network constraints. This model maximises total available generation subject to the network constraints, the unconstrained available generation from each facility and hourly load to determine what the available constrained generation is for each hour, given the constraints.

Note that the maximisation of total available generation that takes place under our constraint optimisation model will differ from SCED dispatch optimisation. In particular, SCED dispatch will seek to meet load at the lowest total system cost and will explicitly reflect bids from generators. Our optimisation does not seek to minimise cost and is agnostic whether a generator that is backed off is high-cost or low-cost. This is immaterial from the perspective of the Reliability Assessment as which particular generator is backed off does not matter in answering whether there is enough capacity to meet load in each period.

An optimisation of this nature will end up with extremely high solve times if we were to run it for every hour of the year, for each of the 5 x 50 forced outage seeds. To reduce computational intensity, we use a capacity gap threshold to reduce the number of solves (or hours) that will require a constrained optimisation solve. We use this threshold as unserved energy is extremely unlikely when the capacity gap is high (e.g. periods of low load); hence applying constraints is unnecessary for the purposes of simulating unserved energy. The threshold triggers the application of the constrained optimisation model when the capacity gap (available capacity - load) for a period prior to the application of constraints is lower than the threshold. We have used a threshold of 400 MW.

2.4.3 Treatment of Electric Storage Resources

ESRs (whether standalone or part of a hybrid facility) have an obligation to offer in their Reserve Capacity Obligation Quantity (RCOQ) during the Electric Storage Resource Obligation Intervals (ESROIs) of a Trading Day.

The RCOQ for the ESR component of a facility is based on AEMO's reasonable expectation of the Linearly De-rated Capacity that each ESR can sustain over the ESROIs.

AEMO has determined the ESROIs to be 4:30pm-8:30pm in all Trading Intervals for the 2023-24 Capacity Year[16]. We have used AEMO's determination and assume ESROIs to be constant throughout the Long Term PASA modelling horizon.

AEMO determines the Linearly Derated Capacity of an Electric Storage Resource in accordance with the WEM Certification Procedure[17]. AEMO's assessment is based on the relevant Market Participant's declaration of the amount the ESR can send out over the ESROIs and any other information it considers appropriate.

Hence, we calculate the RCOQ for ESRs as the minimum of the MW power rating and the MWh ESR capacity divided by four to reflect the four hours over the ESROIs:

$$\widehat{RCOQ_e}(h) = \begin{cases} min\left[P_e, \frac{S_e}{4}\right] \ \forall\ h \in ESROIs, \\ 0\ otherwise \end{cases}$$

Where:

- $\widehat{RCOQ}_e(h)$ is our approximation of the RCOQ of ESR e in hour h,
- P_e is the MW power rating of ESR e
- S_e is the MWh storage capacity of ESR e.

16 https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2021/2021-esroi-analysis.pdf?la=en

17 https://aemo.com.au/-/media/files/electricity/wem/procedures/certification-of-reserve-capacity-for-the-2022-and-2023-reserve-capacity-cycles.pdf?la=en&hash=780FC17A40B7D0F1BD3DAF2EBA68EA1F

This approximation ensures that a given ESR is providing capacity over the ESROIs but is not infeasibly dispatched above its ability to provide power or energy[18]. It also makes the simplifying assumption that ESRs will not be available in non-ESROIs.

We do not model ESR charging as we have assumed that ESR charging will not take place in any period where there is a risk of unserved energy; as such charging should have no impact on unserved energy or Availability Class 1 capacity.

The simplified assumptions will be sufficient to ensure that we capture the material impacts of ESRs on the EUE assessment, without introducing excessive complexity or increasing model run-time. These assumptions will need to be revisited in future years as larger quantities of ESR enter the WEM.

For hybrid facilities (facilities with both an intermittent resource and an ESR), we model the intermittent generator and ESR as two separate facilities.

2.4.4 Treatment of intermittent generation

We developed intra-day hourly profiles for each of the five reference years (Capacity Years 2016-17 to 2020-21). Our process is as follows:

- For each reference year, for each month (Jan, Feb, ..., Nov, Dec), we assign an intra-day hourly profile to each Intermittent Generating System.
- This means each Intermittent Generating System has 5 x 12 intra-day hourly profiles (one for each month of the year for each of the five reference years).
- Hence, $\overline{Gen_{r,h,m}} = \left(\frac{\sum_{d\ (days) \in Month\ m} Gen_{r,h,d}}{\#\ days\ in\ month\ m\ of\ \mathrm{ref}\ year\ r}\right)$
- For a given Intermittent Generating System:
- $\overline{Gen_{r,h,m}}$ denotes the average generation (MWh) in hour h of month m of reference year r.
- $Gen_{r,h,d}$ denotes the historical or estimated generation value (see below) in hour h of day d (in month m) of reference year r.

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[18] As an example of how this would work in practice, consider a 5 MW/18 MWh ESR. In this case, the ESR would have an available capacity of $\min(5, \frac{18}{4})$ i.e. 4.5 MW from 4pm to 8pm each day and 0 MW outside of this time. If this ESR instead had a power rating of 3 MW (while maintaining the same storage capacity), then the power rating would set the RCOQ and the ESR's available capacity during the ESROIs would be 3 MW.

Note that the $\overline{Gen_{r,h,m}}$ value for a given Intermittent Generating System is scaled to reflect the ratio of the RCT to total Capacity Credits in each modelled year.

