Forecast Accuracy Report

January 2024

Review of the 2022 demand, supply and reliability forecasts for the National Electricity Market

Important notice

Purpose

This Forecast Accuracy Report has been prepared consistent with AEMO's Reliability Forecast Guidelines and the AEMO Forecast Accuracy Report Methodology for forecast improvements and accuracy. It is for the purposes of clause 3.13.3A(h) of the National Electricity Rules. It reports on the accuracy of demand and supply forecasts in the 2022 Electricity Statement of Opportunities (ESOO) and its predecessors for the National Electricity Market (NEM).

This publication is generally based on information available to AEMO as at 31 August 2023 unless otherwise indicated.

Disclaimer

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Version control

Version	Release date	Changes
1	05/01/2024	Initial release

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

Each year, AEMO publishes an assessment of forecast accuracy to help inform its Forecast Improvement Plan and build confidence in the forecasts produced. This 2023 *Forecast Accuracy Report* primarily assesses the accuracy of AEMO's 2022 *Electricity Statement of Opportunities* (ESOO)[1] for each region in the National Electricity Market (NEM). The report assesses the accuracy of forecast drivers and models of demand and supply that influenced the reliability assessments for the 2022-23 financial year, in particular the summer.

Given the varying nature of each component and forecast, quantitative metrics are not always feasible. Table 1 summarises the qualitative assessment of forecasting accuracy in this report, using the following indicators:

- (Green) Forecast has performed as expected.
- (Yellow) Inaccuracy observed in forecast is explainable by inputs and assumptions. These inputs should be monitored and incrementally improved where possible, provided the value is commensurate with cost.
- (Red) Inaccuracy observed in forecast needs attention and should be prioritised for improvement.

Table 1 Forecast accuracy summary by region, 2022-23

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Energy consumption	Green	Yellow	Green	Red	Green	Good alignment across most regions except Queensland and Tasmania. Variance in Queensland was mainly driven by unplanned outages in two of the region's largest loads. While variance in Tasmania is partially explained by operational variance from the region's large industrial loads, the forecast model has potential to improve by further breaking down consumption factors.
Summer maximum demand	Green	Green	Green	Red	Green	Good alignment between observed actuals and forecasts across most regions except Tasmania, where actual demand fell significantly under the forecast distribution. Given it is a consistent theme for Tasmania across both summer and winter maximum demand, this will be investigated further.
Winter maximum demand	Green	Yellow	Yellow	Red	Green	Winter maximum demand outcomes in Queensland, South Australia and Tasmania were below the forecast distributions. The winter was exceptionally mild, but some further investigation will be done for Tasmania given the magnitude of the deviation from forecast and it also being an issue at summer.
Annual minimum demand	Yellow	Yellow	Green	Green	Yellow	The actual annual minimum demand outcomes for New South Wales, Queensland and Victoria were just below the forecast distribution. For the first two regions, under-forecast of distributed photovoltaic (PV) installations could be the explanation, though AEMO will continue to review how the initial forecast distribution is set and the assumptions used.
Demand side participation	Yellow	Green	Green	Green	Green	Generally, more demand side participation (DSP) was observed than forecast for higher price bands. Given both summer and winter were mild, prices were generally low at time of peak and minimal price responses were observed. Only New South Wales had a Lack of Reserve (LOR) 2 called on the day but observed DSP was significantly lower than forecast. This was due to non-response by a small number of large DSP providers and should be monitored.
Installed generation capacity	Green	Green	Green	Green	Yellow	New generator installations matched expectations in Tasmania, and were relatively close in New South Wales, South Australia, and Queensland. Project development delays against the dates provided to AEMO by project proponents and higher capacity provided by the participants than actual in Victoria significantly lowered availability compared with what was modelled.
Summer supply availability	Green	Yellow	Green	Green	Green	The mild temperature in 2022-23 summer months resulted in actual availability being mostly within the 2022 ESOO simulated availability range in New South Wales, South Australia, Tasmania, and Victoria. Outages of key coal-fired units during summer months, lower summer availability of gas-fired units, and delayed commissioning of new projects resulted in actual availability being lower than what was modelled for Queensland.

[1] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo/2022-nem-electricity-statement-of-opportunities.

The accuracy of the forecasts is critical to ensure informed decision-making by AEMO – for the Retailer Reliability Obligation (RRO), Reliability and Emergency Reserve Trader (RERT), and *Integrated System Plan* (ISP) – and by industry and governments.

This report highlights good forecasting performance across the areas relevant to AEMO's reliability assessment, with differences in the areas of summer maximum demand and generator availability generally explained by another year of La Niña influence on weather outcomes. The milder La Niña weather meant summer demand generally was lower and therefore there was a reduced need for generators to be available at all times.

A number of potential forecasting improvements have, however, been identified – in particular for the winter maximum demand, annual minimum demand and annual consumption forecasts.

In summary:

- **Annual consumption** was within the forecast target across most of the NEM regions except Queensland and Tasmania. The variance in Queensland was mainly driven by unplanned outages in two of the region's largest loads. The variance in Tasmania is partially explained by the region's large industrial loads (LILs), however, the forecast accuracy has potential to increase by further analysing sectoral trends in consumption, and the sensitivity of models to short term growth trends in actual consumption. More broadly across the NEM, there is also scope to analyse actual electricity consumption and connection data, to identify any trends in electrification. These improvements may enable further analysis of the residual variance in the consumption forecast, and build a better understanding of how different sectors are responding to economic conditions, and decarbonisation opportunities.
- The observed actual **summer and winter demand outcomes** were often in the lower end of the range formed by the 10% probability of exceedance (POE)[2] and 90% POE forecasts, and in some cases below the 90% POE forecast, but this is to be expected, as both summer and winter were mild. For Tasmania, the actual summer and winter maximum demands both fell well below the 90% POE forecast. While this can be partially explained by lower than forecast demand from LILs, it does not fully explain this and the Tasmanian models require further review. The forecast approach for LILs in Tasmania during maximum demand conditions is already being investigated, to allow this to better reflect variability of LILs across the year and the impact it may have on maximum demand.
- For **annual minimum demand**, actual results were observed below the 90% POE forecast in three regions. In two of the regions, under-forecast of rooftop photovoltaic (PV) installations could at least partially explain this. However, since three out of five regions were below 90% POE, AEMO will re-assess its minimum demand models and assumptions to determine if there are more fundamental issues at the root of the under-forecast.
- **Generator commissioning and actual capacity** did not match participant-provided information, resulting in 753 megawatts (MW) less capacity available in 2022-23 than was forecast. AEMO has reviewed the generator commissioning methodology for the treatment of new assets in forecasts in the updated *ESOO and Reliability Forecast Methodology Document*[3]. As the methodology has been implemented in the 2023 ESOO, improvements are expected to be observed in next year's *Forecast Accuracy Report*. AEMO will continue to work with participants to collect more accurate generator capacity to minimize capacity difference between forecast and actual.

[2] The 10% POE forecast should on average only be exceeded one in 10 years.

[3] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en .

- **Planned and unplanned outages** impacted supply availability for numerous regions and technologies, with actual outage rates observed above participant provided projections. AEMO has since published a new methodology for collecting and forecasting random outage parameters in the updated *ESOO and Reliability Forecast Methodology Document*. As the methodology has been implemented in the 2023 ESOO, improvements are expected to be observed in next year's *Forecast Accuracy Report*.
- **Electric vehicle** (EV) numbers have been included in this *Forecast Accuracy Report* for the first time. Although not yet a material driver of energy use and reliability, the expected influence of EVs warrants starting to track and improve forecast performance. Given the fast rate of change of this newly adopted technology, initial forecast error is high, so EV forecasting is addressed in the improvement plan. The energy use associated with EVs is not yet included, as obtaining relevant data is lagging behind sales data.

Forecast Improvement Plan

The improvement plan is an important tool to guide investigation work and improvements in forecasting. It is composed of forecast improvement priorities for 2023 and ongoing research and improvement areas.

The short-term, priority initiatives to be incorporated in the 2024 ESOO are:

- **Improve EV forecast approaches.** AEMO plans to improve EV forecasts by modifying short-term forecast models to more quickly respond to recent sales data, including plug-in-hybrids.
- **Review the sensitivity of short-term annual consumption models**. AEMO considers that the consumption models have performed reasonably well for the NEM overall. For Tasmania, however, the variance that cannot be explained by input drivers is around 4.5% of operational consumption (as generated). A downward revision has already been implemented in the 2023 ESOO forecast for Tasmania, being 7% lower than the 2022 ESOO forecast in 2023-24. While AEMO does not propose any changes to model structure and approach in the near term, AEMO proposes to expand the annual review of recent growth trends for Tasmania in particular. AEMO will continue to investigate the potential for changes to the forecasting approach, based on future reviews, and in consultation with stakeholders, to ensure that short-term consumption models respond effectively to capture these trends.
- **Review large industrial loads**. Improvements to the LIL forecasts were already put in place for the 2023 ESOO, including for both maximum demand and annual consumption models. AEMO will monitor LIL consumption that comprise the largest variances compared to the forecast, including unplanned outages and significant operational variations.
- **Review minimum demand models**. Before the 2023 ESOO, AEMO implemented a revised half-hourly demand forecasting model which demonstrated increased accuracy at time of both minimum and maximum demand. AEMO will undertake further review of its minimum demand forecast models to further establish whether the results lower than 90% POE recorded for minimum demand were related to under-forecast of rooftop PV or some other factor(s).

Apart from the immediate forecast improvement priorities for 2023, AEMO also identifies ongoing forecasting research and improvement initiatives to continuously improve its forecast accuracy. These include:

- **Understand changes in future load shape from technology uptake and usage**. AEMO will assess data from Project Edge and Project Symphony to support insights into future load shapes, and will continue to collaborate with industry participants, researchers and government in researching the uptake and operation of EVs and battery storage.

- **Track electrification trends.** AEMO will investigate whether fuel switching trends from natural gas to electricity are observable in actual consumption and connection data, with the aim to better understand the impacts on energy consumption forecasting.
- **Improve representation of weather by modelling additional weather years.** The growth in new generation capacity driven by new large-scale wind and solar projects, along with the projected decommissioning of dispatchable thermal generators, increases the importance of weather when assessing future reliability outcomes. For the 2022 ESOO, AEMO used 12 reference weather years to assess the impacts of different weather patterns on reliability. For increasing shares of variable renewable generation, this may be insufficient to identify high risk periods of coincident low availability of renewable generation, and AEMO plans for more weather reference years to be available for the 2024 ESOO.
- **Improve visibility of sectoral consumption.** To improve understanding of what is driving differences between forecast and observed consumption, AEMO plans to continue investigating opportunities for a further breakdown of consumption, in particular into industry sectors. This will help identify opportunities for data and model improvements to reduce consumption forecast variance in the 2024 ESOO. A more detailed sectoral split will also allow better modelling of future decarbonisation scenarios, as individual sectors may perform very differently for different emission reduction targets. Sectoral consumption is also a key input in forecasting various input components (influencing fuel switching, economic growth and energy efficiency projections), and improving this data set is expected to lead to forecasting improvements in the longer term.
- **Monitor demand side trends.** While the 2023 demand side participation (DSP) forecasts were able to incorporate actual wholesale demand response (WDR) data in four regions, the scheme is still in its relative infancy, and WDR in Queensland and South Australia in particular, is very low. AEMO will continue to monitor how WDR is used compared to forecast, to guide any future updates of the DSP forecast. The response of large DSP providers during Lack of Reserve (LOR) events (for example, in New South Wales) will be monitored to ensure that current assumptions about their responses during reliability events are still valid.
- **Monitor planned outages**. The ESOO methodology excludes consideration of generator planned outages, on the basis that they are assumed to be scheduled away from periods of supply scarcity. Planned outages however continue to be observed during periods of high demand, and during potential periods of supply scarcity, challenging this assumption. AEMO will monitor planned outages for scheduled generators and determine whether methodology changes are required for planned outages in the ESOO model.

Invitation for written submissions

Stakeholders are invited to submit written feedback on any issues related to the **Forecast Improvement Plan** outlined in Section 8 of this report. Submissions are requested by **5.00 pm (AEDT) Monday, 5 February 2024** and should be sent by email to energy.forecasting@aemo.com.au.

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Tables

Figures

1 Stakeholder consultation process

The publication of this *Forecast Accuracy Report* marks the commencement of AEMO's Forecast Improvement Plan consultation[4].

Section 8 of this report, the Forecast Improvement Plan, has been guided by assessment of the main contributors to forecast inaccuracies in the rest of this report. This consultation covers the initiatives outlined in the Forecast Improvement Plan only, and not the *Forecast Accuracy Report* methodology.

The finalised Forecast Improvement Plan will be implemented, to the extent possible, prior to AEMO developing reliability forecasts to be published in the 2024 ESOO.

AEMO is seeking feedback on the Forecast Improvement Plan, in particular:

- Is the Forecast Improvement Plan outlined in Section 8 of this report reasonable, and does it focus on the areas that will deliver the greatest improvements to forecast accuracy?
- If not, what alternative or additional improvements should be considered to address the accuracy issues identified in this report?

AEMO welcomes stakeholder feedback on the above questions in the form of written submissions, which should be sent by email to energy.forecasting@aemo.com.au no later than **5.00 pm (AEDT) Monday, 5 February 2024**.

The table below outlines AEMO's consultation on the improvement plan. The consultation will follow the single-stage process outlined in Appendix B of the Forecasting Best Practice Guidelines[5] published by the Australian Energy Regulator (AER).

Table 2 Consultation timeline

Consultation steps	Indicative dates
Forecasting Reference Group discussion of draft report	29 November 2023
Forecast Accuracy Report and Forecast Improvement Plan published	5 January 2024
Submissions due on Forecast Improvement Plan	5 February 2024
Final Forecast Improvement Plan published along with a Submission Response document	20 May 2024

[4] At https://aemo.com.au/consultations/current-and-closed-consultations/2022-forecast-improvement-plan-consultation.

[5] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

2 Introduction

In accordance with National Electricity Rules (NER) 3.13.3A(h), AEMO must, no less than annually, prepare and publish information related to the accuracy of its demand and supply forecasts, and any other inputs determined to be material to its reliability forecasts. Additionally, AEMO must publish information on improvements that will apply to the next *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM). The objective of this transparency is to build confidence in the forecasts produced.

To meet this requirement, AEMO has prepared this *Forecast Accuracy Report* for a broad set of demand, supply, and reliability forecast components, consistent with AEMO's Forecast Accuracy Report Methodology[6] and Reliability Forecast Guidelines[7].

Specifically, this 2023 *Forecast Accuracy Report* assesses the accuracy of the 2022-23 demand and supply forecasts published in AEMO's 2022 ESOO for the NEM[8] and related products, in addition to the resulting reliability forecasts for each region in the NEM. The 2022 ESOO forecasts are the latest that can be assessed against a full year of subsequent actual observations. While AEMO published the *Update to the 2022 ESOO* in February 2023, it is not subject to review.

2.1 Definitions

Any assessment of accuracy relies on precise definitions of technical terms to ensure forecasts are evaluated on the same basis they were created. To support this:

- All forecasts are reported on a "sent out" basis unless otherwise noted.
- Historical operational demand "as generated" (OPGEN) is converted to "sent out" (OPSO) based on estimates of auxiliary load, which reflect load used within generator sites.
- Auxiliaries are typically excluded from demand forecasts as they relate to the scheduling of generation and do not correlate well with underlying customer demand.
- All times mentioned are NEM time – Australian Eastern Standard Time (UTC+10) – not local times, unless otherwise noted.
- Terms used in this report are defined in the glossary.

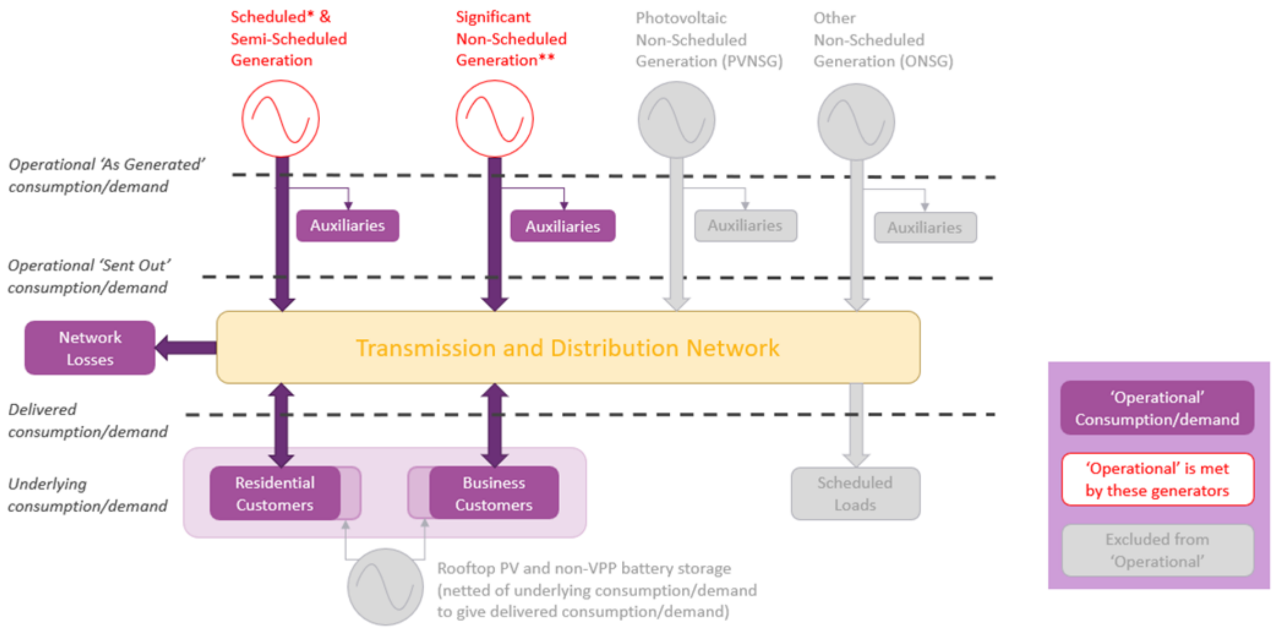
Figure 1 shows the demand definitions used in this document.

[6] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

[7] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

[8] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo/2022-nem-electricity-statement-of-opportunities.

Figure 1 Demand definitions used in this document



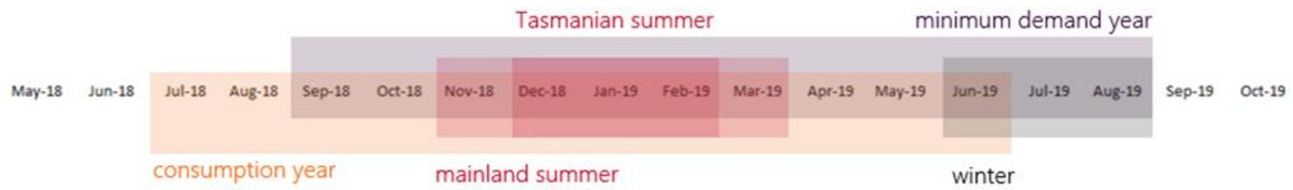
* Including injection from grid-scale storages and virtual power plants (VPP) from aggregated behind-the-meter battery storage.
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

Seasonal definitions

For consistency, data and methodologies of actual observations (or 'actuals') are the same as those used for the corresponding forecasts in the 2022 ESOO. This means an energy consumption year is aligned with the financial year, being July to June inclusive, and, as Figure 2 shows:

- A year for the purposes of annual minimum demand is defined as September to August inclusive.
- Summer is defined as November to March for all regions, except Tasmania, where summer is defined as December to February inclusive.
- Winter is defined as June to August inclusive for all regions.

Figure 2 Seasonal definitions used in this document



Percentage errors

The percentage errors that measure the differences between forecast and actual values presented in the report are calculated in line with AEMO's Forecast Accuracy Report Methodology[9]:

[9] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-reporting-methodology-report-aug-20.pdf.

$$percentage\ error = \frac{forecast - actual}{actual} \text{ x } 100$$

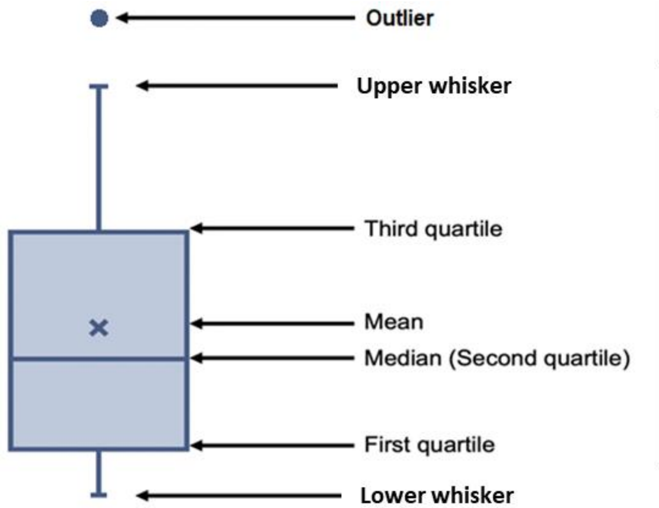
Using this approach, a negative percentage error indicates an under-forecast compared to actuals, where a positive error is an over-forecast. Specifically, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

Box plots

In this report, some figures use box plots to illustrate the forecast accuracy. A box plot (sometimes also referred to as a box and whiskers plot) is a way of displaying the distribution of data based on the following five points: upper whisker, third quartile, median (second quartile), first quartile, and lower whisker. This way, it graphically shows if the distribution is symmetrical, how tight the distribution is, and if the data is skewed.

The end points of the vertical line represent the upper whisker and lower whisker values, while the top and bottom of the box show the third and first quartiles respectively, as illustrated in Figure 3. The line through the box is the median and, if present, the cross will represent the mean. Occasionally, actual observations fall outside a certain range from the first and third quartiles and will be classified as outliers rather than form the upper whisker and lower whisker values otherwise shown. Such outliers are shown as dots.

Figure 3 Explanation of box plots used in this report

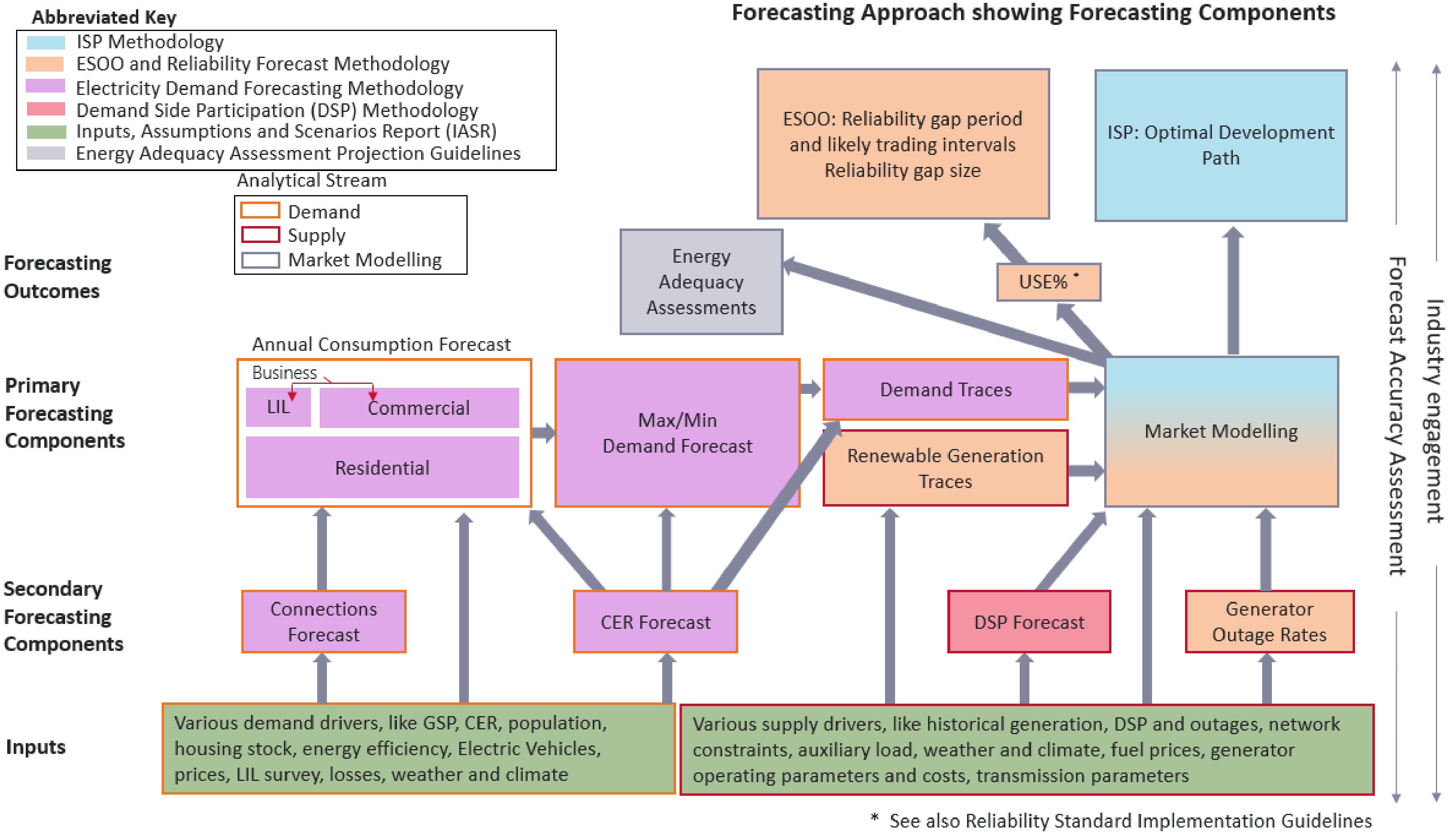


2.2 Forecast components

Production of AEMO's high-level outputs requires multiple sub-forecasts to be produced and appropriately integrated; these are called component forecasts (or forecast components). Figure 4 shows the forecast components leading to AEMO's reliability forecast and the methodology documents (see colour legend) explaining these processes in more detail[10]. In Figure 4, inputs can be seen as data streams (including forecasts provided by consultants) used directly in AEMO's forecasting process. In some cases, AEMO processes such information, for example consumer energy resources (CER), where AEMO combines inputs from multiple consultants into its forecast uptake of distributed photovoltaics (PV), electric vehicles (EVs), and battery storage.

[10] These documents are available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

Figure 4 Forecasting components



2.2.1 Assessability of forecast accuracy

Forecasting is the estimation of the future values of a variable of interest. However, just because a variable of interest can be forecast, it does not mean that it can be rigorously assessed. There are three broad categories of forecasts:

1. Strongly assessable – exact and indisputable actual values for the variable of interest exist at the time of forecast performance assessment. This allows definitive comparison with forecasts produced earlier.
2. Moderately assessable – reasonable estimates for the actual variable of interest are available at the time of forecast performance assessment. The reader of forecast performance should be aware that the forecast performances quoted are estimates.
3. Weakly assessable – there are no acceptable actual values of the variable of interest at the time of forecast performance assessment. It is inappropriate to produce any forecast accuracy metrics for this category.

AEMO focuses the forecast accuracy assessment on strongly and moderately assessable forecast components.

As AEMO gains access to increasing proportions of relevant data, including smart meter data, some weakly assessable forecasts may become moderately assessable. This includes the split of the consumption forecast into residential and business consumption and potentially better insight into the impacts of energy efficiency schemes. AEMO's Forecast Improvement Plan includes initiatives that seek to increase the assessability of forecast components.

2.3 Scenarios and uncertainty

There are two types of uncertainties in AEMO's forecasts:

- **Structural drivers**, which are modelled as scenarios, including considerations such as population and economic growth and uptake of future technologies, such as distributed PV, batteries and EVs.
- **Random drivers**, which are modelled as a probability distribution and include weather drivers and generator outages.

For the random drivers, a probability distribution of their outcomes can be estimated, and the accuracy of this assessed, as is the case for extreme demand forecasts (see Section 5) and generator availability (Section 6).

For the structural drivers, such probability distributions cannot be established, and instead the uncertainty is captured using different scenarios and sensitivities.

The scenarios and sensitivities used for the 2022 ESOO are summarised in Table 3.

Table 3 Key scenarios and sensitivities used in the 2022 ESOO

Scenario	*Slow Change*	*Progressive Change*	*Step Change* (ESOO Central)	*Hydrogen Superpower*
Economic growth and population outlook	Low	Moderate	Moderate	High
Energy efficiency improvement	Low	Moderate	High	High
Distributed PV	Moderate, but elevated in the short term	Moderate	High	High
Distributed battery storage installed capacity	Low	Moderate	High	High
Battery storage aggregation / virtual power plant (VPP) deployment	Low	Moderate	High	High
Battery electric vehicle (EV) uptake	Low	Moderate	High	Moderate/High
EV charging time switch to coordinated dynamic charging	Low	Moderate	High	Moderate/High
Electrification of other sectors (expected outcome)	Low	Moderate	Moderate/High	Moderate/High
Hydrogen consumption	Minimal	Minimal	Limited to domestic hydrogen consumption	Large NEM-connected export and domestic consumption
Decarbonisation target	26-28% reduction by 2030	26-28% reduction by 2030	Exceeding 26-28% reduction by 2030, consistent with global targets for a <2°C mean rise in temperature by 2100.	Exceeding 26-28% reduction by 2030, consistent with global targets for a <1.5°C mean rise in temperature by 2100.

3 Trends in demand drivers

Electricity forecasts are predicated on a wide selection of inputs, drivers, and assumptions. Input drivers to the demand models include:

- Macroeconomic growth.
- Electricity connections growth.
- Distributed PV, EVs and behind-the-meter battery uptake.
- Numerous other weakly assessable drivers including energy efficiency and appliance mix.

The 2022 ESOO detailed the changing social, economic, and political environment in which the NEM operates. As this environment evolves, the needs of the market and system will also evolve. As discussed in Section 2.3, four scenarios were therefore developed to illustrate a range of possible pathways: *Slow Change*, *Progressive Change, Step Change* (ESOO Central), *and Hydrogen Superpower*.

Not all input variables are measured regularly, or have material impacts on year-ahead outcomes. For example, distributed PV installations are measurable and have an impact on year-ahead outcomes, while others are less measurable and are less likely to impact the year-ahead forecasts. Input drivers that are suitable for accuracy assessment and comment are discussed in this section.

3.1 Macroeconomic growth

AEMO uses various macroeconomic indicators as key inputs to the scenario forecasts. The 2022 ESOO incorporated consultant forecasts of key economic components relevant for forecasting electricity consumption, for example, Gross Domestic Product (GDP), Gross State Product (GSP), and Household Disposable Income (HDI).

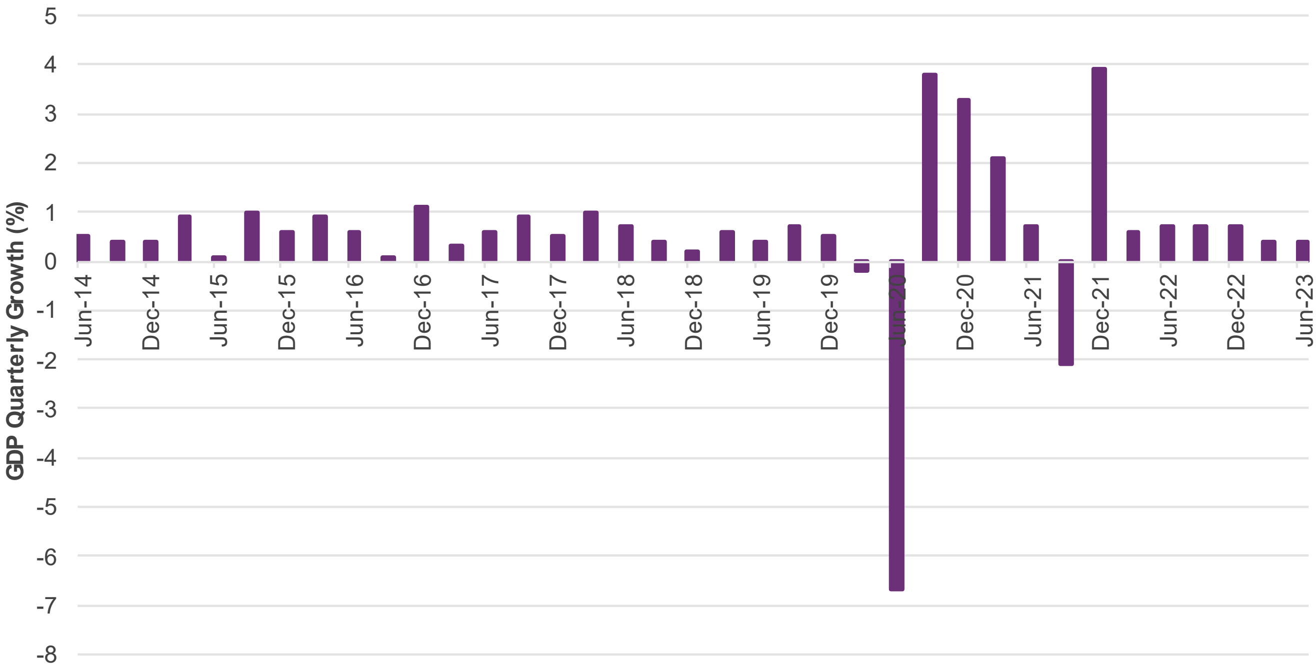
For 2022-23, annual GDP was forecast to grow by 2.7% in the Central scenario, with the June quarter being the first quarter since the start of the pandemic when international and domestic borders were open without travel restrictions. Similarly, GSP and HDI across the NEM regions were forecast to grow in the Central scenario by an average of 2.6% and 3.1% respectively in 2022-23.

At the time of the forecast, the economic impacts of COVID-19 started to normalise again as both travel and capacity restrictions had eased, and household saving rates continued to decline back to pre-pandemic levels, with household consumption driving economic growth. An average annual growth rate of 2.6% p.a. was forecast over the first five years of the forecast period, driven by strong growth projections for the services industries as restrictions eased and the construction sector, impacted by government stimulus (such as the HomeBuilder scheme). Both GSP and HDI were also expected to see moderate growth within that period.

Lower than the forecast, actual GDP increased in 2022-23 by 2.1%, with the construction sector hindered by unfavourable weather and rising materials costs. Actual quarterly GDP growth is shown in Figure 5[11].

[11] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2023, available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release#data-download. Accessed 31 October 2023.

Figure 5 Macroeconomic growth rates, chain volume measures, seasonally adjusted



All things being equal, slower economic growth would lead to lower electricity demand than forecast. However, the sector in which the economic activity slows can affect energy consumption significantly due to differences in energy intensity[12] between sectors.

3.2 Connections growth

The number of new electricity connections is a key growth driver for electricity consumption in the residential sector. The forecasts are based on population and household growth forecasts from AEMO's economic consultant (Oxford Economics Australia) and the Australian Bureau of Statistics (ABS) and are shown in Table 4. For the 2022 ESOO, the short-term forecasts were found by blending the short-term trend of National Metering Identifier (NMI) growth from the AEMO database with data provided by Oxford Economics Australia[13] and the ABS.

Table 4 Connections forecast for 2022-23 and actuals for 2022-23

Region	2022 forecast for 2022-23 (no. of customers)	Actual for 2022-23 (no. of customers)*	Difference (%)^
NSW	3,609,478	3,567,617	1.2%
QLD	2,084,768	2,075,631	0.4%
SA	809,893	807,814	0.3%
TAS	260,733	260,273	0.2%
VIC	2,793,783	2,773,983	0.7%
NEM	**9,558,655**	**9,485,318**	**0.8%**

* Actuals represent for no. of customers as at the end of financial year 2022-23 (30 June 2023).
^ Negative number reflects an under-forecast of actuals, positive numbers an over-forecast.

[12] Energy intensity is a measure of the general energy efficiency of an economy. It is calculated as units of energy per unit of economic growth.

[13] The Oxford Economics Australia dwellings forecasts are re-based to the previous census year.

Despite predicted growth in new dwellings, building activity generally decreased through 2022-23[14], due in part to supply chain issues, and rising material costs and interest rates. In general, the actual number of connections is still aligned reasonably well with the forecast, and the contribution to the overall NEM consumption forecast variance is minimal (see Figure 7 in Section 4).

3.3 Rooftop PV and PV non-scheduled generation

In AEMO's modelling, distributed PV is split into:

- Rooftop PV (installations typically on rooftops up to 100 kilowatts [kW] in size), and
- PV non-scheduled generation (PVNSG), which ranges from 100 kW to 30 megawatts (MW) in size.

To define actual rooftop PV installed capacity in the 2022 ESOO, AEMO received installation data from the Clean Energy Regulator and adjusted it to reflect system replacements. However, rooftop PV actuals are not known precisely at any point in time, and are subject to revision because PV installers have up to one year to submit applications for Small-scale Technology Certificates (STCs) to the Clean Energy Regulator.

AEMO's 2022 ESOO Central forecast adopted an averaging approach of the forecasts provided by AEMO's two CER consultants: CSIRO[15] and Green Energy Markets (GEM)[16]. The average was chosen[17] as the forecasts mapped to the central scenario were considered to be each consultant's best estimates, consistent with the scenario narratives. With two forecasts, using two independent models but aligned to the same assumptions and scenario narratives, AEMO considered that the accuracy of the forecasts is improved over a single view.

The differences between forecasts and actuals by region are highlighted in Table 5, showing this for the 2022 ESOO's Central scenario.

Table 5 Rooftop PV and PV non-scheduled generation (PVNSG) installed capacity comparison by region, as at 30 June 2023 (MW)

As installed at 30 June 2023		NSW	QLD	SA	TAS	VIC	NEM
Rooftop PV	Estimated actual (MW)	5,912	5,559	2,193	269	4,070	18,003
	Central forecast (MW)	5,700	5,399	2,184	265	4,056	17,604
	Central forecast error (%)	-3.6%	-2.9%	-0.4%	-1.5%	-0.3%	-2.2%
PVNSG	Estimated actual (MW)	334	243	251	4	351	1,183
	Central forecast (MW)	369	272	241	10	388	1,280
	Central forecast error (%)	11%	12%	-4%	152%	11%	8%
Total	Central forecast error (%)	-2.8%	-2.3%	-0.8%	0.7%	0.5%	-1.6%

Actuals are based on AEMO's latest actual data as of 5 September 2023.

[14] Australian Bureau of Statistics: Building Activity Australia (Jun 2023 release), at https://www.abs.gov.au/statistics/industry/building-and-construction/building-activity-australia/latest-release. Accessed 19 November 2023.

[15] CSIRO: Small-scale solar and battery projections 2022 (December 2022), at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf.

[16] Green Energy Markets: Final Projections for distributed energy resources – solar PV and stationary energy battery systems (December 2022), at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf.

[17] This choice was described and consulted upon with stakeholders via the Inputs, Assumptions and Scenarios Report.

For all NEM regions, rooftop PV forecasts were somewhat under-forecast, with higher than expected energy prices leading to stronger uptake. As installed rooftop PV capacity is negatively correlated with operational consumption, maximum demand, and in particular minimum demand, higher uptake typically lowers operational consumption and demand. PV forecasts included in the 2023 ESOO, which will be assessed in the 2024 *Forecast Accuracy Report*, have been subject to a small upward revision, suggesting that existing processes are sufficient to reflect new trends as they emerge.

PV non-scheduled generation (PVNSG) is a much smaller market than rooftop PV. As shown in the table, PVNSG was over-forecast in all regions, however the actual figures are subject to likely upward revision as the administrative process for recognising additional power stations lags physical installations.

3.4 Electric vehicles

While AEMO has forecast the rapid uptake of EVs for several years, correctly identifying the timing of rapid uptake is challenging for the accuracy of short-term forecasts. Typical methodologies for short-term forecasts, including those used by AEMO, incorporate regression and trend analyses, which have limited suitability for rapidly evolving consumer technology. Furthermore, forecasts of new technologies suffer from low baseline figures, which tends to result in larger forecast errors when expressed as a percentage.

AEMO uses a spread of forecasts across scenarios however growth was even higher than the highest scenario.