2.4.5 Planned outages

For planned outage scheduling, we use Market Participant provided scheduled outage dates[19] as a starting point but then evaluate these outages to ensure that the planning margin contemplated under WEM Rule 3.18.11 would be met if all proposed planned outages were allowed to proceed[20].

We compare the weekly peak load forecasts derived from the final operational hourly load forecast (for each reference year) described in Section 2.2 to the Medium Term PASA second deviation weekly peak load forecasts (which is used by System Management to approve outages), where the horizons for these two forecasts overlap. This allows us to develop scaling factors reflecting the average difference between the Long Term PASA and Medium Term PASA forecasts, by year and season.

We then scale up our weekly peak load forecasts as follows:

- For Capacity Years that match up with the Medium Term PASA horizon (2022-23, 2023-24 and early 2024-25), we scale the hourly operational load forecasts created in Section 2.3.5 using the seasonal and annual scaling factors described above.
- For Capacity Years outside of the Medium Term PASA horizon (late 2024-25 onwards) we use the scaling factors derived for the latest season for which Medium Term PASA forecasts are available (i.e., Q3, Q4: 2023-24, and Q1, Q2: 2024-25).

The purpose of this scaling is to ensure that we use a weekly peak load forecast for planned outage scheduling that is sufficiently conservative. As our load forecasting process focuses on correctly determining peak demand over the entire year, weekly peaks in our load forecasts (and in particular, during weeks with lower demands) tend to be slightly lower than that in the Medium Term PASA.

The planned outage scheduling is conducted as follows (for each reference year):

1. Subtract the weekly peak load (as derived above) from available generation to calculate a capacity margin reflecting the amount of generation available above needed levels.

[19] This information was collected by AEMO through the information request process in accordance with WEM Rule 4.5.3.

[20] This approach is not designed to exactly replicate the process AEMO uses to approve planned outages under WEM Rule 3.18.11; instead it is intended to remove concurrent planned outages which would not be allowed under real operating conditions.

2. If the capacity margin is greater than the planning margin, then we have used the Market Participant provided planned outage inputs.
3. If the capacity margin is less than the planning margin, we have moved the Market Participant provided planned outage inputs to meet the outage evaluation criteria, while ensuring that the timing of the outage request is similar to what the Market Participant has requested..

Following previous years, we do not model opportunistic maintenance. This is because opportunistic maintenances are subject to AEMO's evaluation process, whereby an outage will not be approved if it violates the requirements in Section 3.18 of the WEM Rules. Furthermore, no planned outage would proceed in a period with a tight margin and a non-trivial risk of unserved energy.

2.4.6 Forced outages

Forced outages are randomised by:

- Determining a forced outage probability for each generator.
- Randomly assigning plant outages in a sampled hour based on the specified probability for a given iteration.

CAPSIM generates 50 sequences of forced outages for each generator, for each of the five reference years (250 in total) across the modelling horizon.

Forced outage assumptions were developed by analysing the 36-month historical FOR for each plant (from the most recent 36 months) and are presented in Section A.3.2.

We also developed a mean time to repair (MTR) value which denotes the amount of time a plant will be offline following a forced outage event. This value is derived by examining the historical downtime (from the most recent 36 Months) of all facilities (both intermittent and scheduled generation), following a forced outage. Outages are classified into outage "events" by identifying sequential outage periods from the same facility. The mean duration of all outage events for a facility is the raw MTR. After this calculation is completed, plants are classified into short (12 hours), medium (24 hours), and long (144 hours) duration outage plants based on their raw MTR[21]. For new

[21] Briefly, where the raw MTR of a facility is ≥12, the final MTR will be 12; where the raw MTR is > 12 and ≤ 96, the final MTR will be 24; and where the raw MTR is >96 the final MTR will be 144. This ensures that only plants that consistently go on long duration outages are classified as long duration plants.

plants or plants which have no historical outages we have assumed forced outage rates and mean times to repair will be similar to current plants of a similar technology.

2.5 Phase 3: Availability Class requirements

Having determined the RCTs for each year, the next phase involves assessing how much capacity is required for the two Availability Classes defined in the WEM Rules to satisfy the targets for the second and third Capacity Years of the Long Term PASA Study Horizon as set out in WEM Rule 4.5.12. The modelling for the Availability Class Requirements does not use the five reference year approach from the EUE assessment (Section 2.4). Instead we use the average intermittent profile across the five reference years and the load forecasting process in Section 2.3[22]..

In this section, we outline the methodology used to determine the Availability Class requirements (WEM Rule 4.5.12(b) and 4.5.12(c))

2.5.1 Determine WEM Rule 4.5.12(b)

WEM Rule 4.5.12(b) requires the determination of the minimum generation capacity requirement:

For the second and third Capacity Years of the Long Term PASA Study Horizon, AEMO must determine the following information:

> *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
>
> 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

[22] We also use the hourly (hour of the year) average DPV and battery capacity factors (again, across the five reference years) to create one 'average' load forecast

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;

We calculate the minimum generation requirement by simulating unserved energy (for the second and third years of the Long Term PASA Study Horizon) as described in Section 2.4 with the following differences:

1. The load forecast is created using the average historical hour-of-the-yearly DPV and battery capacity factors and an average load profile to create one 'average' load forecast for use in the modelling.
2. We use the average intermittent profile (of each Intermittent Generating System) across the five reference years
3. ESR dispatch in ESROIs (based on its RCOQ, see Section 2.4.3) is deducted off the forecast load duration curve (as created in Step 1).
4. DSM is modelled in greater detail to take into account the constraints around the availability of DSM providers.[23] In short, we allocate DSM throughout the year using an optimisation model that dispatches DSM to minimise the peak subject to scheduling and availability constraints. See below for further details on our approach to modelling DSM. DSM dispatch (as modelled above) is deducted off the ESR-adjusted forecast load duration curve in Step 3. This represents the net level of load that Availability Class 1 capacity will need to meet.
5. We specify a planning margin in the market model that represent the Ancillary Services requirement and Ready Reserve Standard contemplated in WEM Rule 3.18.11.
6. Forced outages are taken out of the model. The reason for the removal of forced outages is that the specification of a planning margin on top of forced outages effectively over-estimates the capacity margin. The purpose of the Ancillary Services Requirement and Ready Reserve Standard is to cover unforeseen events such as forced outages. As such, if there

[23] Availability constraints for DSM are not modelled in the EUE assessment as it is assumed that DSM will be dispatched in any 'last resort' situation, i.e. when there is risk of EUE.

were a forced outage in a given period, the operating reserve would be used to generate to prevent unserved energy. Hence, including forced outages and maintaining the Ancillary Services Requirement and Ready Reserve Standard would lead to the overestimation of EUE in a modelled Capacity Year.

7. Finally, for each year of the relevant Reserve Capacity Cycle, we iterate the model to reallocate the amount of DSM, ESR, and generating capacity (reducing the generating capacity as DSM increases, keeping the total capacity capped at the RCT level) until the EUE requirement in WEM Rule 4.5.9(b) is violated.

The level of generation capacity at which the EUE equals 0.002% of expected demand then sets the minimum generation capacity.

DSM Modelling Methodology

DSM in the WEM is subject to availability constraints.[24] We have forecasted hourly DSM dispatch by allocating available DSM throughout the year based on an optimisation model that takes into account these constraints. Our approach is detailed further below:

1. We forecast sequential hourly load for the year using the methodology described in Section 2.3, applying the average historical DER profile across the five reference years to create one 'average' load forecast for use in the modelling.
2. We then deduct ESR dispatch in ESROIs (based on its RCOQ, see Section 2.4.3) off the load forecasts in Step 1 to reflect the impact of ESR dispatch on load.
3. We use a spreadsheet-based optimisation model which, given the forecasted hourly load, dispatches DSM Facilities for each year to minimise the forecasted peak demand subject to the DSM's availability and dispatch constraints. The model performs the dispatch using a heuristic allocation method, iteratively dispatching the DSM quantities to minimise the peak load, across all periods, each iteration is tested against the dispatch constraints, with each iteration moving towards the optimal[25] dispatch with the lowest overall peak load.

[24] As specified in WEM Rules 4.10.1(f).

[25] It should be noted that the nature of the problem of optimally allocating DSM is such that it would be computationally infeasible to guarantee that the result is the absolute optimum dispatch of DSM. The heuristic used produces a dispatch that is close to optimal. We consider this to be acceptable, as the real-world dispatch of DSM is unlikely to be optimal either.

4. Finally, we adjust the load profile used in the market modelling by subtracting the forecasted DSM dispatch in the relevant hours from the ESR adjusted load forecast (see Step 2). This adjusted load profile represents the "effective demand" and is used in the modelling of the minimum generation capacity contemplated by WEM Rule 4.5.12(b).

2.5.2 Determine WEM Rule 4.5.12(c)

WEM Rule 4.5.12(c) requires determining the capacity associated with Availability Class 2:

For the second and third Capacity Years of the Long Term PASA Study Horizon, AEMO must determine the following information:

> *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).*

This is a straightforward calculation that is computed by:

1. Subtracting the minimum generation capacity, calculated above (see Section 2.5.1) from;
2. The RCT for the relevant Capacity Year

2.6 Phase 4: Availability Curves

WEM Rule 4.5.10(e) requires AEMO to develop a two-dimensional duration curve of the forecast minimum capacity requirements over the Capacity Year ("Availability Curve") for each of the second and third Capacity Years of the Long Term PASA Study Horizon. This provides a breakdown of the forecast capacity requirement by Trading Interval and shows the relationship between the RCT and how much capacity is required in other Trading Intervals.

In this section, we outline the methodology we use to determine the two Availability Curves (WEM Rule 4.5.10(e)).

2.6.1 Determine WEM Rule 4.5.10(e)

WEM Rule 4.5.10(e) requires AEMO to:

…develop a two-dimensional duration curve of the forecast minimum capacity requirements over the Capacity Year ("Availability Curve") for each of the second and third Capacity Years of the Long Term PASA Study Horizon. The forecast minimum capacity requirement for each Trading Interval in the Capacity Year must be determined as the sum of:

i. *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); and*

ii. *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.*

Our interpretation of WEM Rule 4.5.10(e)(i) and the load scenario contemplated in WEM Rule 4.5.10(a)(iv) in deriving the LDC above was undertaken in consultation with AEMO in previous years. Particularly, the approach above is predicated on the assumption that the difference between a 50% POE peak year and a 10% POE peak year (assuming expected demand growth scenario) would only manifest itself in the first 24 hours (i.e. the peakiest part of the LDC). Hence, we model the forecast capacity requirement as a combination of the 50% POE peak LDC and 10% POE peak LDC.

Our approach to determining this quantity is summarised below.