Table 6 shows forecast errors associated with fleet size and fleet share in the 2022 ESOO forecasts, relative to the actuals recorded in June 2023. Fleet size is defined as the count of EVs[18] currently on the road, while fleet share is the percentage of the total road fleet, which includes battery Evs (BEVs) and plug-in hybrid EVs (PHEVs).

The 2022 forecasts underestimated actual fleet size figures across all NEM regions, by around 40%, however the impact on energy consumption and demand forecasts remains negligible.

Table 6 Electric vehicle (BEV and PHEV) fleet size and fleet share by region, as on 30 June 2023

As on 30 June 2023		NSW	QLD	SA	TAS	VIC	NEM
Fleet size	Estimated actual*	46,010	25,656	7,486	2,424	35,503	117,079
	Central forecast	26,530	14,987	3,959	1,539	22,984	69,999
	Central forecast error (%)	-42.3%	-41.6%	-47.1%	-36.5%	-35.3%	-40.2%
Fleet share	Estimated actual	0.71%	0.55%	0.48%	0.46%	0.65%	0.63%
	Central forecast	0.43%	0.37%	0.28%	0.33%	0.47%	0.41%
	Central forecast error (%)	-39.3%	-32.5%	-40.8%	-28.1%	-28.0%	-34.1%

* Actual data sourced from Electric Vehicle Council (EVC) and Federal Chamber of Automotive Industries (FCAI). Note the data source for forecasts was the ABS motor vehicle census. This change of source may have contributed to forecast error. The new data source is considered comprehensive and reliable.

3.5 Network losses

Network losses refers to the electricity lost due to electrical resistance heating of conductors in the transmission and distribution networks. AEMO states losses as percentages of the energy entering the network. Intra-regional

[18] The total of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

transmission and distribution losses are sourced from either the Regulatory Information Notice submitted by transmission or distribution network service providers, or directly from the relevant network service providers.

AEMO assumes the loss percentage for the latest financial year is a reasonable estimate for losses over the entire forecast period. AEMO has assessed this assumption against recent trends and found it is appropriate. Interconnector losses are modelled explicitly, predominantly as a function of regional load and flow.

The latest reported losses provide a best estimate of the actuals for 2022-23. As shown in Table 7, transmission losses are generally higher than was assumed at the time of the 2022 ESOO for all the regions. Forecast of distribution losses were higher than the actual estimated losses for New South Wales and Victoria, while the remaining regions all had estimated losses lower than forecast, with Tasmania having the highest difference between forecast and observed losses.

Table 7 Estimated network loss factors

	Transmission loss factor		Distribution loss factor	
	Applied to 2022 forecast	Used to estimate actuals for 2022-23	Applied to 2022 forecast	Used to estimate actuals for 2022-23
New South Wales	2.23%	2.40%	4.23%	4.10%
Queensland	2.23%	2.35%	4.81%	4.88%
South Australia	2.62%	3.31%	6.11%	6.90%
Tasmania	2.74%	2.80%	2.86%	4.00%
Victoria	1.99%	2.14%	4.72%	4.59%

Using the latest reported network losses as estimates for 2022-23 contributed to -0.5% variance overall for the NEM in the 2022 ESOO consumption forecast (see Table 9 in Section 4) meaning actual estimated losses were higher than forecast. Looking at individual regions, the higher loss factors are the main driver for the higher losses. The biggest impact is in South Australia, where losses contributed to -1.8% forecast variance. The actual overall consumption was lower in South Australia than forecast, and generally that would result in lower losses. However, the significantly higher loss factors provided to AEMO, as shown in Table 7 above, resulted in the actual estimated losses being higher than those forecast.

4 Operational energy consumption forecasts

AEMO forecasts annual operational energy consumption by region on a financial year basis. Figure 6 shows central forecasts prepared from 2018 to 2023, for each region, relative to history. Most recent forecasts have been somewhat similar. The forecasts in the Update to the 2021 ESOO, 2022 and 2023 generally projected relatively flat or steadily increasing consumption compared to earlier forecasts. The original 2021 ESOO forecasts showed lower and declining consumption because of re-baselining the underlying business mass market forecast with revised historical actuals data thereafter[19]. This section focuses on the 2022 ESOO forecasts, unless otherwise stated.

Figure 6 Recent annual energy consumption forecasts by region

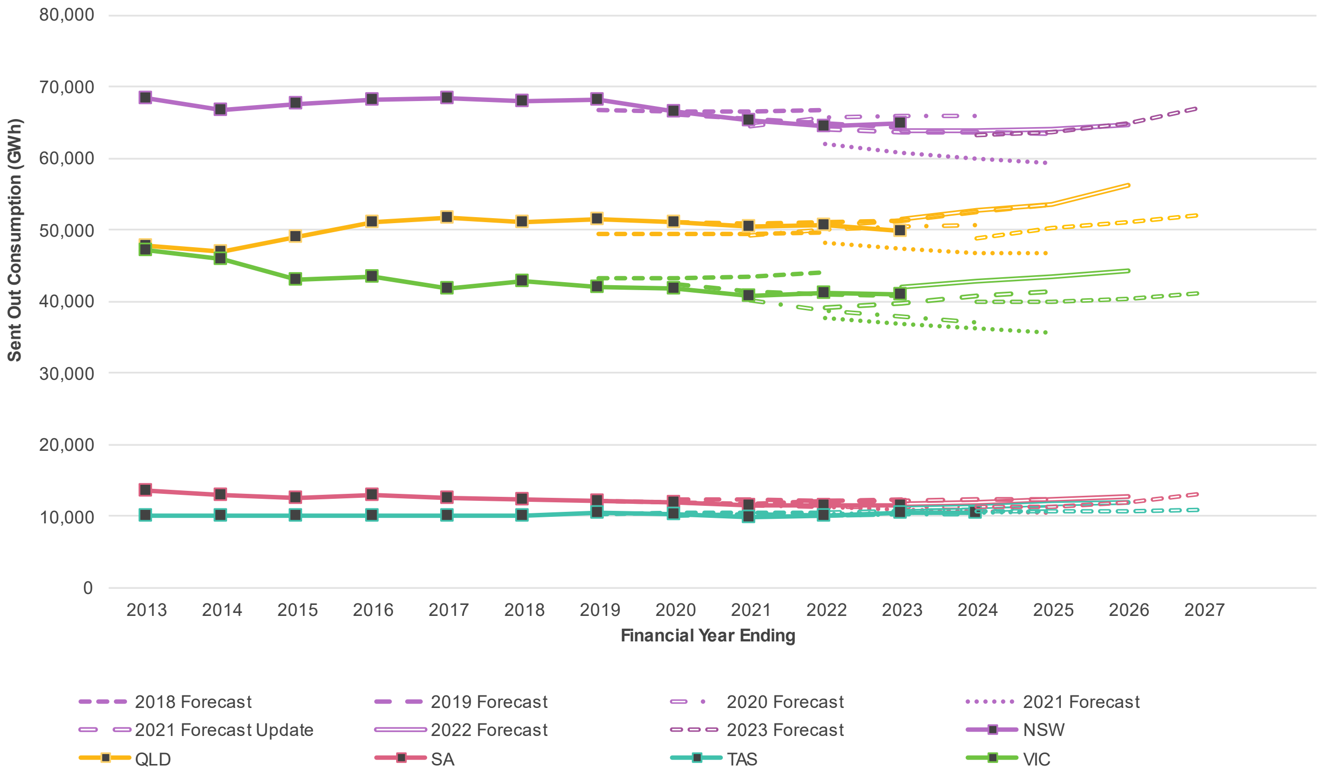


Table 8 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using the percentage error calculation outlined in Section 2.1. As shown in the table, in the last five years, the percentage errors for forecasts in the individual regions were mostly within ±3% except the 2021 ESOO. Similarly, the NEM weighted average has had a percentage error within ±1.5% except the initial 2021 ESOO which had an error of -5% and was reduced to -1.1% from the improvements made in the *Update to the 2021 ESOO*.

[19] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/update-to-2021-electricity-statement-of-opportunities.pdf?la=en for details.

Table 8 Recent one-year ahead operational sent out energy consumption forecast accuracy by region

One-year ahead annual operational consumption accuracy (%)	2018 ESOO forecast in 2018-19	2019 ESOO forecast in 2019-20	2020 ESOO forecast in 2020-21	2021 ESOO forecast in 2021-22	2021 ESOO Update forecast in 2021-22	2022 ESOO forecast in 2022-23
New South Wales	-2.0%	-0.6%	-1.1%	-3.9%	-0.7%	-1.7%
Queensland	-3.9%	0.0%	-2.4%	-5.2%	-0.3%	3.4%
South Australia	-1.5%	2.6%	-0.3%	-0.8%	6.5%	2.7%
Tasmania	1.2%	2.2%	2.4%	-1.3%	-0.3%	6.3%
Victoria	3.0%	1.3%	-1.7%	-8.4%	-5.0%	2.4%
NEM	**-1.2%**	**0.4%**	**-1.3%**	**-5.0%**	**-1.1%**	**1.4%**

* Negative number reflects an under-forecast of actuals, positive numbers an over-forecast.

Table 9 shows the sources of variance for the 2022-23 consumption forecast of the NEM as forecast in the 2022 ESOO. The largest contributors to forecast error relate to an over-forecast of LILs. Meanwhile, the third consecutive La Niña[20] event in Australia caused milder than average summer weather as reflected in reduced cooling degree days and cooler than average winter-spring weather as reflected in increased heating degree days compared to the forecast.

Table 9 NEM operational energy consumption forecast accuracy by component

Category	2022 forecast (gigawatt hours [GWh])	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	4,598	3,597	27.8%	0.5%
Heating Degree Days	7,752	8,498	-8.8%	-0.4%
Connections Growth	765	511	49.6%	0.1%
Large Industrial Loads	46,401	43,255	7.3%	1.7%
Liquefied natural gas (LNG)	6,844	6,315	8.4%	0.3%
Rooftop PV*	20,338	20,242	0.5%	-0.1%
PV non-scheduled generation*	2,179	1,999	9.0%	-0.1%
Other non-scheduled generation*	4,088	4,395	-7.0%	0.2%
Network losses	9,608	10,495	-8.5%	-0.5%
Operational sent out	**180,246**	**177,673**	**1.4%**	**1.4%**
Auxiliary load	8,359	7,902	5.8%	0.2%
Operational as generated	**188,605**	**185,575**	**1.6%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation are supply side items, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

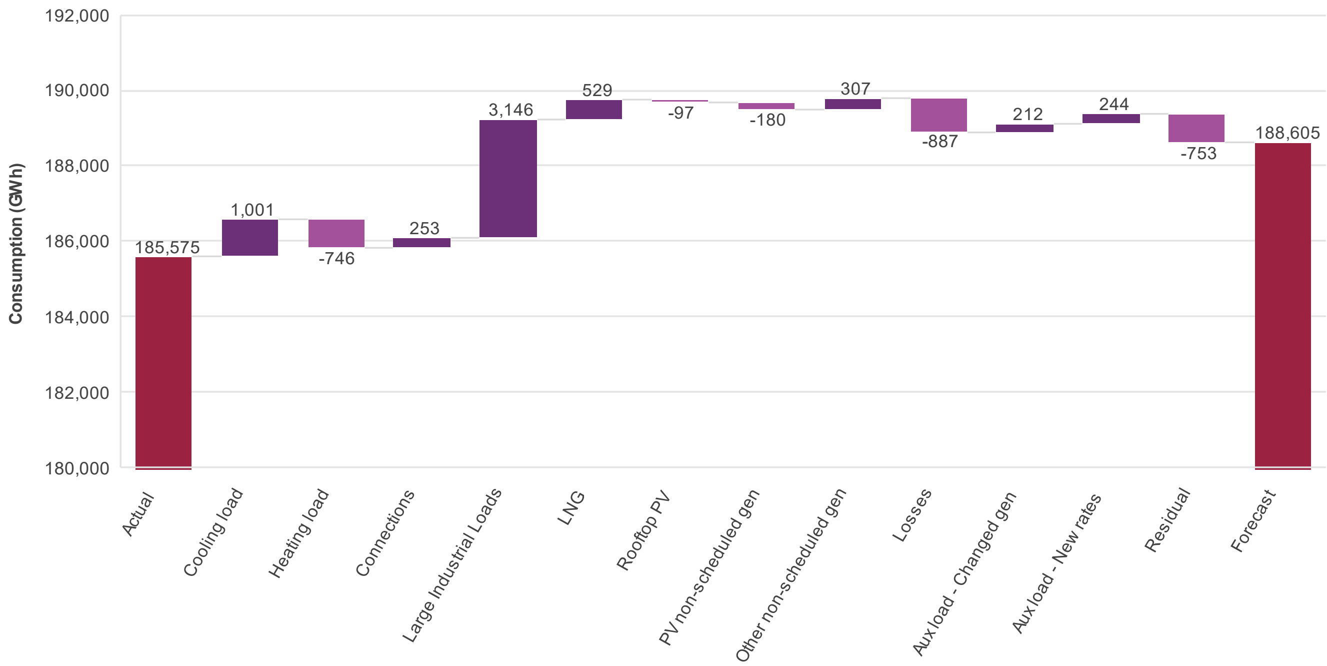
Figure 7 shows the variance components graphically and highlights a residual variance which represents the variance that is not explained by any of the measured components. The residual variance includes the impact of differences in economic growth, electrification, and other factors such as COVID-19 not otherwise accounted for through variations in forecast components such as connections growth or rooftop PV installations.

As component variances may net out at NEM level, region-specific variances are important to interpret forecast accuracy. The rest of this section details the regional breakdown of these components. In summary:

[20] Bureau of Meteorology: "What is La Niña and how does it impact Australia?", at http://www.bom.gov.au/climate/updates/articles/a020.shtml. and "La Niña in 2022-23 financial year" at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml#tabs=Influences

- Cooling degree days, which influences the forecast cooling load, were below forecast in all mainland states, driven by mild weather caused by La Niña. The La Niña conditions also caused higher than forecast heating load as represented by heating degree days due to cooler winter-spring weather across all NEM regions except South Australia.
- NMI connections growth was over-forecast, due to supply chain issues, and rising material costs and interest rates negatively impacting building activity through 2022-2023.
- LILs were over-forecast in all regions, excluding New South Wales. The forecast variance of LILs was the largest source of difference between forecasts and actuals of the components measured at the NEM level. It was also the most significant factor driving QLD and TAS forecast variance exceeding the target. Most variances can be explained by unplanned outages and lower production rates for existing loads, which differed from anticipated consumption levels identified in AEMO's LIL surveys.
- Liquefied natural gas (LNG) electricity consumption was lower than forecast because LNG gas exports were lower than the forecast value based on gas exporter surveys. There are many factors leading LNG actual consumption to deviate from forecasts, including international gas prices and domestic gas shortfalls.
- Network losses were under-forecast across all NEM regions. Although actual operational consumption was lower than forecast which generally resulted in lower losses, the impact from increases in reported loss factors causes losses to be higher than forecast (see Section 3.5).
- Generator auxiliary loads were overestimated across all states. However, the impact of auxiliary load was generally very small and results from operational sent out demand generally being lower, as explained in Section 3.5.

Figure 7 NEM operational as generated energy consumption variance by component



4.1 New South Wales

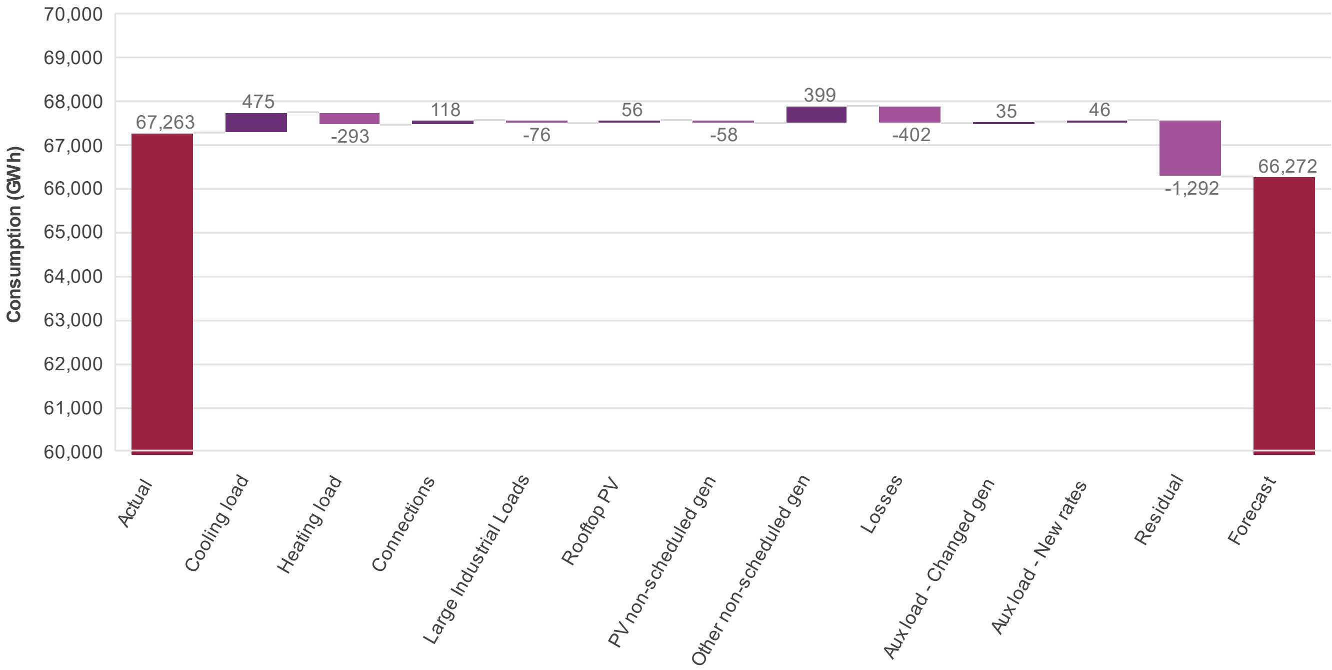
Operational as-generated energy consumption for New South Wales in 2022-23 was above the Central forecast, leading to a percentage forecast error of -1.5%. Table 10 and Figure 8 demonstrate the forecast accuracy by component. The largest inaccuracy driver was the over-forecast cooling load in summer, represented by cooling degree days, driven by the mild weather caused by the La Niña weather conditions. This also caused higher spring-winter heating load, which was represented by higher than forecast heating degree days. Network losses and other non-scheduled generation (ONSG) were also causes for variance. Network losses were mainly caused by an under-forecast of the operational consumption; see Section 3.5 for details. Other differences were less significant, such as connections growth, while the forecast variance of the two types of PV offsetting each other. See Section 3.2 for connection growth and Section 3.3 for PV and PVNSG generation analysis.

AEMO considers that the model for New South Wales has performed sufficiently well with the residual being only -1,292 GWh (or -1.9%), as shown in Figure 8. AEMO considers the model for New South Wales has performed reasonably well. AEMO will, however, conduct research in the future to understand potential factors that have caused the residual forecast variance, such as the trend in fuel switching to electrification.

Table 10 New South Wales operational energy consumption forecast accuracy by component

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	1,811	1,336	35.6%	0.7%
Heating Degree Days	3,194	3,487	-8.4%	-0.4%
Connections Growth	286	168	70.3%	0.2%
Large Industrial Loads	15,384	15,460	-0.5%	-0.1%
Rooftop PV	6,550	6,607	-0.8%	0.1%
PV non-scheduled generation	612	555	10.4%	-0.1%
Other non-scheduled generation	1,159	1,558	-25.6%	0.6%
Network losses	3,367	3,769	-10.7%	-0.6%
Operational sent out	**63,791**	**64,863**	**-1.7%**	**-1.6%**
Auxiliary load	2,481	2,400	3.4%	0.1%
Operational as generated	**66,272**	**67,263**	**-1.5%**	

Figure 8 New South Wales operational as generated energy consumption variance by component



4.2 Queensland

Operational as-generated energy consumption for Queensland in 2022-23 was 3.4% below forecast. Table 11 and Figure 9 show the forecast accuracy by component, highlighting that the biggest difference was LILs, followed by decreased LNG, decreased cooling load and increased heating load caused by the La Niña conditions and network losses as explained in Section 3.5. LNG electricity consumption was lower than forecast because LNG gas exports were lower than the forecast based on gas exporter surveys[21], as described previously. The over-forecast of LILs was mainly due to unplanned outages in two of the region's largest loads. The differences for the other measured components were generally small, with only 74 GWh (0.1%) remaining in the residual component. AEMO considers that most of the forecast variance as explainable and the model for Queensland has performed well.

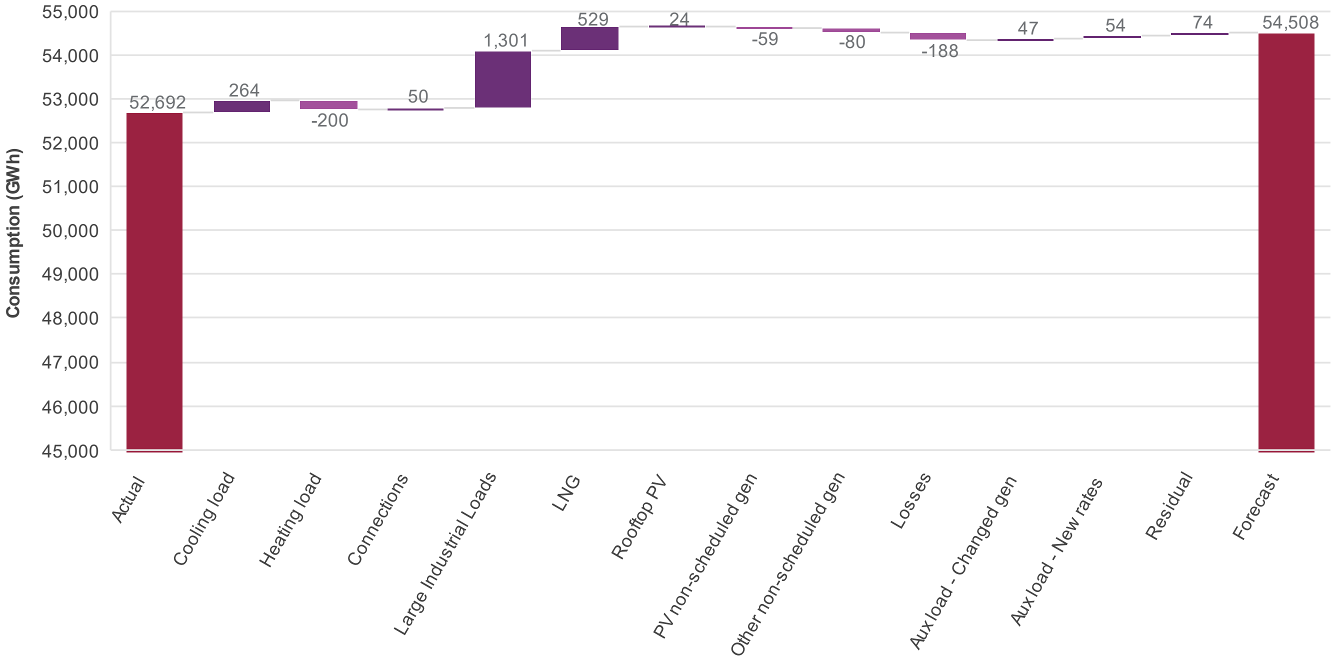
Table 11 Queensland operational energy consumption forecast accuracy by component

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	1,685	1,421	18.6%	0.5%
Heating Degree Days	578	778	-25.7%	-0.4%
Connections Growth	175	125	39.7%	0.1%
Large Industrial Loads	13,952	12,651	10.3%	2.5%
LNG	6,844	6,315	8.4%	1.0%
Rooftop PV	6,653	6,677	-0.4%	0.0%
PV non-scheduled generation	481	422	13.9%	-0.1%

[21] See Section A1.4 of https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2023/2023-gas-statement-of-opportunities.pdf?la=en for more details.

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Other non-scheduled generation	1,577	1,497	5.3%	-0.2%
Network losses	2,588	2,776	-6.8%	-0.4%
Operational sent out	**51,501**	**49,786**	**3.4%**	**3.3%**
Auxiliary load	3,007	2,906	3.5%	0.2%
Operational as generated	**54,508**	**52,692**	**3.4%**	

Figure 9 Queensland operational as generated energy consumption variance by component



4.3 South Australia

Operational as generated energy consumption for South Australia in 2022-23 was 3% below the Central forecast. Table 12 and Figure 10 demonstrate the forecast accuracy by component. The most significant inaccuracy drivers were an over-forecast of LILs and an under-estimate of network losses. The over-forecast of LILs was mainly due to operational variances from a few facilities. The variance in network losses is analysed in Section 3.6. The differences for the other measured components were generally small, with heating load and rooftop PV the largest. Apart from the reduced cooling degree days caused by a mild La Niña summer, South Australia had its warmest winter since 2009 based on mean temperature. This weather condition was driven by a transition to an El Niño winter, which led to the lower than forecast heating load represented by heating degree days[22]. Rooftop PV was over-forecast due to less favourable weather affecting solar irradiance (including higher rainfall from the La Niña weather conditions)[23].

[22] Bureau of Meteorology, "A warmer than average 12 months", at http://www.bom.gov.au/climate/current/financial-year/aus/2023/2023.summary.shtml#tabs=Temperature and Climate.Gov, "March 2023 ENSO update: no more La Niña!", at https://www.climate.gov/news-features/blogs/enso/march-2023-enso-update-no-more-la-nina.

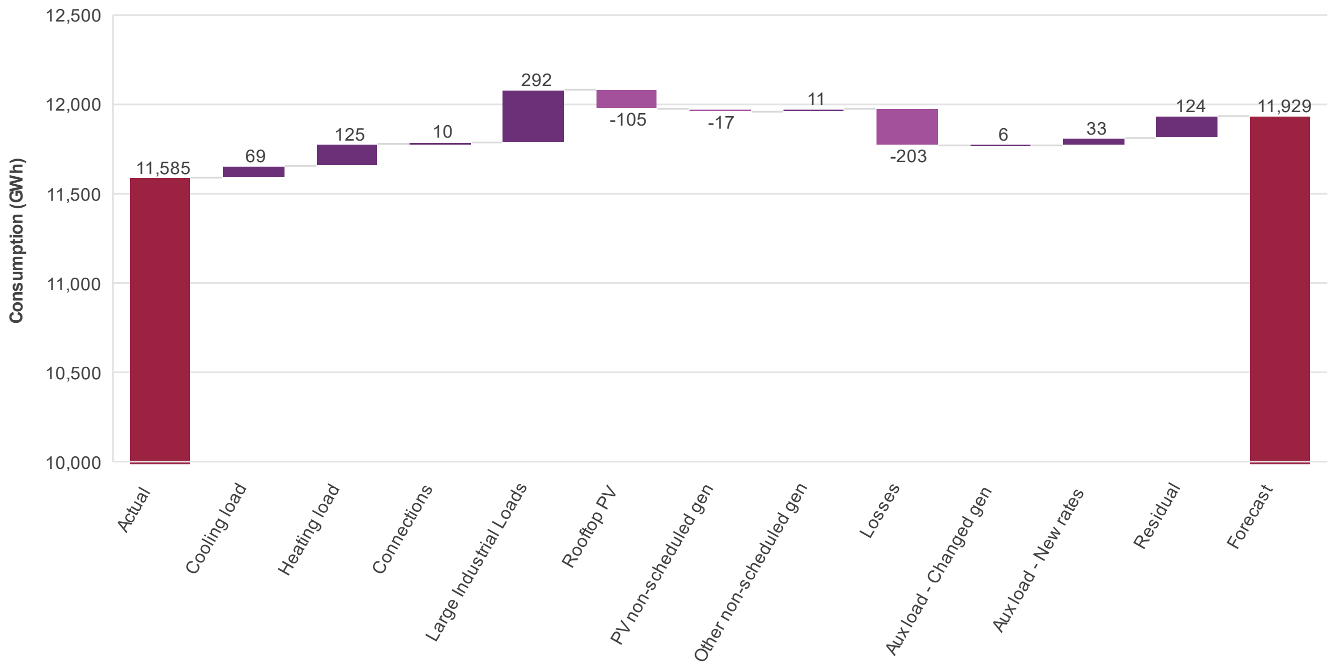
[23] Bureau of Meteorology, "The wettest financial year since 2010–2011", at http://www.bom.gov.au/climate/current/financial-year/aus/2023/2023.summary.shtml#tabs=Rainfall. Accessed 6 November 2023.

Accounting for the other measured elements, this leaves a residual variance of 124 GWh (1.1%) as shown in Figure 10. AEMO considers that the model for South Australia has performed well.

Table 12 South Australia operational energy consumption forecast accuracy by component

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	400	331	20.8%	0.6%
Heating Degree Days	1,015	890	14.0%	1.1%
Connections Growth	42	32	29.9%	0.1%
Large Industrial Loads	3,453	3,161	9.2%	2.5%
Rooftop PV	2,610	2,505	4.2%	-0.9%
PV non-scheduled generation	453	436	3.9%	-0.1%
Other non-scheduled generation	57	69	-16.7%	0.1%
Network losses	795	999	-20.4%	-1.8%
Operational sent out	**11,812**	**11,506**	**2.7%**	**2.6%**
Auxiliary load	118	79	49.8%	0.3%
Operational as generated	**11,929**	**11,585**	**3.0%**	

Figure 10 South Australia operational as generated energy consumption variance by component



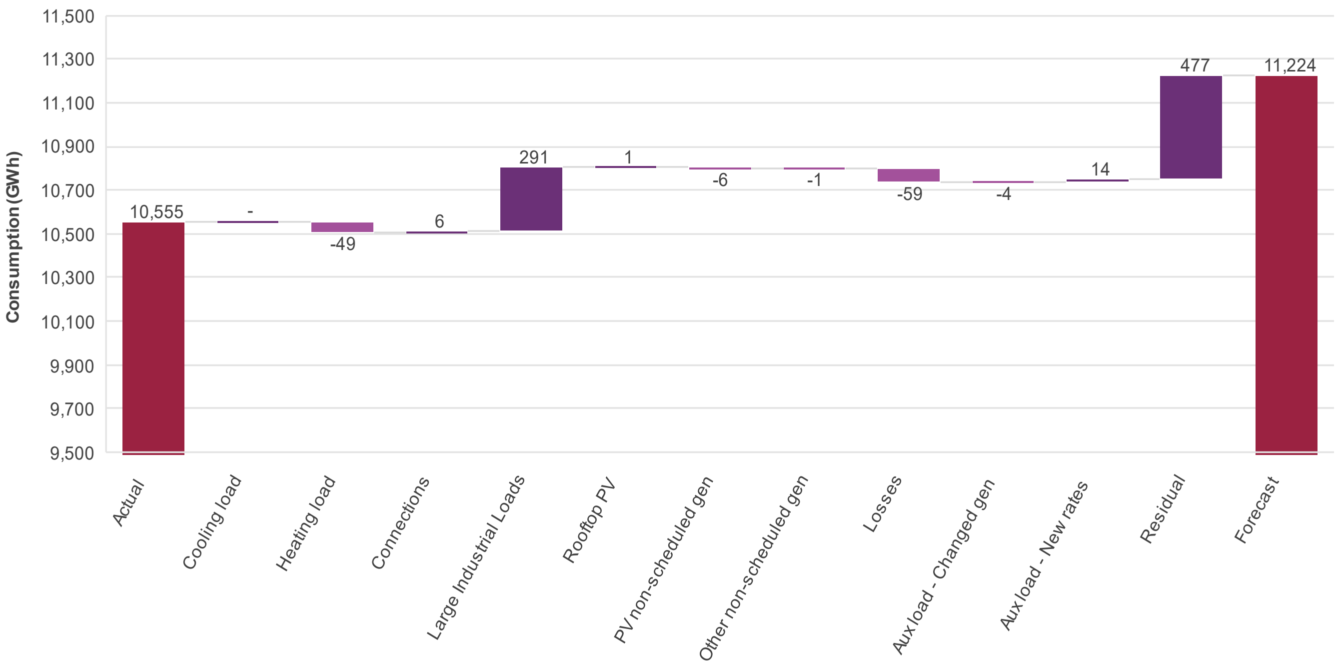
4.4 Tasmania

Operational as-generated energy consumption for Tasmania in 2022-23 was below the Central forecast by 6.3%. Table 13 and Figure 11 demonstrate the forecast accuracy by component. The forecast variance was mainly from an over-forecast of LILs. The over-forecast of LILs was mainly due to variances in consumption within 5-10% for a few facilities. Together with the other measured components, this leaves a residual variance of 477 GWh (4.5%), as shown in Figure 11. AEMO will review LIL forecasts and monitor LIL consumption that comprise the largest variances, such as unplanned outages and significant operational variations. AEMO will seek to understand the cause of the remaining residual difference by seeking to improve the ability to break down consumption into sectors, and reviewing the sensitivity of the short-term model to growth trends in actual consumption.

Table 13 Tasmania operational energy consumption forecast accuracy by component

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	0	0	0.0%	0.0%
Heating Degree Days	722	771	-6.3%	-0.5%
Connections Growth	26	20	30.5%	0.1%
Large Industrial Loads	6,466	6,175	4.7%	2.8%
Rooftop PV	267	268	-0.4%	0.0%
PV non-scheduled generation	11	6	99.0%	-0.1%
Other non-scheduled generation	443	442	0.3%	0.0%
Network losses	439	498	-11.9%	-0.6%
Operational sent out	**11,126**	**10,466**	**6.3%**	**6.3%**
Auxiliary load	97	88	10.4%	0.1%
Operational as generated	**11,224**	**10,555**	**6.3%**	

Figure 11 Tasmania operational as generated energy consumption variance by component



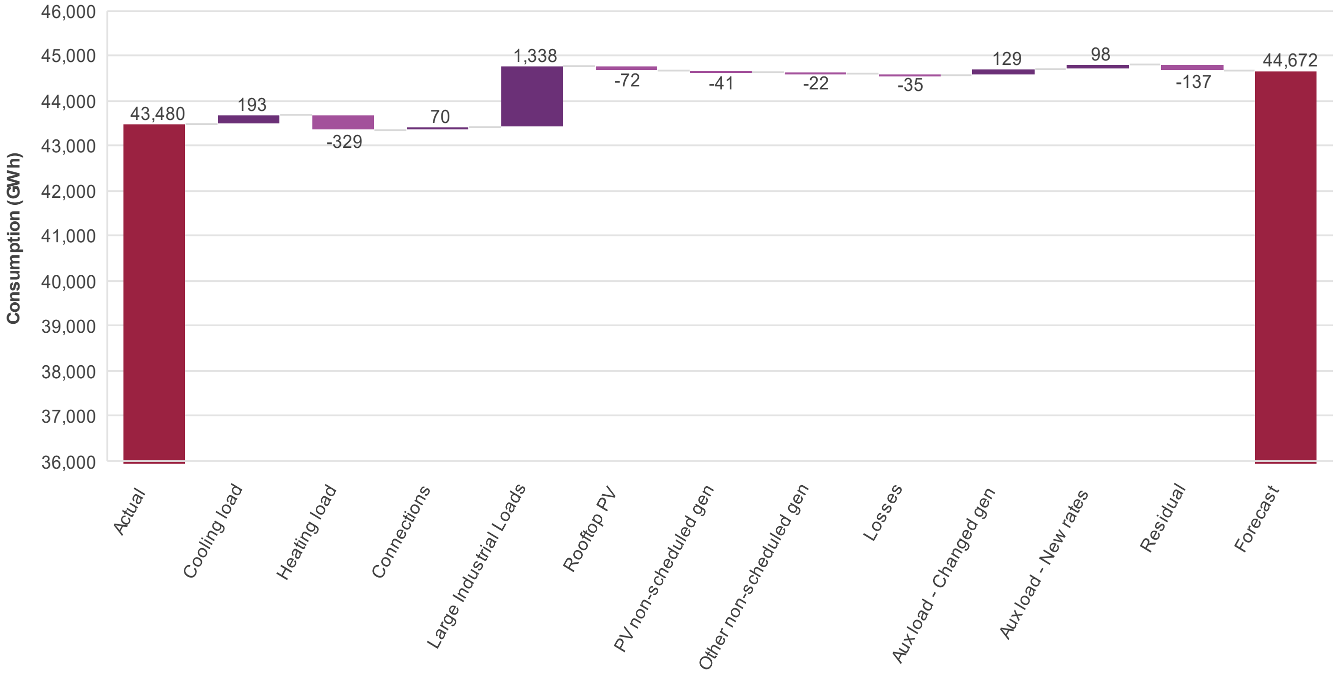
4.5 Victoria

Operational as-generated energy consumption for Victoria in 2022-23 was above the Central forecast by 2.7%. Table 14 and Figure 12 demonstrate the forecast accuracy by component. The largest inaccuracy driver was an over-forecast of LILs, followed by heating and cooling load variances. The former was predominantly driven by lower consumption at two of the region's largest loads because of unexpected production conditions. The latter was driven by the La Niña weather conditions which led to less cooling load and greater heating load. The differences for the other measured components were generally small. Accounting for the other measured elements, this leaves a residual of 137 GWh (or -0.3%). AEMO considers that the model for Victoria has performed well.

Table 14 Victoria operational energy consumption forecast accuracy by component

Category	2022 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	703	510	37.8%	0.4%
Heating Degree Days	2,244	2,573	-12.8%	-0.8%
Connections Growth	236	166	42.2%	0.2%
Large Industrial Loads	7,147	5,808	23.0%	3.1%
Rooftop PV	4,257	4,185	1.7%	-0.2%
PV non-scheduled generation	622	581	7.1%	-0.1%
Other non-scheduled generation	851	829	2.7%	-0.1%
Network losses	2,418	2,453	-1.4%	-0.1%
Operational sent out	**42,016**	**41,051**	**2.4%**	**2.2%**
Auxiliary load	2,656	2,429	9.3%	0.5%
Operational as generated	**44,672**	**43,480**	**2.7%**	

Figure 12 Victoria operational as generated energy consumption variance by component



5 Extreme demand forecasts

There are three extreme demand events of interest for assessing reliability and system security, and each has differing relevance for forecasting and system engineering:

- Summer maximum.
- Winter maximum.
- Annual minimum.

Maximum demand events are driven by high business and industrial loads coincident with high residential appliance use, typically in response to extreme heat or cold. Minimum demand events typically occur with extremely mild weather, sometimes overnight when customer demand is low, though more frequently now during the day when high solar irradiance results in high rooftop PV generation coinciding with mild conditions which avoid high daytime heating or cooling appliance use.

Unlike the consumption forecast, which is a point forecast (a single estimate assuming typical weather conditions eventuate on average across the year), the minimum and maximum demand forecasts are represented by probability distributions. The minimum and maximum probability distributions are summarised for publishing via 10%, 50%, and 90% probability of exceedance (POE) forecast values. AEMO assesses the accuracy of those in accordance with the Forecast Accuracy Report Methodology[24].

Probability distributions of demand extremes aim to capture a variety of random drivers including weather driven coincident customer behaviour and non-weather driven coincident behaviour. Non-weather driven coincident customer behaviour is driven by a wide variety of random and social factors, including:

- Work and school schedules, traffic, and social norms around mealtimes.
- Many other societal factors, such as whether the beach is pleasant, or the occurrence of retail promotions.
- Industrial operations.

While there is a strong relationship between weather and demand, non-weather factors are also a large driver of variance, so for the same temperature, maximum demand can vary by thousands of megawatts across the NEM due to other factors.

To better elucidate model performance in the presence of this variance, AEMO reports the probabilistic drivers of extreme events graphically, overlaid with the actual value of the input. This is consistent with the recommendations from the expert review of AEMO's forecast accuracy metrics by University of Adelaide conducted in 2019[25].

[24] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-accuracy-report-methodology/forecast-accuracy-reporting-methodology-report-aug-20.pdf.

[25] Cope, R.C., Nguyen, G.T., Bean, N.G., Ross, J.V. (2019) Review of forecast accuracy metrics for the Australian Energy Market Operator. The University of Adelaide, Australia, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/ForecastMetricsAssessment_UoA-AEMO.pdf.