1. We use the operational peak demand and expected annual operational consumption forecasts (from AEMO) to forecast the LDC for a given year as specified in WEM Rule 4.5.10(e)(i). To do this:
    a. We estimate the forecast load in the first 24 hours assuming a 10% POE peak forecast under the expected demand growth scenario (i.e. the load scenario contemplated in WEM Rule 4.5.10(a)(iv)). This has been done using the average operational load profile developed for the Availability Class Requirement modelling (Section 2.5), we have applied this profile up to the 10% POE operational peak forecasts provided by AEMO using the same process described in Section 2.3.5.
    b. We then estimate the forecast load for the remaining hours (hours 25-8,760) assuming a 50% POE peak forecast under the expected demand growth scenario (i.e. the load forecasts created for the Availability Class Requirement in Section 2.5).
    c. We then use a smoothing function[26] to smooth out the LDC in the first 72 hours.
    d. We then convert the hourly LDC created above to Trading Intervals (as required by WEM Rule 4.5.10(e)) by assuming that the MW demand in any given half-hourly Trading

[26] We use a quadratic approximation to smooth the LDC.

Interval is the same as the associated hour, i.e. if the demand was 4000 MW for 8:00 A.M on 1/10/2022 it would also be 4000 MW for 8:30 A.M.

2. We add the reserve margin, IML allowance and LFAS component of the WEM Rule 4.5.9(a) calculation (as provided by AEMO) on top of the above LDC as required by WEM Rule 4.5.10(e)(ii).

3 Results

3.1 EUE Assessment

The EUE assessment indicates that for all Capacity Years of the Long Term PASA Study Horizon (2022-23 to 2031-32 Capacity Years) the RCT has been set by the forecast peak quantity determined by WEM Rule 4.5.9(a).

Table 8 summarises the results of the reliability assessment. Here we see that the peak forecast component is sufficient to limit expected energy shortfalls to 0.002% of annual energy consumption in all Capacity Years. Furthermore, the absolute value of EUE is well short of the reliability threshold specified in WEM Rule 4.5.9(b). The EUE estimates from the previous year's modelling are included for comparison.

Table 1: Base Scenario EUE Summary

Capacity Year	RCT (MW) [a]	50% POE peak forecast (MW)	Expected Annual energy consumption (MWh)	0.002% of Expected annual energy consumption (MWh)	EUE - 2022 WEM ESOO (MWh)	EUE as % of expected annual energy consumption	EUE – 2021 WEM ESOO (MWh)
2022-23	4490.00	3780.5	16,545,290.00	347.4098	4.62	0.0000280%	3.61
2023-24	4503.00	3790.16	16,205,860.00	343.381	0.0000	0.0000000%	0.87
2024-25	4525.59	3821.47	15,892,830.00	339.2624	1.4175	0.0000089%	7.97
2025-26	4554.11	3855.1	15,758,820.00	336.623	0.1518	0.0000010%	1.89
2026-27	4605.28	3899.12	15,762,650.00	334.1336	1.7989	0.0000114%	9.45
2027-28	4641.84	3934.46	15,681,750.00	332.12	0.8568	0.0000055%	3.65
2028-29	4675.31	3967.2	15,615,460.00	329.4702	0.2977	0.0000019%	9.06
2029-30	4723.09	4018.19	15,680,140.00	327.8926	0.8758	0.0000056%	39.12
2030-31	4770.16	4075.04	15,871,200.00	329.0408	2.1156	0.0000133%	4.57
2031-32	4837.07	4141.35	16,151,240.00	334.1518	0.7080	0.0000044%	

Overall, the EUE estimated for the 2022 Long Term PASA assessment is roughly similar to levels estimated for the 2021 Long Term PASA assessment with most of the differences explained by variations in forced outages and curtailment patterns. The only sizeable difference in EUE is a reduction in the 2029-30 Capacity Year. In this case EUE has reduced from 39.12 MWh (2021 Long Term PASA) to 0.8758 MWh (2022 Long Term PASA). The high level of EUE in the 2021 Long Term PASA was caused by the interaction of Planned Outages and high winter loads for these reference years, leading to lower capacity margins. In this year's analysis, the level of Planned Outages is lower in 2029-30 leading to less unserved energy.

Table 2 and Table 3 respectively break down the level of EUE (MWh) by month and hour, and by Capacity Year and load shape reference year.

Table 2: Hourly/Monthly Contribution to total EUE (MWh)

Month/Hour	17:00	18:00	19:00
January	0.00	0.01	0.00
February	0.00	1.73	0.38
March	0.67	2.90	1.24
April	0.00	0.00	0.00
May	0.00	0.00	0.00
June	0.36	2.42	0.00
July	0.00	1.27	0.00
August	0.00	0.74	0.00
September	0.00	0.53	0.25
October	0.00	0.13	0.00
November	0.00	0.00	0.00
December	0.00	0.12	0.00
Total	1.03	9.86	1.87

Table 3: Capacity Year-Scenario Contribution to total EUE (MWh)

Capacity Year/Scenario Year	2016-17	2017-18	2018-19	2019-20	2020-21	Total
2022-23	0.39	4.14	0.10	0.00	0.00	4.62
2023-24	0.00	0.00	0.00	0.00	0.00	0.00