5.1 Extreme demand events in 2022-23

AEMO forecasts demand in the absence of load shedding, network outages, and any customer response to price and/or reliability signals, known as demand side participation (DSP). DSP is explicitly modelled as a supply option to meet forecast demand, as detailed in Section 6.6.

A maximum demand day observed during summer may have occurred at a time of supply shortages, leading to load shedding, or very high prices which may have reduced demand. Comparing actual observed demand with forecast values can only be done if on the same basis, so some adjustments to actual demand are necessary to accommodate these responses.

For the purposes of assessing forecast accuracy, adjustments have been grouped into two types:

- Firm – adjustments estimated based on metering data.
- Potential – adjustments that are more speculative and are based on expected behaviour rather than metering data.

In 2022-23, all regions except for Tasmania are subject to minor adjustments for their summer maximum demand as follows:

- New South Wales – 18 MW firm adjustment up based on estimated price-driven DSP at time of maximum demand.
- Queensland – 24 MW firm adjustment up based on estimated impact of Energy Queensland's Peak Smart DSP program being called during the half-hour maximum demand was reached.
- South Australia – 10 MW firm adjustment up based on estimated price-driven DSP at time of maximum demand.
- Victoria – 25 MW firm adjustment up applied as result of AusNet Services' Critical Peak Demand program, which impacted the period 14:00– 18:00 AEST on the maximum demand day and therefore the half-hour ending 18:00.

5.1.1 Summer 2022-23 maximum demand events

Table 15 shows the summer maximum demand periods for NEM regions in 2022-23, with slight adjustments for the mainland NEM regions (see above).

Table 15 Summer 2022-23 maximum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent-out	Adjustment (firm)*	Adjustment (potential)	Adjusted sent out
NSW	Mon, 6 March 2023 18:00	13,136	369	12,767	18		12,785
QLD	Fri, 17 March 2023 17:30	10,070	439	9,631	24		9,655
SA	Thu, 23 February 2023 19:00	3,125	41	3,084	10		3,094
TAS	Thu, 15 December 2022 7:00	1,392	9	1,383			1,383
VIC	Tue, 17 January 2023 18:00	8,988	363	8,625	25		8,650

* New South Wales, Queensland, South Australia and Victoria include firm adjustments as outlined above the table.

5.1.2 Winter 2023 maximum demand events

AEMO has also reviewed the winter maximum demand events to determine if any firm or potential adjustments were necessary. As indicated in Section 6.6, prices were generally too low at time of peak to trigger any price response. The winter maximum demand outcomes are shown in Table 16 below.

Table 16 Winter 2023 maximum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	Tue, 20 June 2023 19:00	12,567	436	12,131			12,131
QLD	Mon, 24 July 2023 18:30	8,137	418	7,79			7,719
SA	Thu, 22 June 2023 18:30	2,523	13	2,510			2,510
TAS	Thu, 22 June 2023 8:30	1,678	21	1,657			1,657
VIC	Thu, 19 June 2023 18:00	8,018	337	7,681			7,681

5.1.3 Annual 2022-23 minimum demand events

AEMO has reviewed the minimum demand events across the year. All regions had daytime minimums, even Tasmania, which historically has had its annual minimum demand occurring overnight. Overall, the minimum demand days occur on weekends or arounds holidays when electricity consumption is relatively low, especially when the weather is mild and there is abundant sunlight, allowing solar PV to reach close to maximum output, but while temperature is not high enough to drive any significant cooling demand, or low enough to cause a need for heating.

In 2022-23, all regions except Tasmania reached their lowest minimum demand levels since the establishment of the NEM[26]. The minimum demand events are listed in Table 17 by region.

Table 17 Annual minimum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	Sun, 9 April 2023 13:00	4,101	144	3,957			3,957
QLD	Sun, 9 April 2023 12:00	3,487	254	3,233			3,233
SA	Sun, 16 October 2022 13:00	100	4	96			96
TAS	Sun, 6 November 2022 13:00	846	6	840			840
VIC	Sun, 18 December 2022 13:00	2,195	206	1,989			1,989

5.2 New South Wales

Figure 13 shows the half-hourly time-series for New South Wales OPSO demand, and extreme demand events for the last year until the end of winter 2023. Further detail on the extreme demand events observed during the year is provided in Table 18.

[26] Preliminary data suggests that new minimum demand records will likely be set for all regions except Tasmania in 2023/24.

Figure 13 New South Wales demand with extreme events identified

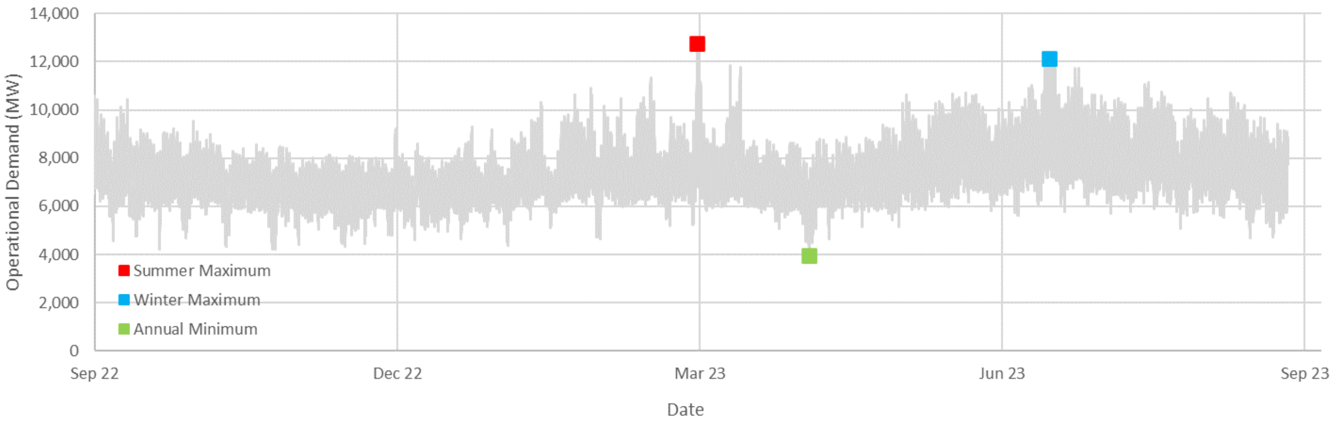


Table 18 New South Wales 2022-23 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Monday, 6 March 2023 18:00	Tuesday, 20 June 2023 19:00	Sunday, 9 April 2023 13:00
Temperature* (°C)	35.8	6.8	20.5
Max temperature (°C)	38.9	16.3	20.7
Min temperature (°C)	19.1	3.6	14.6
Losses (MW)	774	732	209
Non-scheduled generation (NSG) output (MW)	223	184	366
Rooftop PV output (MW)	269	0	3249
Sent out (OPSO)	**12,767 (adjusted to 12,785)^**	**12,131**	**3,957**
Auxiliary (MW)	369	436	144
As generated (OPGEN)	**13,136 (adjusted to 13,154)^**	**12,567**	**4,104**

* Bankstown Airport weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted due to observed price-driven DSP.

Figure 14 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and customer behaviour. The summer and winter maximum demand events both fell well within their respective forecast distributions, while the annual minimum demand event fell just below the forecast 90% POE.

Figure 14 New South Wales simulated extreme event probability distributions with actuals

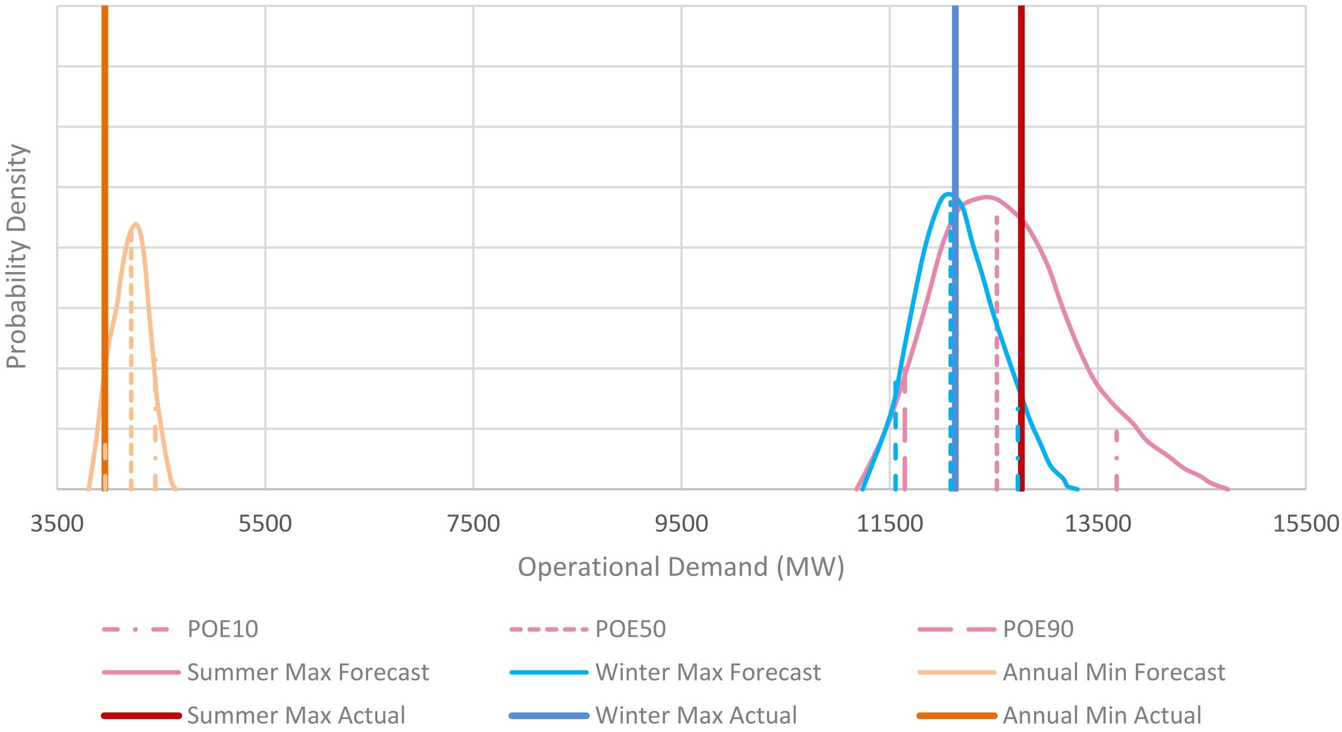


Figure 15 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Summer maximum operational (sent out) demand occurred on Monday, 6 March 2023 18:00 NEM time. At the time of maximum demand, Bankstown recorded a temperature of 35.8°C with a daily maximum of 38.9°C.

Overall, summer maximum demand was within forecast expectations.

- The temperature at the time of this maximum demand event was within the distribution of the simulated temperature outcomes at the time of maximum demand. New South Wales experienced a mild La Niña summer, with temperatures generally lower than forecast. However, starting from March 2023, the conditions gradually transitioned into an El Niño Watch.
- The summer maximum demand event aligned with this ENSO (El Niño–Southern Oscillation) transition, and it coincided with the day of the highest daily summer maximum temperature which happened in March. On this day, not only was the highest daily temperature of the 2023 summer reached, but the temperatures in the morning and evening were also the highest. The temperature was already at 30.4°C at 9:00 NEM time and increased to 38.9°C by 15:30 NEM time. OPSO demand peaked at 18:00 when the temperature was 35.8°C. Because of the high temperatures starting early in the day and lasting into the evening, the accumulated heat created a significant demand for cooling, leading to the maximum demand event.
- Simulation outcomes were weighted towards maximum demand occurring in late January/early February. The summer of 2023 was an exception because, as noted, summer was dominated by La Niña conditions and mild temperatures until a sudden shift to El Niño Watch conditions in March and the resultant maximum demand event. The summer maximum demand event falling on a Monday is consistent with the simulations where most of these events occurring on weekdays.

The time of summer maximum demand event fell in the middle of the distribution. PV generation at time of maximum demand sits within the forecast PV generation distribution, but slightly to the left. The relatively lower PV generation is another factor contributing to the maximum demand being slightly higher than the 50% POE.

Winter maximum demand occurred on Tuesday, 20 June 2023 at 19:00 NEM time, with a temperature of 6.8°C recorded at Bankstown. The maximum temperature of the day was 16.3°C. The minimum temperature on the day was 3.6°C.

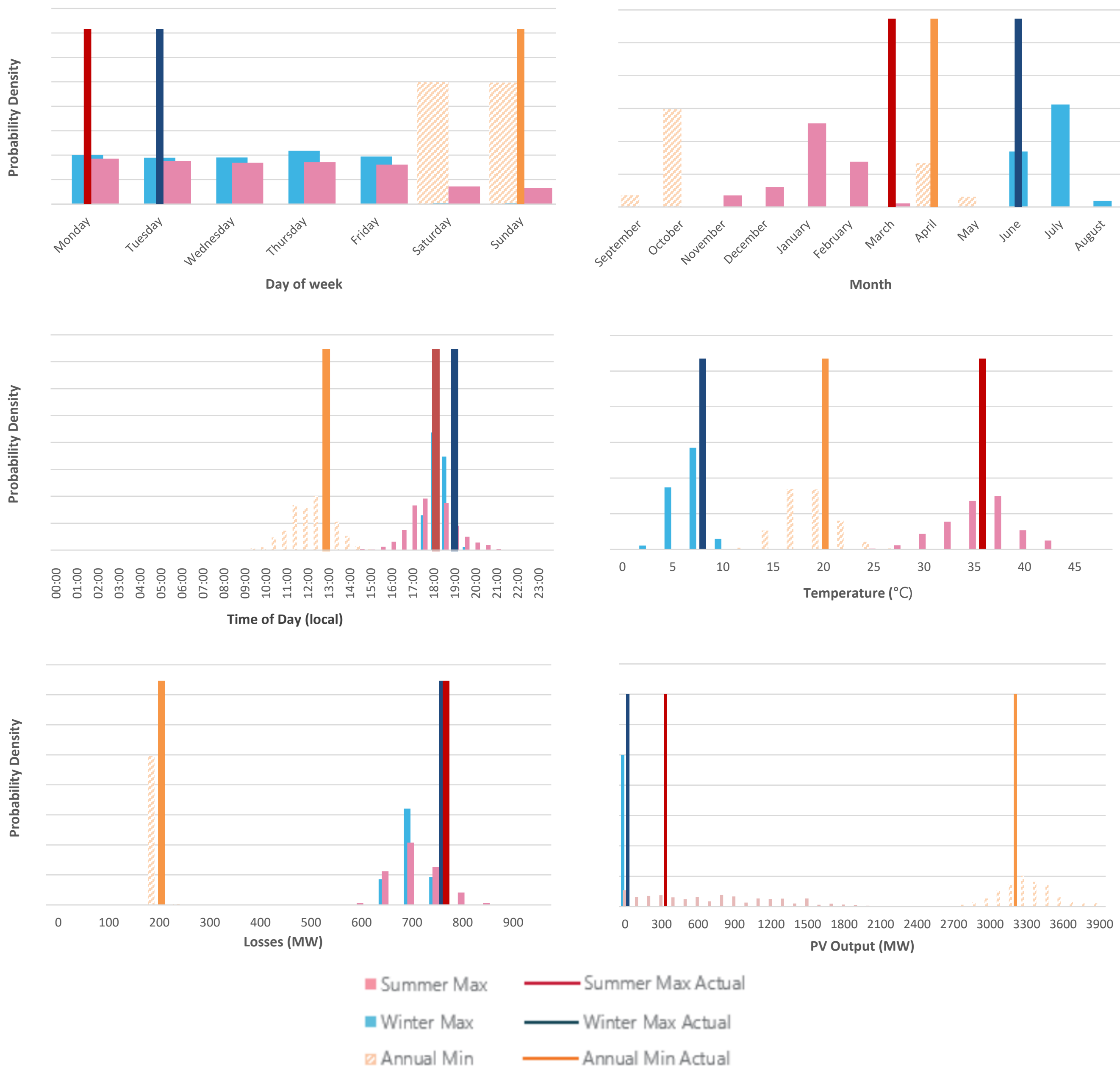
The observed maximum demand is within expectations, falling just above the 50% POE forecast

- Winter maximum demand events exhibit a relatively narrow temperature distribution, with the highest density occurring in the range of 5-7.5°C, which matches the observed temperature, and this supports why the maximum demand is close to 50% POE. Maximum demand peaked at 19:00 NEM time, well after sunset, so PV generation was zero at the time of maximum demand.
- The forecast expected that winter maximum demand would occur in late June or in July, when heating loads are normally significantly higher, which is consistent with the observed maximum demand.

Annual minimum demand occurred on Sunday 9 April 2023 at 13:00 NEM time, when the temperature was 20.5°C.

- Actual minimum demand was just below 90% POE. 3.3Predicting demand on weekends, especially during mild weather, is challenging, because firstly, unlike extreme maximum and minimum demand, temperature variations in the mild range do not have clear directional impact on demand and secondly, by their nature, weekends provide fewer data points over time than weekdays on which to assess demand drivers. The actual demand is influenced by several non-weather factors that cannot be modelled due to a lack of available data, such as traffic patterns and appliance usage. AEMO has implemented a method to enhance the accuracy of its minimum demand models by allocating residuals based on temperature to better capture non-weather components. This improvement was applied to the 2023 ESOO.
- Simulation outcomes were weighted towards occurring during weekends, with their lower commercial and industrial demand, and typically in October and April due to the mild temperatures, where there is less demand for either cooling and heating, and solar PV systems are not adversely affected by high temperatures, maintaining their efficiency. This is consistent with the actual occurrence of annual minimum demand on Sunday 9 April 2023.
- With most drivers within expectations, AEMO will investigate why the actual fell under the 90% POE value. A contributing factor AEMO will look into is the higher than forecast installed capacity of rooftop PV (see Section 3.3), which would have lowered demand at time of minimum relative to what was forecast. Given three regions recorded minimum demands lower than the 90% POE forecast, AEMO will seek to determine if there is a common cause.

Figure 15 New South Wales simulated extreme event probability distributions with actuals



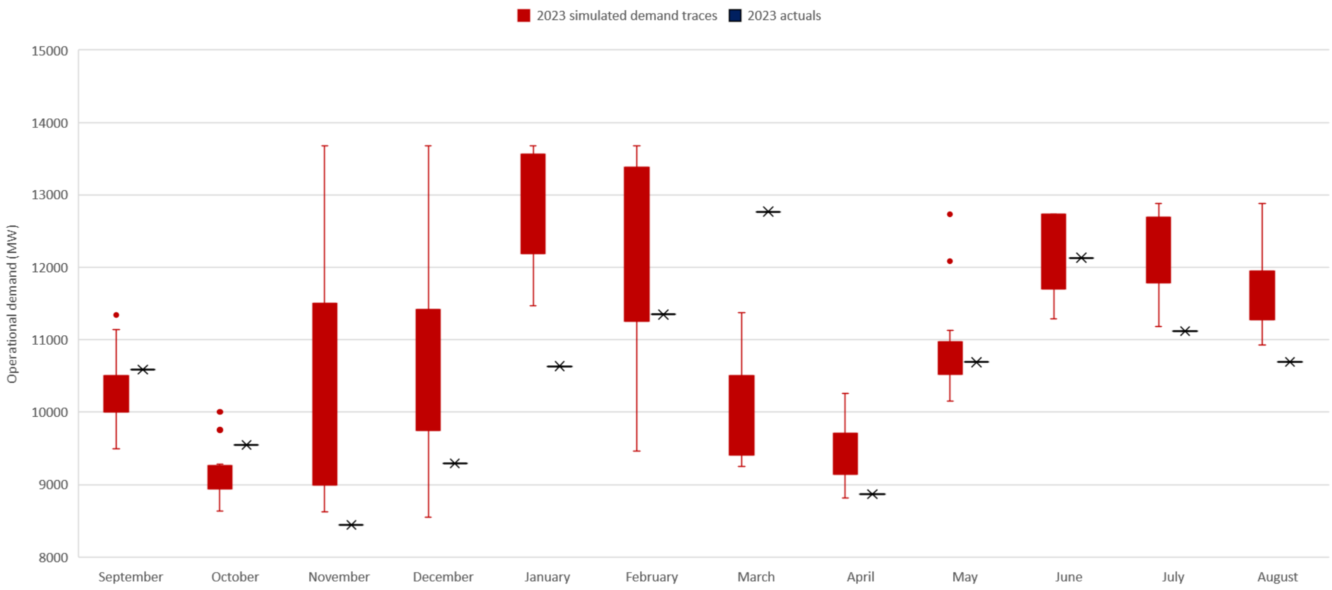
Monthly maximums

The operational energy consumption and extreme demand forecasts are used to develop profiles of 30-minute customer demand in time-series consistent with the weather patterns observed in 12 reference years (2011-22), transformed to hit 10% POE and 50% POE demand forecasts, referred to as demand 'traces'. Each trace is independently scaled to achieve the summer and winter maximum demand forecasts at least once throughout summer and winter respectively. These traces are used in assessing reliability in the ESOO, the Energy Adequacy Assessment Projection (EAAP), and the Medium-Term Projected Assessment of System Adequacy (MT PASA).

Due to actual weather patterns in some months being warmer or cooler than the range of historical weather patterns observed across the reference years, it is reasonable to expect that a limited number of actuals may fall outside the range of monthly maximums of operational demand in the demand traces.

The box plot[27] in 0 shows the range of monthly demand maximums for the 2023 simulated demand traces for 10% POE and 50% POE annual forecasts. The red dots represent outliers, which are observations at the tail end of the distribution. During both the summer and winter months, several actual monthly maximums fell outside the distribution range, primarily due to the influence of ENSO variations. Before March 2023, the prevailing ENSO condition was La Niña, but it abruptly transitioned to El Niño watch and El Niño Alert. This shift explains why the majority of actual maximum temperatures in summer were below the distribution range, and then in March, they suddenly rose above it. The unusually warm winter resulted in actual maximums consistently being lower than those simulated. As the simulations exclude 90% POE traces, outcomes slightly below the shown traces are in line with expectations for mild outcomes like January, July and August.

Figure 16 New South Wales monthly maximum demand in demand traces compared with actuals



5.3 Queensland

Queensland's half-hourly OPSO demand time-series and extreme events are shown below in Figure 17. Further detail on the extreme demand events for the year is provided in 0.

[27] Box plots are explained in Section 2.1.

Figure 17 Queensland demand with extreme events identified

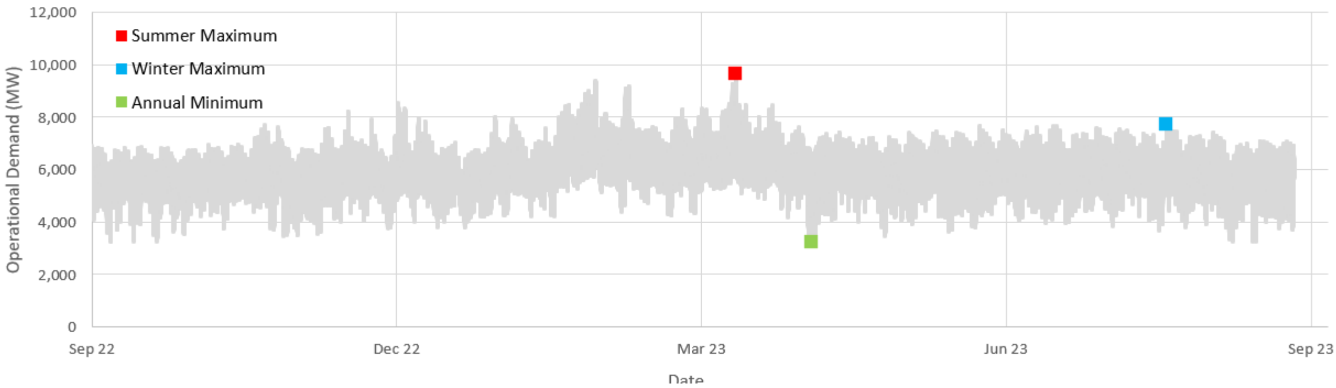


Table 19 Queensland 2022-23 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Friday, 17 March 2023 17:30	Monday, 24 July 2023 18:30	Sunday, 9 April 2023 12:00
Temperature* (°C)	30.1	15.6	25.7
Max temperature (°C)	36.1	19.7	27.5
Min temperature (°C)	23.5	10.6	14.9
Losses (MW)	599	460	135
NSG output (MW)	207	170	295
Rooftop PV output (MW)	476	0	3,324
Sent out (OPSO)	**9,631 (adjusted to 9,655)^**	**7,719**	**3,233**
Auxiliary (MW)	439	418	254
As generated (OPGEN)	**10,070 (adjusted to 10,084)^**	**8,137**	**3,487**

* Archerfield Airport weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to include the impact of Energy Queensland's Peak Smart program, which was called during the half-hour where maximum demand was observed.

Figure 18 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The summer maximum demand outcome fell well within the forecast distribution. The winter maximum demand was, however, well below the simulated range and the annual minimum demand event fell just below its forecast distribution.

Figure 18 Queensland simulated extreme event probability distributions with actuals

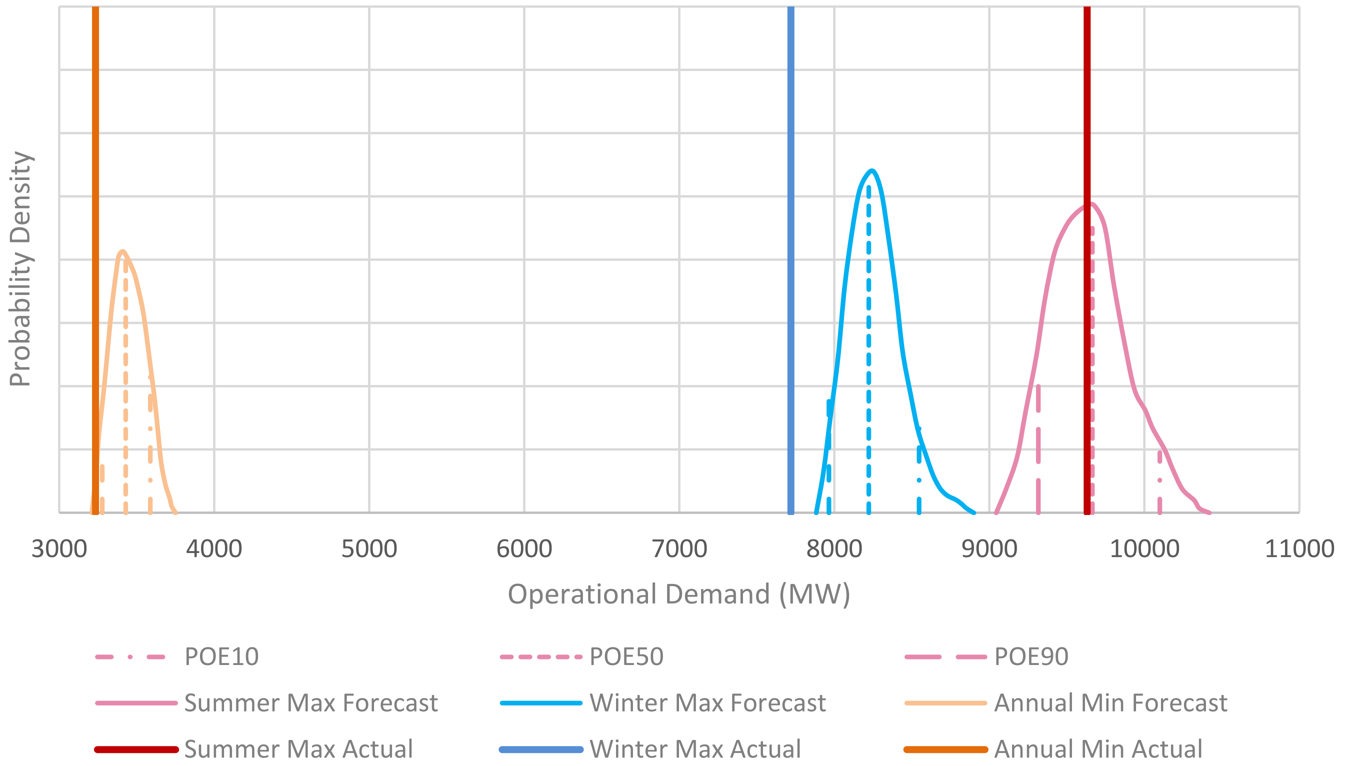


Figure 19 shows the probability distribution and actuals for relevant model inputs. A discussion of the insights from these figures follows.

Maximum demand occurred in summer on Friday 17 March 2023 at 17:30 NEM time. At the time of maximum demand, Archerfield recorded a temperature of 30.1°C with an earlier daily maximum of 36.1°C.

- Figure 18The maximum demand was within the range expected by the forecast, falling around the 50% POE. The maximum demand event happened on the second hottest weekday in the summer. The highest daily maximum temperature was recorded on 6 December 2022, reaching 36.3°C. On 17 March 2023, the maximum temperature was slightly lower at 36.1°C. However, the apparent temperature on 17 March 2023 was higher due to the higher relative humidity experienced during the late afternoon, approximately ranging from 40% to 60%. Furthermore, in the days leading up to 17 March 2023, there was a continuous period of four days with hot weather, where the daily maximum temperatures exceeded 30°C. In contrast, on 6 December 2022, only the preceding day had temperatures exceeding 30°C. This trend was influenced by the transition of ENSO from La Niña to El Niño Watch, starting in March 2023. This transition made it more likely for consecutive hot weather and heatwaves to occur, ultimately making 17 March 2023 the day with the highest electricity demand.
- The maximum demand event happened on a Friday, which is within expectations, consistent with the simulations indicating a weekday peak. However, simulation outcomes were weighted towards occurring in December to February, with the actual occurrence in March due to the unique characteristics of the summer in 2023, due to the previously explained ENSO observations.
- The development of a sea breeze, emerging cloud cover, and subsequent storms dropped temperatures and the dew point, causing the time of maximum demand to fall in the early range of the simulated time-of-day outcomes. The early timing caused the actual PV output to be upper range of the simulated PV output.

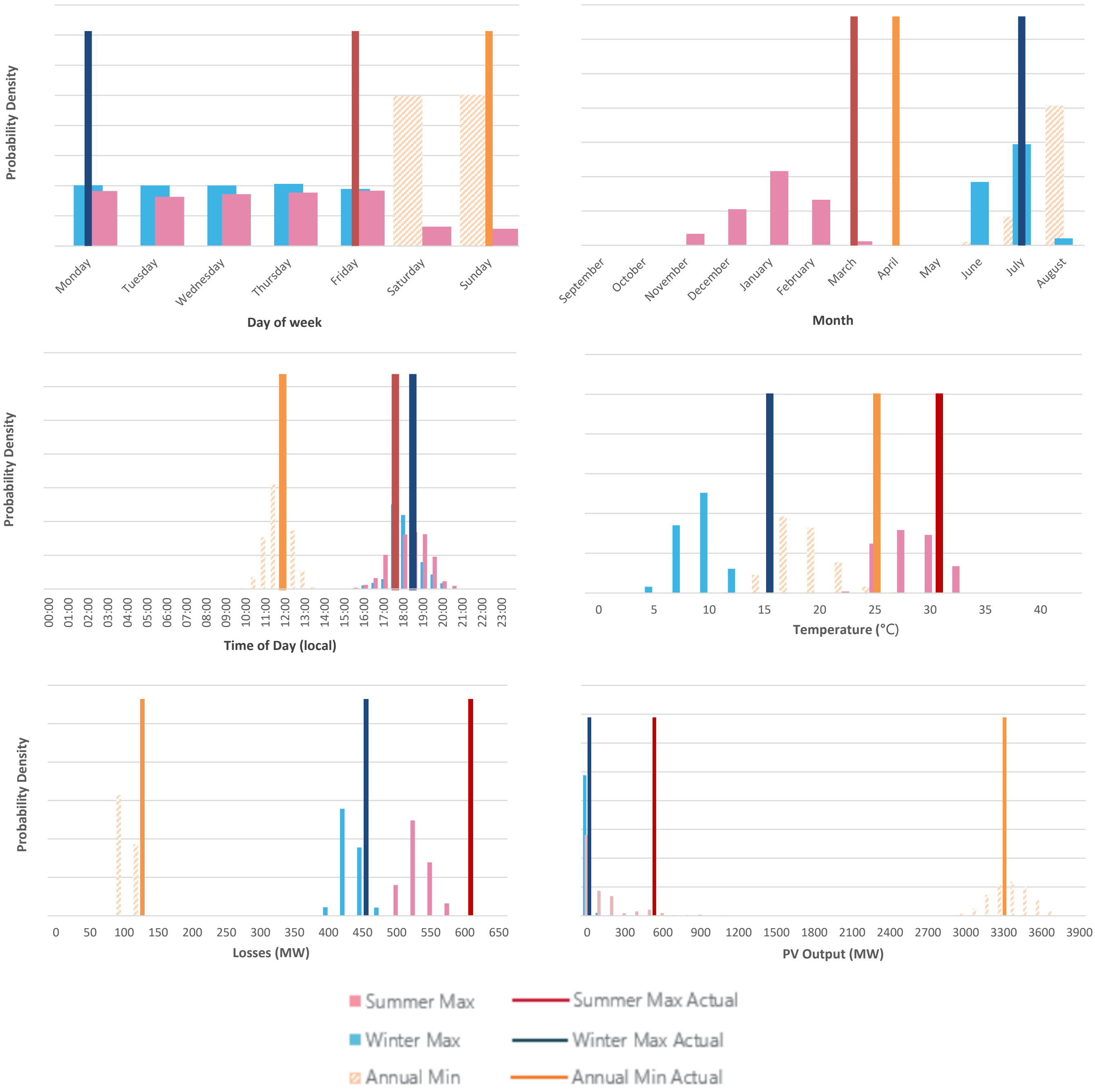
Winter maximum demand occurred on Monday 24 July 2023 at 18:30 NEM time. Temperature at the time was 15.6°C at Archerfield. Maximum demand did fall below the 90% POE forecast, as would likely be expected, given the El Niño Alert winter and 2023 being one of the warmest winters in NEM history. The winter of 2023 was notably warm, with an average daily maximum temperature of around 23°C throughout the season. On the day of the maximum demand event, the highest temperature recorded was 19.7°C, and the temperature at the time of the event was 15.6°C. The warm winter led to a reduction in heating demand, causing the maximum demand to fall below 90% POE.

- Maximum demand occurred on a Monday, in July, at 18:30 NEM time, consistent with the simulation outcomes. The temperature at the time of maximum demand was towards the far-right range of the simulated weather distribution, further confirming that the warm winter in 2023 was historically unusual.
- The actual losses and PV output at maximum demand event were both within the simulation outcomes.

Annual minimum demand occurred on Sunday 9 April 2023 at 12:00 NEM time, when the temperature was 25.7°C.

- Minimum demand was lower than forecast expectations, falling below 90% POE value. It occurred in April, rather than the most simulated month of August. This is because the temperature on 9 April 2023 was quite mild, resulting in minimal heating and cooling demand, leading to a relatively low underlying demand. Additionally, the weather conditions on that day were ideal for PV generation. These factors, combined with the low underlying demand and high PV output, turned April 9th into a minimum demand day.
- The time of minimum demand and PV generation at time of minimum demand event matched closely with the simulation outcomes.
- The temperature at time of minimum demand however fell in the high range of the simulation. Being a Sunday, impact on cooling needs in the commercial sector would be limited (office buildings start cooling at temperatures well below residential households). With such a high temperature, the actual falling under the 90% POE value is unexpected, so AEMO will review the minimum demand model.

Figure 19 Queensland simulated input variable probability distributions with actuals

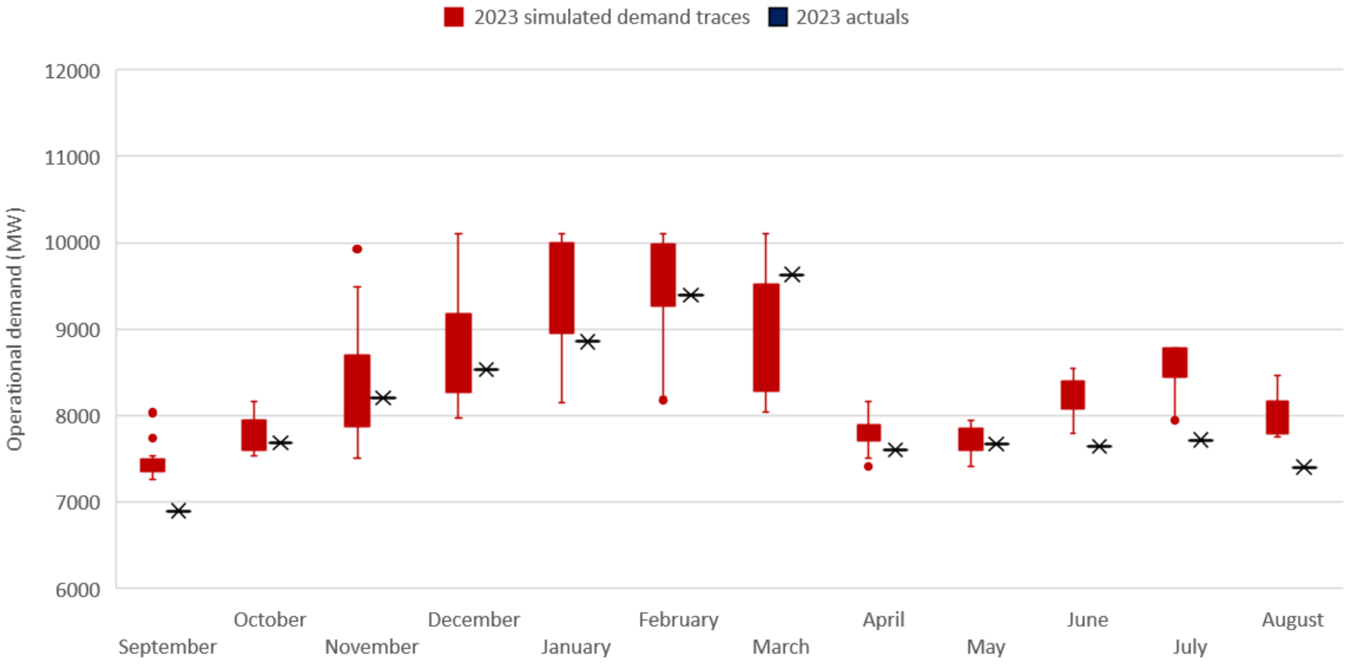


Monthly maximums

The box plot in Figure 20 shows the range of monthly demand maximums for the 2023 simulated demand traces for 10% POE and 50% POE annual forecasts. The red dots represent outliers, which are observations at the tail end of the distribution.

With the exception of the winter months, monthly maximums generally fell within the distribution range. The winter of 2023 was one of the warmest in history, which is why actual maximums being much lower than 50% POE forecast were as expected.

Figure 20 Queensland monthly maximum demand in demand traces compared with actuals



5.4 South Australia

South Australia's half-hourly OPSO demand time-series and extreme events are shown below in Figure 21. Further detail on the extreme demand events for the year is provided in 0.