Capacity Year/Scenario Year	2016-17	2017-18	2018-19	2019-20	2020-21	Total
2024-25	0.20	0.00	0.71	0.51	0.00	1.42
2025-26	0.04	0.00	0.11	0.00	0.00	0.15
2026-27	0.31	0.08	1.24	0.00	0.17	1.80
2027-28	0.00	0.00	0.84	0.00	0.01	0.86
2028-29	0.00	0.00	0.30	0.00	0.00	0.30
2029-30	0.72	0.00	0.04	0.11	0.00	0.88
2030-31	0.00	0.00	2.04	0.07	0.00	2.12
2031-32	0.27	0.00	0.44	0.00	0.00	0.71
Total	2.45	4.00	5.82	0.69	0.19	12.85

As expected, unserved energy occurs exclusively in peak periods from 5 pm to 8:00 pm, with most of the unserved energy occurring between 6 pm and 7 pm. The seasonal distribution indicates that unserved energy occurs in almost all months except April, May and November with very small amounts of unserved energy occurring in January, October and December. This shift from unserved energy occurring in summer afternoons to evenings throughout the year is expected given the increasing penetration of DER shifting the operational peak to the evening. This is resulting in the winter peak growing faster than the summer peak, with potential unserved energy occurring in both summer and winter. This pattern is very similar to the 2021 Long Term PASA assessment where we noted unserved energy occurring primarily between 6 pm and 9 pm in all months except April, May, October and November (with very small amounts of unserved energy in January and December).

Unserved energy usually occurs in periods where planned outages almost, yet don't quite violate the planning margin (contemplated under WEM Rule 3.18.11) as part of the outage scheduling process (see Section 2.4.5). As the winter/shoulder season months have the most planned outages, they are the most likely candidates for unserved energy when combined with forced outages.

Table 4 summarises the extent to which binding network constraints contribute to unserved energy. The MWh value of unserved energy occurring due to binding constraints is shown outside of parentheses, while unserved energy caused by network curtailment as a percentage of total unserved energy is shown in parentheses. For example, we note that in 2022-23 the EUE in the 2017 reference year was 4.14 MWh (see Table 3). Of that, 3.729 MWh or 90% (see Table 4) of EUE occurred as a result of binding network constraints and the remainder due to forced outages.

The contribution of binding constraints on EUE ranges from 7% to 100%. The facilities constrained the most are Yandin and Warradarge. All other facilities are constrained little or not at all in periods with unserved energy.

Table 4: Contribution of binding network constraints to EUE by Long Term PASA year and load shape reference year

Capacity Year/Reference Year	2016-17	2017-18	2018-19	2019-20	2020-21
2022-23	0.277 (72%)	3.729 (90%)	0.098 (100%)	0 (0%)	0 (0%)
2023-24	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
2024-25	0.2 (100%)	0 (0%)	0.243 (34%)	0.507 (100%)	0 (0%)
2025-26	0.044 (100%)	0 (0%)	0.008 (7%)	0 (0%)	0 (0%)
2026-27	0.091 (30%)	0.078 (100%)	0.832 (67%)	0 (0%)	0.14 (81%)
2027-28	0 (0%)	0 (0%)	0.467 (55%)	0 (0%)	0.013 (100%)
2028-29	0.001 (100%)	0 (0%)	0.297 (100%)	0 (0%)	0 (0%)
2029-30	0.252 (35%)	0 (0%)	0.044 (100%)	0.111 (100%)	0 (0%)
2030-31	0 (0%)	0 (0%)	1.731 (85%)	0.075 (100%)	0 (0%)
2031-32	1.348 (100%)	0 (0%)	2.192 (100%)	0 (0%)	0 (0%)

3.2 Availability Class Requirements

Table 5: Availability Class requirements (2023-24 and 2024-25)

	2023-24	2024-25
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1		
Minimum capacity	3566	3,890.59
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2		
ESR + DSM	937	635

Table 6: Comparing 2022 Availability Class requirements to 2021 (2021 results in parentheses)

2023-2024	
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	
Minimum capacity	3566 (3496)
RCT	
RCT	4503.00 (4396)
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	
ESR + DSM	937 (900)

In 2023-24, the minimum capacity that can be provided by AC2 capacity has increased by 37 MW compared to last year's results. This small increase is the result of an EUE reduction from 0.87 MWh to 0 MW between reliability assessments.

In 2024-25, the AC2 capacity decreases by 302 MW (relative to 2023-24) to 635 MW due to higher forecast EUE compared to 2023-23, which is largely driven by the retirement of MUJA_G6. The retirement reduces the total amount of controllable (i.e. non-intermittent or ESR) generation capacity available by 4.4%, and results in a corresponding increase in intermittent generation whose output will vary depending on weather conditions (and therefore varies depending on the reference year). The increased share of intermittent generation combined with planned outages and curtailment of North Country windfarms result in higher levels of unserved energy.

3.3 Availability Curves

The Availability Curves (WEM Rule 4.5.10(e)) are illustrated in Figure 2 and Figure 3.