Figure 21 South Australia demand with extreme events identified

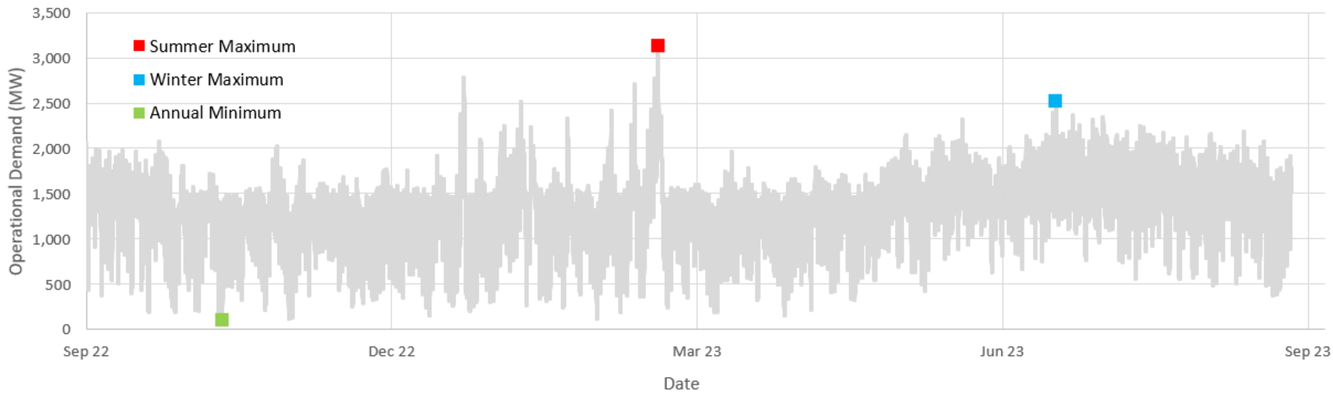


Table 20 South Australia 2022-23 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Thursday, 23 February 2023 19:00	Thursday, 22 June 2023 18:30	Sunday, 16 October 2022
Temperature* (°C)	35.6	9.6	18.7
Max temperature (°C)	39.8	11.3	19.7
Min temperature (°C)	26.6	8.5	7.2
Losses (MW)	289	236	-6
NSG output (MW)	33	6	181
Rooftop PV output (MW)	80	0	1281
Sent out (OPSO)	**3,084 (adjusted to 3,094)^**	**2,510**	**96**
Auxiliary (MW)	41	13	4
As generated (OPGEN)	**3,125 (adjusted to 3,135)^**	**2,523**	**100**

* From 1 August 2020 measurements use the Adelaide (West Terrace) weather station, Bureau of Meteorology station 023000. For more information, see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to observed price-driven DSP at time of peak demand.

Figure 22 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The actual summer maximum demand and the annual minimum demand events both fell well within forecast distributions, while the winter maximum demand event fell outside its forecast probability distribution, for reasons discussed below.

Figure 22 South Australia simulated extreme event probability distributions with actuals

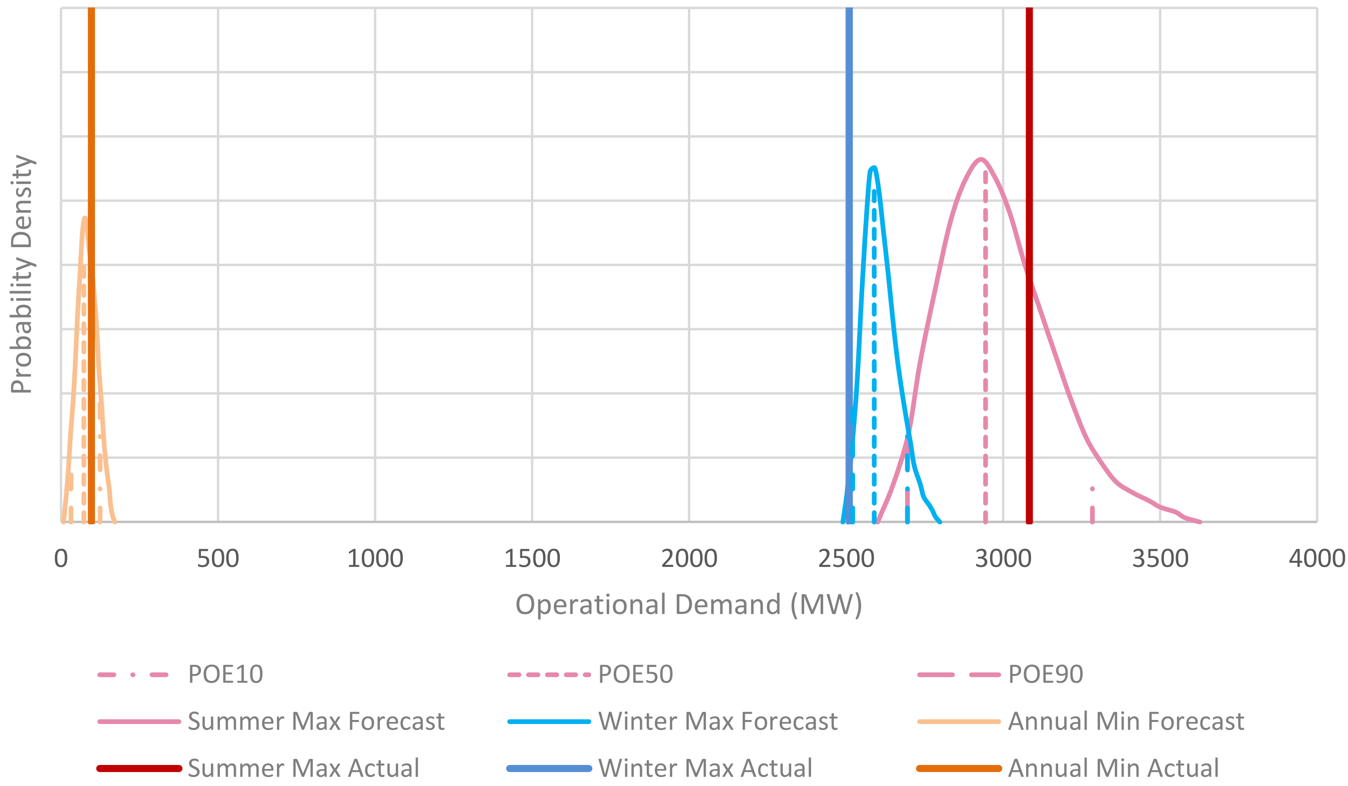


Figure 23 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum demand occurred in summer on Thursday 23 February 2023 at 19:00 NEM time with a temperature of 35.6°C recorded at Adelaide (West Terrace).

The maximum demand was well within the distribution of the simulations falling between 50% POE and 10% POE forecast.

- Simulation outcomes were weighted toward the maximum occurring on a weekday and in January/February, consistent with what was observed.
- The temperature at the time of maximum demand occurred within the simulated temperature range, which was around the midpoint of the distribution.
- The summer maximum demand event coincided with the working day of the highest temperature. The temperature on 23 February 2023 started high, reaching 31.3°C as early as 9:00 NEM time, and the preceding two days had temperatures exceeding 35°C. The extended period of extreme temperatures is a contributing factor to the actual peak falling above the 50% POE forecast.
- The time of the maximum demand was consistent with the simulations also, peaking at 19:00 NEM time.
- PV output at the time of maximum demand was in the middle of the PV forecast distribution, in line with the time of day being in the middle of its distribution as well.

Winter maximum demand occurred on Thursday 22 June 2023 at 18:30 NEM time, with a temperature of 9.6°C recorded at Adelaide (West Terrace).

The winter maximum demand was within the overall simulation range but did fall slightly below 90% POE forecast.

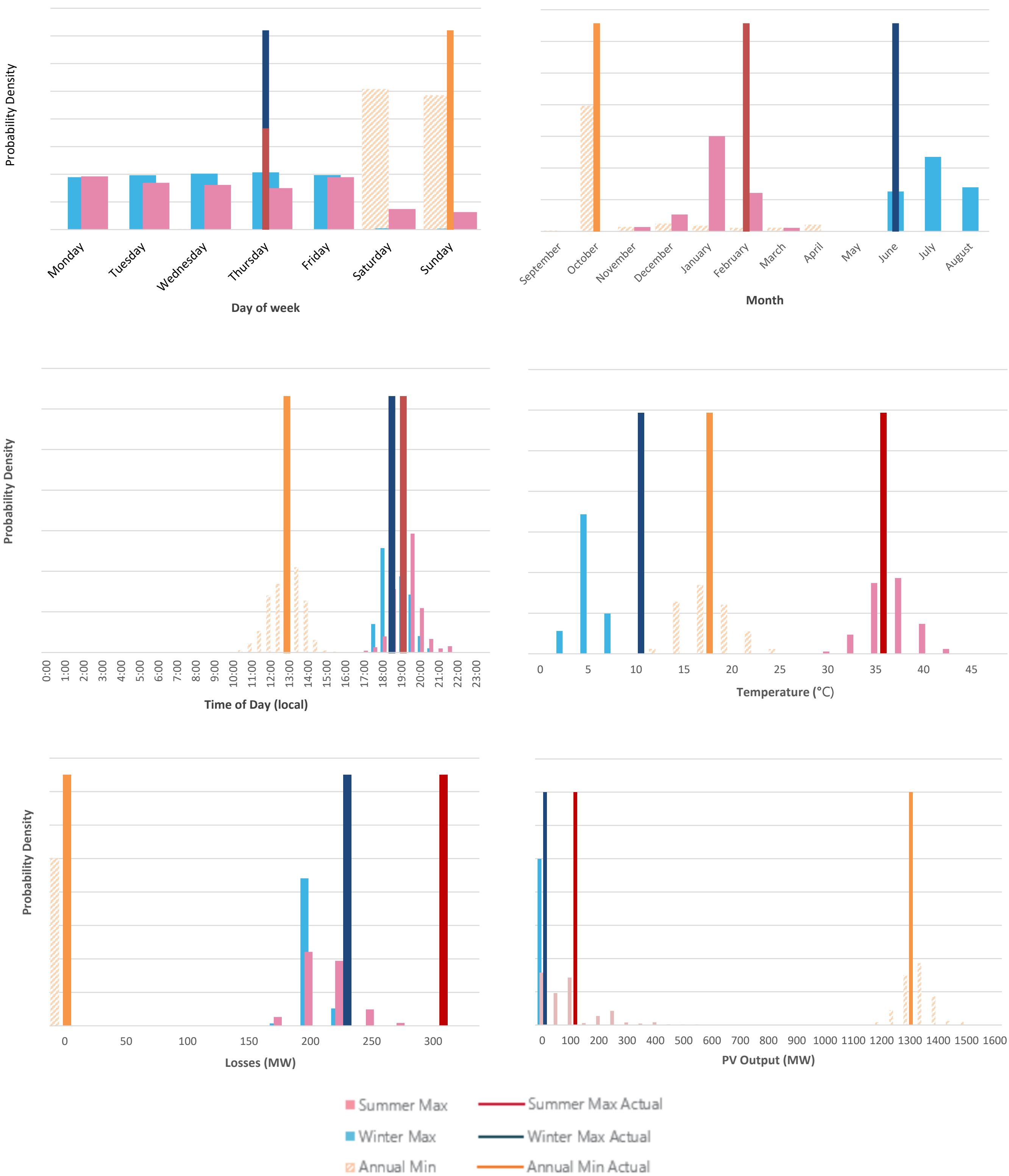
- The winter of 2023 was warm, as the ENSO condition was on El Niño Alert. A temperature of 9.6°C was recorded at the time of maximum demand, which fell at the very top end of the range of the simulated temperature distribution. Consequently, the maximum demand occurred in the low range of the simulations.
- The winter maximum demand event happened on a weekday in June at 18:30 NEM time in line with expectations and following the simulation outcomes closely.
- The late timing of the peak, as usual for winter, meant that rooftop PV did not contribute to lower demand at the time as expected.

Annual minimum demand occurred on Sunday 16 October 2022 at 13:00 NEM time, when the temperature was 18.7°C; this is a typical temperature for such events, requiring minimal cooling or heating demand.

The minimum demand fell within the simulation distribution, close to the 50% POE forecast.

- Simulation outcomes suggest that the minimum demand is likely to happen on a weekend in October, in the middle of the day. The actual minimum demand event was consistent with the simulations.
- PV generation was in line with expectations from the simulated outcomes.

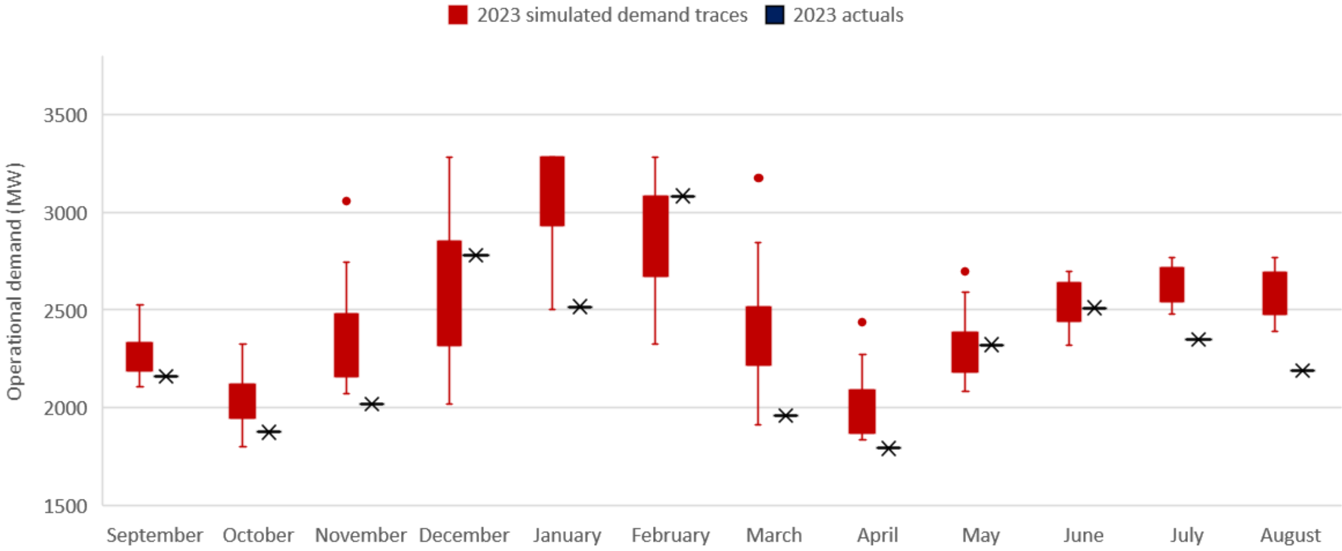
Figure 23 South Australia simulated input variable probability distributions with actuals



Monthly maximums

The box plot in Figure 24 shows the range of monthly demand maximums for the 2023 simulated demand traces for 10% POE and 50% POE annual forecasts. The actual monthly maximum October, January and April all fall slightly below the ranges formed by the traces. As the modelling did not include 90% POE traces, outcomes slightly below the shown traces are in line with expectations and the influence of ENSO variations as the monthly maximums tend to fall below the 50% POE during the El Niño winter.

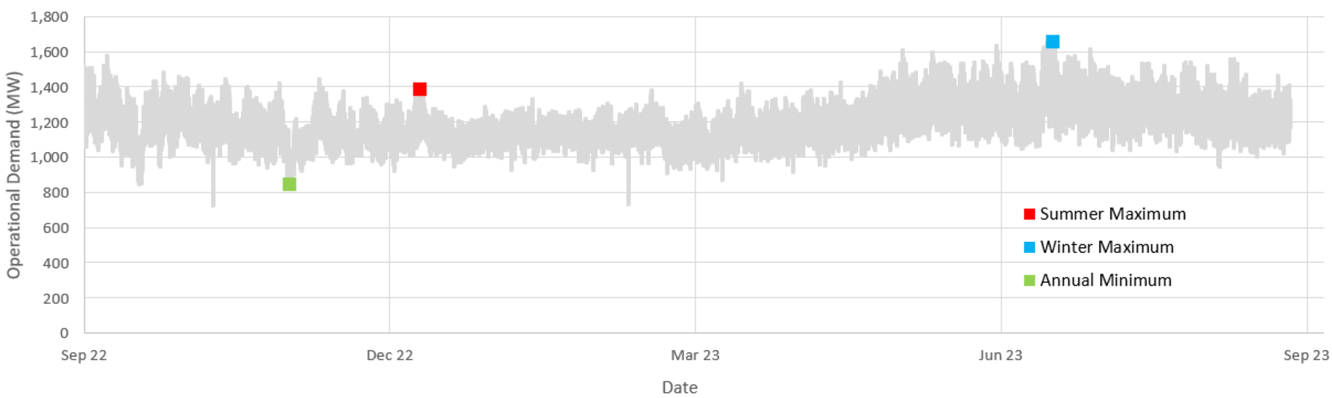
Figure 24 South Australia monthly maximum demand in demand traces compared with actuals



5.5 Tasmania

Tasmania's half-hourly OPSO demand time-series and extreme events are shown below in Figure 25. Tasmania is winter peaking, with summer maximums substantially below the winter maximums. Further detail for the extreme demand events for the year is provided in Table 21.

Figure 25 Tasmania demand with extreme events identified



Note: two events above have been excluded for the assessment of annual minimum demand, with dips in demand on both 14 October 2022 and 15 February 2023 being caused by load shedding following a trip of the Basslink interconnector.

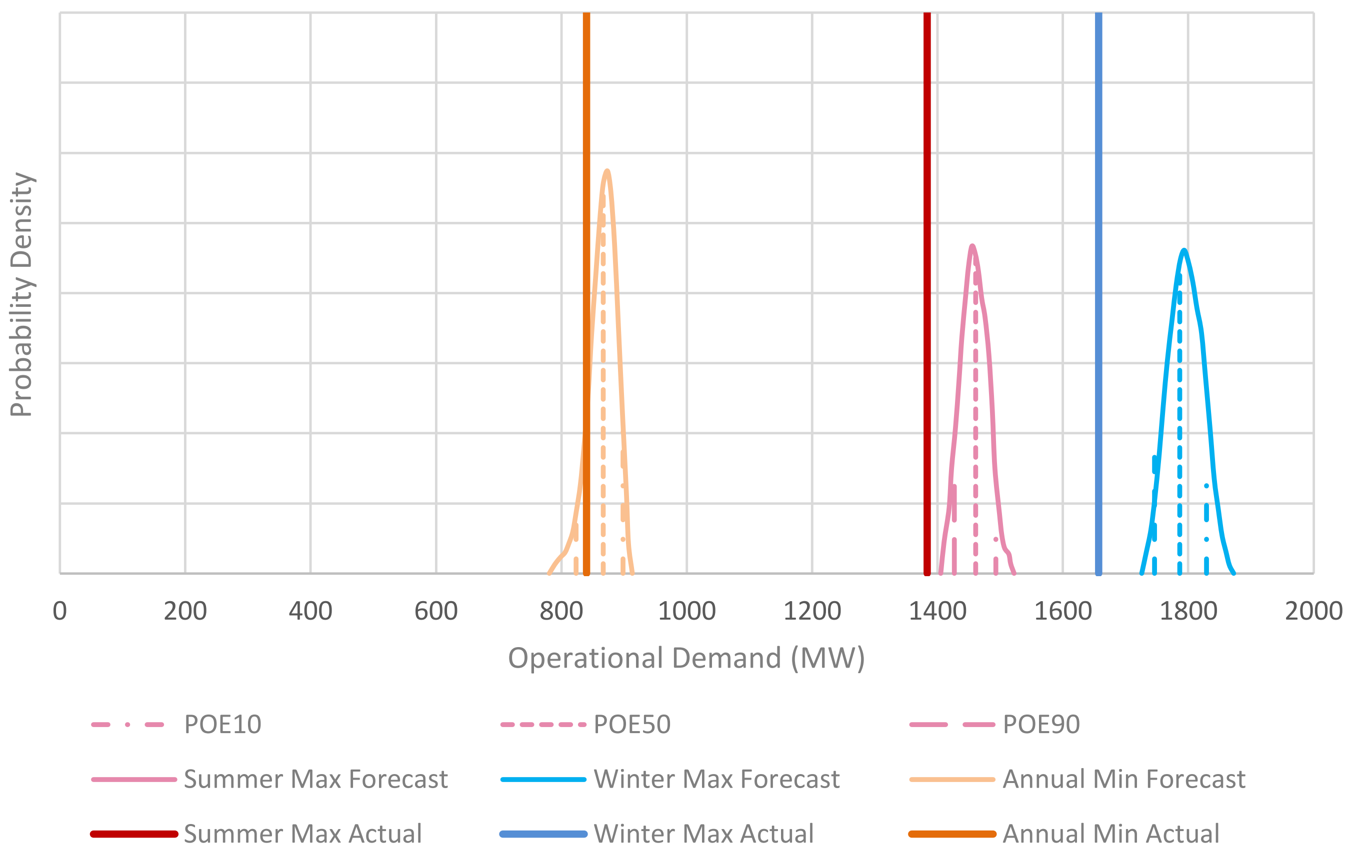
Table 21 Tasmania 2022-23 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Thursday, 15 December 2022 7:00	Thursday, 22 June 2023 8:30	Sunday, 6 November 202213:00
Temperature* (°C)	9	3.4	22.5
Max temperature (°C)	11.3	7.6	24.6
Min temperature (°C)	8.3	2.8	10
Losses (MW)	67	88	37
NSG output (MW)	22	56	73
Rooftop PV output (MW)	27	2	134
Sent out (OPSO)	**1,383**	**1,656**	**840**
Auxiliary (MW)	9	21	6
As generated (OPGEN)	**1,392**	**1,678**	**846**

* Hobart (Ellerslie Road) weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).

Figure 26 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. Both the summer and winter maximum demand events fell below their respective forecast probability distributions, while the annual minimum was well within the projected outcomes.

Figure 26 Tasmania simulated extreme event probability distributions with actuals



Demand in Tasmania is different from the mainland regions in two ways:

- Tasmania is consistently winter peaking; that is, its annual maximum demand is driven by winter heating load rather than summer cooling loads.
- Tasmania is influenced to a much larger extent by LIL operations, and weather (such as temperature) has a therefore smaller impact relative to other regions.

Figure 27 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum demand occurred in winter on Thursday, 22 June 2023 at 8:30 NEM time, with a temperature of 3.4°C recorded at Hobart (Ellerslie Road).

Maximum demand was below expectations, being below the 90% POE forecast by approximately 90 MW.

- Tasmania experienced a winter maximum demand event on the day with the lowest daily maximum temperature (7.6°C). The temperature started low with 3.4°C at 8:30 NEM time. These temperature conditions drive up heating load and make the maximum demand occur in the morning instead of evening.
- Simulation outcomes were weighted towards maximum demand occurring during a weekday evening in June to August. The time of peaking can be either in the morning or in the evening, depending on the weather profile and other factors like what large industrial load was doing at the time. The actual time of maximum demand event was consistent with the simulation.
- The temperature at the time of maximum demand event was around the middle of the simulation outcomes.
- Occurring around sunrise, PV generation was nearly zero at the time of the observed maximum demand.
- LILs at time of peak were 698 MW, whereas the forecast had a 50% POE value of 744 MW (10% POE was 774 MW, and the 90% POE was 714 MW). The outcome being below the 90% POE LIL value partially explains why the overall maximum demand fell just below the 90% POE. AEMO will review other components contributing to the over-forecast winter maximum demand.

Summer maximum demand occurred on Thursday 15 December 2022 at 7:00 NEM time, with a temperature of 9°C recorded at Hobart (Ellerslie Road).

The observed demand fell slightly below 90% POE outcome by approximately 44 MW.

- This year, the summer maximum was a morning peak during a cold snap in summer, different from the typical cooling demand-driven afternoon peaks observed on the mainland. This is in line with the simulations, which have some outcomes occurring during the morning.
- Simulation outcomes were weighted towards occurring on a weekday and in December to February, which is consistent with the Thursday 15 December occurrence. Similarly, PV generation at time of maximum was within expectations.
- LILs at the time of summer maximum were at 732 MW, lower than the forecast 90% POE outcome (748 MW). As for the winter maximum demand, LIL contribution to peak partially explains why the overall actuals value fell below the 90% POE. AEMO will review other components contributing to the over-forecast summer maximum demand.

Annual minimum demand occurred on Sunday, 6 November 2022 at 13:00 NEM time, when the temperature was 22.5°C. Tasmania is particularly affected by industrial demand, and variation in this causes minimum demand to be more volatile and unpredictable in terms of timing. The occasional low points of LIL were excluded in this report.

The annual minimum demand fell within the distribution between 90% POE and 10% POE.

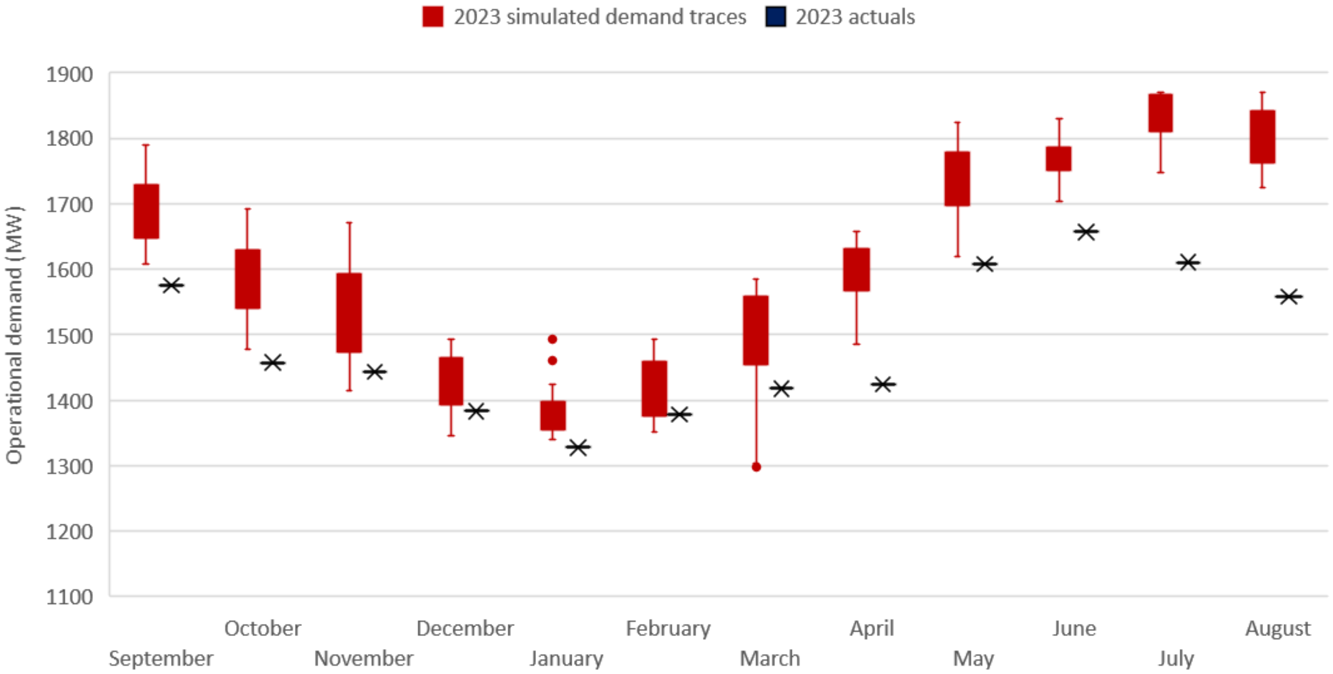
- Minimum demand was forecast to most likely occur in the middle of the day, on days with moderate temperatures and moderate PV generation.
- The simulations projected minimum demand most likely to be in March or November, in alignment with the actual outcome.
- Simulation outcomes were weighted towards occurring on the weekend, which aligns with the actual minimum demand event happened in a Sunday.

Figure 27 Tasmania simulated input variable probability distributions with actuals

Monthly maximums

The box plot in 0 shows the range of monthly demand maximums for the 2023 simulated demand traces for 10% POE and 50% POE annual forecasts. Many of the monthly actual maximum demand events fell below the range formed by the traces. It should be noted that these exclude 90% POE and it is therefore expected that some values would fall below the range formed by the 10% and 50% POE traces, especially in the very mild winter season experienced. Lower than forecast LIL demand may also be a contributing factor. But the magnitude of values falling below the range suggests that traces were too high for the summer and in particular winter maximum demand values, and this will be reviewed as discussed earlier.

Figure 28 Tasmania monthly maximum demand in demand traces compared with actuals



5.6 Victoria

Victoria's half-hourly OPSO demand time-series and extreme events are shown below in Figure 29. Further detail on the extreme demand events observed during the year is provided in Table 22.

Figure 29 Victoria demand with extreme events identified

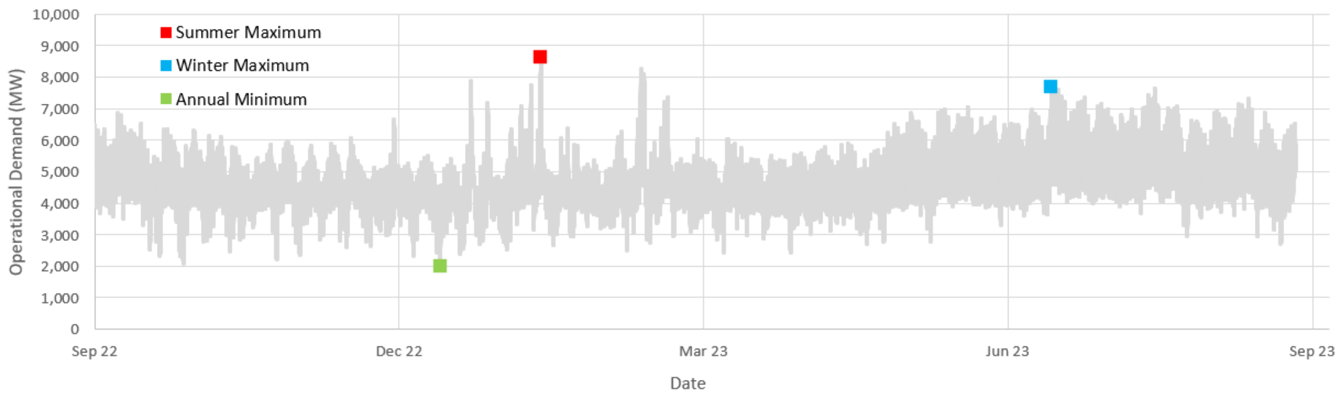


Table 22 Victoria 2022-23 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Tuesday 17 January 2023, 18:00	Monday, 19 June 2023, 18:00	Sunday, 18 December 2022, 13:00
Temperature* (°C)	34.9	8.2	22.1
Max temperature (°C)	36.5	11.8	23.5
Min temperature (°C)	6.8	6.8	11.8
Losses (MW)	546	487	107
NSG output (MW)	165	123	375
Rooftop PV output (MW)	372	0	2502
Sent out (OPSO)	**8,625 (adjusted to 8,650)^**	**7,681**	**1,989**
Auxiliary (MW)	363	337	206
As generated (OPGEN)	**8,018 (adjusted to 9,013)^**	**8,018**	**2,195**

* Melbourne (Olympic Park) weather station. For more information please see Section 3.3.2 of the 2021 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to include the impact of Ausnet Services' CPD program that was called for that day.

Figure 30 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The actual summer and winter maximum demand outcomes fell within forecast expectations, but annual minimum demand outcome was just below the forecast 90% POE. The likely reasons are discussed below.

Figure 30 Victoria simulated extreme event probability distributions with actuals

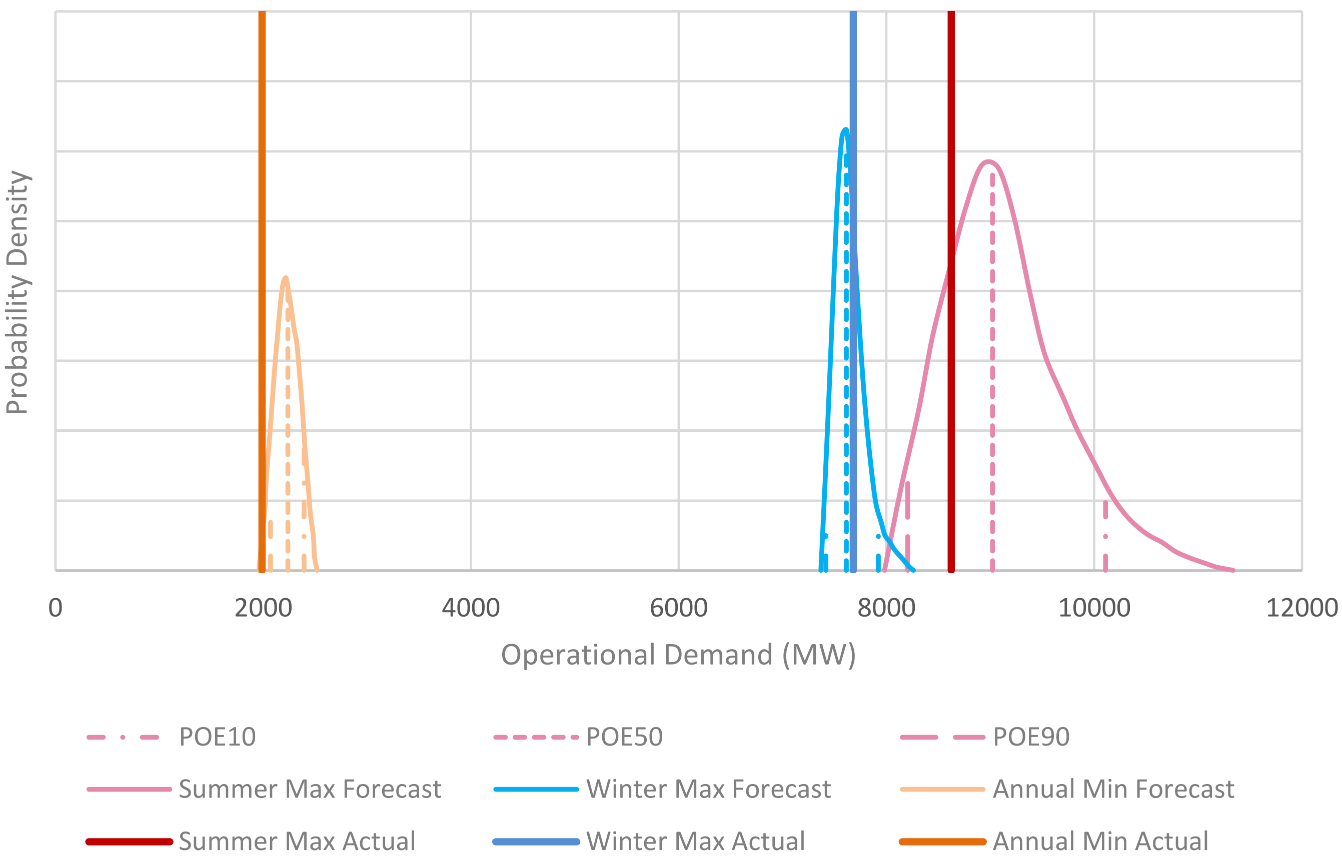


Figure 31 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum demand occurred in summer, on Tuesday 17 January 2023 at 18:00 NEM time. At the time of maximum demand, Melbourne (Olympic Park) recorded a temperature of 34.9°C, with an earlier daily maximum temperature of 36.5°C.

The actual maximum demand was between 50% POE and 90% POE forecast.

- The maximum demand occurred on the second hottest working day in the summer. It did not occur on the day with the highest daily temperature, which was on February 17, 2023, reaching 39.6°C, because the temperature sharply dropped after reaching the day's highest temperature, going from 39.6°C at 14:00 NEM time to 27.6°C at 15:00 NEM time, a rapid 12°C decrease within one hour. On the other hand, on January 17 2023, the temperature was relatively high from the beginning of the day, with a temperature of 28.1°C reached at 9:00 NEM time. Driven by high cooling load, the electricity demand remained high until 18:00 NEM time with the temperature still at 34.9°C. Following this, from 18:30 NEM time the temperature started to drop rapidly.
- The simulation outcomes were weighted towards the maximum demand event happening on a weekday in January in the late afternoon to early evening period. They are consistent with the actual maximum demand event.
- Actual PV generation was just below the median of the simulated outcomes, consistent with the time of day.
- The temperature at the time of maximum demand was at the middle range of the simulation outcome. The two previous days had been relatively mild, and the lack of heat build-up is likely to have contributed to the actual outcome being below 50% POE forecast.

Winter maximum demand occurred on Monday 19 June 2023 at 18:00 NEM time, with a temperature of 8.2°C recorded at Melbourne (Olympic Park).

The maximum demand fell just above the 50% POE and thus well within the simulated range.

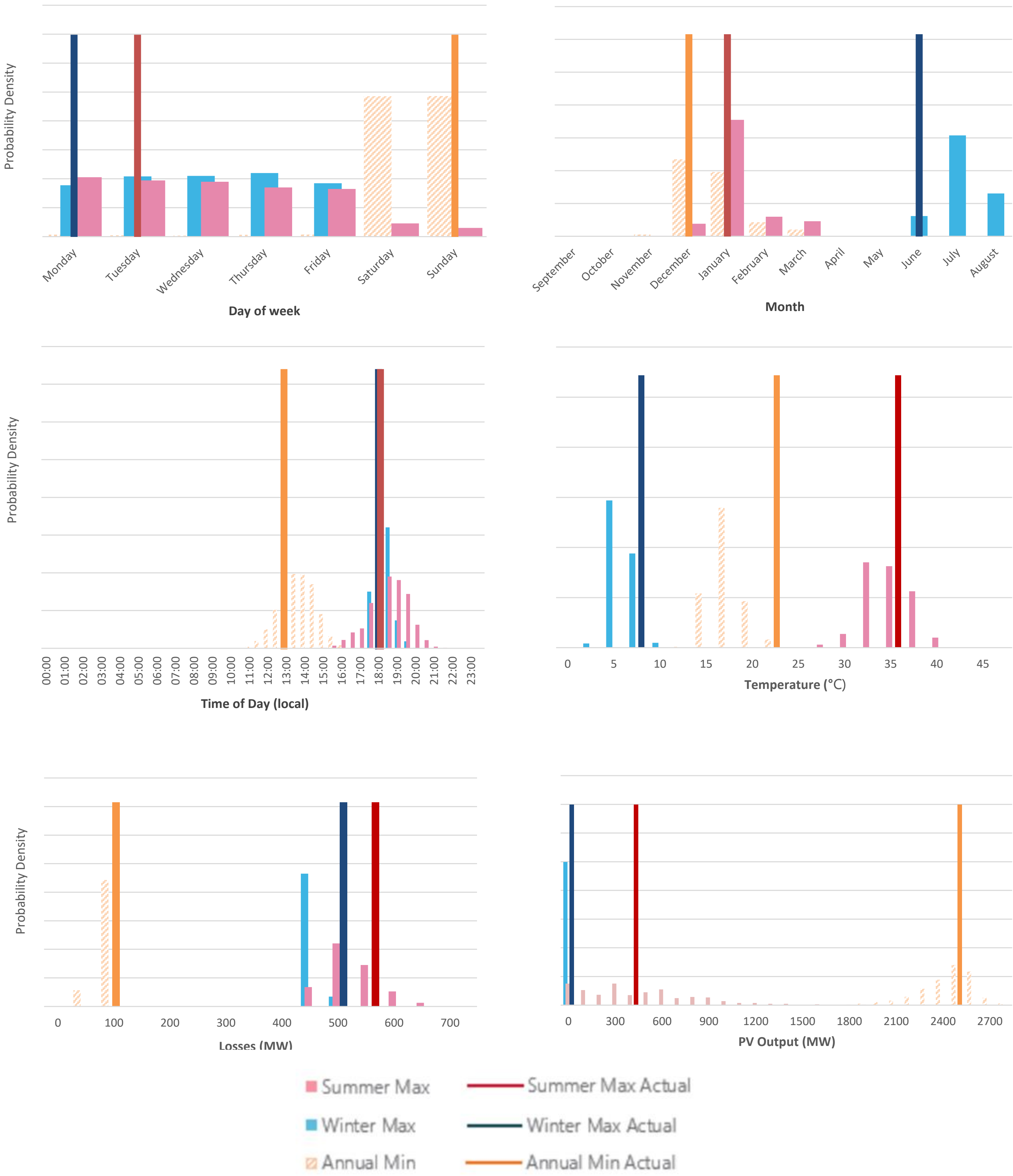
- Victoria had its winter evening peak in 2023 on one of the coldest days of the season with a very small temperature range, a daily maximum temperature of 11.8°C and a daily minimum of 6.8°C. The temperature is towards the very top end of the simulated range, so there would have been relatively less need for heating. The demand outcome above the 50% POE forecast is therefore slightly higher than expected. The continued focus on high gas prices at the time may have caused more to use electric heating, where they had the choice. AEMO has initiated work to better track electrification trends.
- Simulation outcomes were weighted towards a maximum demand event in June/August period. The actual event happening in June is on the early side, but not unexpected as starting from June, the El Niño Watch conditions transitioned to an El Niño Alert.
- The actual maximum demand event fell on a Monday at 18:00 NEM time, matching the simulation outcome of event more likely to happen on a weekday, in late afternoon to early evening.
- Given the timing after sunset, PV generation was 0 MW at the time of the maximum demand event, consistent with the simulation outcomes.