Figure 2: Availability Curve (2023-24 Capacity Year)

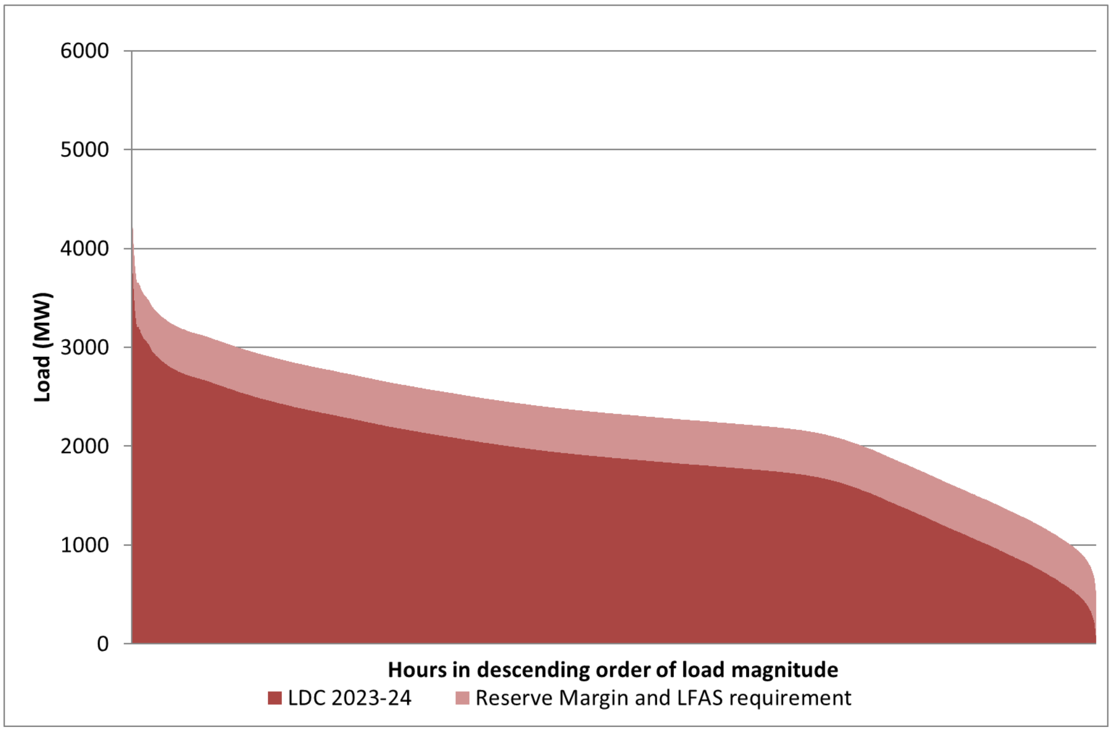
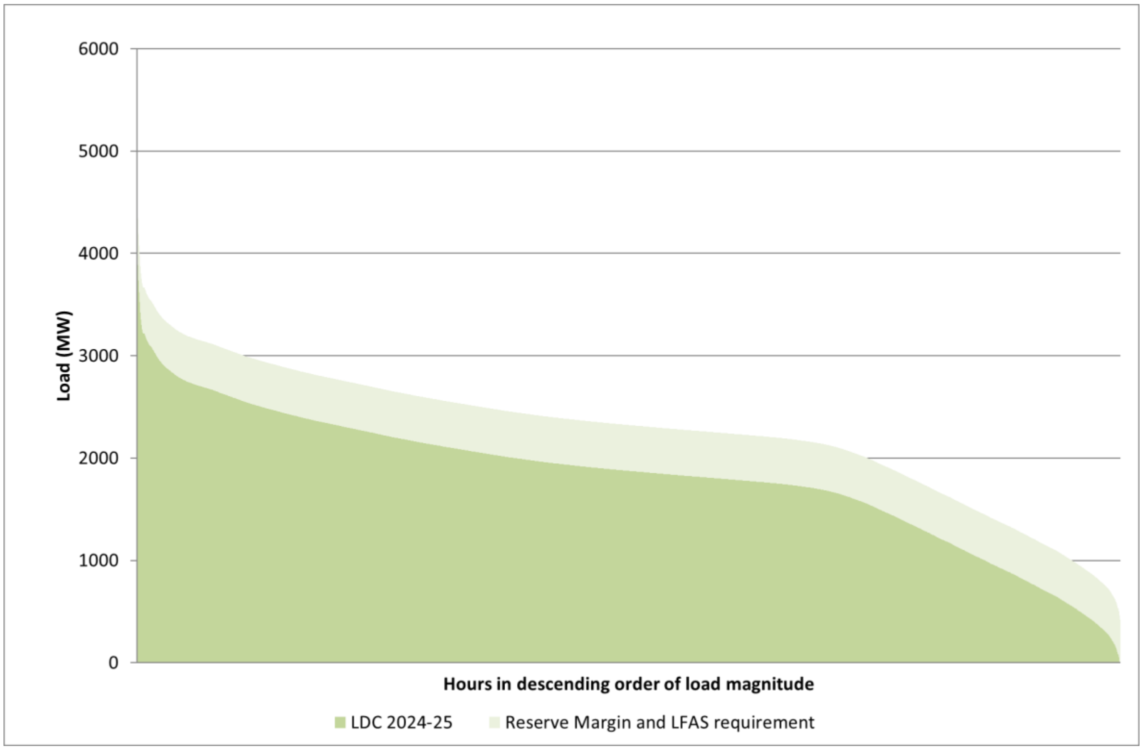


Figure 3: Availability Curve (2024-25 Capacity Year)



Appendix A MODELLING ASSUMPTIONS

A.1 Capacity Credits

The amount of Capacity Credits assumed by facility is summarised in this section.