Annual minimum demand occurred on Sunday 18 December 2022 at 13:00 NEM time, when the temperature was 22.1°C. This is the fourth year where minimum demand has during the day rather than overnight.

The actual minimum demand fell just below the 90% POE.

- PV generation at time of minimum was in the upper end of the distribution, which is consistent with the prevailing weather conditions on the day. The higher PV output contributed to the actual demand falling in the lower range of the distribution. An outcome below 90% POE is slightly lower than expected. The installed capacity of rooftop PV and PVNSG for Victoria was closely aligned with forecast (see Section 3.3) so this was not a contributing factor, and AEMO will look into the models that set the starting distribution of the forecast.
- The minimum demand event occurred in December, which is consistent with simulation outcomes.
- Simulation outcomes were weighted towards a minimum event over the weekend in the late morning to early afternoon period, consistent with the Sunday 13:00 NEM time occurrence.

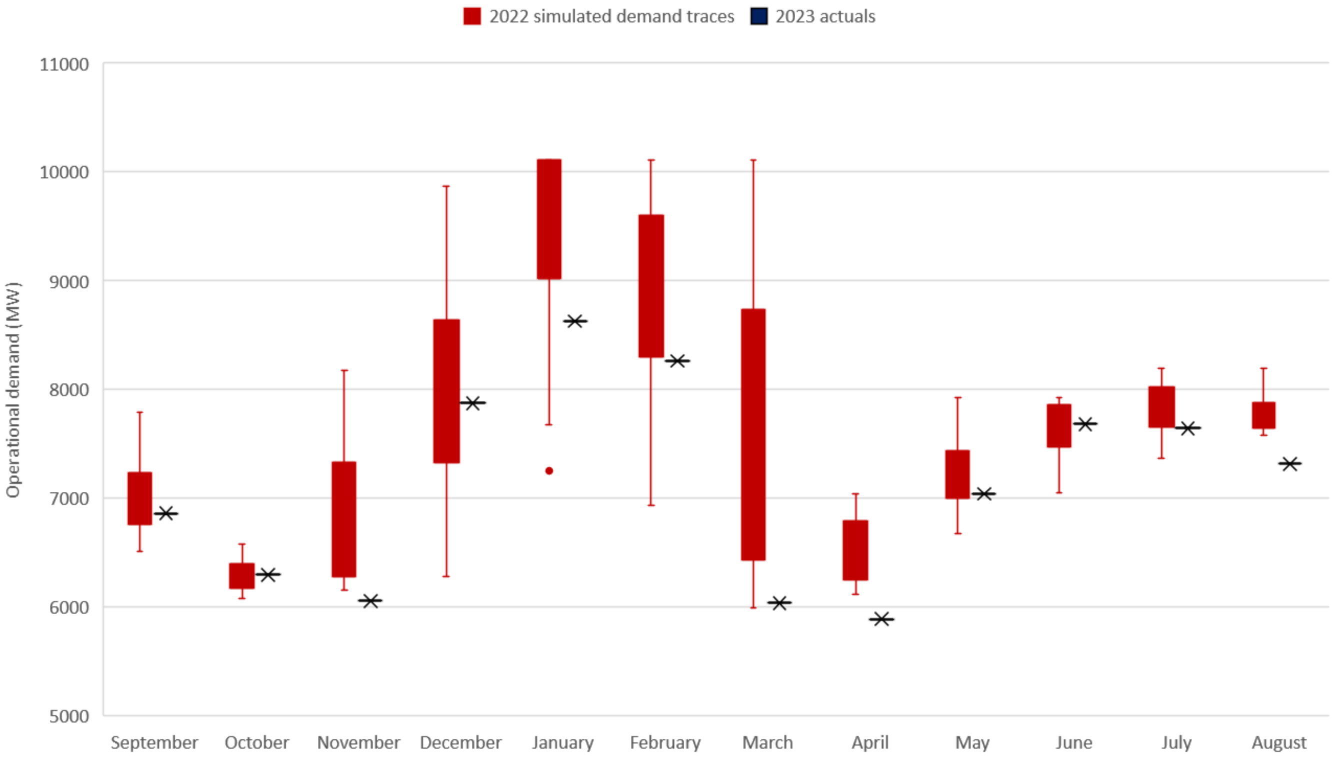
Figure 31 Victoria simulated input variable probability distributions with actuals



Monthly maximums

The box plot in Figure 32 shows the range of monthly demand maximums for the 2023 simulated demand traces for 10% POE and 50% POE annual forecasts. The majority of monthly maximums fell within the predicted range, but mostly on the lower end. In November, April and August, the demand was lower than the 50% POE due to the transition from a La Niña summer to an El Niño winter, resulting in reduced cooling and heating demands.

Figure 32 Victoria monthly maximum demand in demand traces compared with actuals



6 Supply forecasts

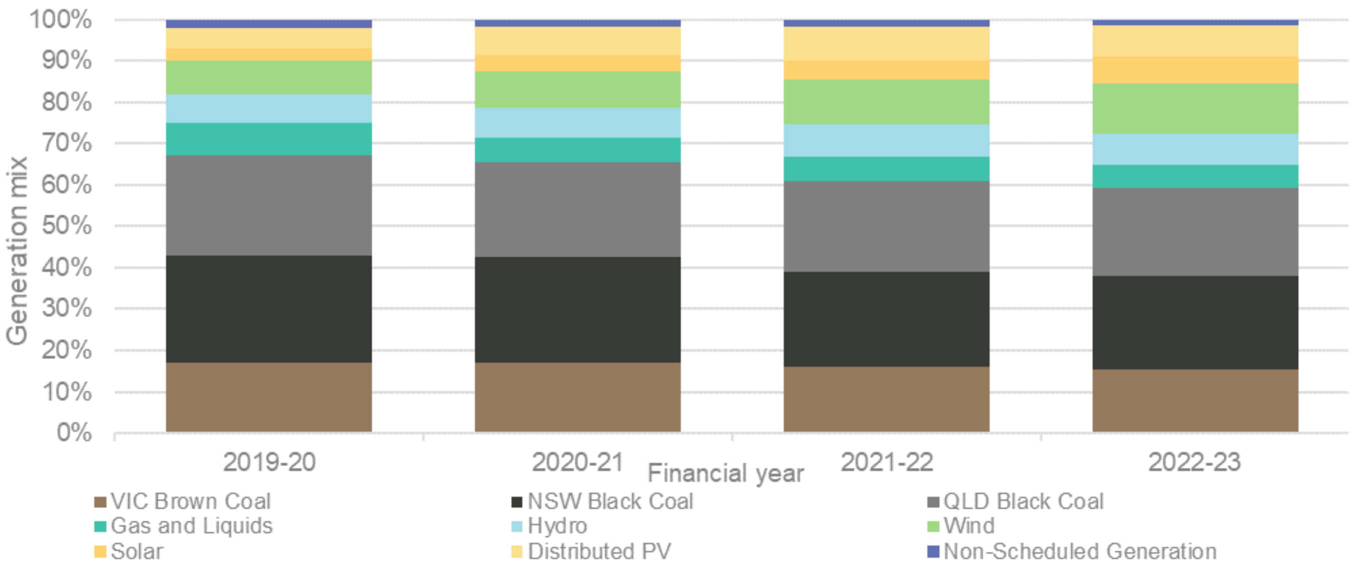
Generation supply in the NEM comes from a variety of fuel sources, and the energy supply proportion changes over time, as shown in Figure 33. Black and brown coal remain the largest source of energy production in the NEM, yet show a decrease in the relative proportion of energy supplied between 2019-20 and 2022-23. Solar and wind generation show the largest increase in the relative proportion of energy supplied between 2019-20 and 2022-23.

To assess the performance of supply forecasts, this section assesses:

- Forecasts of new generator connections.
- Forced outage rates for major generation sources.
- Supply availability, per region.

Assessments have been made for the major generation sources for each region. The category 'gas and liquids' includes open and combined cycle gas turbines, diesel generators, and other similar peaking plant.

Figure 33 NEM generation mix change by energy, including demand side components, from 2019-20 to 2022-23



Supply availability is an important input in reliability studies, given that supply outages are a key driver of unserved energy (USE) estimates during periods of high demand and low variable renewable energy (VRE) generation output. Supply forecasts are therefore assessed by the degree to which capacity availability estimated in the 2022 ESOO matched actual generation availability.

There are numerous reasons why actual supply availability from scheduled generators or actual generation from semi-scheduled generators may not match that forecast during peak periods of interest, including:

- Commissioning or decommissioning of generators may not match schedules provided by generator participants.
- Generator ratings during peak temperatures may not match ratings provided by generator participants.

- Unplanned outages may vary from expectations, as informed by forecast outage rates (full, partial, or high impact outages).
- Planned outages or unit decommitment may occur during peak periods, which forecasts assume will not occur.
- Weather resources for variable renewable energy generators may fall outside the forecast simulation range, or the efficiency of renewable generators to convert wind or solar resources to electricity may be different to that which is assumed.
- Generation curtailment due to constraints representing system security and network limitations.
- Participants provided different capacities compared with actual plant capability.

Consistent with the Forecast Accuracy Report Methodology[28], AEMO implements and publishes a variety of metrics to assess supply forecast accuracy. For each region, AEMO assesses the accuracy of generator commissioning and decommissioning schedules, then assesses supply availability, comparing actual availability with simulated availability, including additional exploration of forced outage rates and other relevant considerations where appropriate.

Section 6.6 assesses the accuracy of the DSP forecasts, which are considered a component of AEMO's supply forecasts.

AEMO assesses the accuracy of the supply availability forecasts by comparing ESOO simulated availability to actual PASA availability from 40 hours sampled from the top 10 hottest days of each simulated, or actual year, ordered from highest to lowest. This availability is expressed as two ranges in this year's report:

- One is showing the full simulated range.
- The other is showing the variation between the 2.5th and 97.5th percentile of the forecast simulations used.

The weather observed in summer 2022-23 was relatively mild, absent of the types of days considered in the development of generator peak summer ratings (typically being days with maximum temperatures above 40°C, for mainland regions)[29].

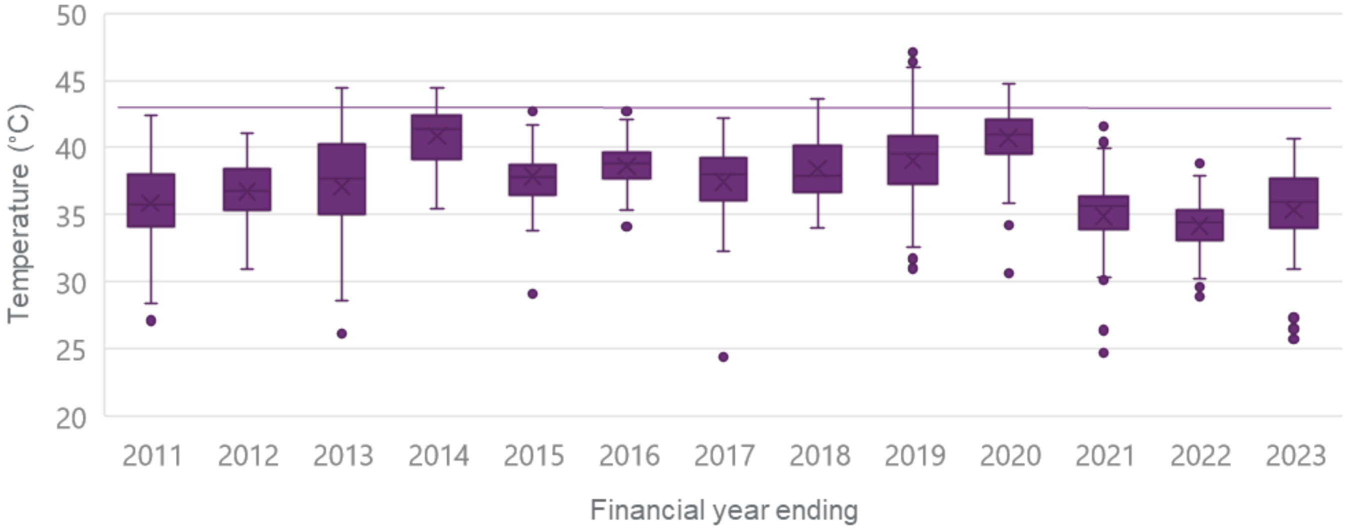
Figure 34 shows a box plot[30] of the temperature range of the identified 40 hours in each of the last 13 years in South Australia as well as the reference temperature of 43°C in South Australia. Weather in other regions was observed to follow a similar pattern. Without such high temperatures and the associated equipment derating, actual supply availability is expected to exceed forecast availability.

[28] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-accuracy-report-methodology/forecast-accuracy-reporting-methodology-report-aug-20.pdf.

[29] AEMO's Generation Information dataset provides each regional summer rating temperature as part of its Background Information. Queensland has a reference temperature of 37°C, but all other mainland NEM regions exceed 40°C, with South Australia being the highest at 43°C.

[30] For explanation of box plots, see Section 2.1.

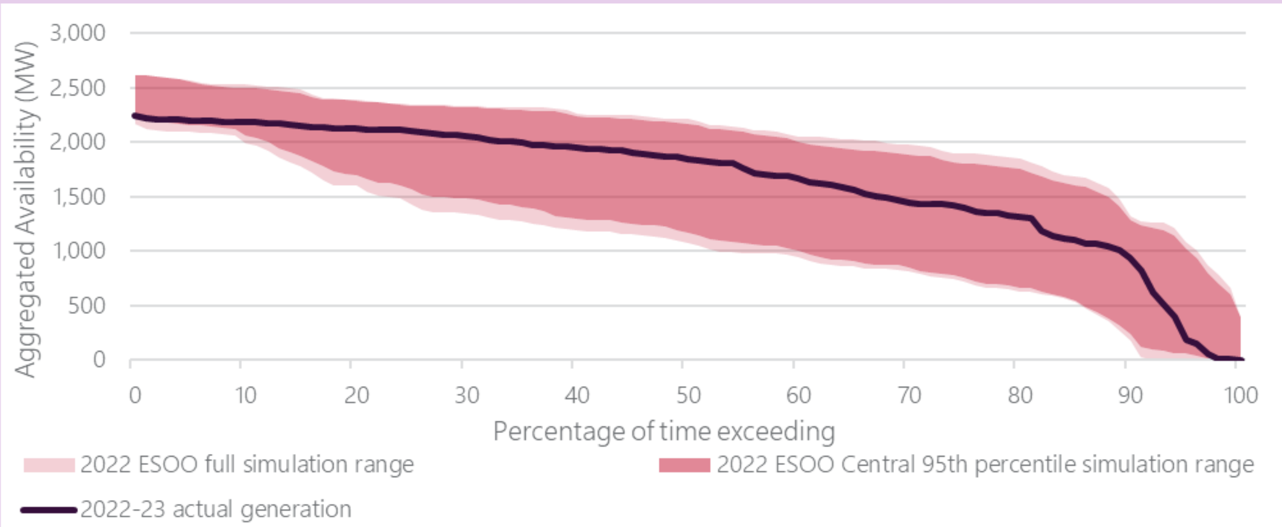
Figure 34 Box plot of South Australia temperature of 40 hours sampled from the 10 hottest days



Example supply availability interpretation

Figure 35 shows an example graph of supply availability, using New South Wales' large-scale solar generators as an example. It compares simulated availability under full simulation range and central 95th percentile simulation range (between the 2.5th and 97.5th percentile), to actual generation (semi-scheduled generators) or actual availability (scheduled generators) for identified periods of each simulated, or actual year, ordered from highest to lowest availability. The red range shows the 2022 ESOO simulated aggregate availability of this generation class for 80 intervals (40 hours) from the top 10 hottest days.

Figure 35 Example simulated and actual supply (New South Wales large-scale solar generation)



The 2022 ESOO simulated ranges, shown in red, demonstrate that aggregate solar output was expected to be as high as 2,618 MW, and as low as 0 MW, depending on time of day and variability in cloud cover. Actual (observed) generation, shown as the dark line, predominantly is within the simulated range during the high temperature days of interest, between 2,248 MW and 0MW. In this example, actuals are primarily within the simulation range, due to development delays of a few solar farms in New South Wales.

The rest of this section details the regional assessment of supply availability forecast performance. In summary:

- Actual supply availability from all technology types of new projects are observed to be within or below forecast availability range in most regions, due to development delays against the dates provided to AEMO by project proponents.
- Wind availability inputs provided by participants typically apply significant derating under high temperature conditions. Given the mild summer temperatures observed, actual wind generation in New South Wales and Queensland exceeded the simulated range, consistent with expectations under lower temperature conditions. Actual wind generation in other regions are within the simulated range despite the mild temperature observed, due to project development delays against the dates provided to AEMO by project proponents or less actual availability compared with values provided from the participant.
- Total actual supply availability is expected to have exceeded the simulated range in all regions, given the mild temperatures observed. However, observed supply availability was below the simulated range in Queensland, and observed supply availability was within the simulated range in all other regions. This was caused by higher levels of planned and unplanned outages, and potential unit decommitment from scheduled plants, as well as development delays or less actual generation from VRE generators.

6.1 New South Wales

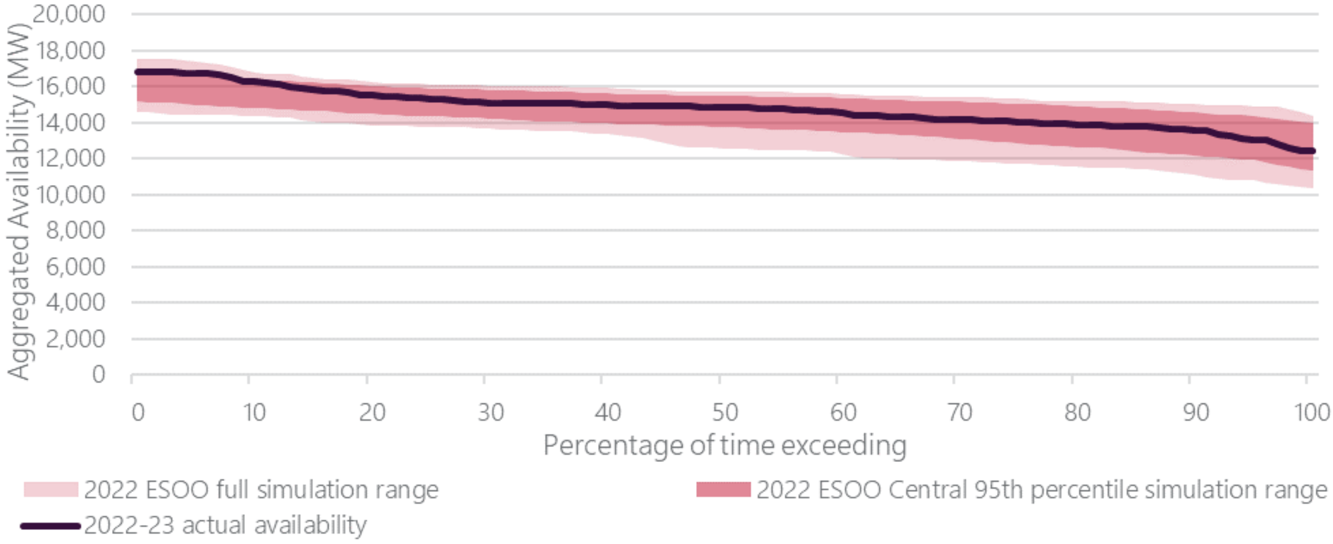
AEMO collects generation information reported from generator participants on the commissioning, decommissioning, and the capacity of individual production units. Table 23 shows how the information was implemented in the 2022 ESOO, compared to actual generator characteristics for February 2023. Compared with the forecast, one project was found to have begun commissioning ahead of schedule and was able to provide generating capacity through summer. However, development delays for four other generators balanced out this extra capacity. As a result, 25 MW more capacity was forecast last summer than actually operating.

Table 23 Forecast and actual generation count and capacity, February 2023

New South Wales	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	45	4,801	46	4,776	25	0.5%
Non-VRE generation/storage	50	14,281	50	14,281	0	0%
All generation	95	19,082	96	19,057	25	0.1%

Figure 36 shows total summer availability for New South Wales for the identified high temperature periods. Due to the mild weather observed in the 2022-23 summer, actual availability should have exceeded the simulation range, but instead was within the simulation range, predominantly due to reduced generation from solar compared to forecast and reduced availability from hydro generators compared to forecast.

Figure 36 New South Wales supply availability for the top 10 hottest days



Black coal

Figure 37 shows the New South Wales black coal equivalent full unplanned outage rate, considering partial, full, and long duration outages. The outage rate in 2022-23 was accurately estimated in the 2022 ESOO projection, based on participant submissions that forecast improved performance. The forecast outage rate increases consecutively from 2020 ESOO to 2023 ESOO.

Figure 37 New South Wales black coal equivalent full unplanned outage rates, including long-duration outages

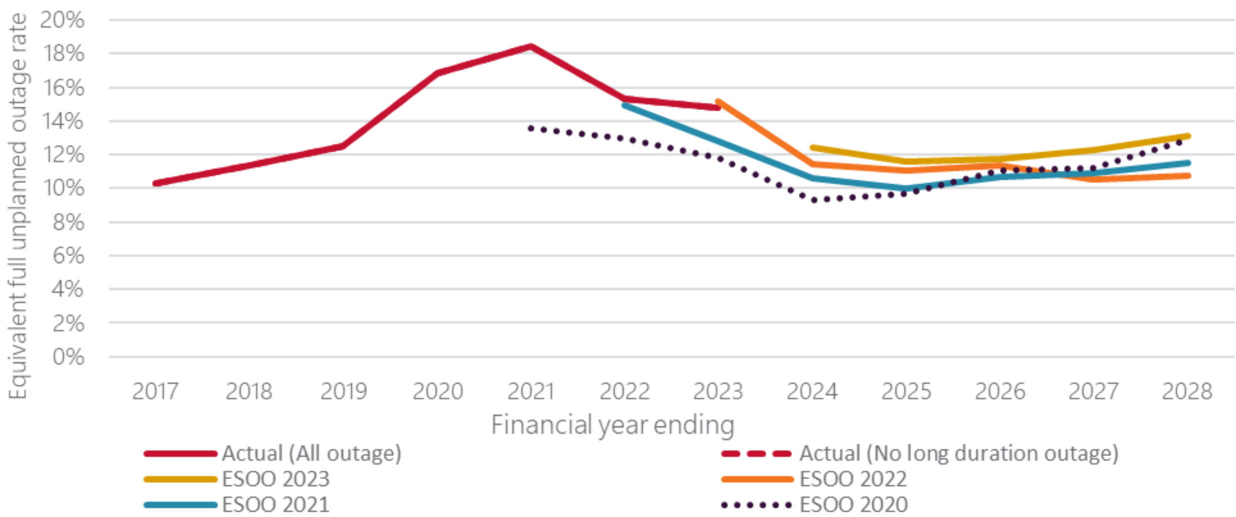
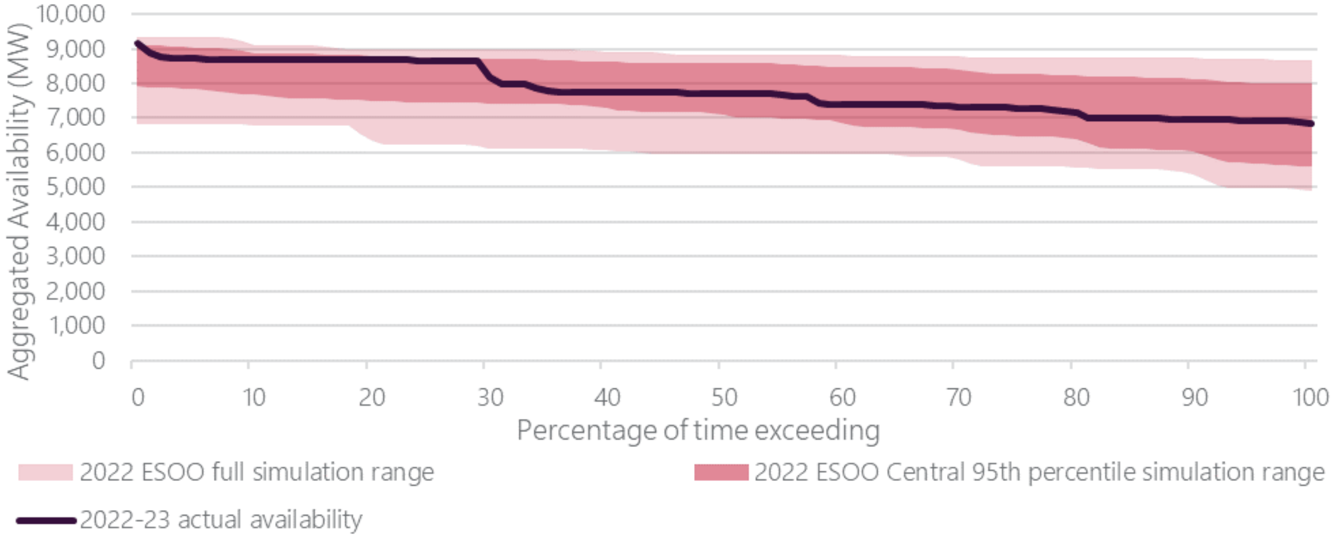


Figure 38 shows that actual availability for New South Wales black coal generators over the top 10 hottest days was within the 2022 ESOO simulated range. Due to the mild summer weather, actual availability should have been above or within the upper end of the simulation range, but it is within the simulated range, likely due to planned and unplanned outages during the identified high temperature periods.

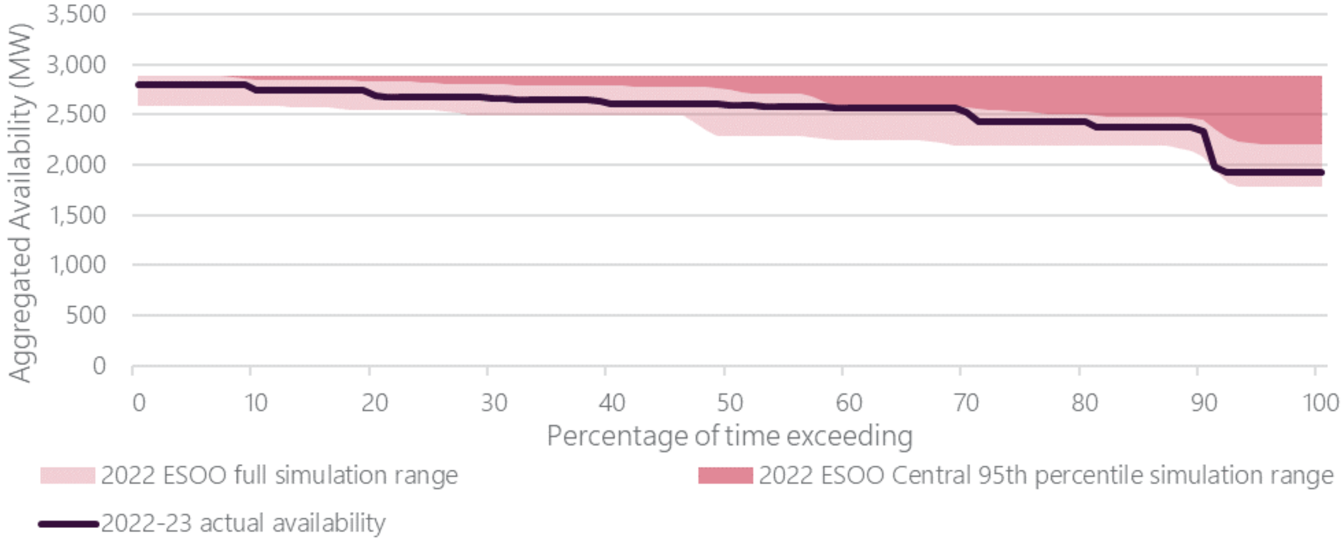
Figure 38 New South Wales black coal supply availability for the top 10 hottest days



Hydro

Figure 39 shows supply availability for New South Wales hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2022-23, the observed availability was primarily within the lower end of the 2022 ESOO simulation range, mainly due to planned outages on Shoalhaven and Tumut 3 over the observed period.

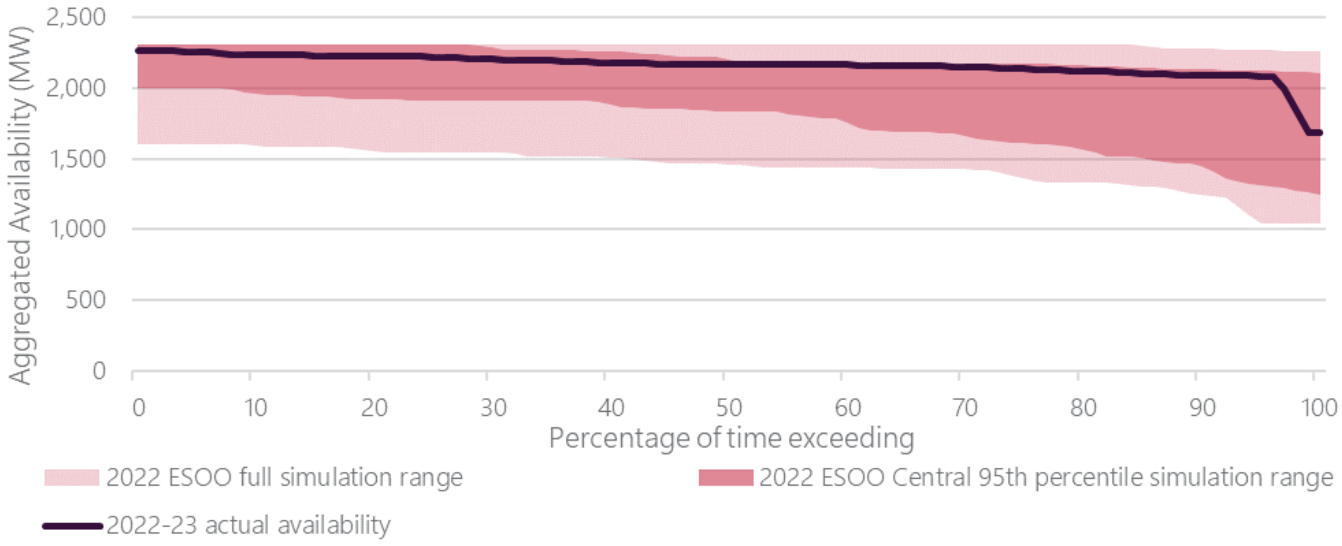
Figure 39 New South Wales hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 40 shows supply availability for New South Wales gas and liquid generators over the top 10 hottest days, comparing actual with simulated availability. In 2022-23, the observed availability was primarily above the 2022 ESOO forecast range, consistent with expectation given the mild weather observed.

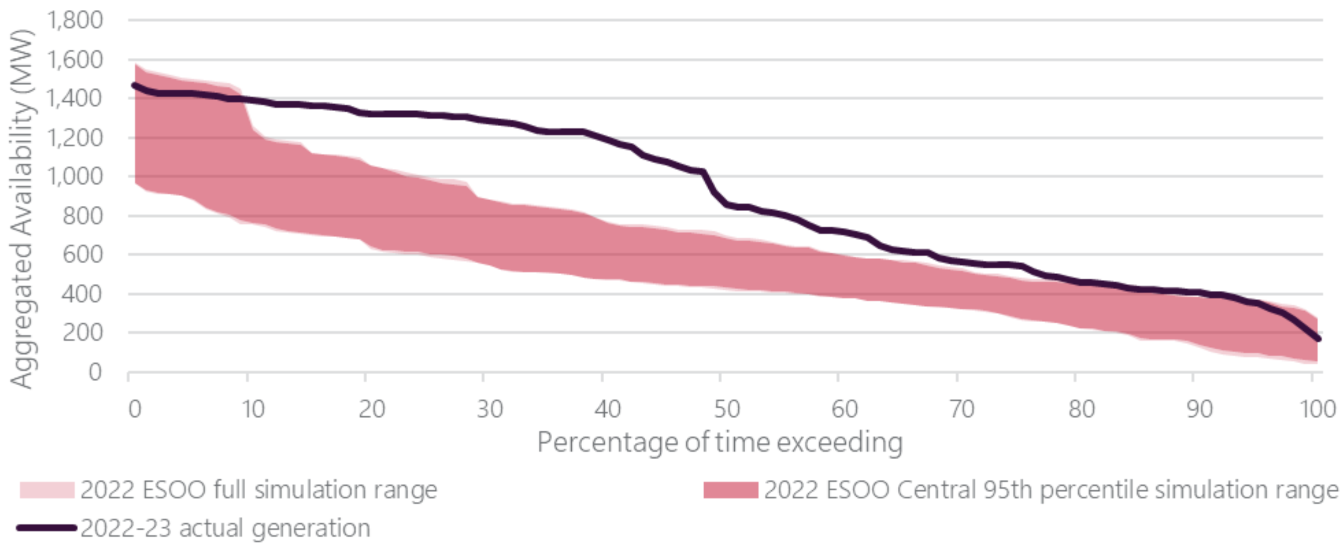
Figure 40 New South Wales gas and liquid supply availability for the top 10 hottest days



Wind

Figure 41 shows aggregate generation for New South Wales wind generators over the top 10 hottest days, comparing actual generation with simulated availability. The observed output was mostly above the 2022 ESOO simulated range, mainly due to the mild summer temperature in New South Wales, where wind availability provided by participants has applied significant derating under high temperature conditions. This outcome matches expectation, and in a year with higher temperature conditions, greater alignment should be visible. Early commissioning of one wind farm also contributed to higher than anticipated wind generation.

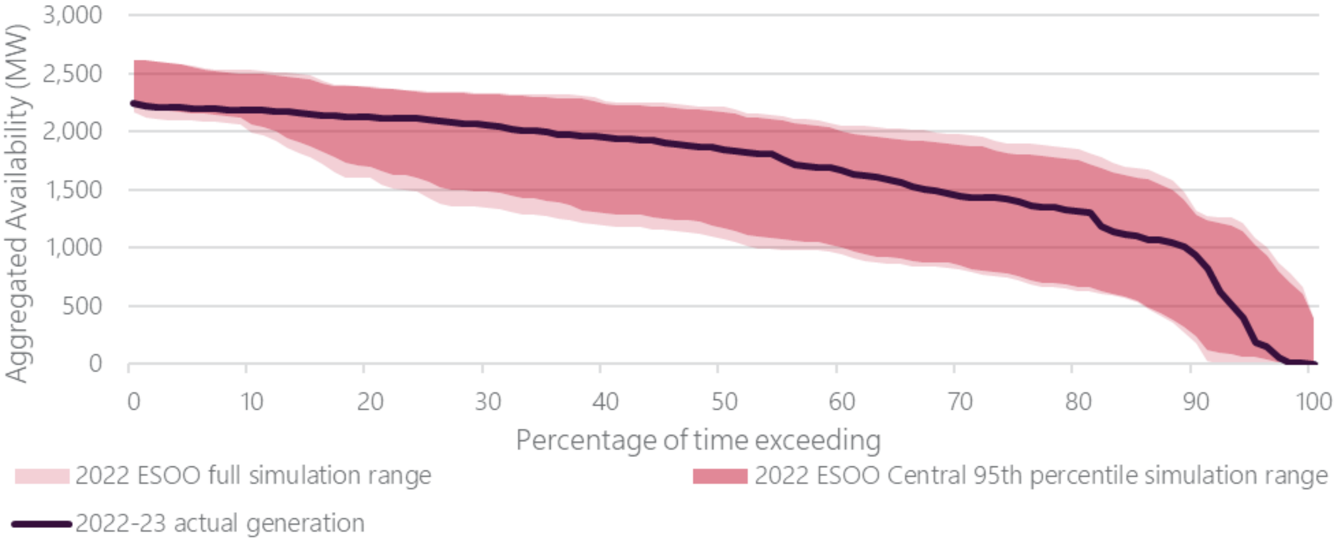
Figure 41 New South Wales wind supply availability for the top 10 hottest days



Large-scale solar

Figure 42 shows supply availability for New South Wales large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated availability in the 2022 ESOO. The observed output was mostly within the simulated range, driven by the late commissioning of solar farms.

Figure 42 New South Wales large-scale solar supply availability for the top 10 hottest days



6.2 Queensland

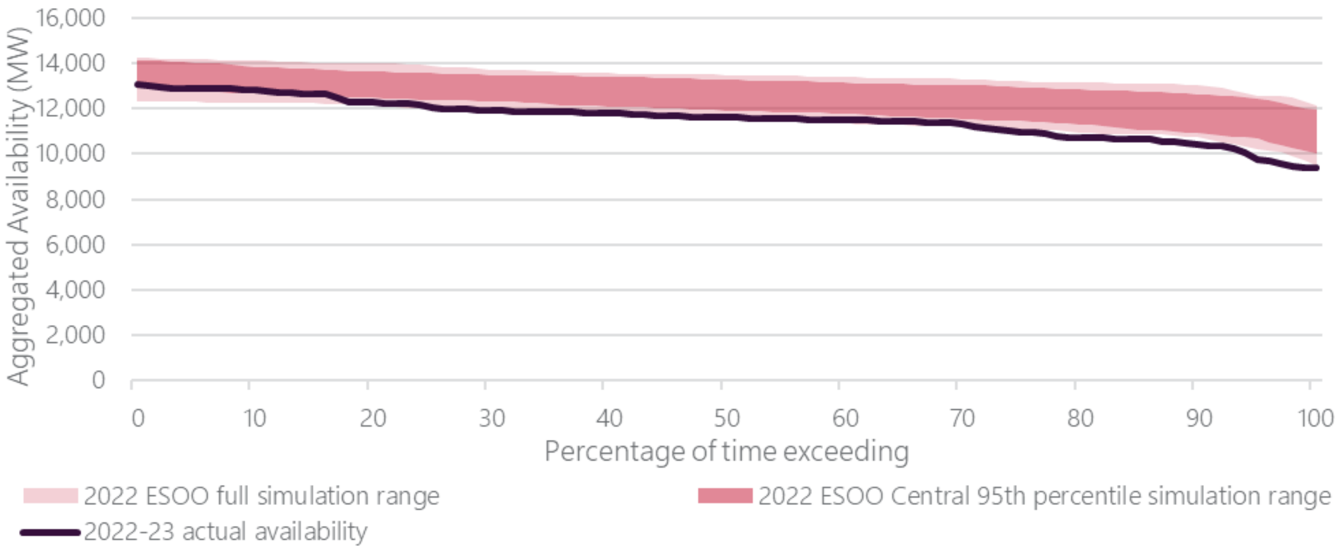
Table 24 shows how participant-provided generation information was implemented in the 2022 ESOO, compared to actual generator characteristics for February 2023. In comparison to forecast, three VRE projects began commissioning ahead of schedule and were able to provide generating capacity through summer. This extra actual generation was offset by development delays for numerous VRE generators. In total, 124 MW more capacity was forecast last summer compared to what was actually operating.

Table 24 Forecast and actual generation count and capacity, February 2023

Queensland generation	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	34	3,380	37	3,257	124	3.8%
Non-VRE generation/storage	56	12,501	56	12,501	0	0%
All generation	90	15,881	93	15,757	124	0.8%

Figure 43 shows total summer availability for Queensland's identified high temperature periods, comparing actual with simulated availability in the 2022 ESOO. Actual availability was mostly towards the lower end of the simulation range, due to project development delays, lower than expected gas-fired unit availability, and the planned maintenance or economic decommitment of some coal-fired units.

Figure 43 Queensland supply availability for the top 10 hottest days



Black coal

Figure 44 shows the actual unplanned outage rate in 2022-23 was higher than the projection used in the 2022 ESOO, particularly due to the occurrence of long duration outages.

Figure 44 Queensland black coal equivalent full unplanned outage rates, including long-duration outages

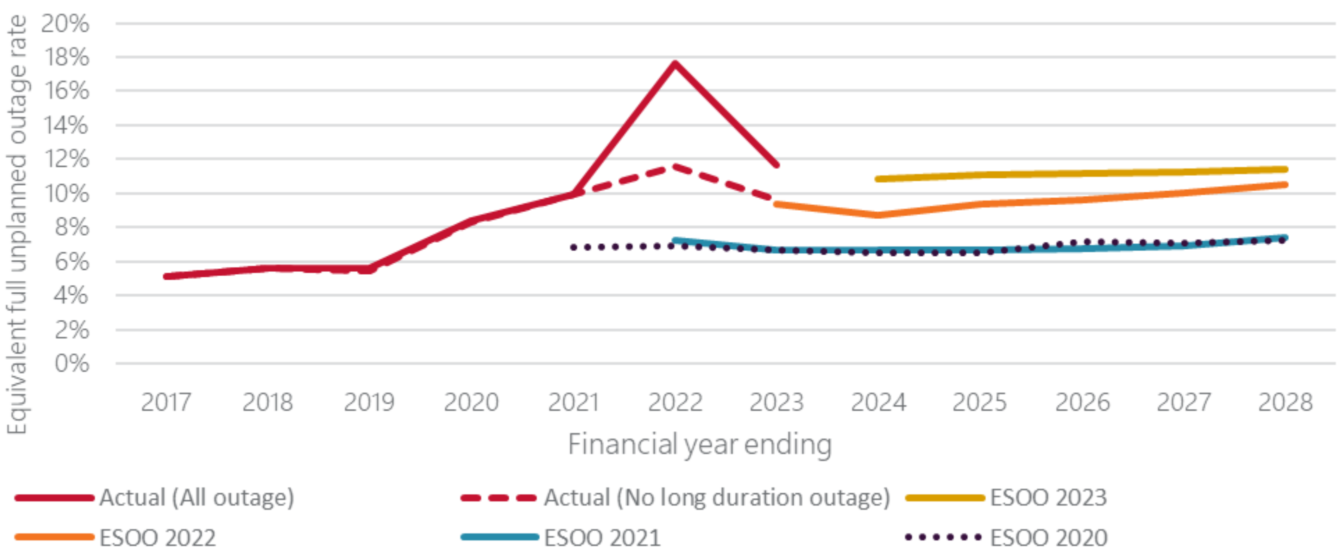
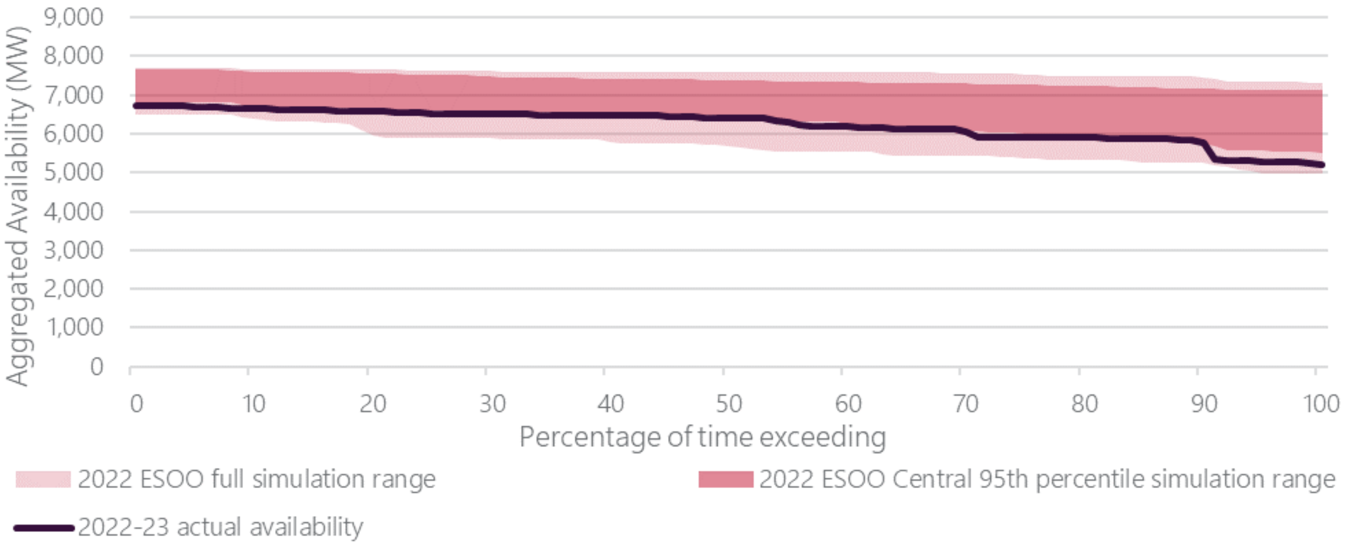


Figure 45 shows supply availability for Queensland black coal generators over the identified high temperature days, comparing actual with simulated availability. The observed availability was mostly within the 2022 ESOO full simulated range, and towards the lower end of the central 95th percentile simulated range. Callide C Unit 3 remains on extended outage, plus a number of planned maintenance outages or economic decommitments were observed in the identified period, reducing actual availability compared with the 2022 ESOO forecast.

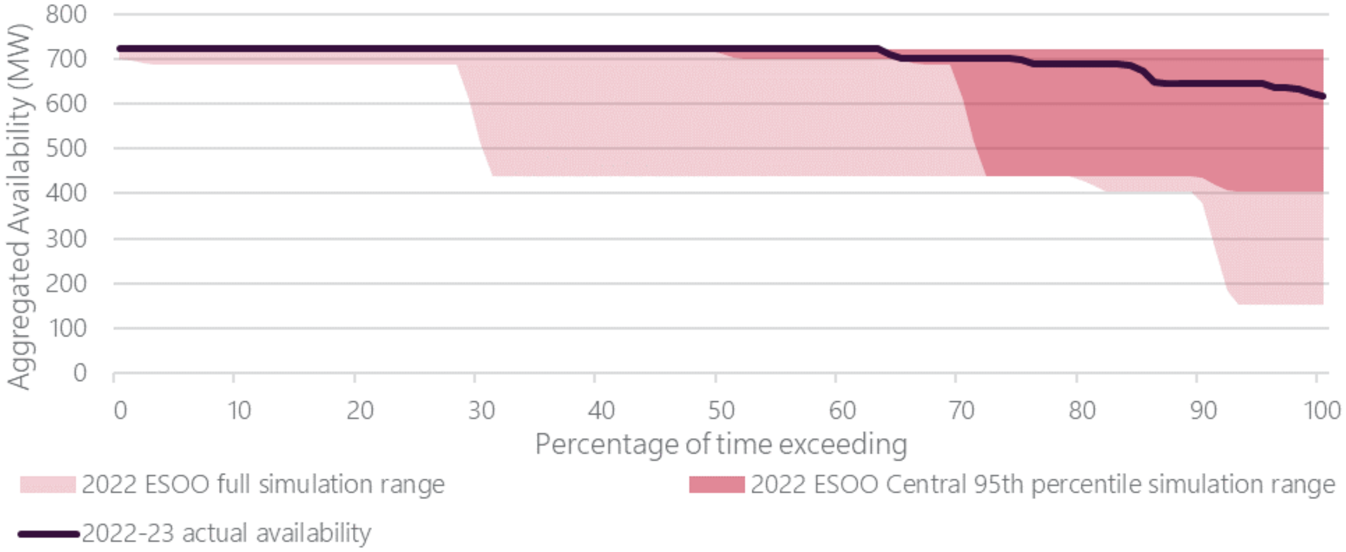
Figure 45 Queensland black coal supply availability for the top 10 hottest days



Hydro

Figure 46 shows supply availability for Queensland hydro generators over the top 10 hottest days, comparing actual with simulated availability under full simulation range and central 95th percentile simulation range. The forecast performed as expected for a mild temperature year, as the observed availability was towards the upper end of the 2022 ESOO simulated range.

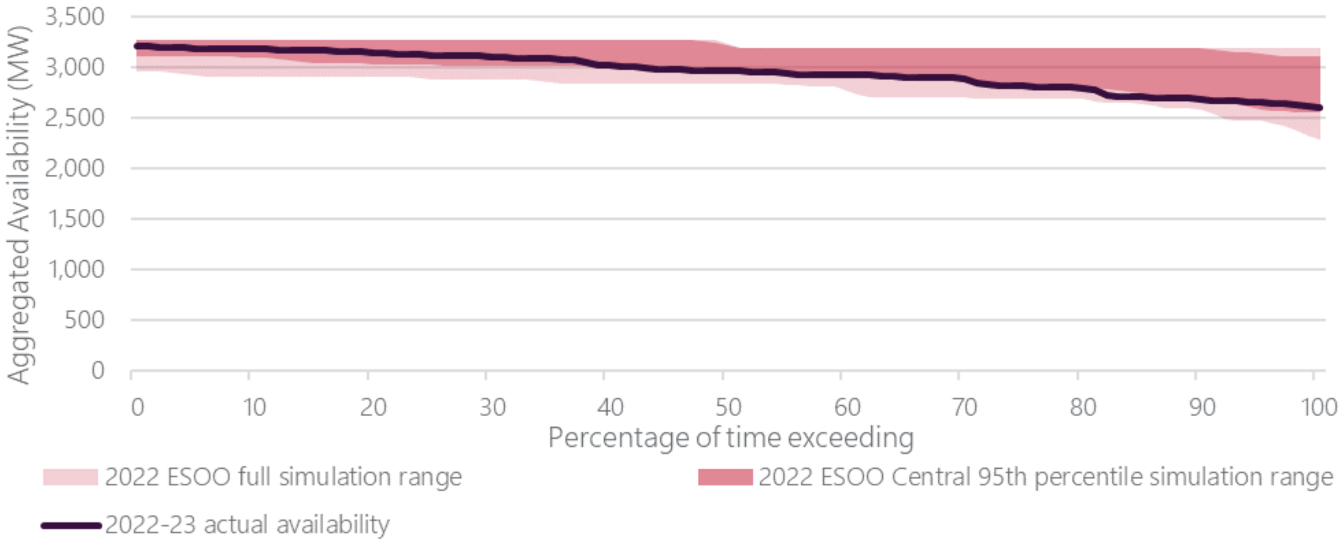
Figure 46 Queensland hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 47 shows supply availability for Queensland gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly within the 2022 ESOO simulated range, however is lower than expected for a mild temperature year, due mostly to planned outages coinciding with the identified periods.

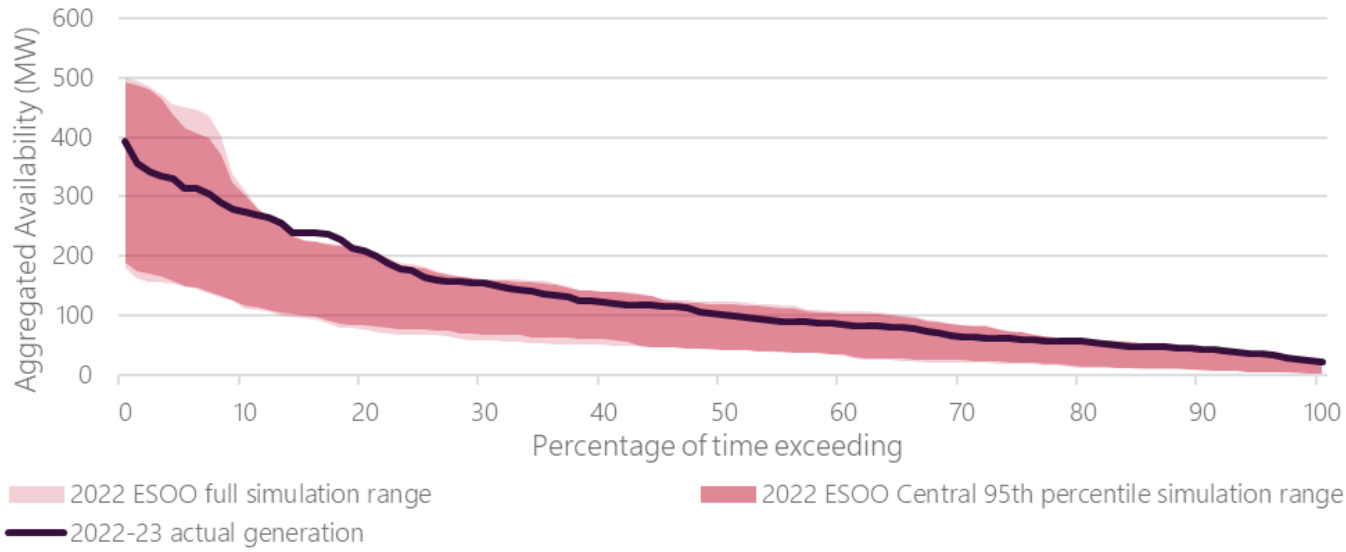
Figure 47 Queensland gas and liquids supply availability for the top 10 hottest days



Wind

Figure 48 shows wind generation supply for Queensland over the top 10 hottest days, comparing actual generation with the 2022 ESOO simulated availability range. The observed output was mostly in the higher end of the simulated range as expected, due to mild temperatures in Queensland in 2022-23 summer and the early commissioning of one wind farm.

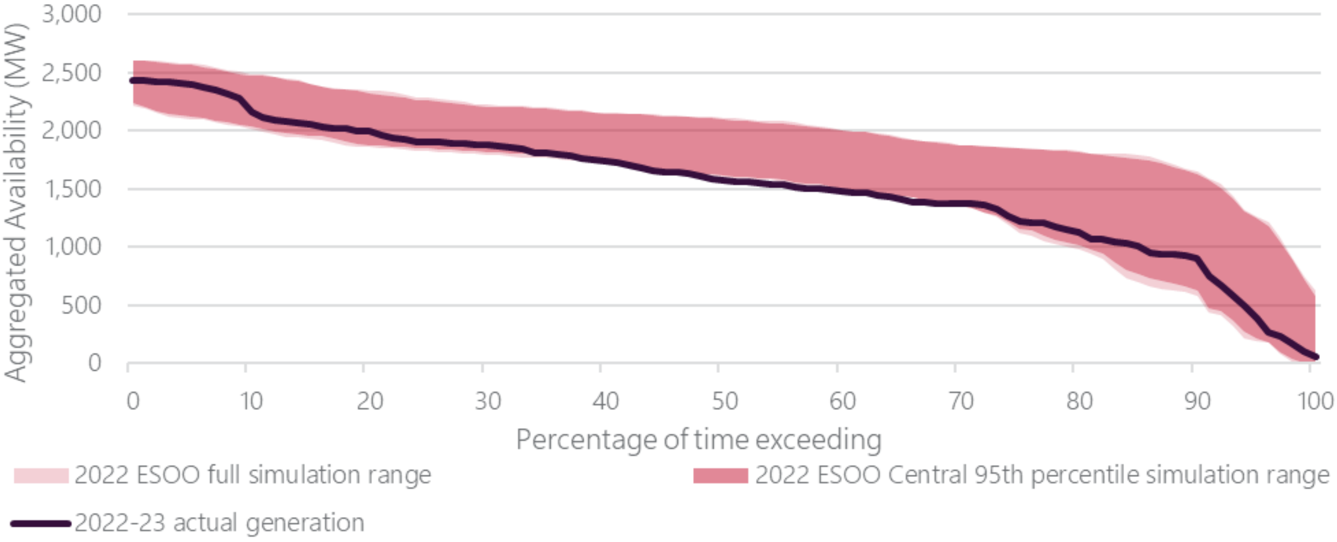
Figure 48 Queensland wind supply availability for the top 10 hottest days



Large-scale solar

Figure 49 shows the output of Queensland large-scale solar generators over the top 10 hottest days, comparing actual with the 2022 ESOO simulated availability range. The actual generation was mostly towards the lower end of the simulated availability range, mostly due to commissioning delays.

Figure 49 Queensland large-scale solar supply availability for the top 10 hottest days



6.3 South Australia

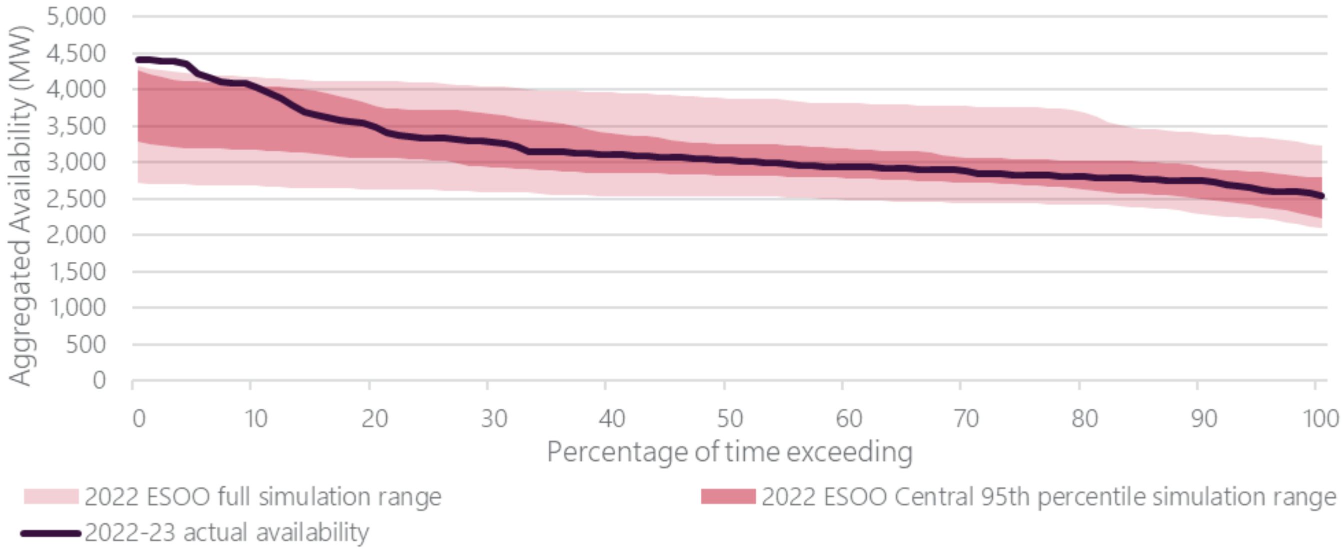
South Australian generation information, as reported by generator participants for the 2022 ESOO, is shown in Table 25 alongside actual generator characteristics in February 2023. Two VRE projects were modelled in the 2022 ESOO, but were not actually generating in February 2023. Additionally, numerous wind farms had less actual availability compared with provided values by the participant for the 2022 ESOO. In total, 102 MW more VRE capacity was forecast than actual. Two batteries were modelled in the 2022 ESOO but were not actually operating in February 2023, with a total of 13 MW more non-VRE generation/storage forecast last summer than actually operated.

Table 25 Forecast and actual generation count and capacity, February 2023

South Australia	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	39	2,837	37	2,735	102	3.7%
Non-VRE generation/storage	63	2,940	61	2,926	13	0.4%
All generation	102	5,776	98	5,661	115	2.0%

Figure 50 shows aggregate summer availability for South Australia during its identified high temperature periods. Actual availability was mostly within the 2022 ESOO simulated range. While forecast gas and liquid availability was below actual, solar generation availability was forecast above actual.

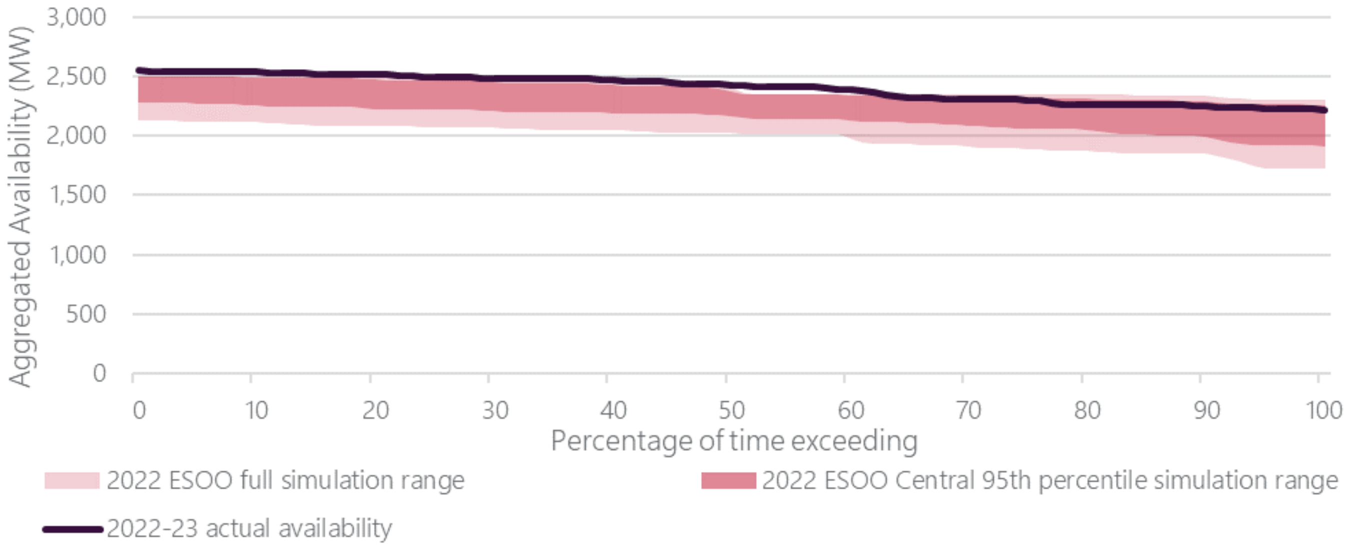
Figure 50 South Australia supply availability for the top 10 hottest days



Gas and liquids

Figure 51 shows that availability over the top 10 hottest days was mostly above the 2022 ESOO central 95th percentile simulation range, or towards the upper end of the 2022 ESOO full simulated availability. This result aligns with expectation given the mild temperatures observed in 2022-23 in South Australia.

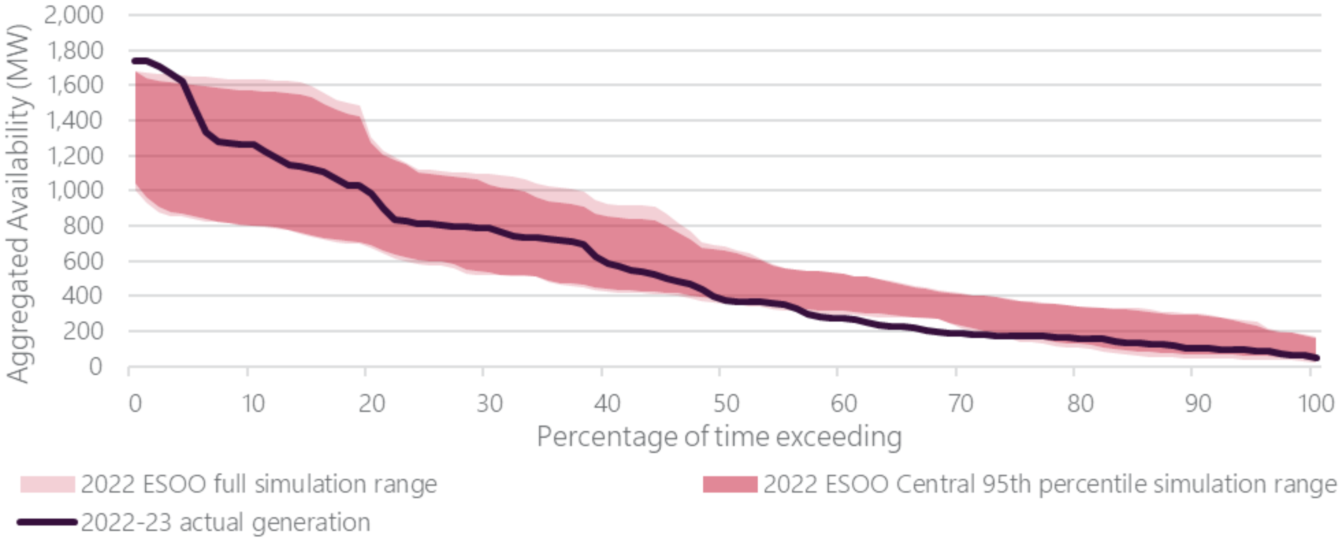
Figure 51 South Australia gas and liquids supply availability for the top 10 hottest days



Wind

Figure 52 shows the output of South Australian wind generators over the top 10 hottest days, comparing actual output with the range of simulated availability. The observed output was mostly within or towards the lower end of the 2022 ESOO simulated availability, mainly due to a few wind farms having less actual generation compared with participant-provided values.

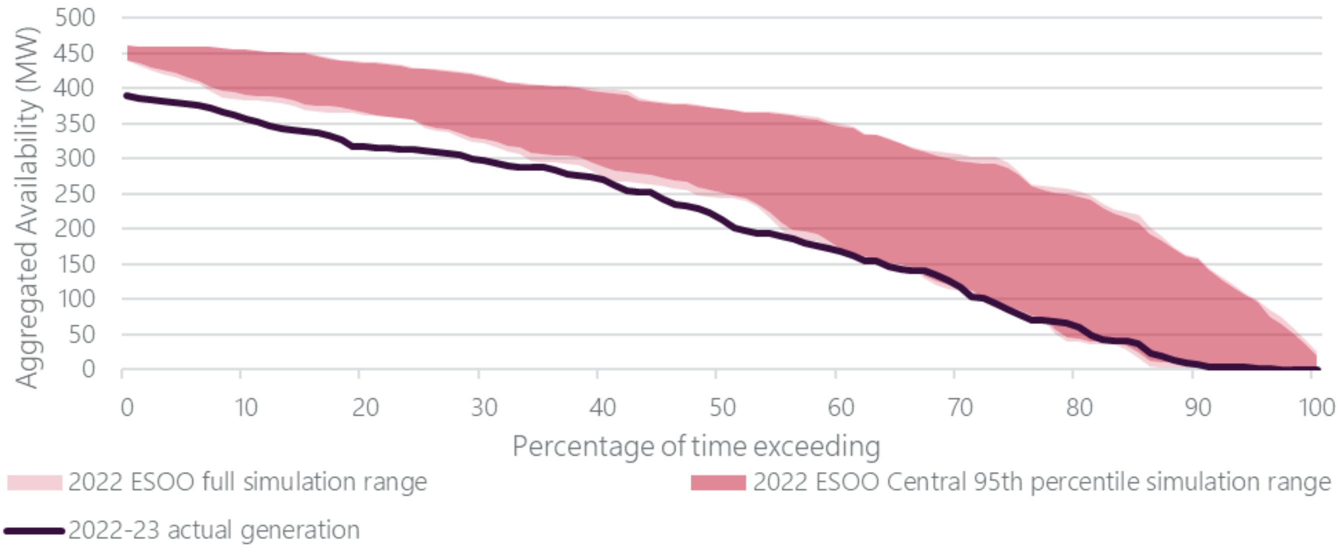
Figure 52 South Australia wind supply availability for the top 10 hottest days



Large-scale solar

Figure 53 shows supply availability for South Australian large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated availability. In 2022-23, the observed generation was mostly below or towards the lower end of the 2022 ESOO simulated availability, due to delayed solar farm commissioning.

Figure 53 South Australia large-scale solar supply availability for the top 10 hottest days



6.4 Tasmania

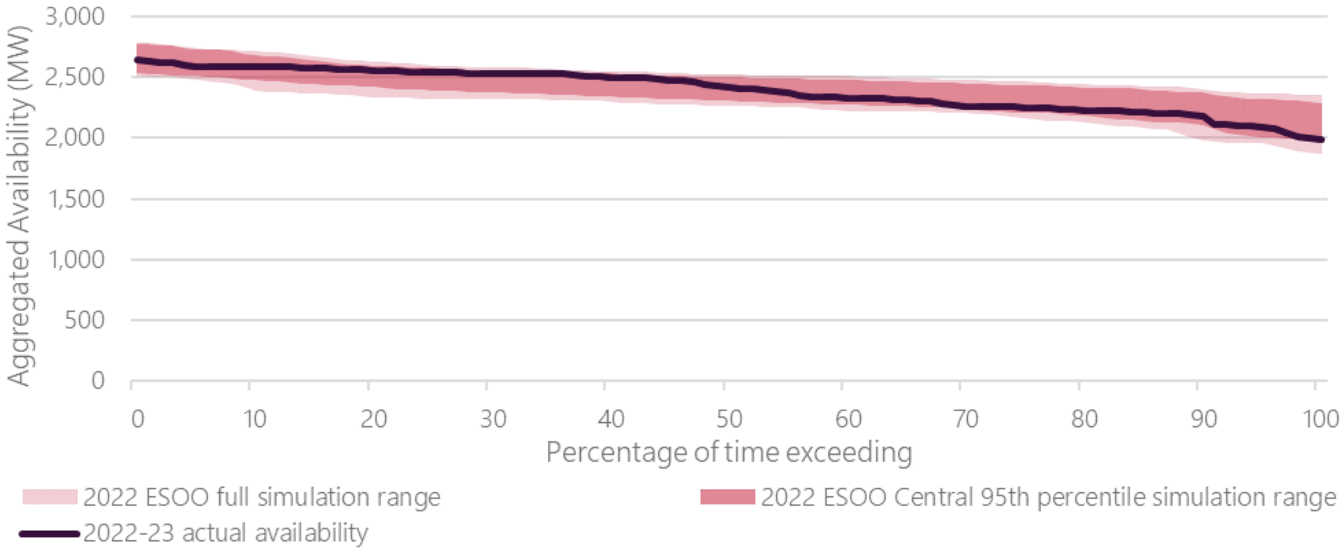
Table 26 shows how Tasmanian generation information was implemented in the 2022 ESOO, compared to actual generator characteristics for February 2023. In general, the assumed capacity in Tasmania in the 2022 ESOO was correct. While Tasmania is a winter-peaking region, the availability of surplus dispatchable hydro generation coupled with the availability of Basslink provides important support to the mainland during summer peak demand events.

Table 26 Forecast and actual generation count and capacity, February 2023

Tasmania	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	4	563	4	563	0	0%
Non-VRE generation/storage	49	2,355	49	2,355	0	0%
All generation	53	2,918	53	2,918	0	0%

Figure 54 shows total summer availability for Tasmania for its highest temperature periods. Actual availability was mostly within the simulation range, due to higher than expected hydro availability compensating for less gas/liquids capacity.

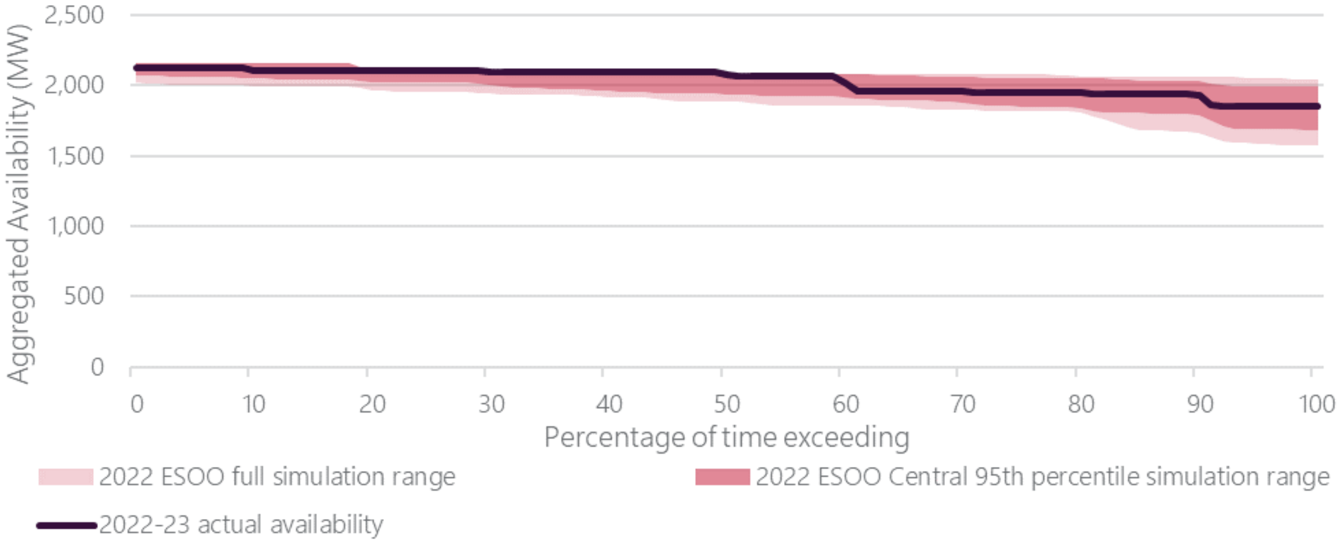
Figure 54 Tasmania supply availability for the top 10 hottest days



Hydro

Figure 55 shows supply availability for Tasmanian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly towards the upper end of the 2022 ESOO simulated range, due to lower rates of Tasmanian hydro generation unavailability during high temperature periods.

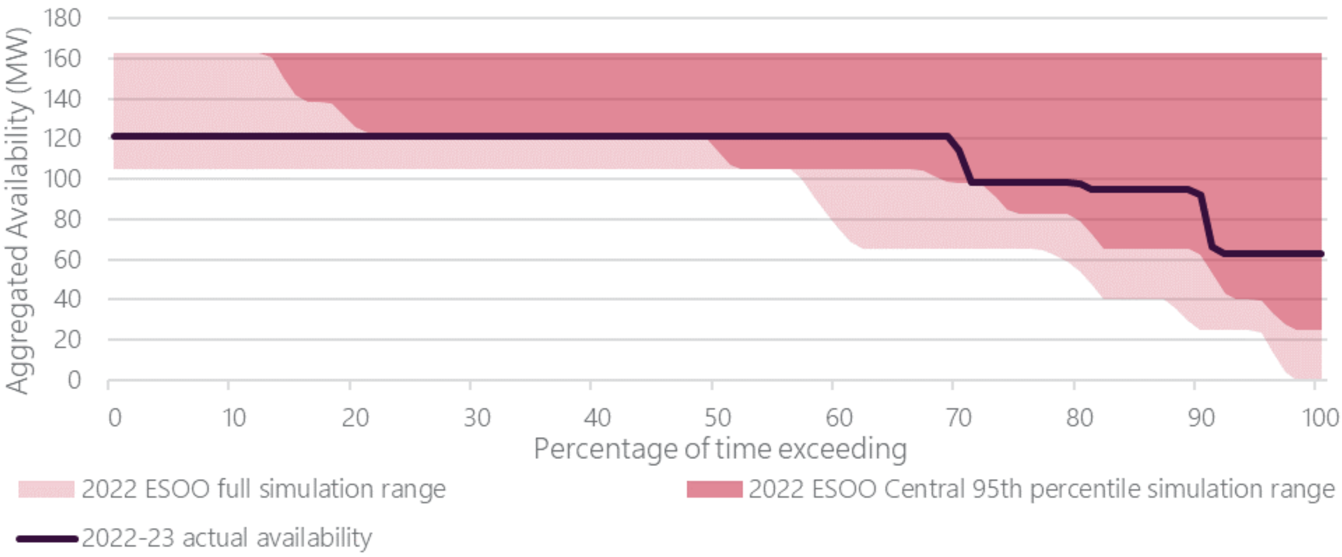
Figure 55 Tasmania hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 56 shows supply availability for Tasmanian gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly towards the lower end of the 2022 ESOO simulated range, due to planned outage of the first Bell Bay Three unit.

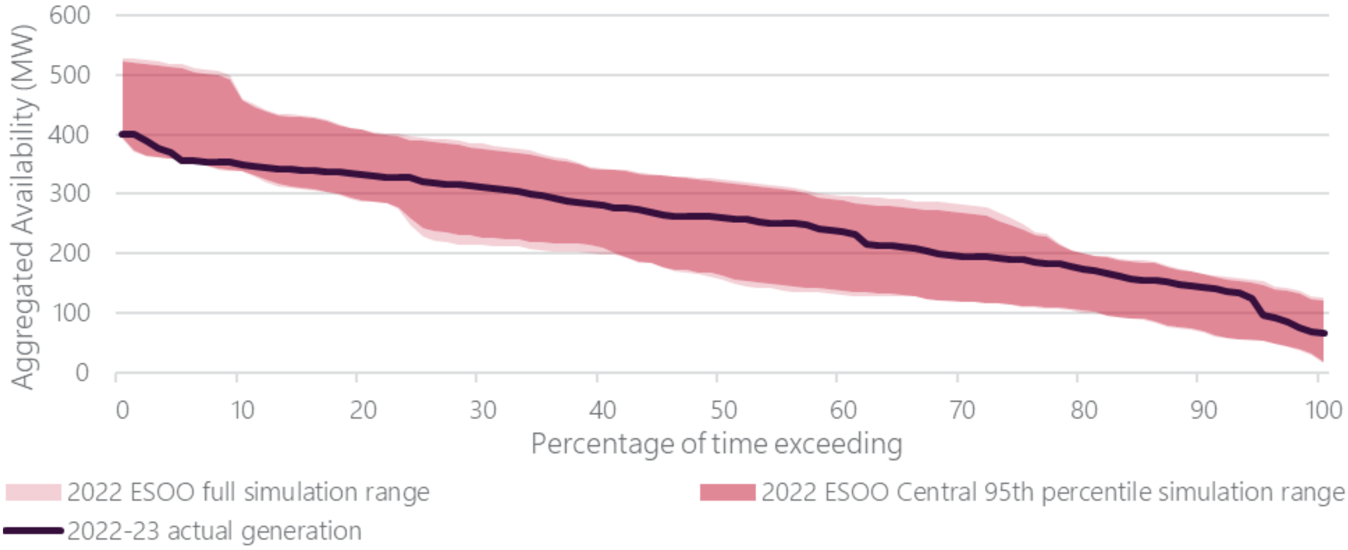
Figure 56 Tasmania gas and liquids supply availability for the top 10 hottest days



Wind

Figure 57 shows the output of Tasmanian wind generators over the top 10 hottest days, comparing actual generation with 2022 ESOO simulated availability. The actual generation was within the 2022 ESOO forecast range.

Figure 57 Tasmania wind output for the top 10 hottest days



6.5 Victoria

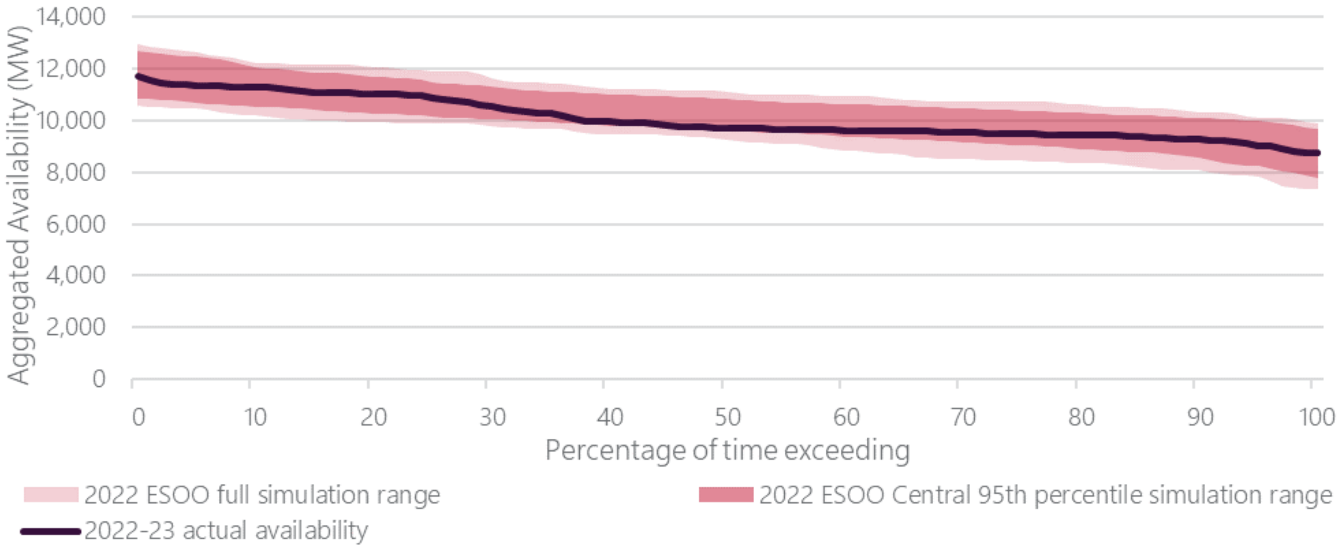
Victorian generation information, as reported by generator participants for the 2022 ESOO, is shown in Table 27 alongside actual generator characteristics for February 2023. In comparison to actual, 490 MW more VRE capacity was forecast in 2022 ESOO. This is mainly due to development delays from new projects, and to numerous projects having less actual generation than participant-provided values.

Table 27 Forecast and actual generation count and capacity, February 2023

Victoria	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	37	4,998	37	4,508	490	10.9%
Non-VRE generation/storage	68	9,549	68	9,549	0	0%
All generation	105	14,547	105	14,057	490	3.5%

Figure 58 shows aggregate summer availability for Victoria during its highest temperature periods. Actual availability was mostly within the 2022 ESOO simulated range. In general, VRE and hydro were less available than forecast, while brown coal and gas and liquids were available at the upper end of forecast ranges, as expected given the mild temperatures observed.

Figure 58 Victoria supply availability for the top 10 hottest days



Brown coal

Figure 59 demonstrates that the actual outage rate in 2022-23 was higher than forecast in the 2022 ESOO, primarily due to long duration outages. Previous ESOO forecasts have been consistently lower than actuals every year with the exception of the 2020 ESOO, despite participant-provided projections for declining plant reliability each year.

Figure 59 Victoria brown coal equivalent full unplanned outage rates, forecasts including long duration outages

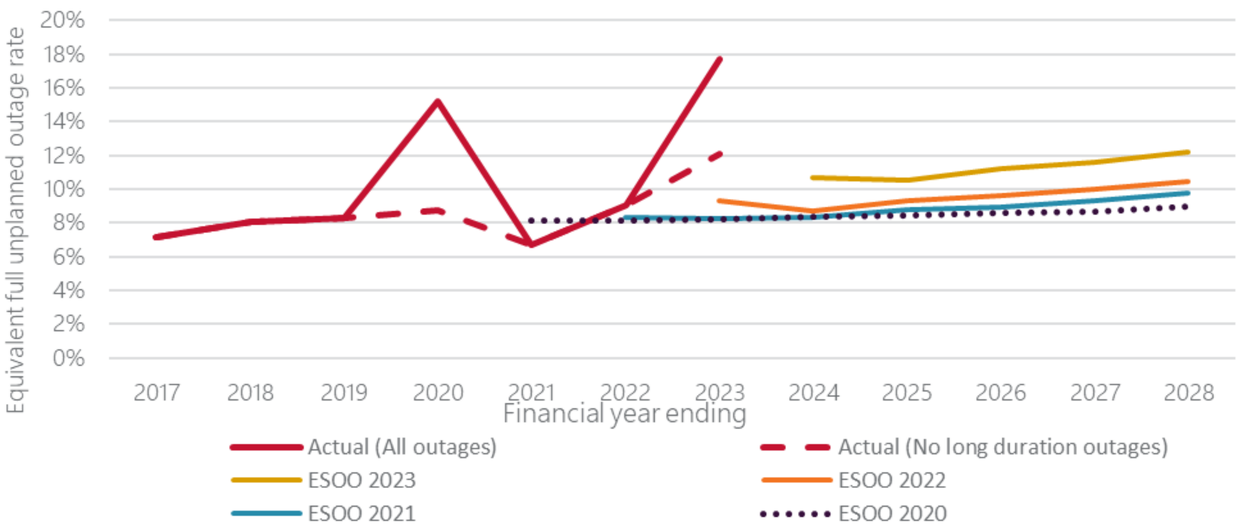
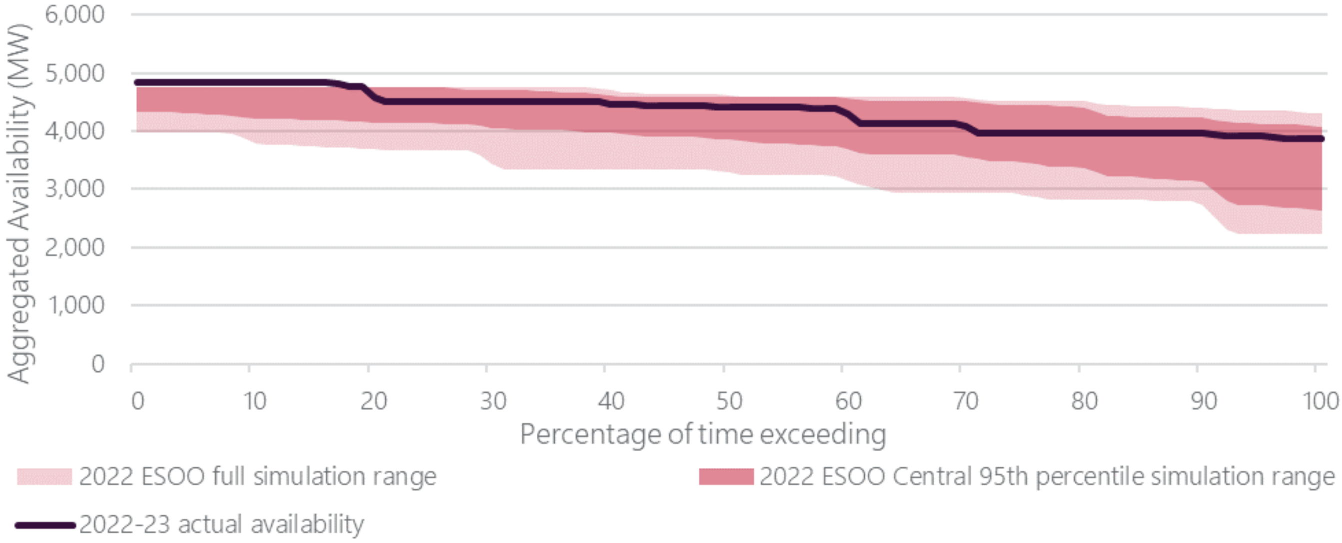


Figure 60 shows that availability over the identified high temperature days for Victorian brown coal was towards the upper end of simulated availability. The higher than forecast availability meets expectations, given the low levels of derating expected during a mild temperature year.

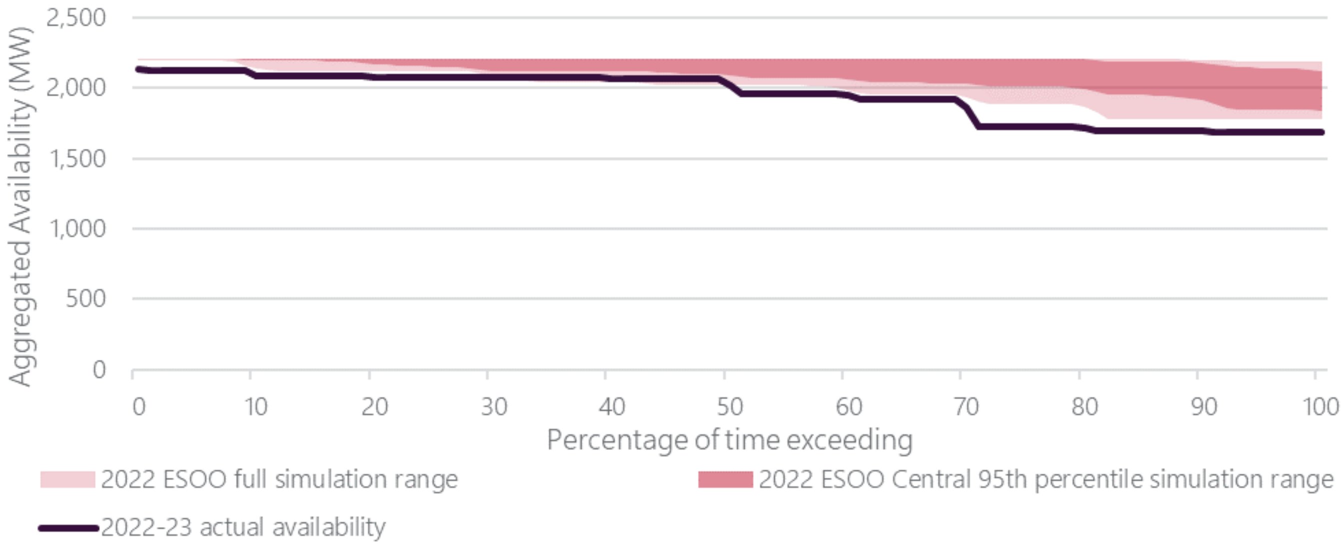
Figure 60 Victoria brown coal supply availability for the top 10 hottest days



Hydro

Figure 61 shows supply availability for Victorian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly below the majority of the 2022 ESOO simulated range, rather than at the upper end which would be expected during a mild temperature year. This is primarily due to planned outages at Murray and Bogong/Mackay.

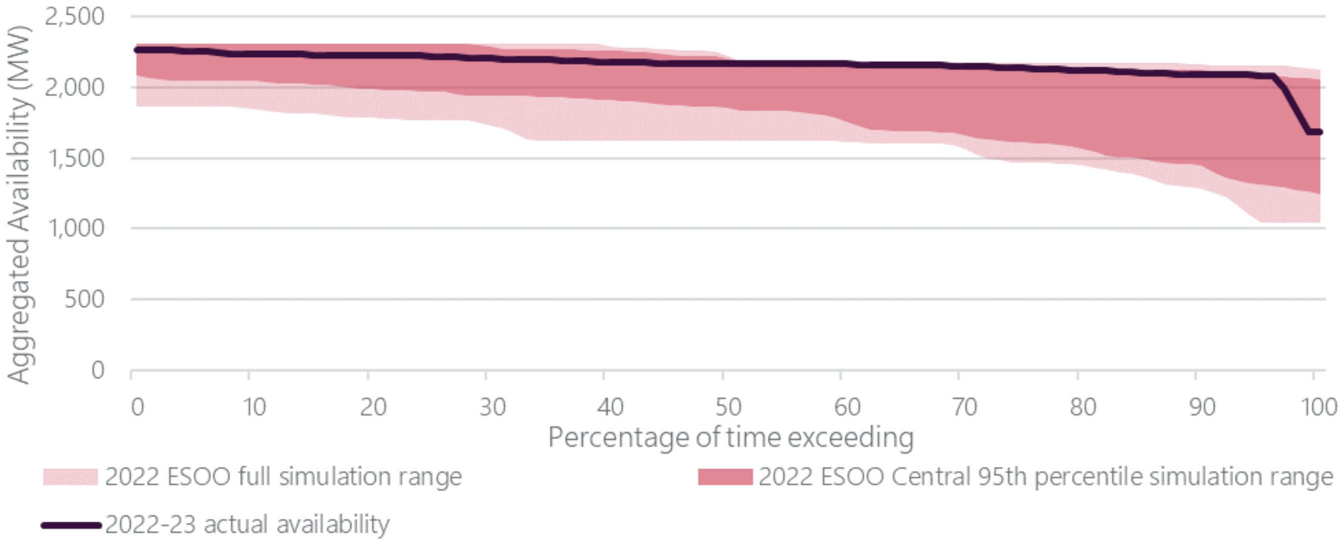
Figure 61 Victoria hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 62 shows that observed availability over the top 10 hottest days was mostly towards the upper end of the 2022 ESOO simulated availability. This was mainly due to low levels of temperature derating, as expected given the relatively mild temperatures observed.

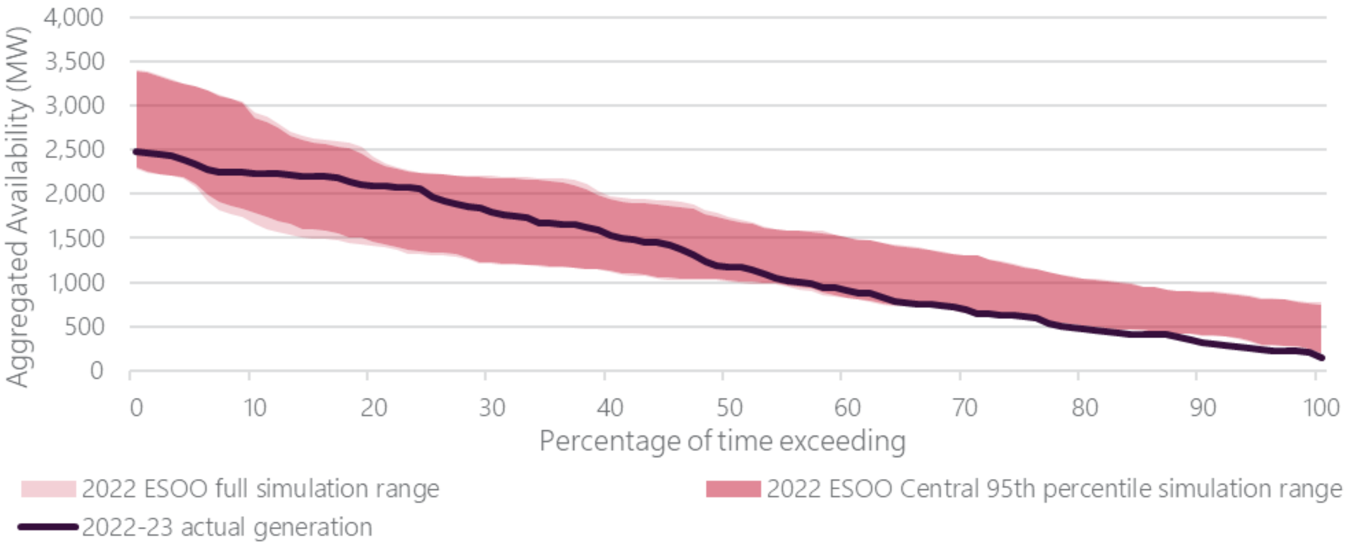
Figure 62 Victoria gas and liquids supply availability for the top 10 hottest days



Wind

Figure 63 shows the aggregate output for Victorian wind generators over the top 10 hottest days, comparing actual output with simulated availability. The observed output was mostly within the 2022 ESOO simulation range, instead of towards the upper end. This is primary due to development delays on new wind farms, and one wind farm had less actual generation than participant-provided values.

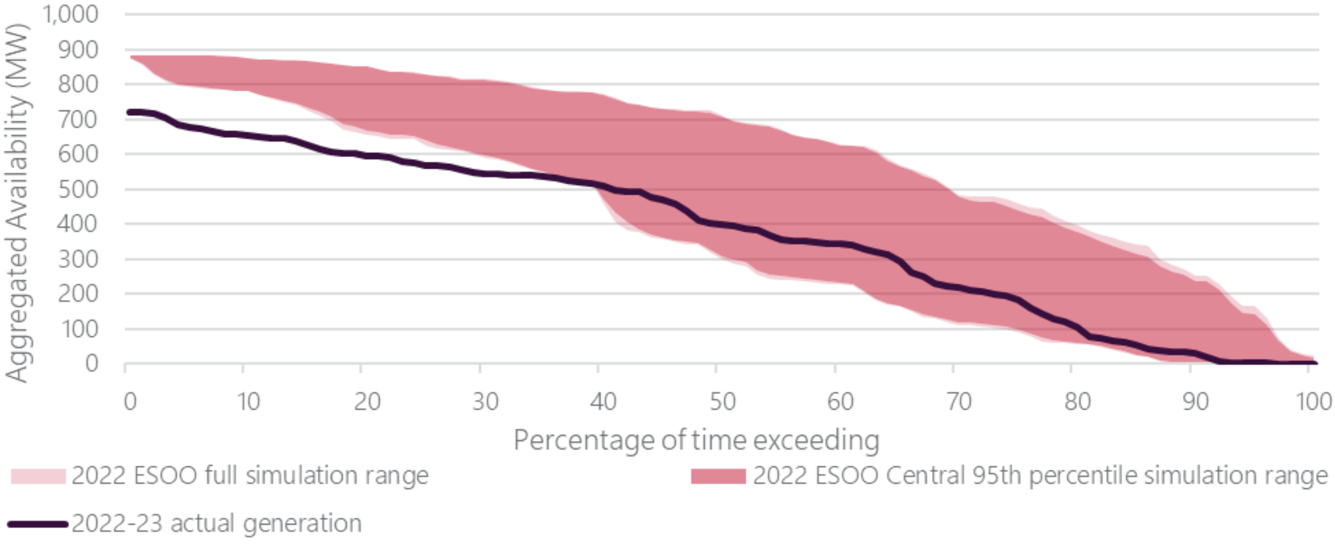
Figure 63 Victoria wind supply for the top 10 hottest days



Large-scale solar

Figure 64 shows aggregate output for Victorian large-scale solar generators over the top 10 hottest days, comparing actual generation with forecast availability range. The observed output was mostly below or towards the lower end of the 2022 ESOO simulation range. The lower than expected output is predominantly due to solar farms commissioning delays and generation curtailment due to constraints representing system security and network limitations.

Figure 64 Victoria large-scale solar supply for the top 10 hottest days



6.6 Demand side participation

AEMO forecasts DSP for use in its reliability assessments (ESOO, EAAP and MT PASA) as well as the ISP. DSP represents a reduction in demand from the grid in response to price or reliability signals. AEMO models DSP similarly to supply options.

AEMO publishes an updated DSP forecast typically once per year. The DSP forecast used for the 2022 ESOO was published along with the 2022 ESOO in August 2022; its accuracy is assessed in the following section.

Background

AEMO's existing DSP forecast methodology[31] estimates the demand response from LILs and any other market participants. Note that subsequent to the publication of the 2023 ESOO, AEMO commenced a consultation on its DSP forecast methodology[32], which could lead to changes in forecasts for the 2024 ESOO and beyond.

The methodology considers DSP responses at a half-hourly level to various price triggers over the previous three years are aggregated to a regional response per event. The aggregate response in a region for a particular trigger is then estimated by taking the 50th percentile of the recorded historical responses.

In addition to DSP in response to various price triggers, additional DSP may operate during periods of extreme scarcity, typically when the system is in an actual lack of reserve (LOR) 2 or LOR 3 state[33]. These programs operated by network service providers are generally only active in summer, contributing to the difference in forecast DSP between seasons.

Consistent with the DSP forecasting methodology, AEMO's 2022 DSP forecast excluded:

[31] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

[32] See https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecasting-methodology-and-dsp-information-guidelines-consultation.

[33] See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/reserve-level-declaration-guidelines.pdf.

- Regular (such as daily) demand variations including responses to time-of-use tariffs and hot water load control.
- Load reductions driven by 'passive' embedded battery storage installations.

These items are excluded from AEMO's DSP forecasts to avoid double-counting, as they are directly accounted for as a reduction in the maximum demand forecasts[34].

AEMO's DSP forecast is used in reliability forecasting to assess the need for reserves under the Reliability and Emergency Reserve Trader (RERT) framework[35], therefore AEMO excludes all RERT resources in the DSP forecasts. However, it has been observed that some sites that have been on the short-notice RERT panel, but not under a RERT contract, have been providing DSP responses voluntarily at times where RERT was not needed. AEMO's 2022 DSP forecast therefore included an additional DSP response from such sites in the reliability driven DSP forecast, to reflect their likely contribution at these times.

Assessment of DSP forecast accuracy

This post-assessment DSP forecast accuracy comprises an assessment of the:

- Median (50th percentile) observed DSP response for various wholesale price triggers during the 2022-23 year compared to the 2022 forecast median response.
- Estimated DSP response against the forecast DSP price or reliability response during the most challenging conditions in the last year, typically the time of regional maximum demand events or periods with an actual LOR 2 or LOR 3 condition.

DSP response by price trigger levels

The median price-driven DSP responses for different wholesale price triggers were assessed using 1 April 2022 to 31 March 2023 consumption data for the same list of DSP resources as the 2022 DSP forecast. This is compared to the forecast DSP responses that were based on consumption data from the three previous years (1 April 2019 to 31 March 2022). The comparisons highlight the difference between forecast DSP and median observed response across the different price triggers.

The comparison does not evaluate performance of the calculation of responses (in particular the baseline estimation). It does, however, highlight whether past observed behaviour (adopted for the DSP forecast) is a reasonable indicator of what DSP response to expect for the coming year.

The comparison of observed to forecast DSP is limited by the number of events that occurred in each season. A low number of observed events makes a comparison challenging, as it may be insufficient to provide a high-confidence estimate of the median observed response.

Comparison results are shown in Figure 65 through to Figure 69, and highlight that compared to previous years, there was an unprecedented spike in the number of high price events in all regions, As the report into the June 2022 NEM spot market suspension noted[36], these high prices were caused by a number of factors, including fuel supply constraints, the early onset of winter, commodity prices, transmission network outages and genetator

[34] In addition to passive energy storages, aggregated energy storages (such as VPPs) are modelled in AEMO's supply side model optimisations.

[35] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT.

[36] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

availability. While all NEM regions experienced more high price events, New South Wales, Queensland and South Australia were affected the most.

Overall, there is generally less DSP observed than forecast for lower price bands. This is directly attributed to the vast and highly unusual number of half-hourly price events at these lower thresholds, with more than 2,000 half-hours of prices >$300 in each of the mainland regions. Most DSP providers do not have the capability to provide responses for such long durations, and for most periods that meet the trigger conditions there may therefore be no observable DSP. It is also harder to detect DSP using the existing methodology[37], which may have been a contributing factor for any forecast inaccuracy. Overall, this reduced (and for some price bands in some regions removed) any visible DSP response.

Conversely, there was an increase in the observed response for higher price bands across most regions, with actual DSP being higher than forecast. This did lead to an uplift to the 2023 DSP forecast published in the 2023 ESOO[38].

Key insights from each region are summarised below:

- No response could be observed in New South Wales for any price bands less than $1,000/megawatt hour (MWh) due to the reasons outlined above. Prices stayed high for much longer periods of time than usual in those lower price bands. For comparison, the year 2022-23 had 2,615 intervals where prices were above $300/MWh, compared to just 137 intervals in 2021-22. For prices over $1,000/MWh and $2,500/MWh, a DSP response was observed, but it was lower than the forecast. For the highest price bands, however, the median observed responses were substantially higher, due to either more loads responding or a more consistent response from the existing DSP providers.
- In Queensland, for all price bands except $300/MWh, the actual DSP is just equal or higher than the forecast. This is well explained by the high price events and its translation to demand lowering by customers. For the $300/MWh price trigger, the actual median observation was lower than the forecast. The difficulties in assessing the response for this trigger level are covered above.
- For South Australia, the median observed DSP was higher than the forecast for all price bands, with the more frequent high prices causing additional businesses to start responding to price (and those already responding, doing so more consistently).
- For Tasmania, the median observed DSP was lower than the forecast, and no significant DSP responses were observed.
- For Victoria, the median DSP observation for all price triggers at $1,000/MWh and above are well over the forecast, reflecting the common trend across the mainland regions of the NEM. The absence of DSP information for price triggers $300/MWh and $500/MWh is due to the same reasons listed for New South Wales above.

[37] This is because the existing DSP algorithm, which is currently up for consultation, generates a baseline demand for each DSP event based on the observed demand during the periods before and after the events. In the specific case of last year, given the long periods of prices above the $300/MWh and $500/MWh triggers, the algorithm in some cases could not reliably calculate a suitable baseline for the duration of the high price event.

[38] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

Figure 65 Evaluation of actual compared to forecast price-driven DSP in New South Wales

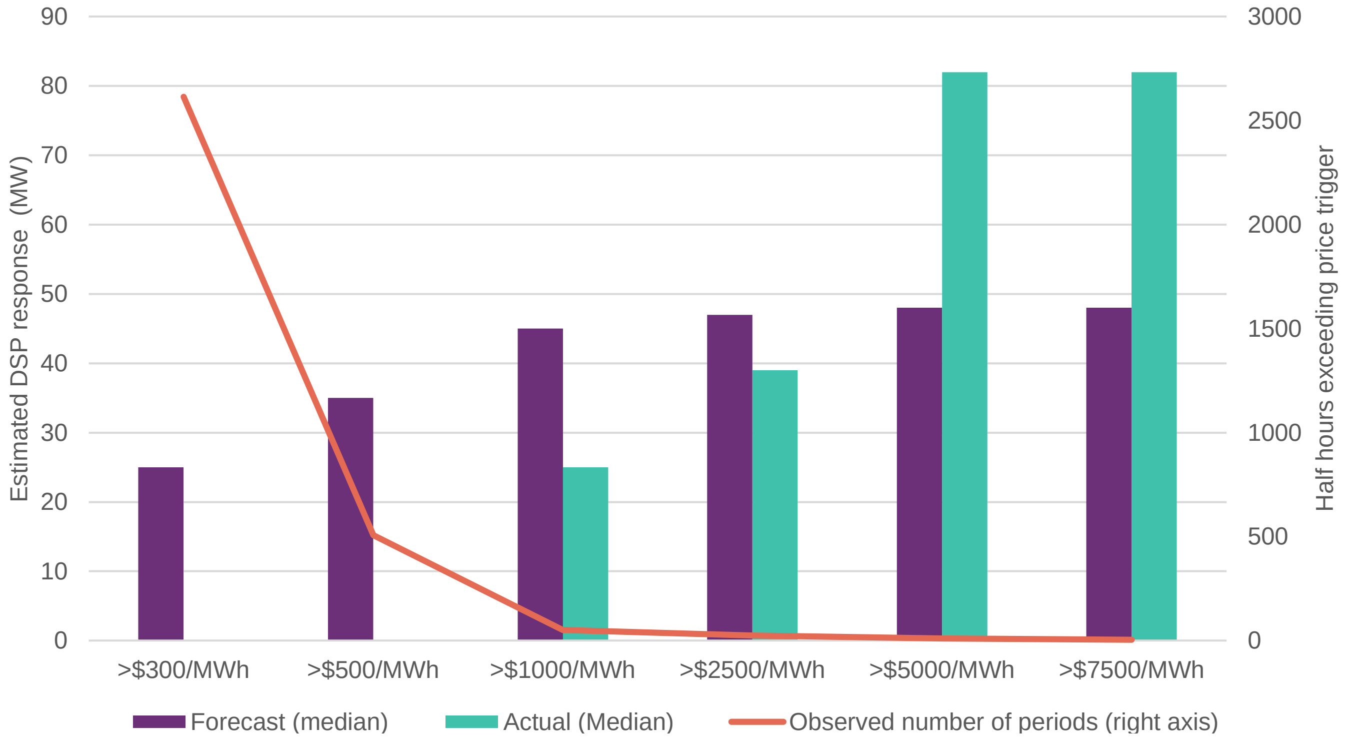


Figure 66 Evaluation of actual compared to forecast price-driven DSP in Queensland

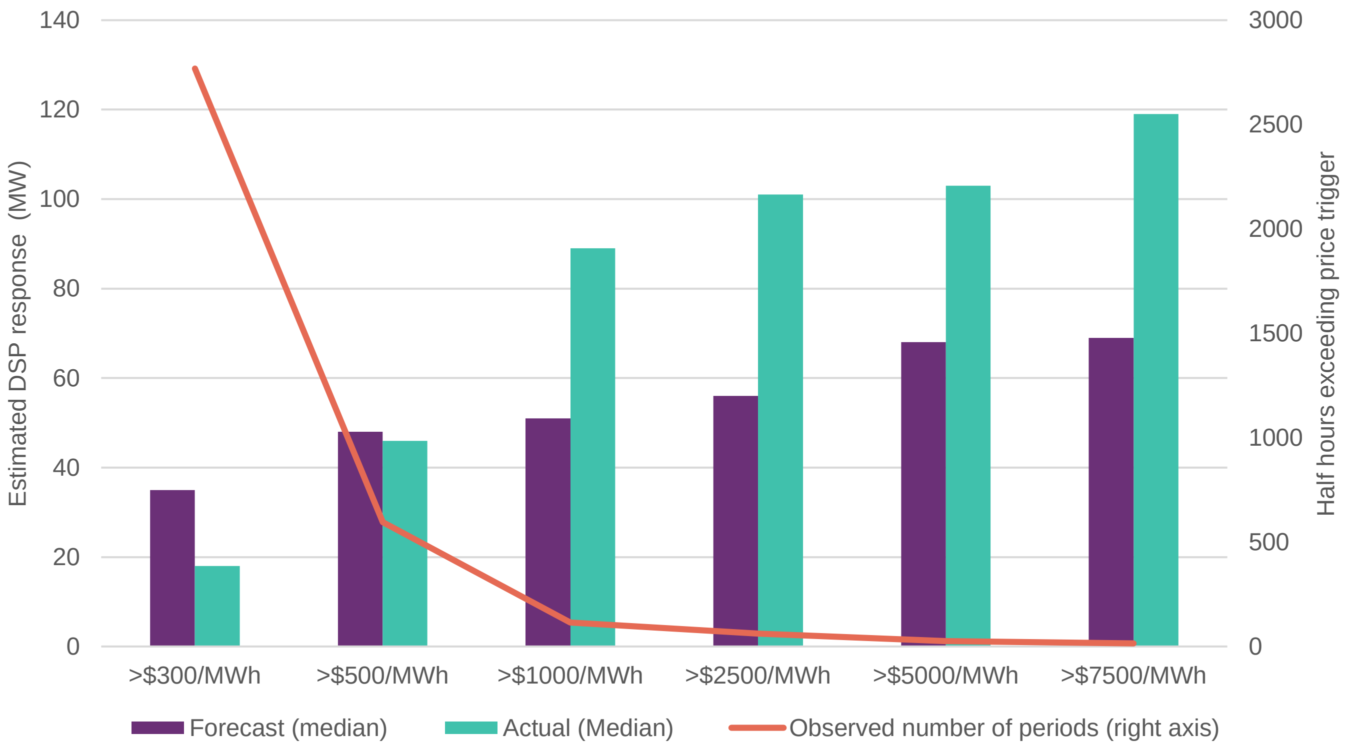


Figure 67 Evaluation of actual compared to forecast price-driven DSP in South Australia

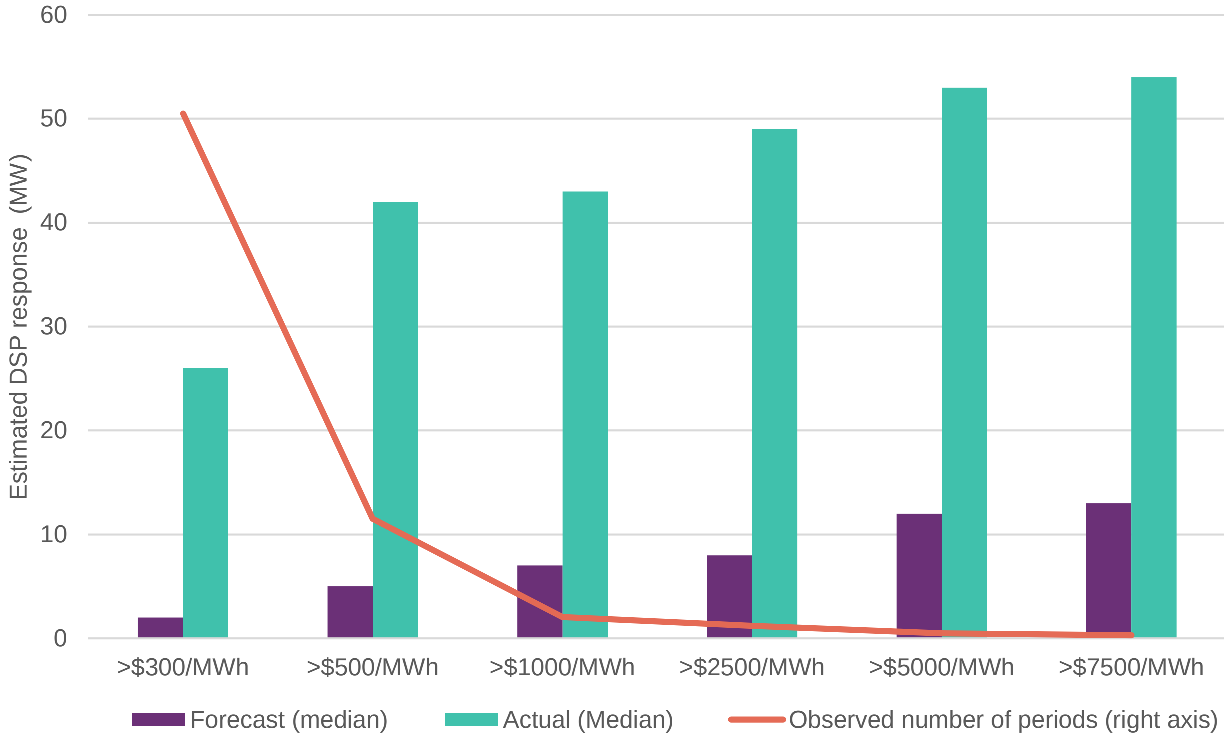


Figure 68 Evaluation of actual compared to forecast price-driven DSP in Tasmania

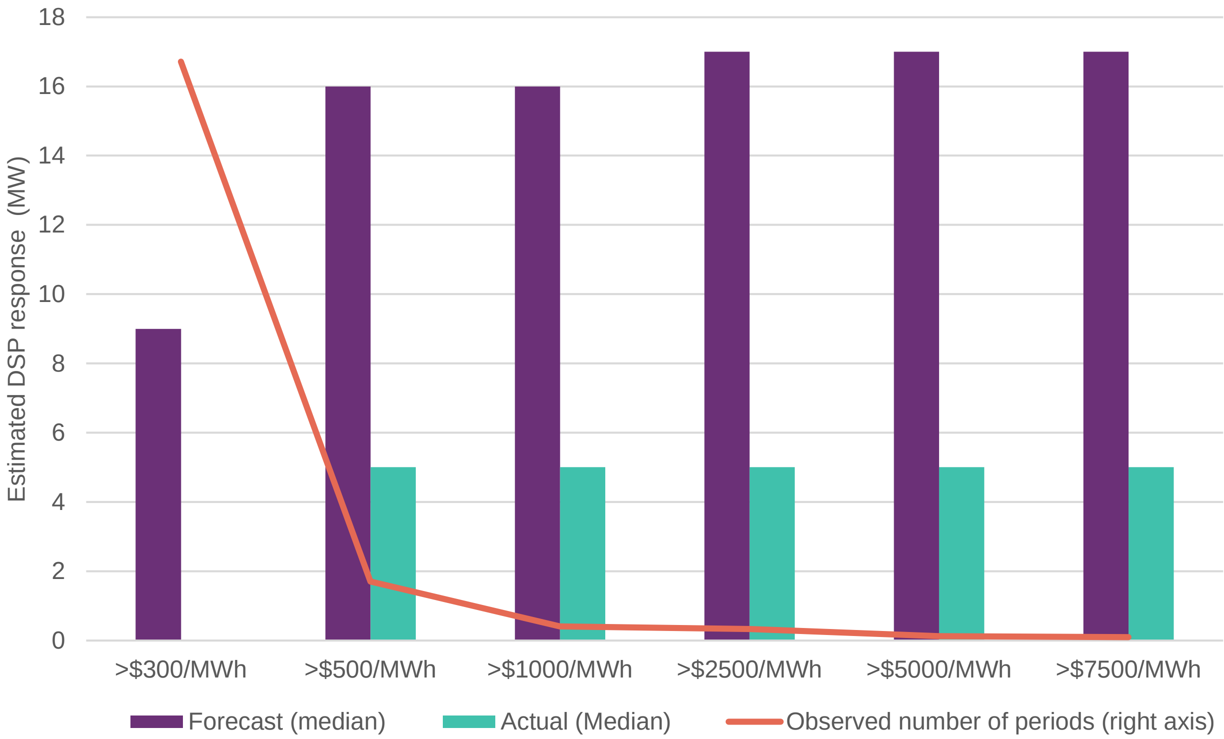
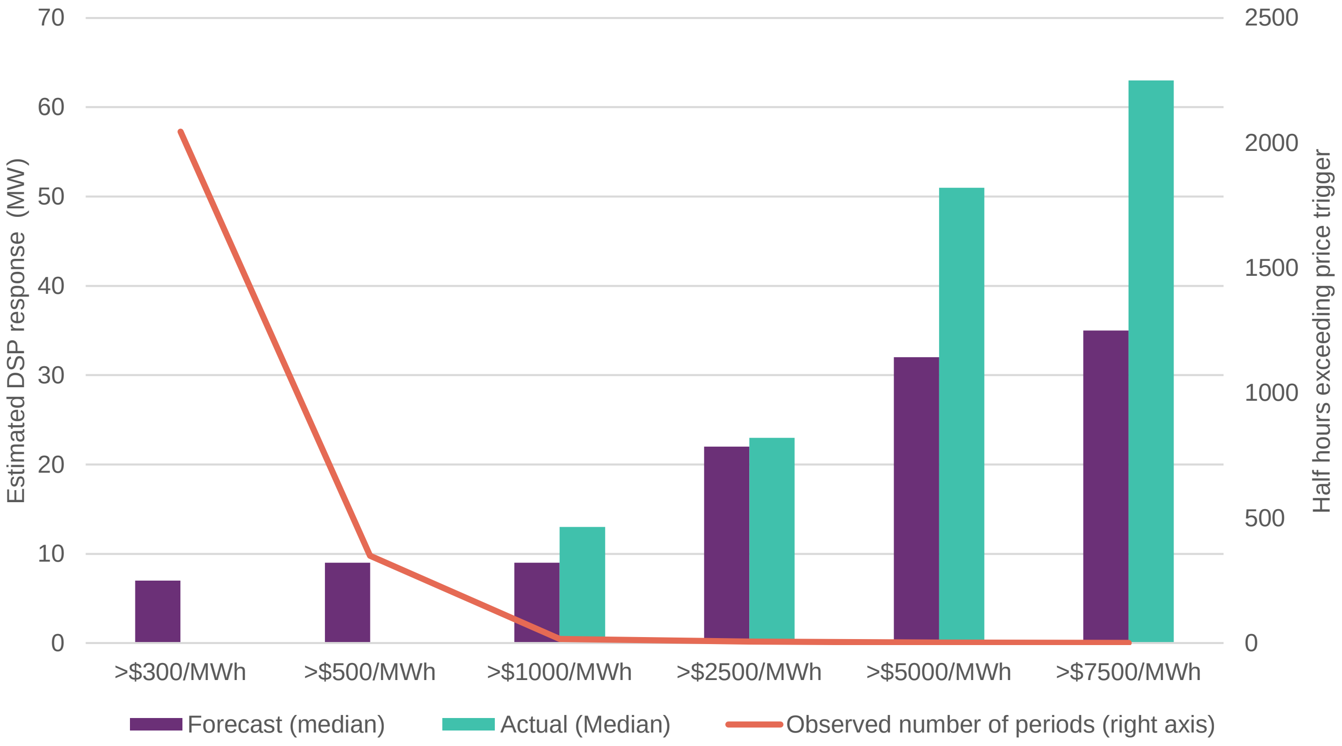


Figure 69 Evaluation of actual compared to forecast price-driven DSP in Victoria



Included in the above discussion of AEMO's DSP forecasts and actuals is the impact of the Wholesale Demand Response (WDR) mechanism. Whilst it is included within the overall DSP forecast, it is forecast as a separate component, using a separate methodology to the rest of DSP. The 2022 ESOO forecast WDR[39] for all regions except Tasmania, and as per the forecast, WDR has been dispatched across all NEM mainland regions. As shown in Table 28:

- In New South Wales and Victoria, the actual WDR was reasonably close to forecast, with the exception of much higher WDR in Victoria in the >$1,000/MWh and >$2,500/MWh price bands.
- In Queensland and South Australia, WDR was significantly lower than forecast. At the time of preparing the 2022 ESOO, WDR had not been previously observed in these regions and therefore the forecasts were based on assumptions linked to how DSP in those jurisdictions may compare to Victoria. This assumption proved to over-estimate the amount of WDR in Queensland and South Australia and subsequent forecasts will be informed by the actual WDR observed in 2022-23.

Table 28 Forecast vs actual WDR in 2022/23 (MW)

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
>$300	0	0	0	0	0	0	0	0	0	0
>$500	0	0	0	0	0	0	0	0	0	0
>$1,000	9	9	1	0	0	0	0	0	1	4
>$2,500	14	13	3	0	1	0	0	0	3	7

[39] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
>$5,000	15	13	6	0	2	0	0	0	6	7
>$7,500	15	13	6	0	2	0	0	0	6	7

* Figures are rounded to nearest MW and therefore the small amount of WDR observed in Queensland and South Australia is not apparent.

Compared to other DSP, WDR is limited in scale and does not materially affect overall DSP forecast accuracy.

DSP response during extreme events

The reliability response from the 2022 ESOO forecast is shown in Table 29. It represents the forecast DSP where the system is in an actual LOR 2 or LOR 3 state.

Table 29 Forecast reliability response in MW during LOR2 or LOR3 during 2022-23 summer and 2023 winter

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Summer	337	262	49	6	257
Winter	337	189	49	6	212

Only New South Wales can be adequately compared with the table above, since it was the only region that recorded an LOR 2 event in summer, which coincided with the maximum demand day. On that day (6 March 2023), prices were generally low, but did increase above the $300/MWh threshold at time of the peak at 18:00. At that point an LOR 2 was declared, and a maximum response of 97 MW was observed. This was considerably lower than the 337 MW forecast, with relatively little response from the most significant industrial loads, which often respond to price (and not just RERT)[40]. While actual DSP may not have happened in this instance, AEMO considers that the forecast remains reasonable in the absence of greater evidence of a more permanent change to industrial load reliability responses.

Whilst New South Wales was the only region to have a reliability event, the DSP response during the other regions' maximum demand events is described below, to provide a fuller picture of how DSP was implemented during the most extreme demand events on the network in each region.

- **Queensland** – the maximum demand day in summer was reached on 17 March 2023. The prices on that day were relatively low except for a sharp peak where the prices rose above $7,000/MWh in the half-hour just after the peak. The brief price spike was insufficient to trigger any observable DSP price response. No LOR event was observed during this time, but Energy Queensland's Peak Smart network DSP program was called 20 minutes into the peak half-hour, which caused an estimated time-weighted response of 24 MW and 72 MW in the following half-hour.
- **South Australia** – the region had its summer 2022-23 maximum demand on 23 February 2023. No LOR events were observed this day. However, the prices on that day did exceed $1,000/MWh for part of the evening. During this time, approximately 10 MW of DSP could be observed.
- **Tasmania** – Tasmania had its annual maximum demand on 22 June 2023. The price was well below the trigger price of $300MWh, so no DSP response was observed.

[40] The Australian Aluminium Council noted in a submission that in May and June 2022 Tomago Aluminium provided 32 hours of response across 18 events, which were a mixture of RERT and responding to high market price. See https://aluminium.org.au/wp-content/uploads/2022/11/221117-Aluminium-Response-Operational-Security-Mechanism.pdf.

- **Victoria** – this region had its maximum demand on 17 January 2023. The price on that day was relatively low, with all prices well below the trigger of $300/MWh. This caused no price-driven DSP events. There were no LOR events observed on this day either, but being a high demand day, a network reliability program was operating, reducing demand by approximately 25 MW at time of peak.[41]

DSP forecast conclusions

Across all high price periods, the actual estimated DSP responses were generally higher than the forecast. This may be due to customers finding ways to respond to high electricity prices more than they have in the past, given the increased frequency of these events.

The unprecedented number of price intervals over $300/MWh and $500/MWh has made assessing DSP in these price trigger bands difficult. AEMO will, as part of its improvement plan, consider whether to exclude some of the very long intervals and/or trial enhanced baseline methods that are more robust across longer durations.

The lack of high demand days with LOR conditions, apart from New South Wales, made it impossible to validate the accuracy of the reliability response this year. For New South Wales, the observed response was significantly lower than the forecast reliability response, but as noted above, responses from large loads at other times are consistent with the forecast value.

As a result of the higher observed DSP responses at higher price triggers in the 2022-23 year, AEMO increased its DSP forecasts for the 2023 ESOO. AEMO will continue to monitor observed DSP against forecast (including use of WDR) over the coming summer to assess whether the higher forecast responses are consistent with what can be observed on the most extreme demand days, or if any further adjustments are required.

[41] As reported in Table 15, this 25 MW was added back to Victorian maximum demand for the purposes of assessing forecast accuracy.

7 Reliability forecasts

AEMO forecasts and reports on scarcity risk of generation supply availability, DSP, and inter-regional transmission capability, relative to demand. This forecast of supply scarcity risk is an implementation of the reliability standard[42] and Interim Reliability Measure (IRM)[43], with the expectation that the market will respond to avoid USE occurring. Further, in operational and planning timeframes, AEMO uses operational mechanisms to avoid USE events where possible.

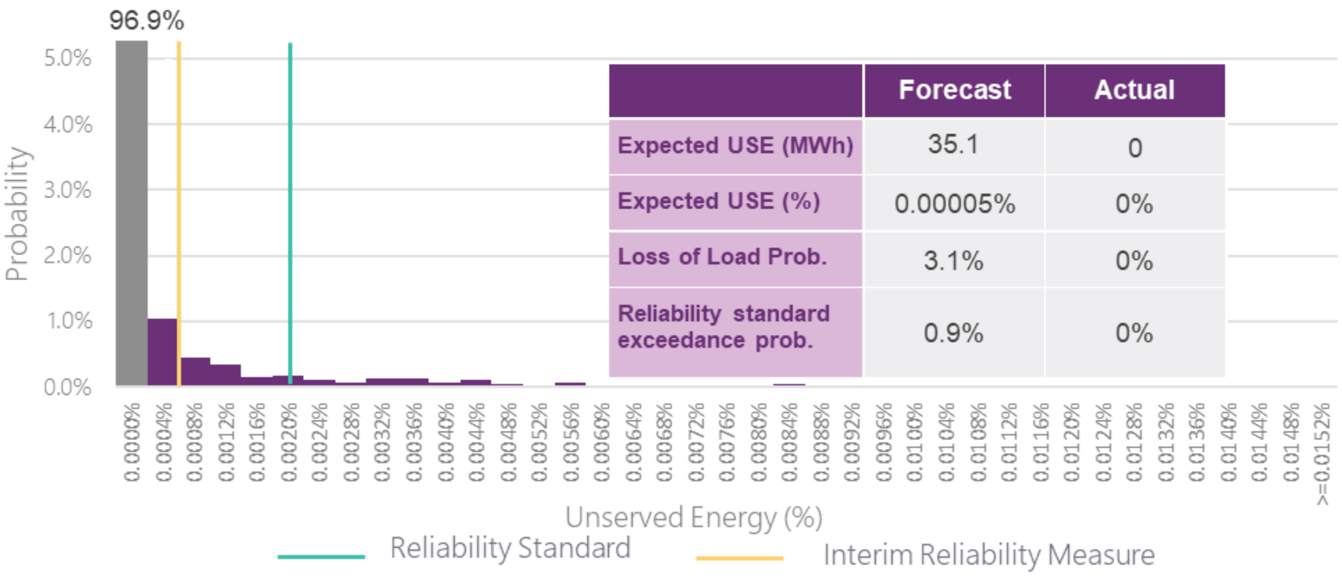
No USE events occurred in 2022-23 in any region.

Reliability forecasts are not presented for the purposes of assessing forecast accuracy, but for information only. Risk of USE is forecast as a probability distribution which is long-tailed – that is, most simulations do not involve a USE event, while a small number involve large USE events. Further, if effective in soliciting a response from market or through RERT, the forecast USE should not eventuate.

7.1 New South Wales

Figure 70 shows the forecast distribution of USE in New South Wales for the 2022-23 summer in the 2022 ESOO. The probability of any loss of load was assessed at 3.1%, and the probability of no USE events was assessed at 96.9%.

Figure 70 New South Wales USE forecast distribution for 2022-23 summer



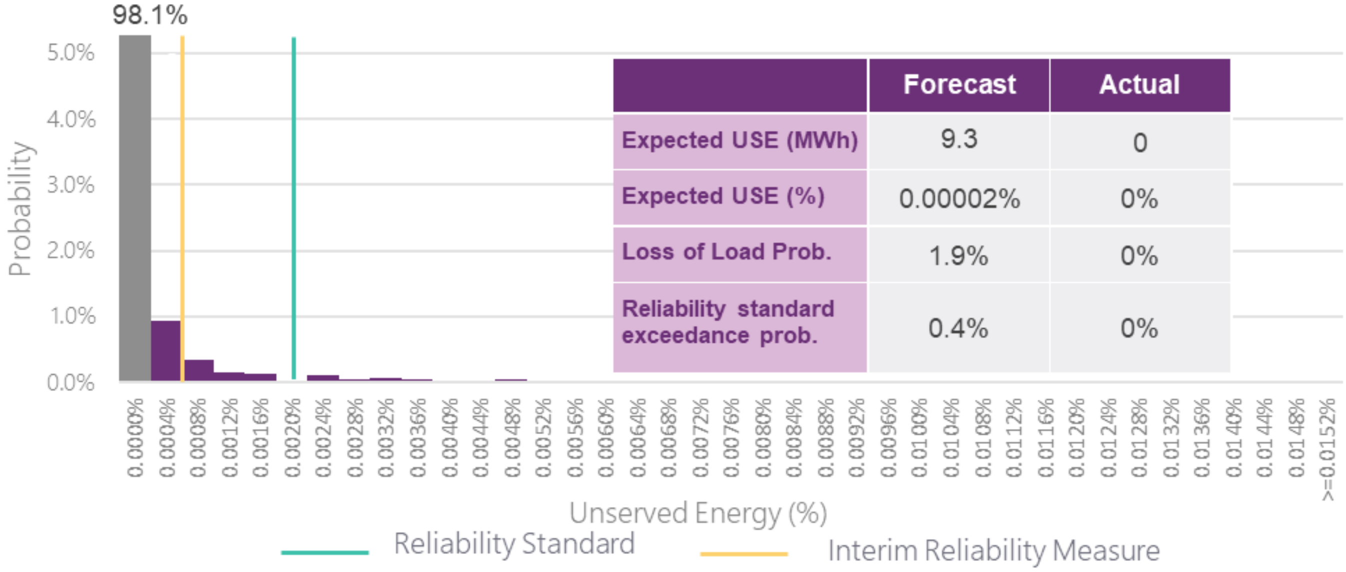
[42] The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

[43] The application of the interim reliability measure of 0.0006% was extended to 30 June 2028 on 21 September 2023, in accordance with clause 11.160 of the NER.

7.2 Queensland

Figure 71 shows the forecast distribution of USE in Queensland for the 2022-23 summer in the 2022 ESOO. The probability of any loss of load was assessed at 1.9%, and the probability of no USE events was assessed at 98.1%.

Figure 71 Queensland USE forecast distribution for 2022-23 summer

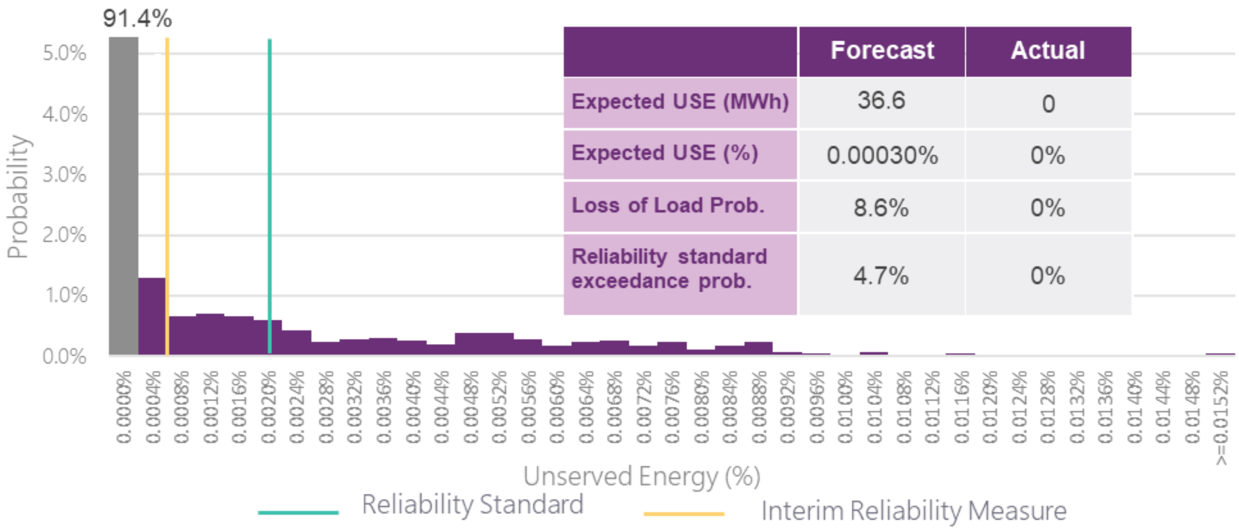


	Forecast	Actual
Expected USE (MWh)	9.3	0
Expected USE (%)	0.00002%	0%
Loss of Load Prob.	1.9%	0%
Reliability standard exceedance prob.	0.4%	0%

7.3 South Australia

Figure 72 shows the forecast distribution of USE in South Australia for the 2022-23 summer in the 2022 ESOO. It shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 8.6% and the probability of no USE events was assessed at 91.4%.

Figure 72 South Australia USE forecast distribution for 2022-23 summer

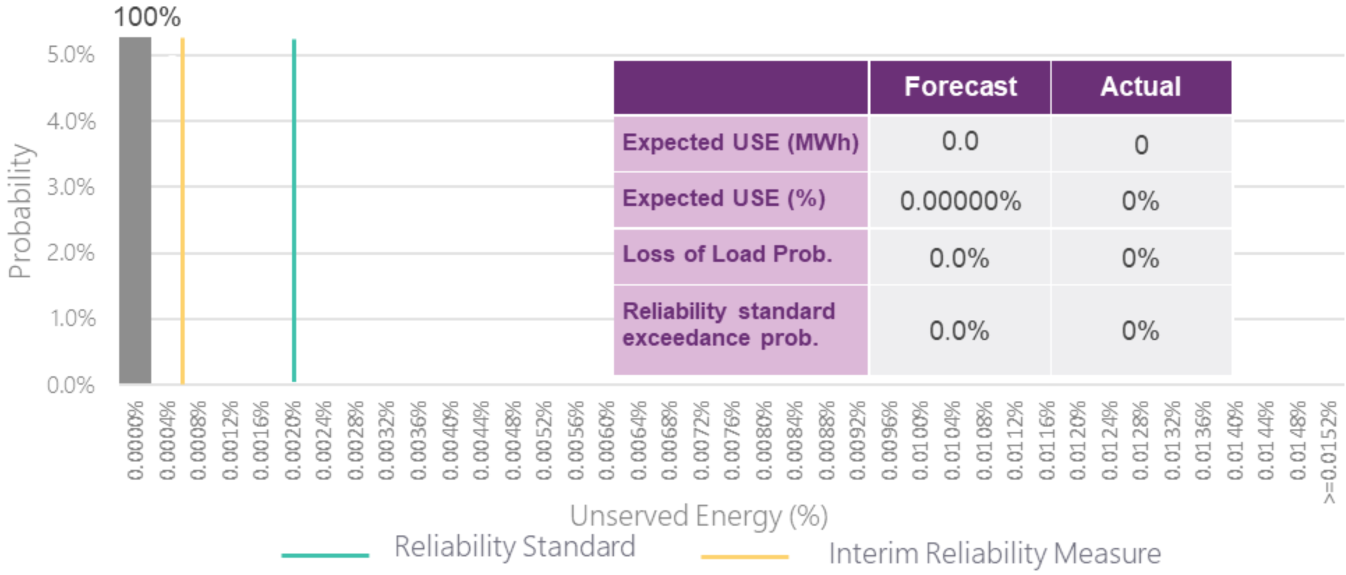


	Forecast	Actual
Expected USE (MWh)	36.6	0
Expected USE (%)	0.00030%	0%
Loss of Load Prob.	8.6%	0%
Reliability standard exceedance prob.	4.7%	0%

7.4 Tasmania

Figure 73 shows the forecast distribution of USE in Tasmania for the 2022-23 financial year in the 2022 ESOO. The distribution shows that no USE events were forecast by the simulations.

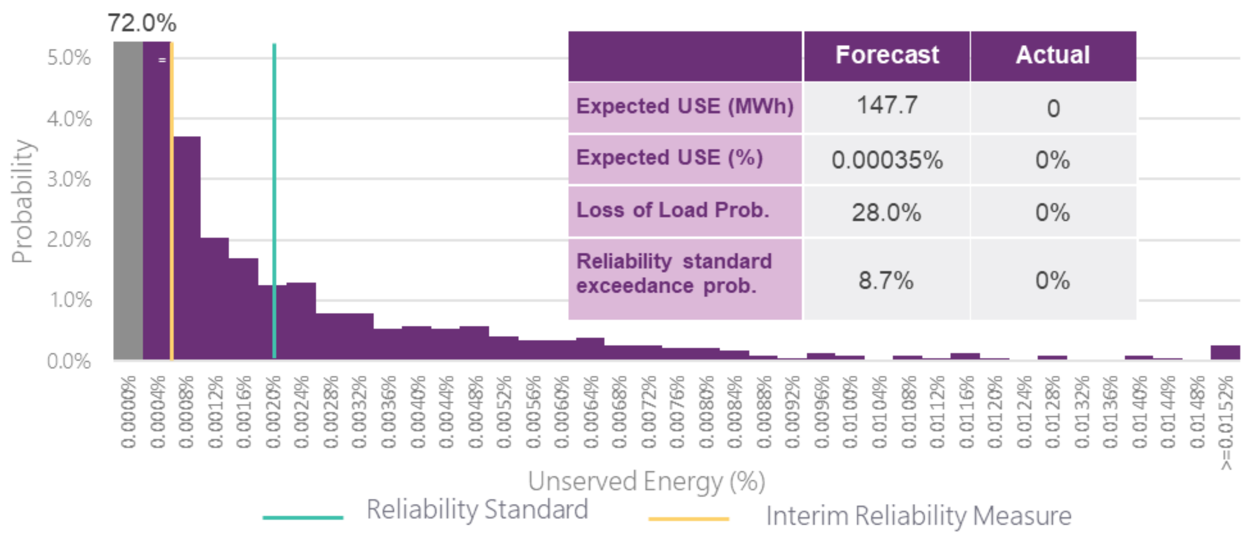
Figure 73 Tasmania USE forecast distribution for 2022-23 financial year



7.5 Victoria

Figure 74 shows the forecast distribution of USE in Victoria for the 2022-23 summer in the 2022 ESOO. The distribution shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 28.0% and the probability of no USE events was assessed at 72.0%.

Figure 74 Victoria USE forecast distribution for 2022-23 summer



8 Forecast Improvement Plan

AEMO acknowledges the importance of forecast accuracy to industry decision-making. The purpose of the annual *Forecast Accuracy Report* is to assess forecast accuracy performance and provide transparency around areas where AEMO intends to focus efforts to improve future forecasts.

The process has three key steps:

1. **Monitor** – track performance of key forecasts and their input drivers against actuals.
2. **Evaluate** – for any major differences, seek to understand whether the reason behind the discrepancy is due to forecast input deviations (actual inputs differed from forecast inputs) or a forecast model error (the model incorrectly translates input into consumption or maximum/minimum demand).
3. **Action** – seek to improve input data quality or forecast model formulation where issues have been identified, prioritising actions based on materiality and time/cost to correct.

This section focuses on the third point, outlining AEMO's intended actions following the review of forecast accuracy, and inviting feedback on those proposals prior to implementation.

It should be noted that not all forecast improvements stem from the actions identified following the forecast accuracy assessment. It is only one of three drivers for changes to the forecasting models and processes:

1. **Forecast accuracy improvements** – in addition to the annual *Forecast Accuracy Report* and Forecast Improvement Plan (and associated consultation), AEMO regularly tracks forecast performance and consults through the Forecasting Reference Group (FRG), and this may drive minor updates to forecasting models, data or assumptions to address identified forecast accuracy issues within the yearly cycle.
2. **Evolution of the energy system** – over time, electricity consumption and demand change in response to structural changes of Australia's economy, such as the emergence of a new sector (for example, the development of LNG export facilities supported by electrical loads associated with coal seam gas [CSG] operations), or consumer behavioural or technological changes (such as EVs or battery storage systems or responses to physical or financial stimuli, such as changing usage patterns to best utilise rooftop PV generation). These developments may impact the total energy consumed across a year by consumers, or the daily demand profile of energy consumption, or both. The demand forecasting process continually evolves to account for these changes, in particular for the longer-term forecasting and planning processes.
3. **Regulatory requirements** – changes to rules and regulations can cause changes to how forecasts are produced, or what needs to be forecast. For example, the RRO required a number of changes to AEMO's forecasting process, and the introduction of an emissions reduction limb to the National Energy Objectives is increasing considerations of emissions reduction activities and policies within AEMO's planning functions.

AEMO's proposed Forecast Improvement Plan, presented in the following sections, focuses on initiatives to improve forecast accuracy. It is guided by the key observations on the performance of the 2022 forecasts summarised in Section 8.1.

The Forecast Improvement Plan comprises two elements:

- Short-term, priority initiatives to be incorporated in the 2024 ESOO are described in Section 8.2.
- Ongoing initiatives that may support longer-term improvements are described in Section 8.3.

Appendix A1 lists the improvements presented in the 2022 Forecast Improvement Plan, along with a summary of the implementation status of each of these initiatives, and any other improvements implemented for the 2023 ESOO.

Consistent with the Forecasting Best Practice Guidelines (FBPG), this Forecast Improvement Plan is subject to a single stage consultation (as initiated by this document). AEMO welcomes stakeholder feedback on the plan.

8.1 2022 forecasts – summary of findings

While AEMO's forecast models have generally performed well, a number of potential forecasting improvements have been identified in response to the forecast outcomes identified in this report. These issues are summarised below:

- **Annual consumption** was within the forecast target across most of the NEM regions except Queensland and Tasmania.
  - The variance in Queensland was mainly driven by unplanned outages in two of the region's largest loads. While such events are largely not predictable at the time of forecast, continuous monitoring of LIL outages and operational changes will contribute to a better understanding of their impacts on energy consumption.
  - The variance in Tasmania is partially explained by the region's large industrial loads, however, there is the potential to increase forecast accuracy by further analysing sectoral trends in consumption and the sensitivity of models to short-term growth trends in actual consumption.
  - More broadly, there is also scope to analyse actual electricity consumption and connection data, to identify any trends in electrification. These improvements may enable further analysis of the residual variance in the consumption forecast, and build a better understanding of how different sectors are responding to economic conditions, and decarbonisation opportunities.
- The observed actual **summer and winter demand outcomes** were often in the lower end of the range formed by the 10% POE and 90% POE forecasts, and in some cases below the 90% POE forecast, driven by the mostly mild summers and relatively warm winters recorded across the NEM. For Tasmania, the actual summer and winter maximum demands both fell well below the 90% POE forecast. While this can be partially explained by lower than forecast demand from LILs, it does not fully explain the variance, and the Tasmanian models require further review. AEMO is already investigating the forecast approach for LILs in Tasmania during maximum demand conditions, aiming to better reflect the variability of LILs across the year and the impact it may have on maximum demand.
- For **annual minimum demand**, actual results were observed below the 90% POE forecast in three regions. In two of the cases, under-forecast of rooftop PV installations could at least partially explain this. However, since three out of five regions were below 90% POE, AEMO will re-assess its minimum demand models and assumptions to determine if there are more fundamental issues at the root of the under-forecast.
- **Generator commissioning and actual capacity** did not match participant-provided information, resulting in 753 MW less capacity available in 2022-23 than was forecast. AEMO has reviewed the generator commissioning methodology for the treatment of new assets in forecasts in the updated *ESOO and Reliability Forecast Methodology Document*[44]. As the methodology has been implemented in the 2023 ESOO, next year's

[44] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

Forecast Accuracy Report will assess whether this improves forecast performance. AEMO will continue to work with participants to collect more accurate generator capacity to minimise capacity differences between forecast and actual.

- **Planned and unplanned outages** impacted supply availability for numerous regions and technologies, with actual outage rates observed above participant-provided projections. AEMO has since published a new methodology for collecting and forecasting random outage parameters in the updated *ESOO and Reliability Forecast Methodology Document*. As the methodology has been implemented in the 2023 ESOO, next year's *Forecast Accuracy Report* will assess whether this improves forecast performance.
- **EV** numbers have been included in the *Forecast Accuracy Report* for the first time. Although not yet a material driver of energy use and reliability, the long-term outlook of EVs warrants starting to track and improve forecast performance. Given the fast rate of change of this newly adopted technology, initial forecast error is high, so EV forecasting features in the improvement plan. The energy use associated with EVs is not yet included, as obtaining relevant data is lagging behind acquiring sales data.

8.2 Forecast improvement priorities for 2023-24

This section describes how AEMO proposes to address the findings described in Section 8.1 to improve the forecasts ahead of the 2024 ESOO. In some cases, AEMO had already detected these issues and took steps to address them in the forecasts for the 2023 ESOO.

8.2.1 Review the sensitivity of short-term annual consumption models

AEMO considers that the consumption models have performed reasonably well for the NEM overall. For Tasmania, however, the variance that cannot be explained by input drivers is around 4.5% of operational consumption (as generated). A downward revision was already implemented in the 2023 ESOO forecast for Tasmania, being 7% lower than the 2022 ESOO forecast in 2023-24. While AEMO does not propose any changes to model structure and approach at this time, AEMO proposes to expand the annual review of recent growth trends for Tasmania in particular, to ensure that short-term consumption models respond effectively to capture these trends.

8.2.2 Review large industrial load

Improvements to the LIL forecasts were already put in place for the 2023 ESOO, including for both maximum demand and annual consumption models. These are described in Appendix A1 and had the effect of reducing forecast LIL consumption and demand contribution, better aligning forecasts with actuals. The impact of these improvements will be assessed in the 2024 *Forecast Accuracy Report*.

Given the improved process already implemented, AEMO does not consider that any further process or approach changes are required, but proposes to expand the annual review of LIL forecasting. This review will monitor LIL consumption that shows the largest variances compared to the forecast, including unplanned outages and significant operational variations. While such events are largely not predictable at the time of forecast, continuous monitoring may contribute to a better understanding of their impacts on energy consumption, and guide forecast updates in the future.

8.2.3 Review minimum demand models

Before the 2023 ESOO, AEMO implemented a revised half-hourly demand forecasting model which demonstrated increased accuracy at time of both minimum and maximum demand. The 2024 *Forecast Accuracy Report* will establish the degree to which this revised model has improved forecast accuracy for minimum demands. In addition to the previously implemented changes, AEMO will undertake further review of its minimum demand forecast models to further establish whether the lower-than-90% POE results recorded for minimum demand were related to under-forecast of rooftop PV or some other factor(s). This may inform the next broad consultation on AEMO's overall Electricity Demand Forecasting Methodology.

8.2.4 Improve EV forecast approaches

AEMO plans to improve EV forecasts by:

- Adjusting short-term forecast models to respond more dynamically to recent sales data.
- Improving the consideration of the popularity and longevity of PHEVs.

8.3 Ongoing research and improvement areas

Apart from the forecast improvement priorities for 2023, AEMO also identifies areas that can be assessed on an ongoing basis to continuously improve its forecast accuracy.

Research is the creation of new knowledge or use of existing knowledge in a new, innovative way. Compared with development work, the key difference is the uncertainty around outcomes (that is, whether the research is successful or not) and how much time it will take to deliver. However, many initiatives may sit in the grey area between implementation of a known approach based on known data, and developing a new method using yet to be identified data.

In the 2022 *Forecast Accuracy Report*, investigations arising from the two improvement actions confirmed that improvements could be made and these were incorporated into the forecasts for the 2023 ESOO. In both cases, the work was an extension of investigations initiated as result of the 2021 *Forecast Improvement Plan*, and are also longer-term programs that are likely to continue into future Forecast Improvement Plans. For this reason, they are treated as ongoing improvement areas.

Monitoring is used where inputs or assumptions within the current forecasting process are known to be at risk of changing, to ensure extra care is taken to validate assumptions ahead of the next forecast. These ongoing efforts to improve forecasts are further described below.

8.3.1 Understand changes in future load shape from technology uptake and usage

As reported last year, there is limited data available on usage (charge and discharge data) of distributed battery storage systems (including VPPs) and EVs, but recent trials may change this. AEMO will assess data from Project Edge and Project Symphony to support insights into future load shapes, and will continue to collaborate with industry participants, researchers and government in researching the uptake and operation of EVs and battery storage.

8.3.2 Track electrification trends

Fuel-switching to electricity is potentially a significant driver of consumption growth in future. AEMO is interested in investigating whether electrification trends may already be observable in meter data. This may enable better understanding of the impact of electrification on the short-term forecasts, and improved validation of inputs from multi-sector modelling.

8.3.3 Improve renewable generation and demand traces, including the quantity used, and their shape

AEMO relies on traces for demand and renewable generation for consistent weather, to ensure the supply modelling reflects coincidence in high demand outcomes with the available supply of variable renewable generation consistent with the likelihood of this actually happening. This consistency has typically been achieved through use of historical weather years; the 2022 ESOO used 12 weather years to create demand reference years matching that weather, along with corresponding profiles for the generation from large-scale wind and solar farms**.**

The NEM is witnessing a rapid transformation of the generation fleet, with more than 4,900 MW of additional committed and 2,800 MW additional anticipated large-scale wind and solar projects as of August 2023. Meanwhile, existing generator operators have advised AEMO of an expected closure schedule that represents 6,730 MW of generation capacity (approximately 20% of the currently registered thermal – coal, gas and diesel – generation fleet) in the next 10 years[45]. This observed growth in new weather-dependent generation capacity, along with the projected decommissioning of dispatchable thermal generators, increases the importance of weather when assessing future reliability outcomes.

Adding additional weather years can be done by using more historical years (if the quality of the data is adequate) or by creating synthetic weather years, which represent potential weather outcomes within the estimated distribution of possible weather outcomes today and in future forecast years.

A weather year will contain information about temperature, wind speed, and solar insolation at half-hourly resolution. Wind and solar generation profiles will be created based on this data, noting the generation profiles for both wind and solar account for temperature-related impacts on generation.

Using more weather years is likely to improve the coverage of weather conditions accounted for in the simulations, including occasions where limited wind and solar resources could increase the risk of USE. AEMO plans for more weather reference years to be available for the 2024 ESOO, including a limited number of synthetic years, and demand traces will need to be created for those. This will be used to validate the appropriateness of synthetic weather traces relative to those purely based on history, and guide how to further increase the number of weather years in future ESOOs.

8.3.4 Improve visibility of sectoral consumption

AEMO commenced analysis of sectoral consumption as part of the 2021 Forecast Improvement Plan. Work is continuing on this initiative with funding received from the Department of Climate Change, Energy, the Environment and Water (DCCEEW) under the National Energy Transformation Partnership (NETP). The aim is to improve the breakdown of both the existing LIL and the broader business mass market sectors. This will help

[45] See AEMO's Generation Information page, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

identify opportunities for data and model improvements to reduce consumption forecast variance in the 2024 ESOO.

An improved sectoral split will increase visibility of the impact of economic activity on the consumption forecasts, particularly as energy intensity varies across economic sectors. It will also enable better integration with economy-wide modelling, such as integrated assessment models (IAMs). IAMs are used to model sectoral trends in future decarbonisation scenarios, including impacts from electrification of various sectors, and are used in AEMO's broad forecasting and planning processes, including the ISP. Without a similar sectoral breakdown, it is difficult to integrate high-level targets of an IAM into AEMO's forecasts.

Sectoral consumption is also a key input in forecasting various input components, influencing fuel-switching, economic growth and energy efficiency projections, and improving this data set is expected to lead to forecasting improvements in the longer term.

8.3.5 Monitor demand side participation trends

While the 2023 DSP forecasts were able to incorporate actual WDR data in four regions, the scheme is still in its relative infancy, and WDR in Queensland and South Australia in particular is very low. AEMO will continue to monitor how WDR is used compared to forecast, to guide any future updates of the DSP forecast.

The response of large DSP providers during LOR events (for example in New South Wales in 2022-23) will be monitored to ensure current assumptions about their responses during reliability events are still valid.

8.3.6 Monitor planned outages

The ESOO methodology excludes consideration for generator planned outages, on the basis that they are assumed to be scheduled away from periods of supply scarcity. Planned outages, however, continue to be observed during periods of high demand, and during potential periods of supply scarcity, challenging this assumption. AEMO will monitor planned outages for scheduled generators and determine whether methodology changes are required for planned outages in ESOO model.

A1. Status of improvements proposed in 2022

The 2022 Forecast Improvement Plan was published in the 2022 *Forecast Accuracy Report*[46]. It proposed a number of improvements planned for the 2023 ESOO or beyond. For visibility of progress, each improvement is listed below along with a summary of feedback and the implementation status.

Table 30 Improvements outlined in the 2022 Forecast Improvement Plan

Improvement	Stakeholder engagement	Status
Improve renewable generation and demand traces, including the quantity used, and their shape AEMO planned for more weather reference years to be available for the 2023 ESOO, including a limited number of synthetic years, and expected to create demand traces for them.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives.	**In progress.** AEMO has progressed work that will allow weather years back to 2007 to be used as reference year basis. Estimated rooftop PV generation before that day is challenging because satellite data is not available, and AEMO is looking at methods to bias-correct ground-based irradiance measurements from before 2007 to align estimated PV generation in these years with estimates post 2008. AEMO expects to be able to use years going back to 2007 at least for the 2024 ESOO.
Improved visibility of sectoral consumption AEMO planned to continue work on this initiative, with the aim of improving the breakdown of both the existing LIL and the broader business mass market sectors.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives.	**In progress.** Building on outcomes from the original project funded under the National Energy Analytics Research (NEAR) Program, the extended ANZSIC Project scope of works focuses on improving the address matching protocol to map National Metring Identifiers (NMIs) to industry sectors, and piloting the use of other industry data sources.
Review initial year of forecast maximum and minimum demand distribution AEMO planned to continue this initiative, by reviewing the models used to set the starting points of the demand distributions.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives. A review of the 2022-23 summer maximum demand was provided at the 29 March 2023 FRG.	**In progress.** Significant improvements were made for the 2023 ESOO, allowing the simulation model to set the starting points of the distribution directly. AEMO will continue to look for improvement opportunities in data (including methods for detrending), model formulation and tuning. It should be noted that the first year set by the model is the latest actual year and the first forecast year therefore also depends on the short-term trend of the consumption forecast, which is also under review now.

[46] Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2022.pdf

Improvement	Stakeholder engagement	Status
Review large industrial load and other non-scheduled generation forecast components AEMO planned to review both the LIL and ONSG forecast components, to better understand both their impacts on consumption and their contributions at time of maximum and minimum demand.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives.	**In progress.** AEMO receives survey information from LILs, and for the 2022 ESOO, this was reviewed more closely against actual consumption. Most variances related to unplanned outages. AEMO plans on monitoring LIL consumption on an ongoing basis to help with future forecast development. For maximum/minimum demand, AEMO implemented a random forest algorithm to reflect variability in LIL across the year and across the day. Variations in LIL can affect the maximum outcomes in regions with high proportion of LIL (Tasmania in particular) and minimum demand more generally as operational demand gets closer to or below zero. For its synthetic trace work, AEMO has been adjusting the methodology further to bootstrap historical LIL outcomes scaled according to LIL growth, which is found to improve the modelling of LIL and its contribution to maximum and minimum demand events even further.
Monitor data availability of uptake and usage of emerging technologies AEMO was monitoring a number of new and/or improved data sources for technologies such as EVs and batteries.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives.	**Ongoing process:** • Batteries – AEMO purchased commercially available battery sales and projections data to inform its forecasts and forecasting approach • EVs – AEMO is liaising with various government agencies to determine the most effective data sources for forecasting and insights • AEMO participates in the ESP-Vic project (led by C4NET) to inform sub-transmission level electricity planning beyond 2030. This informs AEMO's thinking across PV integration, battery storage, EV adoption and electrification
Monitor demand side participation trends AEMO planned to monitor how WDR is used compared to forecast, to guide any future updates of the DSP forecast.	Updates on all 2022 Forecast Improvement Plan initiatives were provided at the 26 April 2023 FRG and again at the 29 November 2023 FRG, providing stakeholders with the opportunity to ask questions about the progress on these initiatives. Draft DSP forecasts (including WDR) were provided at the 31 May 2023 FRG. AEMO commenced a two-stage consultation on its DSP forecast methodology and information guidelines in September 2023.	**Ongoing process.** AEMO reviewed the WDR data for the 2022-23 year and this informed revisions to the WDR forecast, in particular for Queensland and South Australia. AEMO will continue to review WDR data as it evolves.
Energy adequacy scenarios AEMO planned different EAAP scenarios to better capture energy limits risks and required additional inputs and model changes to appropriately understand the risks of energy limits.	AEMO commenced a two stage NEM reliability forecasting guidelines and methodology consultation at the 26 October 2022 FRG and finished the consultation at 24 April 2023.	**Completed**. AEMO reached final determination on the consultation and published Reliability forecasting guidelines and methodology final report. Planned improvement has been implemented in the 2023 ESOO.
New generation, storage, aggregated distributed energy resources and transmission commitment criteria implementation. AEMO planned to seek stakeholder input to determine an appropriate balance of over-forecasting or under-forecasting potential supply from new assets.	AEMO commenced a two stage NEM reliability forecasting guidelines and methodology consultation at the 26 October 2022 FRG and finished the consultation at 24 April 2023.	**Completed.** AEMO reached final determination on the consultation and published Reliability forecasting guidelines and methodology final report. Planned improvement has been implemented in the 2023 ESOO.

Improvement	Stakeholder engagement	Status
Random outage parameters AEMO proposed to collect and include additional outage categories in its reliability forecasts.	AEMO commenced a two-stage NEM reliability forecasting guidelines and methodology consultation at the 26 October 2022 FRG and finished the consultation at 24 April 2023.	**Completed.** AEMO reached final determination on the consultation and published Reliability forecasting guidelines and methodology final report. Planned improvement has been implemented in the 2023 ESOO.
MT PASA generator status and recall times. AEMO proposed status codes consistent with the IEEE standard 762-2006, and recall times under a variety of unit status codes.	AEMO commenced a two stage NEM reliability forecasting guidelines and methodology consultation at the 26 October 2022 FRG and finished the consultation at 24 April 2023.	**Completed.** AEMO reached final determination on the consultation and published Reliability forecasting guidelines and methodology final report. Scheduled generators and integrated resource system participants have provided status codes and recall times for periods of unavailability from October 2023.
Reliability gap calculation AEMO proposed to adjust the calculation method for reliability gap periods, likely trading intervals and reliability gaps in megawatts.	AEMO commenced a two stage NEM reliability forecasting guidelines and methodology consultation at the 26 October 2022 FRG and finished the consultation at 24 April 2023.	**Completed.** AEMO reached final determination on the consultation and published Reliability forecasting guidelines and methodology final report. Planned improvement has been implemented in the 2023 ESOO.

* The ESOO and Reliability Forecast Methodology is available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf.

Measures and abbreviations

Units of measure

Abbreviation	Full name
GW	Gigawatt/s
GWh	Gigawatt hour/s
MW	Megawatt/s
MWh	Megawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BEV	Battery electric vehicles
CER	Consumer energy resources
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DNSP	Distribution network service provider
DSP	Demand side participation
EAAP	Energy Adequacy Assessment Projection
ESOO	*Electricity Statement of Opportunities*
EV	Electric vehicle
EVC	Electric Vehicle Council
FCAI	Federal Chamber of Automotive Industries
FRG	Forecasting Reference Group
GDP	Gross Domestic Product
GEM	Green Energy Markets
GSP	Gross State Product
HDI	Household Disposable Income
IAM	Integrated assessment model
IRM	Interim Reliability Measure
ISP	*Integrated System Plan*
LOR	Lack of Reserve
MT PASA	Medium Term Projected Assessment of System Adequacy
NEAR	National Energy Analytics Research
NEM	National Electricity Market
NEAR	National Energy Analytics Research NEAR

Abbreviation	Full name
NER	National Electricity Rules
NMI	National Metering Identifier
OPGEN	Operational demand as generated
OPSO	Operational demand sent-out
PHEV	Plug-in hybrid electric vehicles
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
STC	Small-scale Technology Certificate
USE	Unserved energy
VRE	Variable renewable energy
WDR	Wholesale Demand Response