As noted in Section 2.4, for each year of the Long Term PASA Study Horizon, we assume reserve capacity (generating capacity and DSM) equals the forecast 10% POE peak (operational) quantity plus reserve margin and Load Following Ancillary Services (LFAS) quantity required for Minimum Frequency Keeping Capacity for normal frequency control as specified in WEM Rule 4.5.9(a). To do this we pro-rate the capacity credits (provided by the AEMO and Market Participants) for each technology or component pertaining to a facility so that the total number of Capacity Credits in a given year sum to the forecast peak component given by WEM Rule 4.5.9(a) for that year as follows:

$$\widehat{CC_i} = CC_i{}^{27} \times \frac{10\%\ POE\ peak + Reserve\ Margin + LFAS}{\sum_{j \in all\ facilities} CC_j}$$

A.2 Retirements and new entry

AEMO has provided data on retirements and new entry expected to occur during the Long Term PASA horizon.

- For new entrant that have a commencement date before the beginning of the first capacity year for which they have been assigned capacity credits, RBP models the plant commencing when its capacity obligations begin.
- For retirements, we zero out the capacity of these facilities on the date specified. However, we pro-rate the capacity of remaining units so that the total capacity still equals the Reserve Capacity Target.

[27] For Non-Intermittent Generating System, CC_i denotes the capacity credits the facility is assigned or anticipates to be assigned. For Intermittent Generating Systems, CC_i denotes the resources' average non-zero hourly generation (based on historic or participant provided generation data). We do not use the Relevant Level value for CC_i as this would underestimate the total available annual generation from an intermittent facility (noting that the Relevant Level is a measure of intermittent generator performance in peak load intervals only).

A.3 Outages

A.3.1 Planned outages

Planned outages did not violate the Ready Reserve Standard in our model. Therefore, the planned outages used were the original planned outages provided by AEMO.

A.3.2 Forced outages

Forced outage rate (FOR) assumptions and mean time to repair (MTR) values have been developed by analysing the 36-month historical (FOR) and MTR (from the most recent 36 months). We have used a 36-month average FOR to align with WEM Rule 4.11.1(h) and WEM Rule 4.11.1D, which may affect a facility's capacity credit assignment if their 36-month average forced outage rate exceeds certain thresholds.

We have assumed a FOR of 0.1% for facilities with a zero historical FOR. Assuming a FOR of 0% is unrealistic as equipment is unlikely to have a zero failure rate.

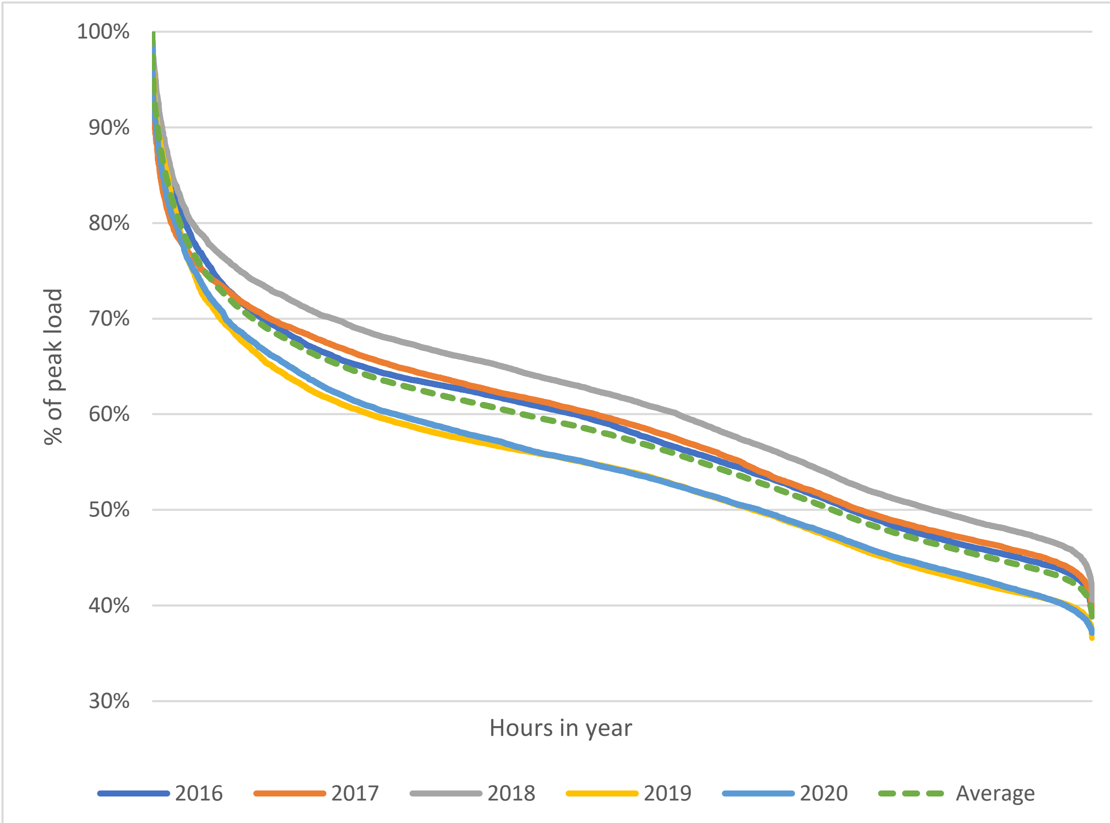
Where average forced outage rates have changed significantly from last year, we have updated our assumptions for this year's modelling. The majority of FOR assumptions remain similar to last year with a few exceptions.

A.4 Demand

We have developed the reference year profile using the *total sent out generation* dataset from AEMO to calculate historical hourly load. Additionally:

- Load curtailments (due to generation shortfall) are also added on to get gross load.
- Historical DPV generation is added to the hourly load

Figure 7: Reference LDC (underlying demand)



A.5 Planning Margin

The minimum generation capacity requirement prescribed by clause 4.5.12(b) of the WEM Rules and used in the planned outage scheduling in Section 2.4.5 is modelled by assuming a planning margin equivalent to applying the Ready Reserve Standard defined in clause 3.18.11A and the Spinning Reserve requirement in clause 3.10.2. As mentioned previously, this margin is calculated as the capacity of the largest generator at a point of time and 70% of the capacity of the second-largest generator, minus the total interruptible load capacity.

The planning margin is for a given year is calculated as:

$$PM = CC_{i \in largestunit} + \left(0.7 \times CC_{i \in 2ndlargestunit}\right) - \sum\nolimits_{i \in IL} CC_i$$

Substituting these values into the formula gives us the following planning margins to be used in the Planned Outage scheduling by Capacity Year(s):

Table 7: Planning Margin

Capacity Year(s)	Planning margin (MW)
2022-22 to 2031-32	524.22

GLOSSARY

Table 5 presents a glossary of the terms used in this document.

Table 5: Glossary

Term	Definition
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 margin	The difference in any period between hourly load and total available capacity
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	Demand is defined as the amount of power consumed at any time. Peak and minimum demand is measured in megawatts (MW) and averaged over a 30-minute period. It is reported on a "sent-out" basis (excluding electricity used by a generator) unless otherwise stated (see below for definition).
Demand Side Management (DSM)	A type of capacity that can reduce its consumption of electricity from the SWIS in response to a dispatch instruction. Usually made up of several customer loads aggregated into one Facility.
Demand side programme (DSP)	A Facility registered in accordance with clause 2.29.5A of the WEM Rules.
Distributed energy resource (DER)	DER includes distributed PV, distributed battery storage, and electric vehicles.Note that for the purposes of the Reliability Assessment, Electric vehicles are excluded from this definition.
Distributed battery storage	Defined as behind the meter battery storage systems installed for residential (less than 10 kW), commercial (between 10 to 100 kW), and large commercial (greater than 100 kW but smaller than 10 MW) that do not hold Capacity Credits in the
Distributed Photovoltaics (DPV)	DPV includes both rooftop PV and PVNSG: • PV: Defined as a system comprising one or more photovoltaic panels, installed on a residential building (less than 15 kilowatts

Term	Definition
	[kW]) or business premises (less than 100 kW) to convert sunlight into electricity. • PVNSG: Defined as non-scheduled photovoltaic generators larger than 100 kW but smaller than 10 MW that do not hold Capacity Credits in the WEM.
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)	A Trading Interval in which an Electric Storage Resource Obligation Quantity for an Electric Storage Resource applies.
Electric Storage Resource Obligation Duration	The eight contiguous Electric Storage Resource Obligation Intervals which apply each Trading Day and commence at the time published by AEMO in accordance with clause 4.11.3A of the Wholesale Electricity Market Rules
Electric Vehicles (EV)	EVs are electric powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
Hybrid facility	Refers to a Facility that comprises two or more heterogenous Facility Technology Types (e.g. a wind farm and Electric Storage Resource located at the same connection point)
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.
Linearly De-rated Capacity	The maximum capacity, in MW, of an Electric Storage Resource that can be guaranteed to be available over the Electric Storage Resource Obligation Duration, being the minimum of: (a) the nameplate capacity; and (b) the maximum Charge Level capability (in MWh) divided by 4 hours, being the maximum sustainable MW capacity, which could be delivered continuously across the Electric Storage Resource Obligation Duration.
Long Term Projected Assessment of System Adequacy (Long Term PASA)	A study conducted in accordance with clause 4.5 of the WEM Rules to determine the Reserve Capacity Target for each year in the Long Term PASA Study Horizon and prepare the WEM ESOO.

Term	Definition
Long Term PASA Study Horizon	The 10 year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
Load chronology	The chronology of a year (periods), ranked by magnitude of load (i.e. 1 is the peak period), sorted into chronological order.
Load shape	Hourly load data for a year (expressed in percentage of peak demand), in descending order of magnitude.
Operational consumption (demand)	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. • Operational consumption includes energy efficiency losses of distributed battery storage operation. • ·Operational demand includes impacts of distributed battery storage discharging (that reduces operational demand) and charging (that increases operational demand). • Peak demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase or reduce operational demand (including storage, coordinated EV charging and demand response). Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained peak operational demand forecasts.
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.
Reference year	A historical Capacity Year, with associated intermittent generation and DER profiles.
Reserve Capacity Cycle	A four-year period covering the cycle of events described in clause 4.1 of the WEM Rules.
Reserve Capacity Obligation Quantity (RCOQ)	The specific amount of capacity required to be provided in a Trading Interval as part of a Reserve Capacity Obligation set by AEMO in accordance with clauses 4.12.4 and 4.12.5 or section 4.28C as adjusted from time to time in accordance with the WEM Rules
Reserve Capacity Price (RCP)	The price for capacity paid to Capacity Credit holders and determined in accordance with clause 4.29.1 of the WEM Rules.

Term	Definition
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
Underlying consumption/demand	The total amount of electricity consumption (demand) by electricity users from their power points (excluding network losses), regardless, if it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation.