AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

Forecast Accuracy Report

December 2022

Review of the 2021 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 2021 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 2022 unless otherwise indicated.

Disclaimer

This publication or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies. AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Copyright

Version control

Version	Release date	Changes
1	16/12/2022	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 2022 *Forecast Accuracy Report* primarily assesses the accuracy of AEMO's 2021 *Electricity Statement of Opportunities* (ESOO)[1,2] 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 2021-22 financial year, in particular the summer.

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

- 🟢 Forecast has performed as expected.
- 🟡 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.
- 🔴 Inaccuracy observed in forecast needs attention and should be prioritised for improvement.

Table 1 Forecast accuracy summary by region, 2021-22

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Energy consumption	🟡	🟡	🟢	🟢	🟡	Two regions were within 3%, but New South Wales, Queensland and Victoria all had larger variances, mainly driven by an issue with forecasting underlying business mass market consumption. A fix was provided in the *Update to the 2021 ESOO* in April 2022.
Summer maximum demand	🟢	🟡	🟡	🟢	🟢	Good alignment across most regions except Queensland and South Australia. Actual maximum demand in Queensland fell just above the forecast range, driven by very high humidity well into the evening. South Australia had an unusually low maximum demand outcome driven by very mild weather across the summer due to the La Niña climate conditions and fell just under the forecast range.
Winter maximum demand	🟢	🟡	🟢	🟡	🔴	Winter maximum demand outcomes in Queensland and Victoria were above forecast distributions and Tasmania below. While the reasons for the deviation for Queensland and Tasmania are known, a review of how the initial year of the forecast is set is required.
Annual minimum demand	🔴	🔴	🟢	🟢	🟢	Three regions showed good alignment, while New South Wales' actual minimum demand was lower than the forecast distribution and Queensland's actual minimum demand was above the forecast. With distributed photovoltaic (PV) installations showing good alignment, the forecast model requires review.
Demand side participation	🟢	🟢	🟢	🟢	🟢	Generally, less demand side participation (DSP) was observed than forecast but with too few observations to conclude with certainty. Queensland had many high price periods though and on average more observed DSP than forecast, but during peak demand, it showed good alignment.
Installed generation capacity	🟢	🟡	🟢	🟢	🟡	New generator installations matched expectations in Tasmania and were relatively close in New South Wales and South Australia. Start date delays and slower commissioning in Victoria and Queensland significantly impacted availability compared with what was modelled.
Summer supply availability	🟡	🟡	🟢	🟡	🟢	Extended outages of key units during summer months together with lower summer availability resulted in actual availability being lower than what was modelled for New South Wales, Queensland and Tasmania, noting some units may not have been made available due to low levels of supply scarcity.

[1] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf.

[2] Including the influence of the *Update to the 2021 Electricity Statement of Opportunities*, published in April 2022.

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 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:

- The observed actual **winter maximum demand outcomes** were above the 10% probability of exceedance (POE) forecast[3] for two regions, Queensland and Victoria. This is consistent with what has been seen for other regions, in particular South Australia, in recent years and highlights that there is a need for further improvements to how the starting points of the forecast POE distributions are set, although for Queensland, the outcome is explained by very cold weather which also extended unusually far north into the state. And while the issues to date have generally been related to actuals being above expectations, for Tasmania the actual winter maximum demand fell below the 90% POE forecast. This can be explained by lower than forecast demand from large industrial loads (LILs). The forecast approach for LILs in Tasmania during maximum demand conditions should be reviewed.
- For **annual minimum demand**, three regions showed good alignment, while New South Wales' actual minimum demand was lower than the forecast distribution and Queensland's actual minimum demand was above the forecast. With rooftop photovoltaic (PV) installations showing good alignment this year, the forecast model requires review particularly as the forecast error is on either side.
- **Annual consumption** had significant differences for three regions, which was identified through AEMO's ongoing monitoring process during the year and corrected in the *Update to the 2021 ESOO* in April 2022. The corrections reduced the observed forecast errors, but some unexplained residuals remain, particularly in the LIL and other non-scheduled generation (ONSG)[4] forecasts in some regions. There are potential benefits from better analysis of observed variances of consumption by customer segment. This will enable further analysis of the residual variance in the consumption forecast, and build a better understanding of how these sectors are responding to economic conditions, decarbonisation challenges, and uptake and use of emerging technologies.

On the supply side, including the consideration of demand side participation (DSP), discrepancies were noted for several supply forecasting inputs. Separate to the Forecast Improvement Plan, AEMO is consulting on its reliability forecast guidelines and methodologies between October 2022 and April 2023, and has proposed methodology changes for several key topics. Observations relevant to this year's accuracy assessment include:

- **Generator commissioning** did not match participant provided information, resulting in 920 megawatts (MW) less capacity available in 2021-22 than was forecast. AEMO proposes to review the methodology for the treatment of new assets in forecasts.

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

[4] This refers to generation from all non-scheduled generation apart from photovoltaic (PV) type installations, which are modelled separately in AEMO's PV non-scheduled generation (PVNSG) forecast.

- **Planned and unplanned outages** impacted supply availability at time of peak demand conditions for numerous regions and technologies. Given the mild temperatures observed, and the methodology used by AEMO regarding high temperature de-rating, actual supply availability in all regions should have been above simulation bounds. Planned and unplanned outages impacted supply availability in some of these cases, and hence AEMO proposes to review the methodology for collecting and forecasting random outage parameters.

Forecast Improvement Plan

The improvement plan is an important tool to guide investigation work and improvements in forecasting. The 2020 *Forecast Accuracy Report* illustrated the need for improvements to the accuracy of the distributed PV forecast. Forecast differences remained high in the 2021 *Forecast Accuracy Report* because the assessed forecasts were issued before the improvement work identified in 2020 was completed. The 2021 report highlighted that the most recent projections of distributed PV improved and recommended that this be monitored. This year's report confirms the success of the improvement initiatives in this area, with actual distributed PV uptake closely aligned with forecast uptake across all regions.

As highlighted further above, some of the observed differences between actuals and forecasts have already led to updated forecasts being issued in the *Update to the 2021 ESOO*. Other differences have helped steer the direction for additional improvements to be implemented for the 2023 ESOO forecasts, to improve forecast accuracy in the first five years of the reliability forecast relied on for the RRO. The priority improvements proposed for the improvement plan are listed below:

- **Review starting point of distributions for winter maximum and annual minimum forecasts.** Previous years' focus has been on improving the inputs, with the distributed PV forecast in particular being an issue. With that now improved, there is a need to improve the broader model performance. AEMO proposes to review the models used to set the starting points of the distribution, including whether additional weather variables like dew point (humidity) can improve model performance. Observed differences could also reflect an underlying change in customer behaviour, for example increased usage of heating/cooling load from customers that have invested in rooftop PV, that the modelling is not adequately picking up in maximum and minimum demand forecasting. This should also be investigated.
- **Review sub-component forecasts for LILs and ONSG.** These should be reviewed both in terms of their impacts on consumption and their contributions at time of maximum and minimum demand. With minimum demand declining, even a smaller component like ONSG may impact forecast accuracy.

In addition to the initiatives listed above, two projects that were initiated last year are still ongoing:

- **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 2021 ESOO, AEMO used 11 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 2023 ESOO.
- **Improve the visibility and understanding of consumption patterns and trends.** To improve understanding of what is driving differences between forecast and observed consumption, AEMO plans to continue to investigate opportunities for a further breakdown of consumption, in particular into industry sectors. This will help to identify opportunities for data and model improvements to reduce consumption forecast variance in the

2023 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.

AEMO also has an ongoing workstream monitoring key inputs. The following are highlighted because of their importance to either the outcomes in this *Forecast Accuracy Report* or expected future forecasts:

- **Monitoring emerging technologies.** AEMO will continue to look for data sources that will allow tracking of uptake and use of emerging technologies currently not covered in the *Forecast Accuracy Report*. This includes behind-the-meter battery storage (including virtual power plants [VPPs]), electric vehicles (EVs) and, longer term, the production of hydrogen from electricity. For EVs, AEMO proposes to increase the tracking of their uptake, as good data sources continue to become available.
- **Monitoring trends in DSP following introduction of Wholesale Demand Response (WDR).** There was little history available with regards to use of WDR when the last DSP forecast was made. Since then, more providers have registered and it is being used more frequently. AEMO will continue to monitor how WDR is used to guide any future updates of the DSP forecast.

On the supply side, AEMO is – as noted earlier – consulting on its reliability forecast guidelines and related guidelines and procedures[5]. As part of the consultation, and informed by the observations in this report, a number of improvements to the data collection and modelling of the supply side have been identified. Consultation on those guidelines is not included in this Forecast Improvement Plan, but have been summarised below for information:

- **Energy adequacy scenarios.** While not discussed in this accuracy report, energy limits were influential in recent supply scarcity events and had not been forecast as material by AEMO in the Energy Adequacy Assessment Projection (EAAP). Current scenarios specified in the EAAP Guidelines predominantly relate to drought situations, however National Electricity Rules (NER) 3.7C allows AEMO to consider other situations such as gas, coal or diesel shortfalls. AEMO proposes different EAAP scenarios to better capture these risks and requires additional inputs and model changes to appropriately understand the risks of energy limits, and to effectively and efficiently model the impact of energy limits as required by NER 3.7C.
- **New generation, storage, aggregated distributed energy resources (DER) and transmission commitment criteria implementation.** The commitment criteria and implementation determine whether a generation, integrated resource system, aggregated DER or transmission project has made a formal commitment to construct, and therefore meets the criteria to be included in AEMO's central scenario reliability forecasts. AEMO seeks stakeholder input to determine an appropriate balance of over-forecasting or under-forecasting potential supply from new assets.
- **Random outage parameters.** AEMO's reliability forecasting models use random outage parameters to simulate a variety of outage categories for scheduled generation or integrated resource systems, and key inter-regional transmission flow paths. In recent reserve shortfall events, including those that occurred in June 2022, outage categories that have not previously been considered in AEMO's reliability forecasts were observed. AEMO proposes to collect and include these additional outage categories in its reliability forecasts.

[5] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

- **Medium Term Projected Assessment of System Adequacy (MT PASA) generator status and recall times.** From October 2023, scheduled generators and integrated resource system participants will be required to provide status codes and recall times for periods of unavailability. AEMO proposes status codes consistent with the IEEE standard 762-2006, and recall times under a variety of unit status codes.
- **Reliability gap calculation.** The 2022 ESOO identified issues with the existing process for calculating reliability gaps, gap periods and likely trading intervals. AEMO proposes to adjust the calculation method for reliability gap periods, likely trading intervals and reliability gaps in megawatts.

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) Friday, 27 January 2023** and should be sent by email to energy.forecasting@aemo.com.au.

Contents

Tables

Figures

1 Stakeholder consultation process

The publication of this *Forecast Accuracy Report* marks the commencement of AEMO's Forecast Improvement Plan consultation[6].

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. AEMO is consulting on 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 2023 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) Friday, 27 January 2023**.

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[7] published by the Australian Energy Regulator (AER).

Table 2 Consultation timeline

Consultation steps	Indicative dates
Forecasting Reference Group discussion of draft report	26 October 2022
Forecast Accuracy Report and Forecast Improvement Plan published	16 December 2022
Submissions due on Forecast Improvement Plan	27 January 2023
Final Forecast Improvement Plan published along with a Submission Response document	24 February 2023

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

[7] 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) clause 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 Reliability Forecast Guidelines[8].

Specifically, this 2022 *Forecast Accuracy Report* assesses the accuracy of the 2021-22 demand and supply forecasts published in AEMO's 2021 ESOO for the NEM[9] and related products, in addition to the resulting reliability forecasts for each region in the NEM. The 2021 ESOO forecasts are the latest that can be assessed against a full year of subsequent actual observations. The *Update to the 2021 ESOO* published in April 2022 will be discussed where comparisons are relevant.

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:

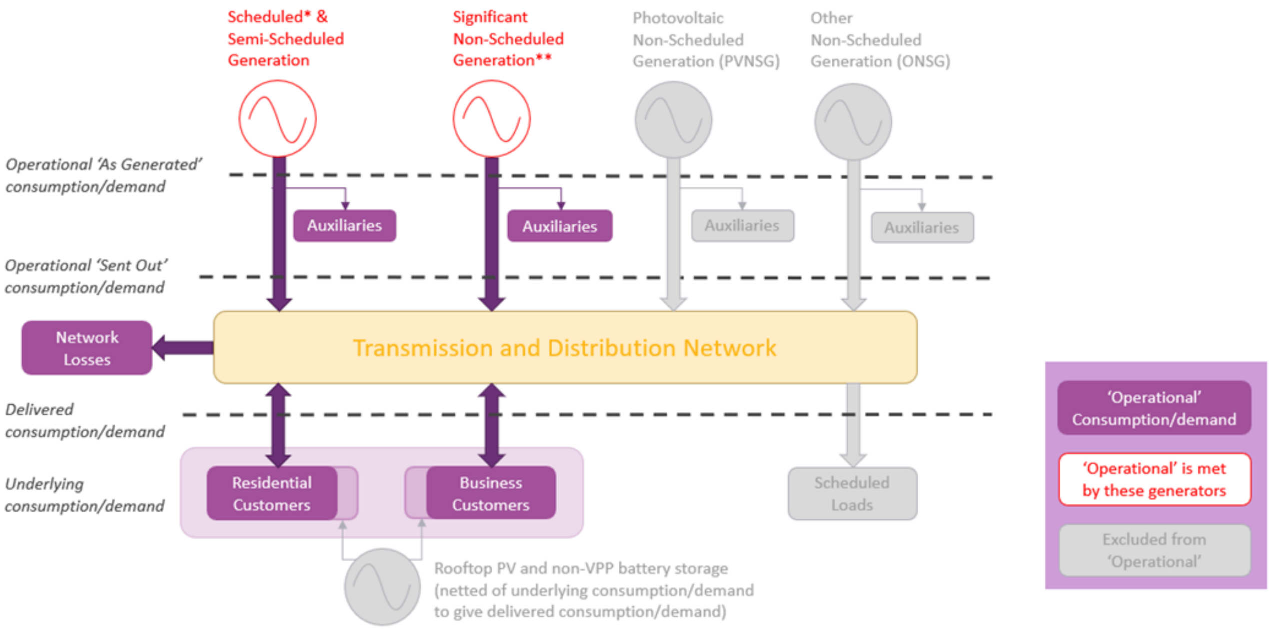
- All forecasts are reported on a "sent out" basis unless otherwise noted.
- Historical operational demand "as generated" (OPGEN) is converted to "sent out" (OPSO) based on estimates of auxiliary load, which reflects load used within the generator site.
- Auxiliaries are typically excluded from demand 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.

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

[9] 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/2021-nem-electricity-statement-of-opportunities.

Figure 1 Demand definitions used in this document



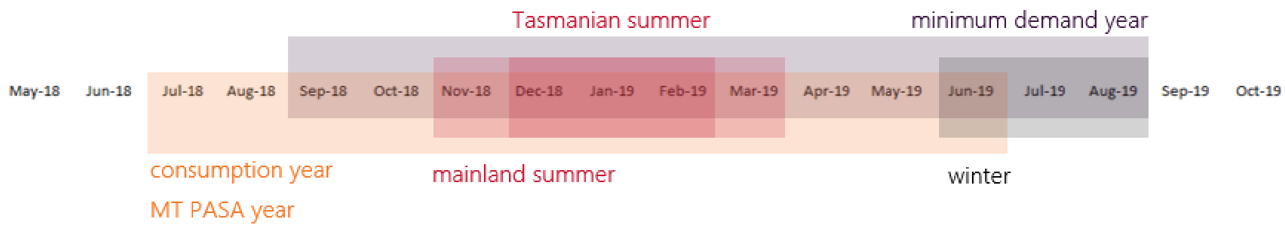
* Including injection from grid-scale storages and VPP from aggregated behind-the-meter battery storage.
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

Seasonal definitions

For consistency, data and methodologies of actual observations (or 'actuals') are the same as those used for the corresponding forecasts in the 2021 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[10]:

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

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

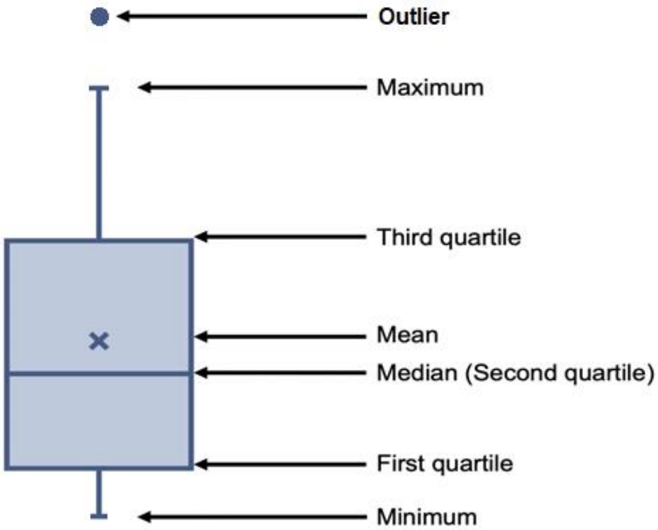
Using this approach, a negative percentage error indicates an under-forecast compared to actuals, where a positive error is an over-forecast. Specifically, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

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: maximum value, third quartile, median (second quartile), first quartile, and minimum value. 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 maximum and minimum 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 maximum and minimum values otherwise shown. Such outliers are shown as dots.

Figure 3 Explanation of box plots used in this report

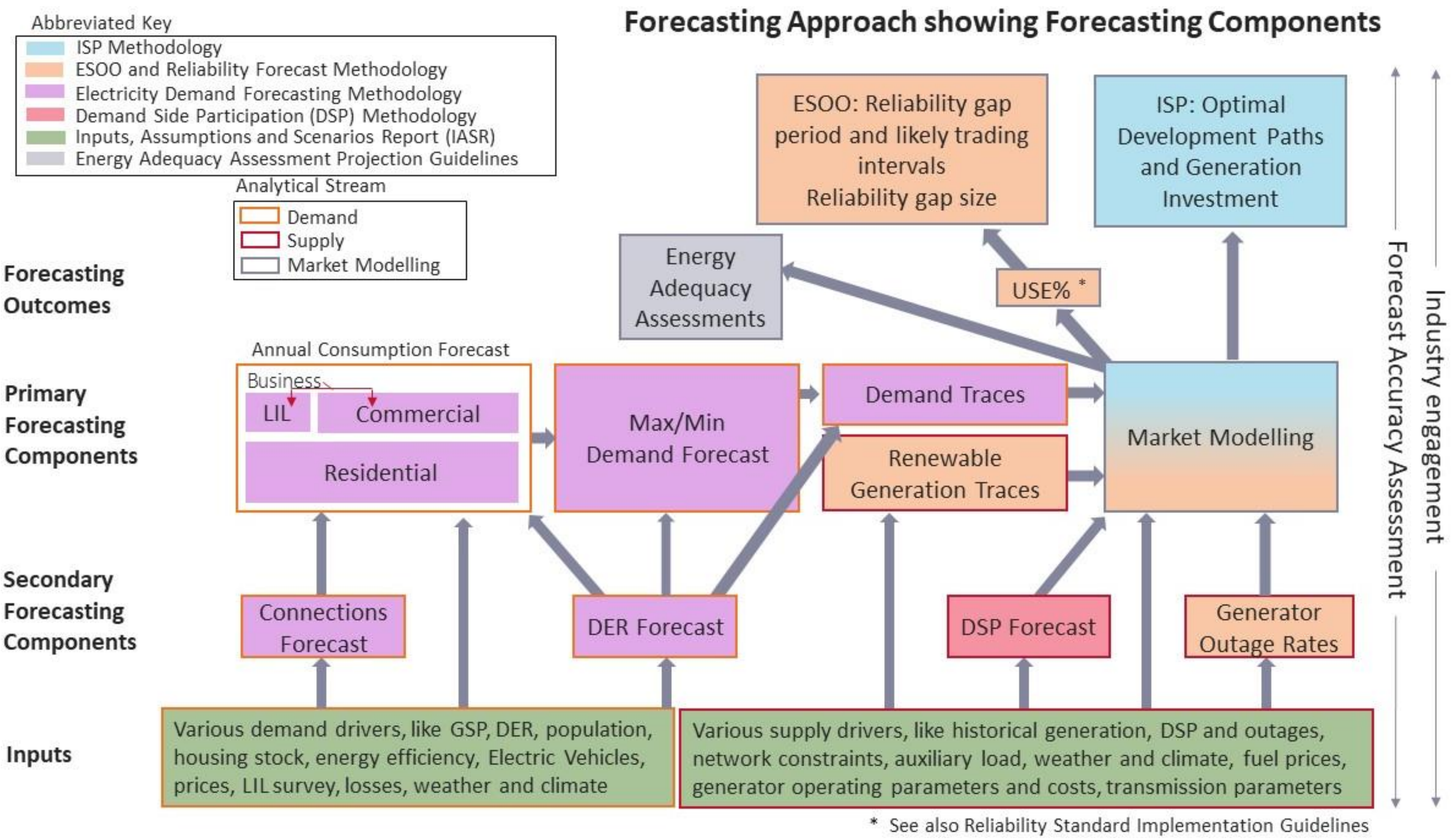


2.2 Forecast components

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[11]. 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 distributed energy resources (DER), where AEMO combines inputs from multiple consultants into its forecast uptake of rooftop photovoltaics (PV), electric vehicles (EVs), and battery storage.

[11] 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 of the weakly assessable forecasts will increasingly 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 2021 ESOO are summarised in Table 3.

Table 3 Key scenarios and sensitivities used in the 2021 ESOO

Scenario/sensitivity	*Slow Change*	Central*	*Hydrogen Superpower*	*Strong Electrification*
Economic growth and population outlook	Low	Moderate	High	High
Energy efficiency improvements	Low	Moderate	High	High
Demand side participation	Low	Moderate	High	High
Distributed PV	Moderate (but elevated in the short term)	Moderate	High	High
Battery storage installed capacity	Low	Moderate	High	High
Battery storage aggregation / virtual power plant (VPP) deployment	Low	Moderate	High	High
Electric vehicle (EV) uptake	Low	Moderate	Moderate/High	High
EV charging time switch to coordinated charging	Low	Moderate	Moderate/High	Moderate/High
Electrification	Low	Low/Moderate	Moderate/High	High
Hydrogen consumption	Minimal	Minimal	Large NEM-connected export and domestic consumption	Minimal
Decarbonisation target	26-28% reduction by 2030	26-28% reduction by 2030	Exceeding 26-28% reduction by 2030, consistent with global targets for a < 1.5°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.

* The Central forecast reflects both the *Steady Progress* and *Net Zero 2050* scenarios from the 2021 *Draft Inputs, Assumptions and Scenarios Report* (IASR), as they are equivalent over the 10-year ESOO timeframe. See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf.

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 and behind-the-meter battery uptake.
- Other weakly assessable drivers (at this time), including:
  - Energy efficiency and appliance mix.
  - EVs.

The 2021 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 and sensitivities were therefore developed to illustrate a range of possible pathways: *Slow Change*, *Central*[12], *Hydrogen Superpower* and *Strong Electrification*.

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 EV forecast accuracy is not currently measurable and does not currently have a material impact on 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 2021 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 2021-22, annual GDP was forecast to grow by 3.2% in the Central scenario, with the severe restrictions on activity due to the COVID-19 pandemic easing and international borders anticipated to open in the first half of 2022. As with GDP, GSP across the NEM regions was forecast to grow by an average of 3.3% in the Central scenario. Conversely, HDI growth was forecast to decline in the Central scenario by an average of 1.1% in 2021-22.

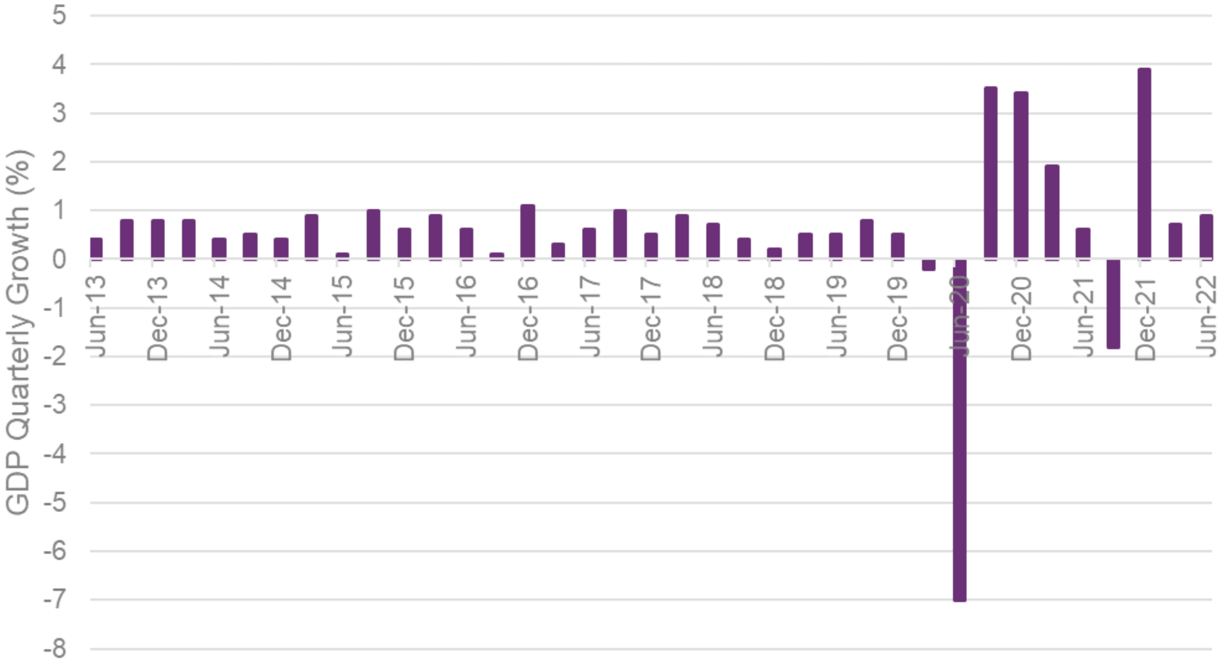
At the time of the forecast, the COVID-19 vaccine program was assumed to provide some certainty, particularly in relation to inter-state border restrictions, and an eventual transition to home quarantine (enabling the reopening of international borders). An average annual GSP growth rate of 2.9% p.a. was forecast over the first five years of the forecast period, driven by strong growth projections for the services industries as restrictions were expected to ease and the construction sector, with the impact of government stimulus (such as the HomeBuilder scheme) was

[12] As per Section 2.3, the Central scenario forecast reflects both the *Steady Progress* and *Net Zero 2050* scenarios over the 10-year ESOO horizon

expected to begin feeding through. GSP, and to a lesser extent HDI, was also expected to see moderate growth within that period.

Similar to the forecast, actual GDP increased in 2021-22 by 3.6%, with growth spurred on by the first full quarter of open domestic and international borders since the beginning of the pandemic. The actual quarterly GDP growth is shown in Figure 5[13].

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[14] between sectors. As lockdowns and social distancing measures predominantly affected business activity in the Services (including hospitality, tourism, and retail) and Construction sectors[15], low economic growth does not necessarily result in similar reductions in electricity consumption.

A more detailed breakdown of consumption by sector would help validate the impact of economic activity on forecast accuracy.

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 (BIS Oxford Economics) and the Australian Bureau of Statistics (ABS), and are shown in Table 4. For the 2021

[13] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2022, available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release#data-download. Accessed 27 September 2022.

[14] 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.

[15] Construction ended up being less affected than forecast, as building activity remained high.

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 BIS Oxford Economics[16] and the ABS.

Table 4 Connections forecast for 2021-22 and actuals for 2021-22

Region	2021 forecast for 2021-22 (no. of customers)	Actual for 2021-22 (no. of customers)	Difference (%)*
NSW	3,573,614	3,535,598	1.1%
QLD	2,058,879	2,053,355	0.3%
SA	803,290	800,078	0.4%
TAS	257,364	257,536	-0.1%
VIC	2,746,448	2,735,802	0.4%
NEM	**9,439,595**	**9,382,369**	**0.6%**

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

Despite predicted growth in new dwellings, building activity generally decreased through 2021-22[17], due in part to supply chain issues and rising 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 2021 ESOO, AEMO received installation data from the Clean Energy Regulator (CER) 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 CER.

AEMO's 2021 ESOO Central forecast adopted an averaging approach of the forecasts provided by AEMO's two DER consultants: CSIRO[18] and Green Energy Markets (GEM)[19]. The average was chosen 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 considers 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 2021 ESOO's Central scenario.

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

[17] Australian Bureau of Statistics: Building Activity Australia (Mar 2022 release). Available at https://www.abs.gov.au/statistics/industry/building-and-construction/building-activity-australia/latest-release. Accessed 18 October 2022.

[18] CSIRO: Small-scale solar and battery projections 2021 (May 2021). Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf.

[19] Green Energy Markets: Final 2021 Projections for distributed energy resources – solar PV and stationary energy battery systems (June 2021). Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf.

Table 5 Rooftop PV and PV non-scheduled generation (PVNSG) installed capacity comparison by region, as at 30 June 2022 (MW)

As installed at 30 June 2022		NSW	QLD	SA	TAS	VIC	NEM
Rooftop PV	Estimated actual (MW)	4,871	4,781	1,926	226	3,465	15,269
	Central forecast (MW)	4,925	4,834	1,999	230	3,494	15,482
	Central forecast error (%)	1%	1%	4%	2%	1%	1%
PVNSG	Estimated actual (MW)	301	227	207	4	338	1,077
	Central forecast (MW)	345	258	220	3	368	1,194
	Central forecast error (%)	15%	14%	6%	-11%	9%	15,269
Total	Central forecast error (%)	2%	2%	4%	1%	2%	2%

Actuals are based on AEMO's latest actual data as of 16 September 2022.

For all NEM regions, rooftop PV actuals were in line with the forecast, with the largest variance seen in South Australia at 4%. This is a significant improvement from last year's assessment, where variances were up to 21%. 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.

PVNSG is a much smaller market compared to rooftop PV. As shown in the table, PVNSG was over-forecast in all regions except for Tasmania which was under-forecast.

3.4 Auxiliary loads

Auxiliary loads account for energy used within power stations (the difference between "as generated" energy and "sent out" energy shown in Figure 1), representing the difference between total generation as measured at generator terminals and the electricity that is sent out into the grid. Auxiliary loads are not directly measured, but are estimated based on dispatch of each generating unit and the typical auxiliary load of this generator's dispatch (in percentage terms). These auxiliary load percentages are provided to AEMO by participants.

The difference in auxiliary load between the 2021 ESOO forecast and the actuals reported in the NEM is approximately 0.2% (see Table 8 in Section 4). In general, it is a very small contributor to forecast variance. For Queensland, however, the contribution is 0.8%, meaning estimated actual auxiliary load is less than forecast. This was driven by lower availability of Queensland coal generators, which led to reduced electricity flow south towards New South Wales than forecast and also caused estimated auxiliary load in New South Wales to be above the forecast level.

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. The intra-regional transmission and the 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 2021-22. As shown in Table 6, transmission losses are generally lower than was assumed at the time of the 2021 ESOO, apart from in Victoria, where estimated losses are now higher. For distribution, Queensland is higher, while South Australia and Tasmania see loss percentages reduced significantly.

Table 6 Estimated network loss factors

	Transmission loss factor		Distribution loss factor	
	Applied to 2021 forecast	Used to estimate actuals for 2021-22	Applied to 2021 forecast	Used to estimate actuals for 2021-22
New South Wales	2.40%	2.23%	4.22%	4.23%
Queensland	2.58%	2.23%	4.64%	4.81%
South Australia	2.79%	2.62%	7.31%	6.11%
Tasmania	2.78%	2.74%	4.76%	2.86%
Victoria	1.79%	1.99%	4.77%	4.72%

Using the latest reported network losses as estimates for 2021-22 contributed to -0.5% variance overall for the NEM in the 2021 ESOO forecast (see Table 8 in Section 4). Looking at individual regions, the biggest impact is in Victoria, where losses contributed to -0.9% forecast variance (actual estimated losses higher than forecast). While part of the reason is the increase in transmission loss factor for Victoria (slightly offset by a lower distribution loss factor), the main factor contributing to the difference in losses was the under-forecast of operational consumption, with the extra observed consumption over what was forecast resulting in a similar increase in losses.

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 2017 to 2022, for each region, relative to history. Most recent forecasts have been somewhat similar; however, the forecasts in 2020 and 2021 generally projected relatively flat or marginally declining consumption compared to earlier forecasts.

The *Update to the 2021 ESOO* forecasts shifted the Central scenario to the *Step Change* scenario, which introduced greater forecast electrification of the economy, such that positive energy consumption growth is now forecast.

This section focuses on the original 2021 ESOO forecasts, unless otherwise stated.

Figure 6 Recent annual energy consumption forecasts by region

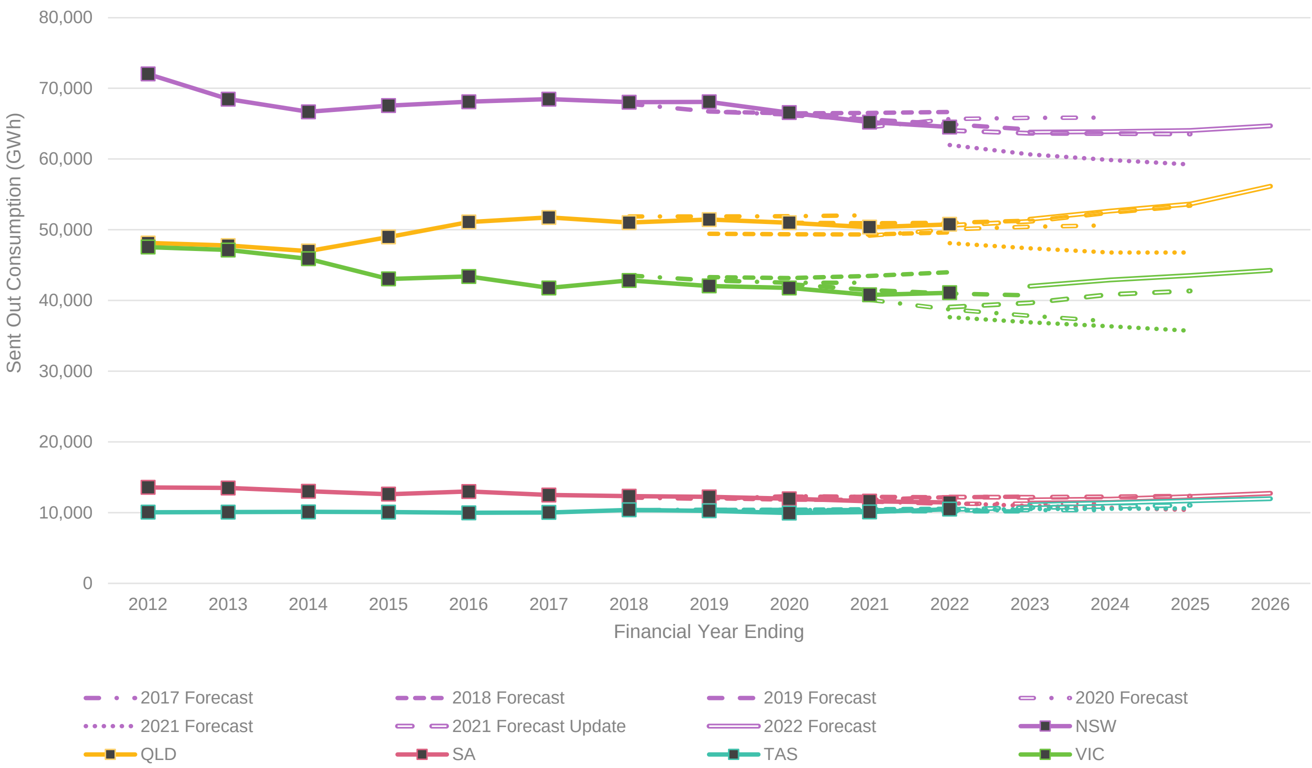


Table 7 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using the percentage error calculation outlined in Section 2.1. The Central forecast from the *Update to the 2021 ESOO* is also shown. It is higher compared to the 2021 ESOO, due to rebaselining the underlying business mass market forecast with revised historical actuals data.

Table 7 Recent one-year ahead operational sent out energy consumption forecast accuracy by region

One-year ahead annual operational consumption accuracy (%)	2017 ESOO forecast in 2017-18	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
New South Wales	-0.3%	-2.0%	-0.6%	-1.1%	-3.9%	-0.7%
Queensland	1.7%	-3.9%	0.0%	-2.4%	-5.2%	-0.3%
South Australia	-1.5%	-1.5%	2.6%	-0.3%	-0.8%	6.5%
Tasmania	-0.3%	1.2%	2.2%	2.4%	-1.3%	-0.3%
Victoria	1.7%	3.0%	1.3%	-1.7%	-8.4%	-5.0%
NEM	0.6%	-1.2%	0.4%	-1.3%	-5.0%	-1.1%

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

As Table 7 shows, in the last five years, the percentage errors for forecasts in the individual regions were mostly within ±3% until 2021-22. The NEM weighted average has had a percentage error within ±1.5%, until the initial 2021 ESOO which had an error of -5%. Improvements made in the *Update to the 2021 ESOO* reduced the percentage error to -1.1%.

Table 8 shows the sources of variance for the 2021-22 consumption forecast of the NEM as forecast in the initial 2021 ESOO. The largest contributors to forecast error relate to an over-forecast of LILs, closely followed by the effect of milder weather (represented as cooling degree days), which were lower than forecast due to a strong La Niña summer[20].

Table 8 NEM operational energy consumption forecast accuracy by component

Category	2021 forecast (gigawatt hours [GWh])	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling degree days	5,177	4,126	25.5%	0.6%
Heating degree days	8,211	8,975	-8.5%	-0.4%
Connections growth	841	559	50.3%	0.2%
Large industrial loads	45,123	43,565	3.6%	0.8%
Rooftop PV	17,520	16,746	4.6%	0.4%
PV non-scheduled generation	2,016	1,742	15.7%	0.1%
Other non-scheduled generation	4,088	4,407	-7.2%	-0.2%
Network losses	9,300	10,257	-9.3%	-0.5%
Operational sent-out	**169,480**	**178,329**	**-5.0%**	**-4.7%**
Auxiliary load	8,562	8,162	4.9%	0.2%
Operational as generated	**178,042**	**186,491**	**-4.5%**	

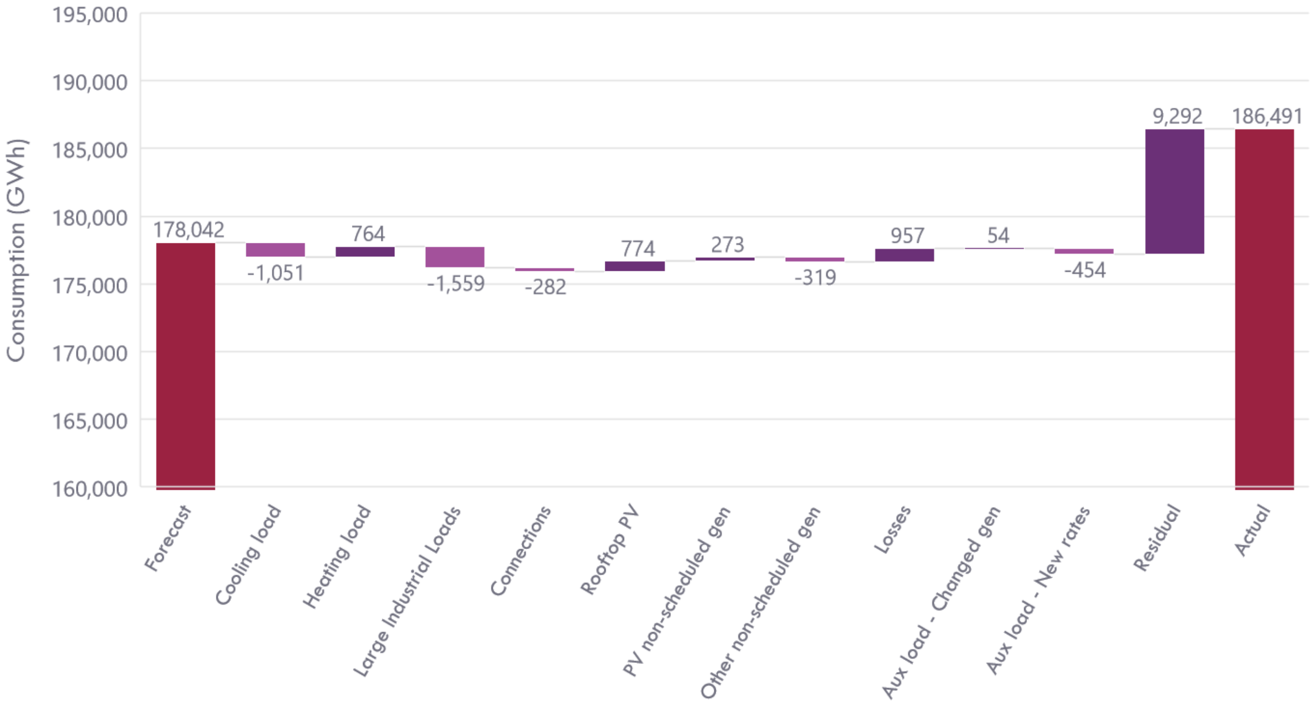
Figure 7 shows this graphically and highlights that the residual variance (the variance that is not explained by any of the measured components) is significant, equating to 9,292 gigawatt hours (GWh) for operational as generated consumption. The residual variance includes the impact of differences in economic growth, and of other factors such as COVID-19 not otherwise accounted for through variations in forecast components such as connections growth or rooftop PV installations.

[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.

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:

- Cooling degree days, which influences the forecast cooling load, were below forecast in all mainland states, driven by mild weather caused by the La Niña.
- NMI connections growth was over-forecast, with lockdowns in New South Wales and Victoria during the first half of 2021-22 contributing to a slowdown in new building activity.
- LILs were over-forecast in all regions, excluding New South Wales. Most variances can be explained by unplanned outages and expansions that did not occur, which differed from anticipated consumption levels identified in AEMO's LIL surveys.
- Changes to network loss factors (see Section 3.5) have caused some differences in Victoria and New South Wales, but overall differences in losses were due to the overall forecast inaccuracy of operational consumption, as losses are calculated as a fixed proportion of this.
- Generator auxiliary loads were overestimated in Queensland and Victoria, as lower availability of coal generation in those states resulted in lower than forecast dispatch of coal generators, which has high auxiliary load, and higher than forecast dispatch of gas-powered generators, which have much lower auxiliary load.

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 2021-22 was above the Central forecast, leading to a percentage forecast error of -4.1%. Table 9 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. Winter heating load, represented by heating degree days, was moderately higher than forecast. ONSG and LILs were also cause for variance, with the latter driven by the inclusion of additional industrial facilities that were previously part of the business mass market sector. Other differences were less significant, with rooftop PV being the largest difference, and with a minor contribution from PVNSG. The over-forecast of the two types of PV was due to lower than forecast generation actuals, caused by less favourable weather factors affecting solar irradiance (such as higher rainfall from the La Niña weather conditions).

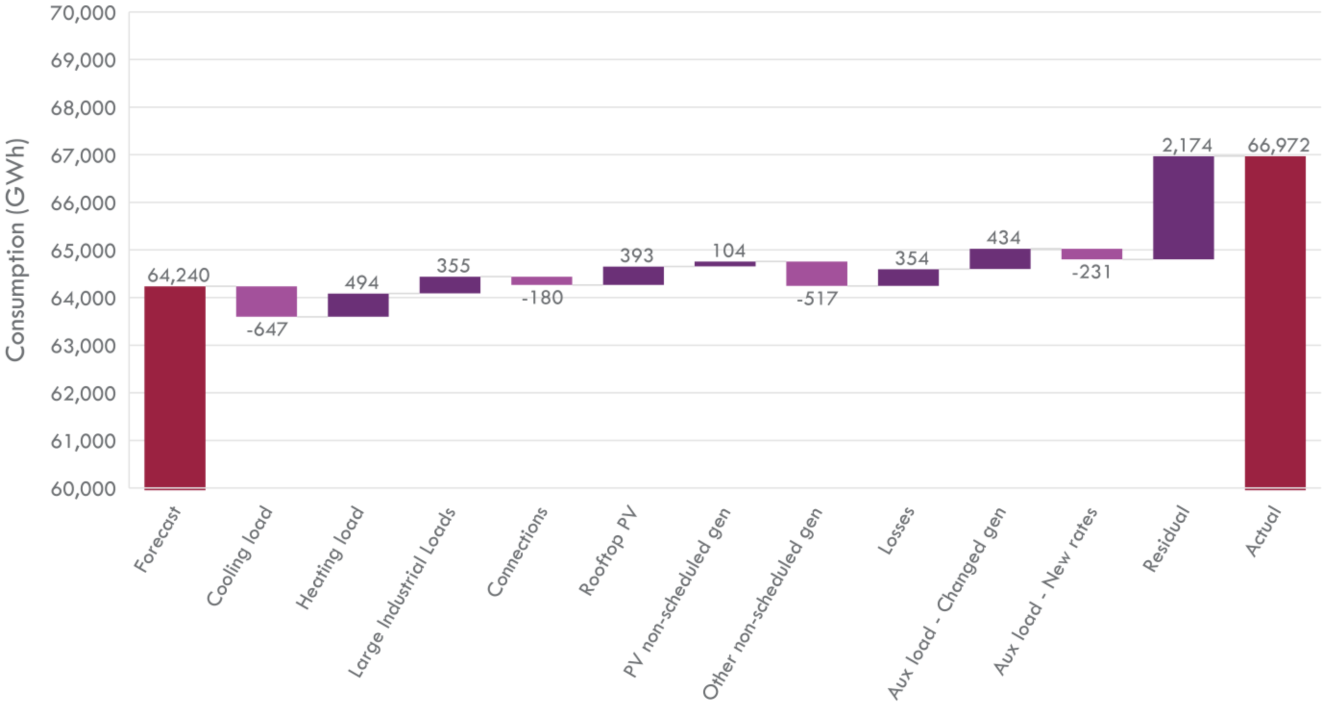
The model for New South Wales has fallen outside the accuracy target with the residual being 2,174 GWh (or -3.2%) as per Figure 8. A significant portion of the residual difference was an under-forecast of business mass market consumption, which was re-baselined with revised historical actuals data for the *Update to the 2021 ESOO*.

For ONSG, AEMO will seek to understand the causes of the difference to consider potential model improvements in the future.

Table 9 New South Wales operational energy consumption forecast accuracy by component

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling degree days	2,063	1,416	45.7%	1.0%
Heating degree days	3,255	3,748	-13.2%	-0.7%
Connections growth	344	164	110.0%	0.3%
Large industrial loads	14,911	15,266	-2.3%	-0.5%
Rooftop PV	5,540	5,147	7.6%	0.6%
PV non-scheduled generation	570	465	22.4%	0.2%
Other non-scheduled generation	1,177	1,694	-30.5%	-0.8%
Network losses	3,367	3,722	-9.5%	-0.5%
Operational sent-out	**61,994**	**64,523**	**-3.9%**	**-3.8%**
Auxiliary load	2,246	2,449	-8.3%	-0.3%
Operational as generated	**64,240**	**66,972**	**-4.1%**	

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



4.2 Queensland

Operational as generated energy consumption for Queensland in 2021-22 was 4.1% below forecast. Table 10 and Figure 9 show the forecast accuracy by component, highlighting that the biggest difference was LILs, followed by auxiliary load. The over-forecast of LILs was mainly due to a partial outage in one of the region's largest loads. The change in source for auxiliary rates is explained in Section 3.4.

The differences for the other measured components were generally small, except for rooftop PV and ONSG. Rooftop PV was over-forecast due to less favourable weather affecting solar irradiance. While the components generally caused an over-forecast, overall consumption was under-forecast, leaving a residual of 2,523 GWh (equal to -4.7%), as shown in Figure 9.

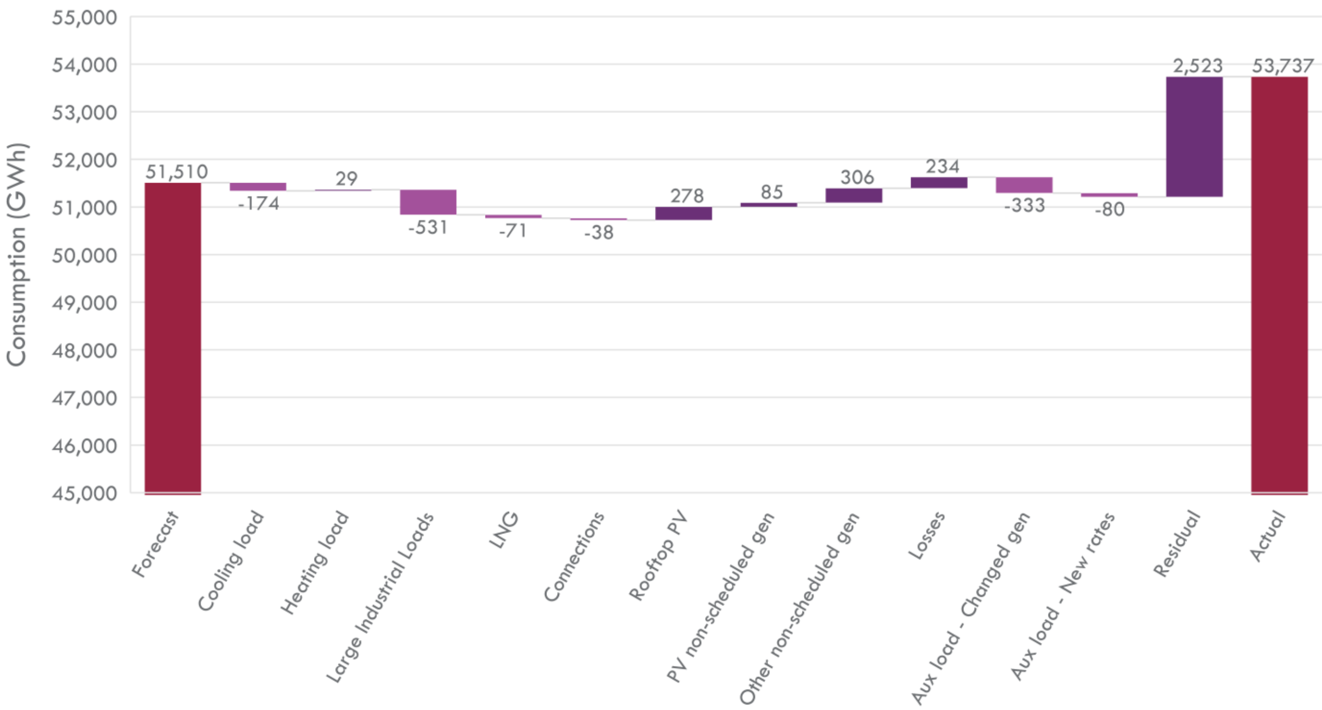
Much of the residual difference was due to an under-forecast of business mass market consumption, which was rebaselined with revised historical actuals data for the *Update to the 2021 ESOO*. For ONSG, AEMO will seek to understand the causes of the difference and consider potential model improvements in the future. AEMO will seek to understand the causes of the remaining residual difference by improving the ability to break down consumption into sectors in the future.

Table 10 Queensland operational energy consumption forecast accuracy by component

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling degree days	1,822	1,649	10.5%	0.3%
Heating degree days	656	686	-4.3%	-0.1%
Connections growth	176	138	27.6%	0.1%
Large industrial loads	13,552	13,020	4.1%	1.0%

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
LNG	6,632	6,561	1.1%	0.1%
Rooftop PV	5,828	5,550	5.0%	0.5%
PV non-scheduled generation	461	376	22.7%	0.2%
Other non-scheduled generation	1,573	1,268	24.1%	0.6%
Network losses	2,504	2,738	-8.5%	-0.4%
Operational sent out	48,124	50,765	-5.2%	-4.9%
Auxiliary load	3,386	2,972	13.9%	0.8%
Operational as generated	51,510	53,737	-4.1%	

Figure 9 Queensland operational as generated energy consumption variance by component



4.3 South Australia

Operational as generated energy consumption for South Australia in 2021-22 was just 0.7% above the Central forecast. Table 11 and Figure 10 demonstrate the forecast accuracy by component.

The most significant inaccuracy driver was an over-forecast of LILs, due to unrealised expansion expectations as provided by survey participants, and unplanned facility closures. Summer cooling load, represented by cooling degree days, was the second largest driver of inaccuracy, driven by above average rainfall and associated cooler maximum temperatures for much of the state[21].

[21] Bureau of Meteorology, Australia in summer 2021–22, at http://www.bom.gov.au/clim_data/IDCKGC2AR0/202202. summary.shtml. Accessed 13 October 2022.

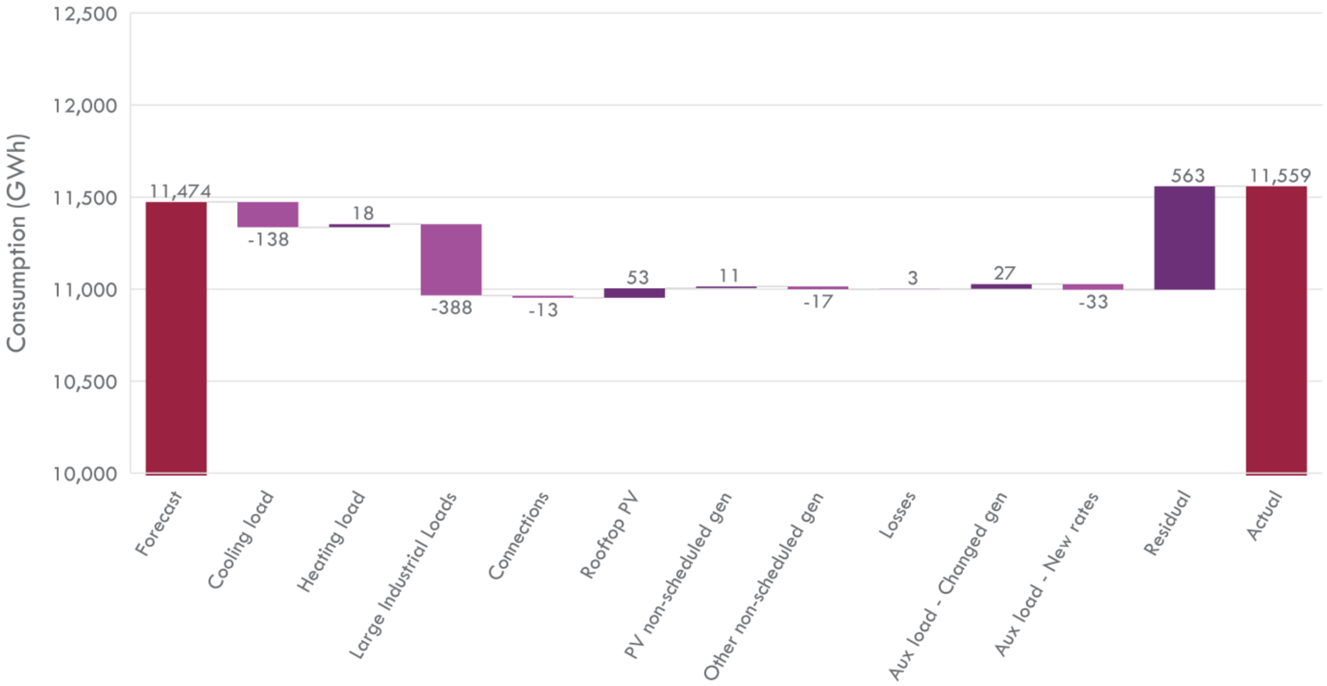
The differences for the other measured components were generally small, with rooftop PV the largest. Unlike New South Wales and Queensland, the difference in the PV forecast was largely driven by actual installed capacity falling below forecast capacity (as per Section 3.3).

Accounting for the other measured elements, this leaves a residual variance of 563 GWh (-4.9%) as shown in Figure 10. A portion of this residual is explained by under-forecast business mass market consumption, an improvement for which was included in the *Update to the 2021 ESOO*.

Table 11 South Australia operational energy consumption forecast accuracy by component

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	513	375	36.8%	1.2%
Heating Degree Days	722	740	-2.4%	-0.2%
Connections growth	43	30	43.5%	0.1%
Large industrial loads	3,449	3,061	12.7%	3.4%
Rooftop PV	2,321	2,269	2.3%	0.5%
PV non-scheduled generation	382	371	2.9%	0.1%
Other non-scheduled generation	59	76	-22.8%	-0.1%
Network losses	853	856	-0.3%	0.0%
Operational sent out	11,357	11,447	-0.8%	-0.8%
Auxiliary load	117	112	4.9%	0.0%
Operational as generated	11,474	11,559	-0.7%	

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



4.4 Tasmania

Operational as generated energy consumption for Tasmania in 2021-22 was below the Central forecast by 1.4%. Table 12 and Figure 11 demonstrate the forecast accuracy by component.

The largest source of inaccuracy was an over-forecast of LILs, followed by an under-forecast of ONSG. The over-forecast of LILs was mainly due to minor variances in consumption within 5-10% for a few facilities. Together with the other measured components, this leaves a residual variance of 318 GWh (-3%), as shown in Figure 11. AEMO considers that the model for Tasmania has performed well.

For ONSG, AEMO will seek to understand the causes of the difference in order to consider potential model improvements in the future.

Table 12 Tasmania operational energy consumption forecast accuracy by component

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	0	0	0.0%	0.0%
Heating Degree Days	686	728	-5.7%	-0.4%
Connections growth	27	27	-1.6%	0.0%
Large industrial loads	6,291	6,195	1.6%	0.9%
Rooftop PV	230	222	3.7%	0.1%
PV non-scheduled generation	5	5	-4.6%	0.0%
Other non-scheduled generation	435	529	-17.8%	-0.9%
Network losses	478	441	8.3%	0.3%
Operational sent out	**10,349**	**10,490**	**-1.3%**	**-1.3%**
Auxiliary load	91	102	-10.6%	-0.1%
Operational as generated	**10,440**	**10,592**	**-1.4%**	

Figure 11 Tasmania operational as generated energy consumption variance by component

4.5 Victoria

Operational as generated energy consumption for Victoria in 2021-22 was above the Central forecast by 7.5%. Table 13 and Figure 12 demonstrate the forecast accuracy by component.

The largest inaccuracy driver was an over-forecast of LILs, followed by network losses. The former was predominantly due to a partial outage at one of the region's largest loads throughout most of the year. The latter was driven by a minor decrease in distribution loss factors reported to AEMO, as covered in Section 3.5, and the consequence of an under-forecast level of consumption on the resulting estimate of network losses.

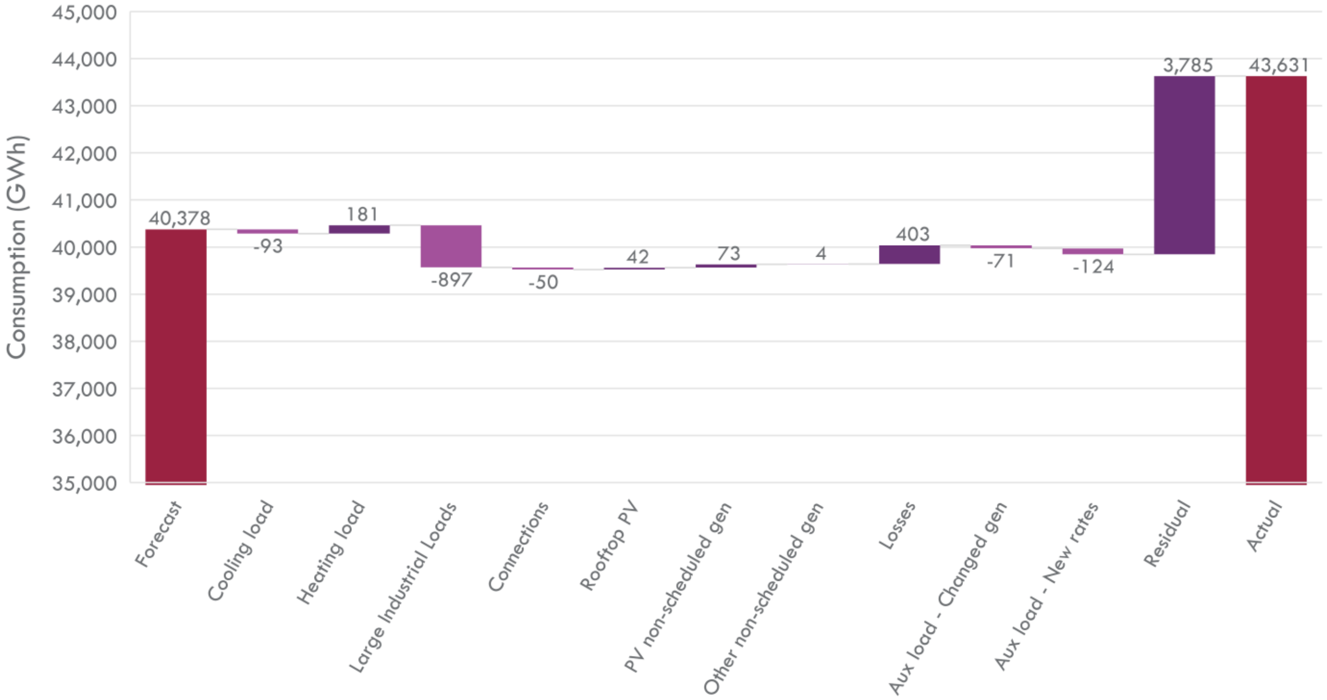
The differences for the other measured components were generally small, with winter heating load (represented by heating degree days) and auxiliary load the largest. Accounting for the other measured elements, this leaves a significant residual of 3,785 GWh (or -8.7%). A substantial portion of this residual is explained by under-forecast business mass market consumption, which was rebaselined with revised historical actuals data for the *Update to the 2021 ESOO*. AEMO will seek to understand the causes of the remaining residual difference by improving its ability to break down consumption into sectors in the future.

Table 13 Victoria operational energy consumption forecast accuracy by component

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling degree days	779	687	13.5%	0.2%
Heating degree days	2,892	3,073	-5.9%	-0.4%
Connections growth	251	200	25.1%	0.1%
Large industrial loads	6,921	6,023	14.9%	2.1%
Rooftop PV	3,601	3,559	1.2%	0.1%

Category	2021 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
PV non-scheduled generation	598	525	13.9%	0.2%
Other non-scheduled generation	845	840	0.5%	0.0%
Network losses	2,097	2,500	-16.1%	-0.9%
Operational sent out	**37,656**	**41,104**	**-8.4%**	**-7.9%**
Auxiliary load	2,722	2,527	7.7%	0.4%
Operational as generated	**40,378**	**43,631**	**-7.5%**	

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 when mild conditions 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[22].

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 driven 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[23].

[22] 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.

[23] 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 2021-22

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.

For example, the maximum demand for Queensland in 2021-22 occurred on 8 March 2022. Prices were very high in the lead up to the actual peak, causing an estimated price response of 103 MW at that time.

5.1.1 Summer 2021-22 maximum demand events

Table 14 shows the summer maximum demand periods for NEM regions in 2021-22, with Queensland being the only region where an adjustment was required (see above).

Table 14 Summer 2021-22 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 1 February 2022 16:30	12,530	415	12,115	-	-	12,115
QLD	Tue, 8 March 2022 19:00	10,058	466	9,592	103*	-	9,695
SA	Tue, 11 January 2022 19:00	2,589	35	2,554	-	-	2,554
TAS	Mon, 21 February 2022 7:00	1,360	12	1,348	-	-	1,348
VIC	Thu, 27 January 2022 18:00	8,599	374	8,225	-	-	8,225

*Queensland includes a firm adjustment of 103 MW, estimated as a price response to very high local wholesale prices.

5.1.2 Winter 2022 maximum demand events

As for summer maximum demand, AEMO has reviewed the winter maximum demand events to see if any firm or potential adjustments were necessary. In particular, Queensland had very high prices during the maximum demand event, but analysis of DSP is inconclusive (see discussion in Section 6.6) so no adjustment has been added. The other regions had relatively low prices during the maximum demand events and no adjustments were necessary. Otherwise, the market generally had elevated prices across the winter, and while the other regions had prices above the typical DSP triggers, given the sustained periods at those price levels, it did not trigger any short-term price response at time of the maximum demand in the other regions.

The winter maximum demand outcomes are shown in Table 15 below.

Table 15 Winter 2022 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, 19 July 2022 18:30	12,370	389	11,981	-	-	11,981
QLD	Mon, 4 July 2022 18:00	8,716	411	8,305	-	-	8,305
SA	Mon, 22 August 2022 19:00	2,499	28	2,471	-	-	2,471
TAS	Tue, 7 June 2022 18:30	1,708	19	1,689	-	-	1,689
VIC	Tue, 7 June 2022 18:00	8,011	328	7,683	-	-	7,683

5.1.3 Annual 2021-22 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 were quite typical, either typically being weekends, with three regions having their minimum in November, where solar PV would be getting close to maximum output, but while temperature is not high enough to drive any significant cooling demand. In 2021-22, all regions but Tasmania reached their lowest minimum demand levels since the beginning of the NEM. The minimum demand events are listed in Table 16 by region.

Table 16 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, 17 October 2021 13:00	4,425	122	4,303	-	-	4,303
QLD	Sat, 20 August 2022 12:30	3,488	240	3,248	-	-	3,248
SA	Sun, 21 November 2021 13:00	104	6	98	-	-	98
TAS	Tue, 9 November 2021 12:30	786	7	779	-	-	779
VIC	Sun, 28 November 2021 13:00	2,333	185	2,148	-	-	2,148

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 2022. Further detail on the extreme demand events observed during the year is provided in Table 17.

Figure 13 New South Wales demand with extreme events identified

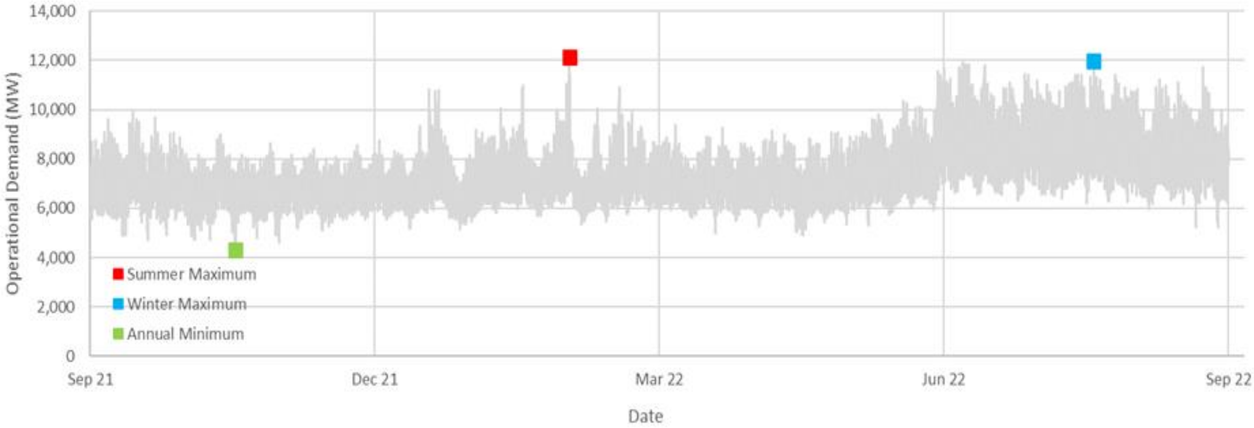


Figure 14 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and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

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

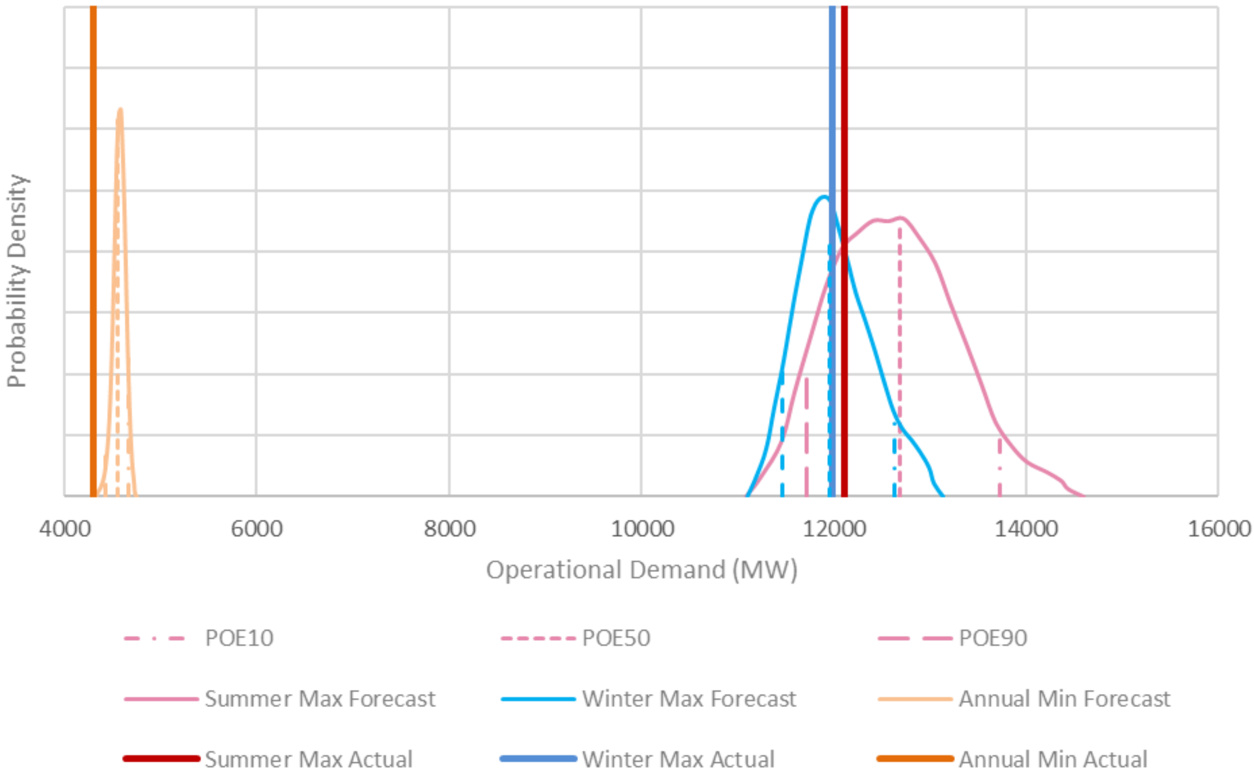


Table 17 New South Wales 2021-22 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Tue, 1 February 2022, 16:30	Tue, 19 July 2022, 18:30	Sun, 17 October 2021, 13:00
Temperature* (°C)	31.2	10.2	22.1
Max temperature (°C)	35.7	14.6	22.1
Min temperature (°C)	21.2	5.8	8.9
Losses (MW)	727	730	232
NSG output (MW)	257	193	436
Rooftop PV output (MW)	611	0	2,802
Sent out (OPSO)^	**12,115**	**11,981**	**4,303**
Auxiliary (MW)	415	389	122
As generated (OPGEN)^	**12,530**	**12,370**	**4,425**

* Bankstown Airport 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).

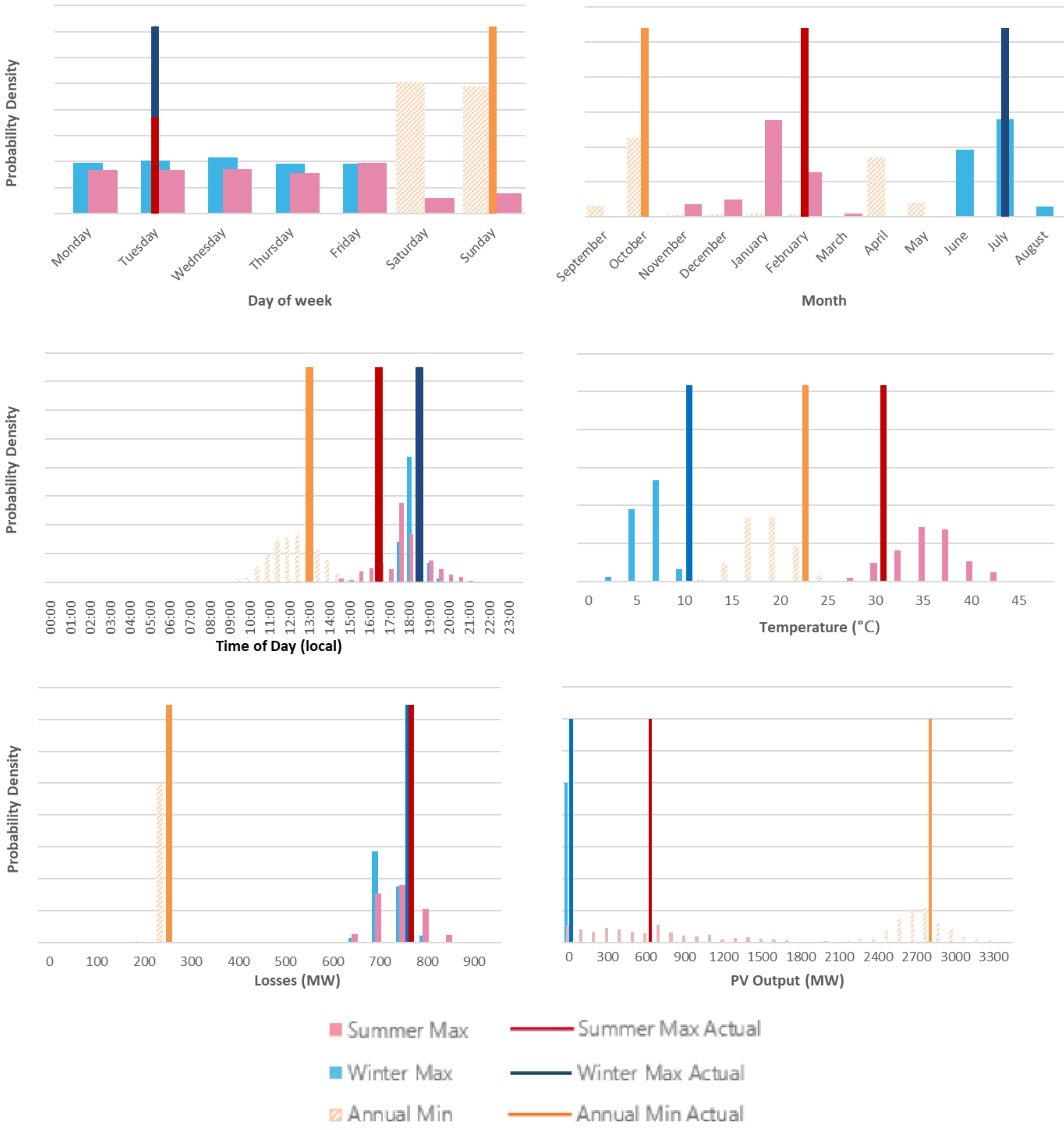
Figure 15 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Summer maximum operational (sent out) demand occurred on Tuesday 1 February 2022 at 16:30 NEM time. At the time of maximum demand, Bankstown recorded a temperature of 31.2°C with a daily maximum of 35.7°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. However, New South Wales experienced a mild La Niña summer, with temperatures generally lower than forecast. The summer maximum demand event coincided with the day of the second highest daily summer maximum temperature (the hottest day was on a weekend day, where demand generally is lower). The temperature was 25.7 °C by 09:00, before reaching a temperature of 34.6°C by 15:00. It was a very humid day, with relative humidity above 80% more than half of the time, but no rainfall until 19:00. The combination of such humidity and high temperature drives up cooling load.
- Simulation outcomes were weighted towards maximum demand occurring in late January/early February, which is consistent with the actual maximum demand day. The summer maximum demand event falling on a Tuesday is consistent with the simulations where most of these events occurring on weekdays. The time of summer maximum demand event is within the simulation outcomes, but earlier than expected. A hotter day in a more extreme summer would normally peak later in the afternoon or early evening.
- PV generation at time of maximum demand sits within the forecast PV generation distribution.

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



Winter maximum demand occurred on Tuesday 19 July 2022 at 18:30 NEM time, with a temperature of 10.2°C recorded at Bankstown. The maximum temperature of the day was 14.6°C. The minimum temperature on the day was 5.8°C.

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

- For all winter days with minimum temperature below 7°C, the day of winter maximum demand event had the smallest range, with the smallest spread between maximum and minimum of only 8.8°C. It was also a windy day, with maximum wind speed of 25.9 km/h, and maximum precipitation level of 4.6 mm. Such conditions all contribute to higher heating load.

- Maximum demand peaked at 18.30 NEM time, well after sunset. Hence, PV generation was zero at the time of maximum demand.
- The forecast expected a later winter peak in July, when heating loads are normally significantly higher, consistent with the observed maximum demand.

Annual minimum demand occurred on Sunday 17 October 2021 at 13:00 NEM time, when the temperature was 22.1°C.

- Actual minimum demand was outside the simulation distribution, significantly lower than 90% POE. The contribution from rooftop PV was well aligned with the simulation outcomes, and installed capacity (see Section 3.3) well aligned with forecast. AEMO will look further into this forecast difference.
- Simulation outcomes were weighted towards occurring in summer months, contrary to the actual occurrence on Sunday 17 October 2021. The monthly distribution does extend into spring, however, so an October observation is not unexpected.

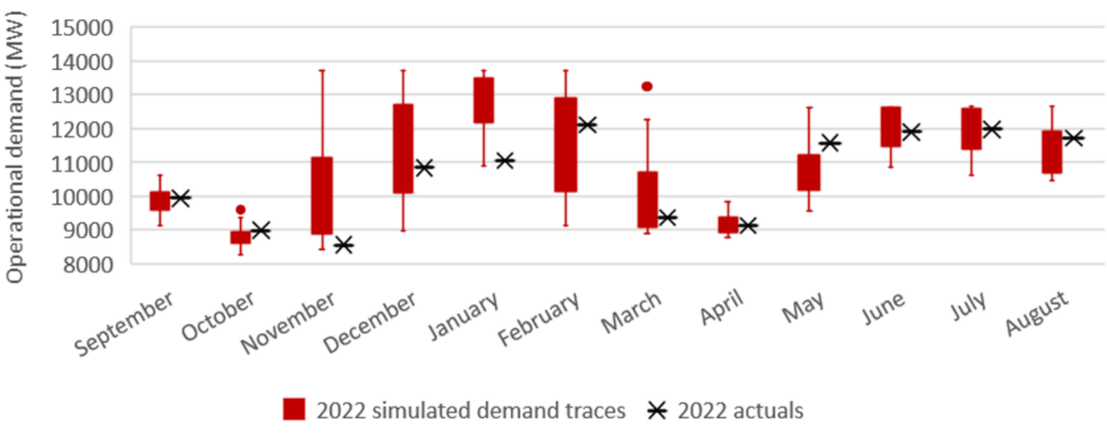
Monthly maximums

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 11 reference years (2011-21), 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 in Figure 16 shows the range of monthly demand maximums for the 2022 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. Actual monthly maximums all fell within the simulated ranges.

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 Table 18.

Figure 17 Queensland demand with extreme events identified

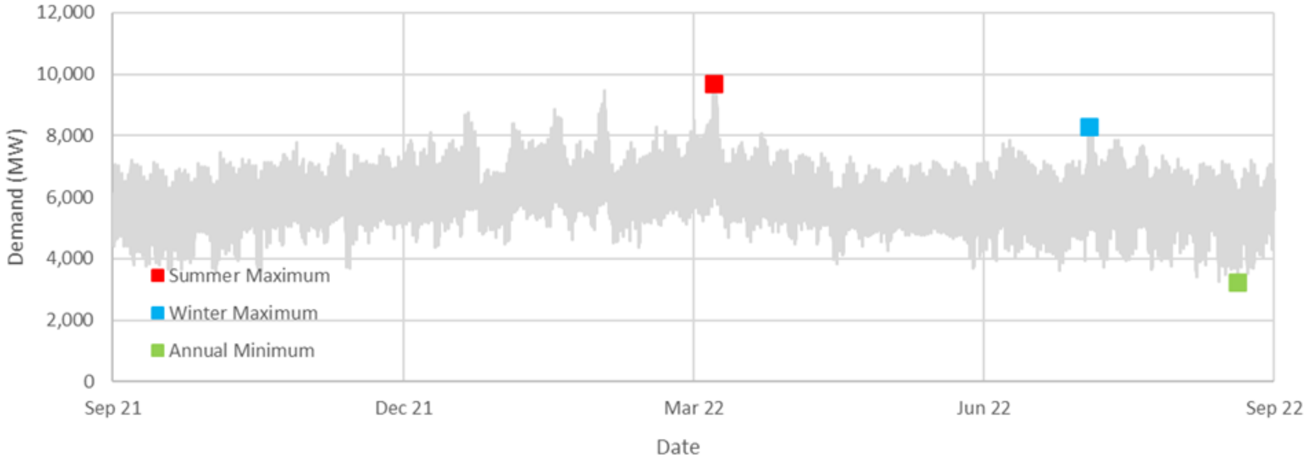


Figure 18 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. For all three forecasts (summer and winter maximum demand and annual minimum demand) actual events fell above or in the very top end of the forecast distributions.

Figure 18 Queensland simulated extreme event probability distributions with actuals

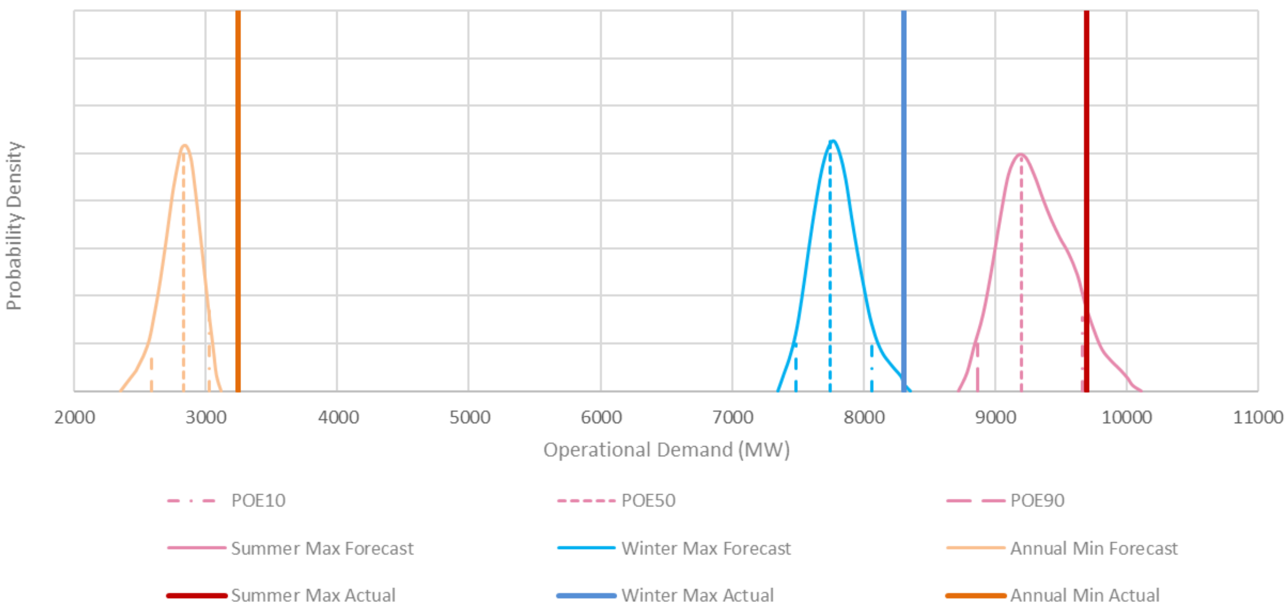


Table 18 Queensland 2021-22 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Tue, 8 March 2022, 19:00	Mon, 4 July 2022, 18:00	Sat, 20 August 2022, 12:30
Temperature* (°C)	27.7	11.2	22.5
Max temperature (°C)	33.8	13.3	24.0
Min temperature (°C)	21.6	10.3	10.2
Losses (MW)	576	498	141
NSG output (MW)	86	118	327
Rooftop PV output (MW)	0	0	3,028
Sent out (OPSO)	**9,592 (adjusted to 9,695)^**	**8,305**	**3,248**
Auxiliary (MW)	466	411	240
As generated (OPGEN)	**10,058 (adjusted to 10,161)^**	**8,716**	**3,488**

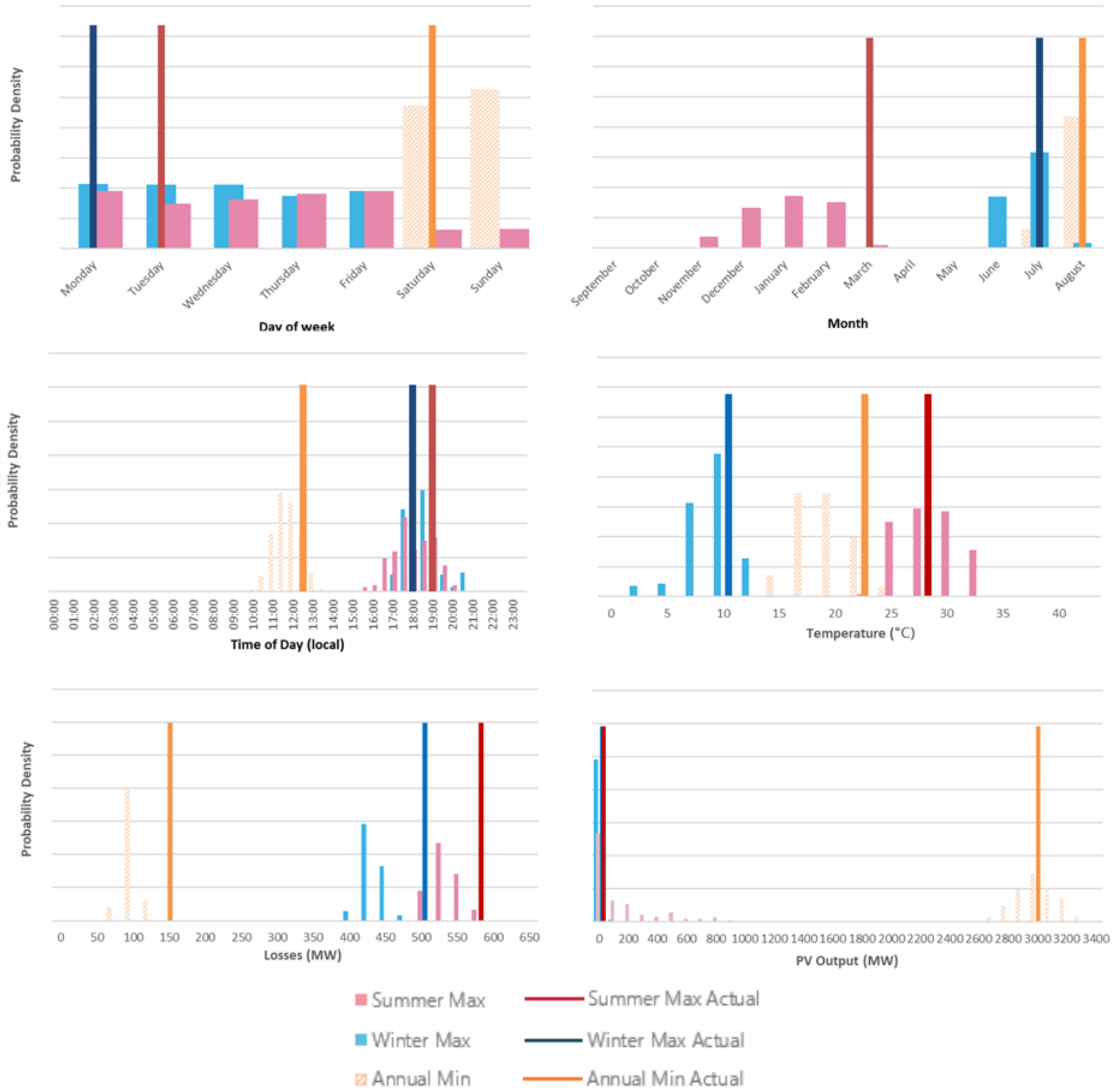
* Archerfield Airport weather station. For more information please see Section 3.3.2 of the 2021 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to include a firm adjustment of 103 MW, estimated as a price response to very high local wholesale prices.

Figure 19 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 8 March 2022 at 19:00 NEM time. At the time of maximum demand, Archerfield recorded a temperature of 27.7°C with an earlier daily maximum of 33.8°C.

- The adjusted maximum demand was broadly within the forecast expectations for the conditions on the day, falling just above the 10% POE value from the simulations based on the "as generated" forecast, and just under based on the "sent out" forecast as shown in Figure 18. The maximum demand event happened on the third hottest weekday in summer. The hottest day, 1 February 2022, recorded a seasonal maximum temperature of 35.3°C but was windier, with maximum windspeed of 33.5 km/h. The second hottest day, 2 February 2022, had a maximum temperature of 34.4°C but had a cool change before the evening. All three days had high humidity, with the humidity on 8 March staying high well into the evening, when rooftop PV no longer offset the demand. Combined, this explains why 8 March had the highest demand over the summer.
- The maximum demand event happened on a Tuesday, 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 much more uncommon.
- Queensland, like most of Australia, was driven by milder temperatures caused by the La Niña event in summer 2021-22, which was reflected in the peak demand event. The fact that the time of maximum demand event was in the late range of the simulated time of day outcomes, caused the actual temperature to be around the median of the simulated temperature outcomes.
- The actual network losses at the time of maximum demand were 576 MW, falling in the higher end of the range of simulated loss outcomes. As losses are proportional to demand, and demand was in the higher end of the distribution, this is expected.
- Maximum demand peaked at 19:00 NEM time, well after sunset, so PV generation was zero at time of maximum demand.

Figure 19 Queensland simulated input variable probability distributions with actuals



Winter maximum demand occurred on Monday 4 July 2022 at 18:00 NEM time. Temperature at the time was 11.2°C at Archerfield. Maximum demand was not within forecast expectation, being above the forecast 10% POE forecast and setting a new all-time record for winter peak demand.

- Though the maximum demand event did not happen on the coldest day at the reference weather station, it was a day with a very narrow temperature range of only 3°C. There was also high humidity across the day, between 61% and 93%, maximum windspeed of 31.3 km/h, along with a maximum precipitation of 3.2mm. All these conditions drive up the heating load.
- The cold snap on 4 July extended far beyond the Brisbane area, with new low temperature records being set for multiple weather stations and the system causing unusually cold weather all the way up to Mackay. The

fact this weather system both reached record low temperatures at some locations and extended so far north, explains why the outcome exceeded the 10% POE forecast.

- Maximum demand occurred on a Monday, in July, at 18:00, consistent with the simulation outcomes. The temperature at the time of maximum demand was towards the high range of the simulated weather distribution, but very close to the median value.
- The actual losses at maximum demand event were higher than the simulation outcomes. As losses are proportional to demand, and demand was in the higher end of the distribution, this is expected.

Annual minimum demand occurred in winter on Saturday 20 August 2022 at 12:30 NEM time, when the temperature was 22.5°C.

- Minimum demand was higher than forecast expectations, falling above POE 10 value.
- Minimum demand occurred on a Saturday in August, consistent with the simulation outcomes.
- The day of the minimum demand event, 20 August, was the warmest weekend in winter. The conditions would not require much heating load compared to other winter days.
- The time of minimum demand was in the later range of the simulation outcomes, but still within expectations.
- The temperature at time of minimum demand fell in the high range of the simulation.
- The PV generation at time of minimum demand event matched closely with the simulation outcomes. However, the actual losses were higher than expected.

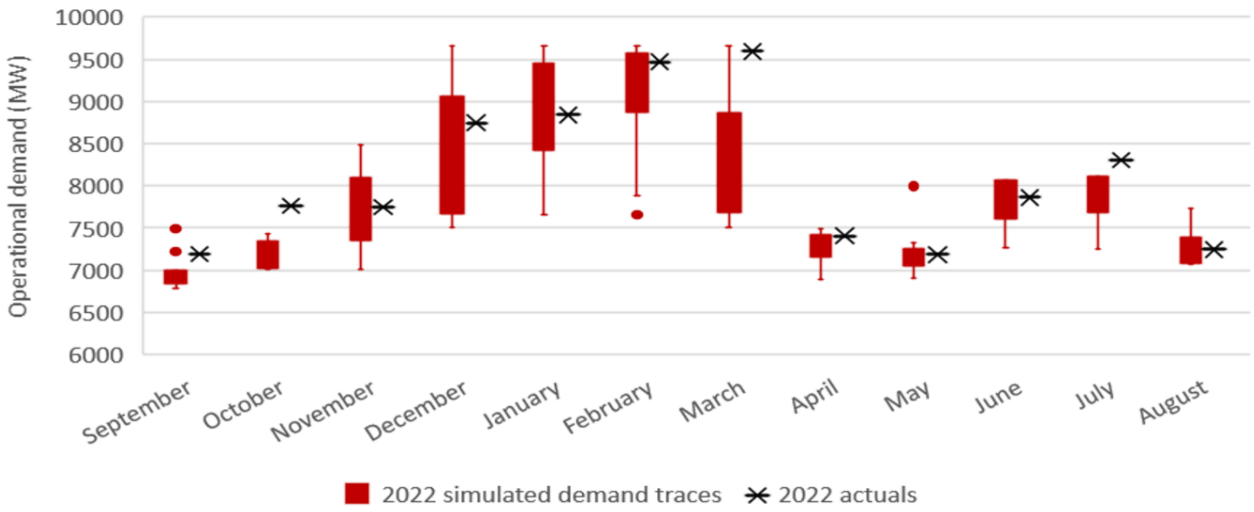
Monthly maximums

The box plot in Figure 20 shows the range of monthly demand maximums for the 2021 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 October and July, monthly maximums fell within the simulated range. July, as explained in the winter maximum demand discussion above, had a very cold weather system that extended far up into Queensland leading to a new record high winter peak that exceeded the forecast 10% POE and therefore also fell outside the ranges of the traces. For October, the 28th was unusually hot, being the warmest October day on record for Queensland as a whole in terms of mean temperature. The associated cooling demand resulted in an actual outcome outside the range formed by the historical traces.

Note that the 2021-22 weather year was included as reference year in the 2022 ESOO (and related processes like MT PASA and EAAP), which widen the range of monthly maximums considered for Queensland in more recent studies.

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 Table 19.

Figure 21 South Australia demand with extreme events identified

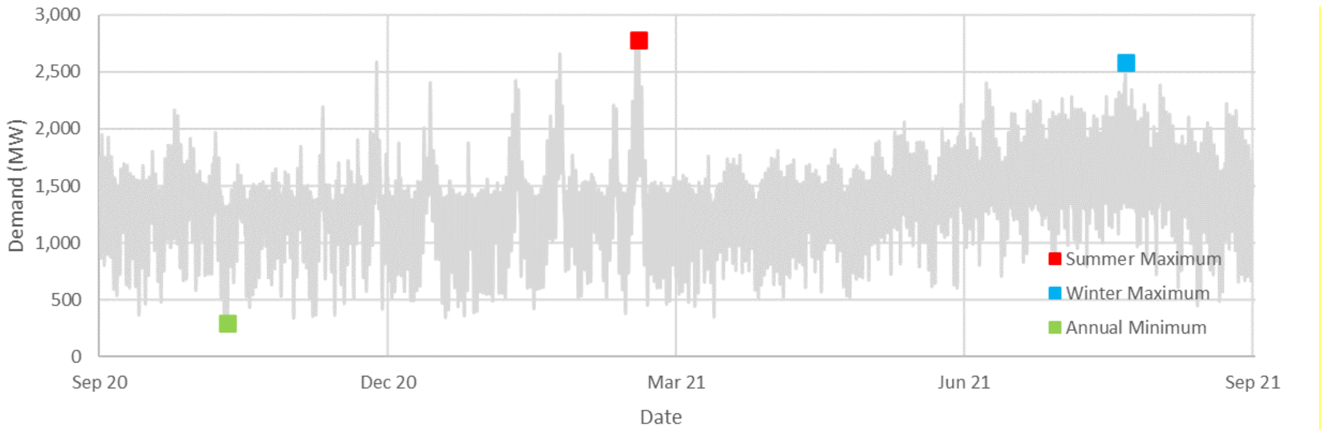


Figure 22 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The actual summer maximum demand event fell well within forecast distributions, while both the winter maximum and the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

Figure 22 South Australia simulated extreme event probability distributions with actuals

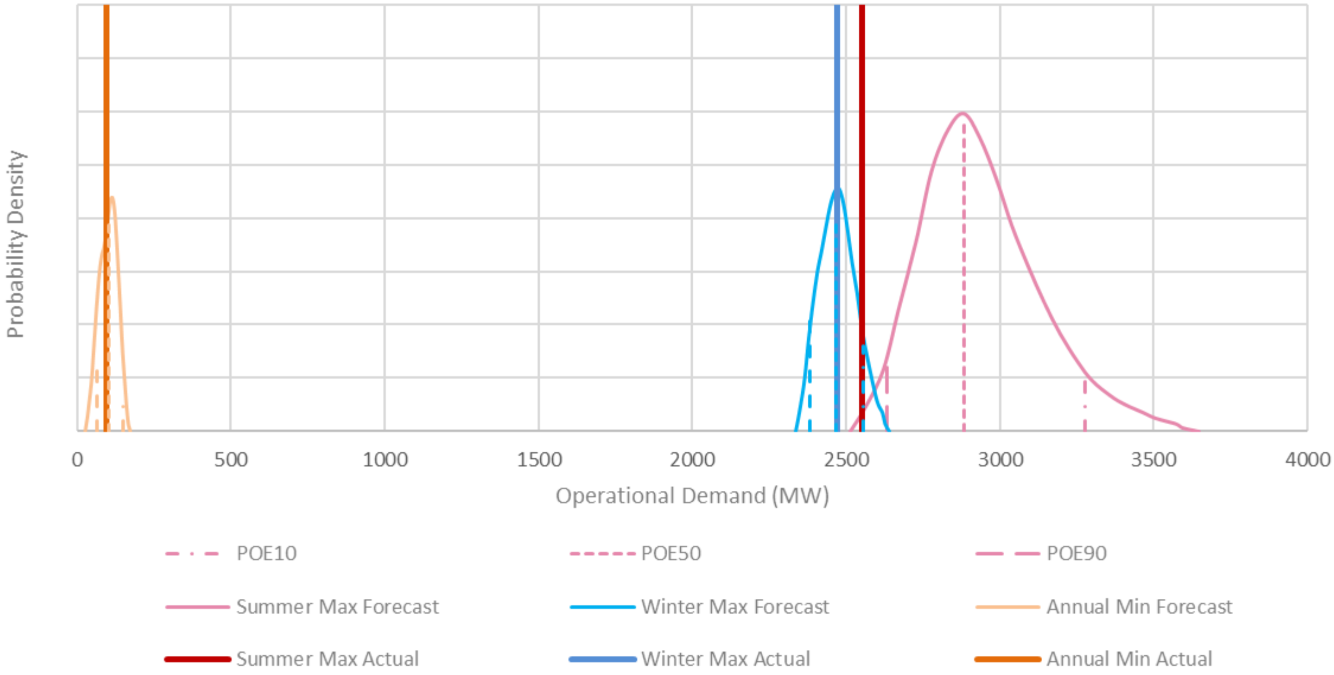


Table 19 South Australia 2021-22 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Tue, 11 January 2022, 19:00	Mon, 22 August 2022, 19:00	Sun, 21 November 2021, 13:00
Temperature* (°C)	25.3	9.6	19.8
Max temperature (°C)	40.2	12.7	21.0
Min temperature (°C)	21.4	6.8	11.2
Losses (MW)	204	196	-1
NSG output (MW)	56	12	170
Rooftop PV output (MW)	121	0	1,221
Sent out (OPSO)	**2,554**	**2,471**	**98**
Auxiliary (MW)	35	28	6
As generated (OPGEN)	**2,589**	**2,499**	**104**

* 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 2021 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf).

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 Tuesday 11 January 2022 at 19:00 NEM time with a temperature of 25.3°C recorded at Adelaide (West Terrace).

- The maximum demand was within the distribution of the simulations, but lower than the 90% POE forecast.
- Simulation outcomes were weighted toward a weekday maximum and in January/February, consistent with what was observed.
- The summer was rather unusual with few, and relatively weak, heat waves, driven by the La Niña conditions.

- The summer maximum demand event coincided with the day of the highest daily temperature. Temperatures were high throughout the day, with a temperature of 30°C at 7:30, before reaching a temperature of 40.2°C at 14:30. The accumulated heat during the day would have been driving up the need for cooling.
- The time of the maximum demand was consistent with the simulations also, peaking at 19:00. However, the actual temperature at the time of maximum demand was considerably lower than the distribution of simulated outcomes, where temperature at time of peak ranged from 30°C to 42.5°C. In a more typical summer, the temperature at time of peak expectedly would be higher.
- 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 Monday 22 August 2022 at 19:00 NEM time, with a temperature of 9.6°C recorded at Adelaide (West Terrace).

- The winter maximum demand was consistent with the simulations, falling almost exactly at the 50% POE forecast.
- The winter maximum demand event happened on a weekday in August at 19:00 NEM time, within expectations and following the simulation outcomes closely.
- The winter maximum demand event did not coincide with the coolest day. However, the event day, 22 August was a cold day with very narrow temperature range (5.9°C between daily maximum and minimum temperatures), and very humid with relative humidity between 80% and 96%, as well as a maximum precipitation of 10.6mm. All these factors drive up the heating load.
- The late timing of the peak meant that rooftop PV did not contribute to lower demand at the time.

Figure 23 South Australia simulated input variable probability distributions with actuals

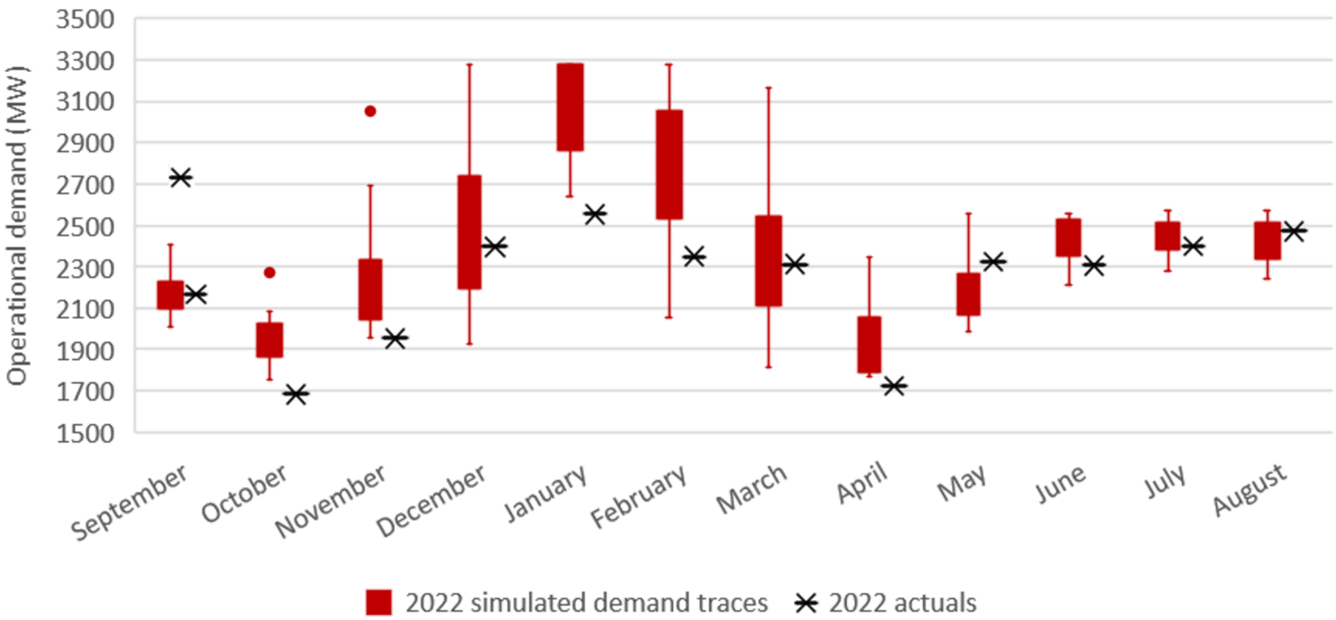
Annual minimum demand occurred on Sunday 21 November 2022 at 13:00 NEM time, when the temperature was 19.8°C; this is a typical temperature for such events, requiring minimal cooling or heating demand.

- South Australian minimum demand has been occurring in the middle of the day for several years, with minimum demand reducing year on year in response to growth in installed rooftop PV capacity. Last year's minimum demand (sent out) for South Australia was 293 MW, compared to 104 MW this year.
- 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 between November and March, 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.

Monthly maximums

The box plot in Figure 24 shows the range of monthly demand maximums for the 2021 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 no further review is required.

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 in this year is provided in Table 20.

Figure 25 Tasmania demand with extreme events identified

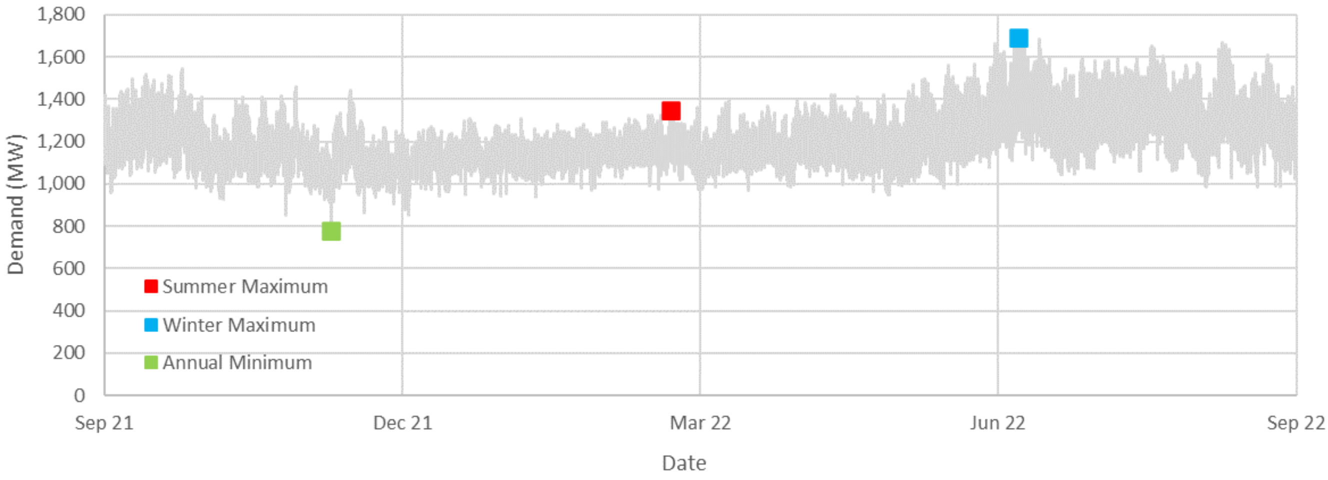


Figure 26 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. All minimum and maximum demand events fell towards the lower end of their respective forecast probability distributions, with the summer maximum and annual minimum very close to a 90% POE outcome.

Figure 26 Tasmania simulated extreme event probability distributions with actuals

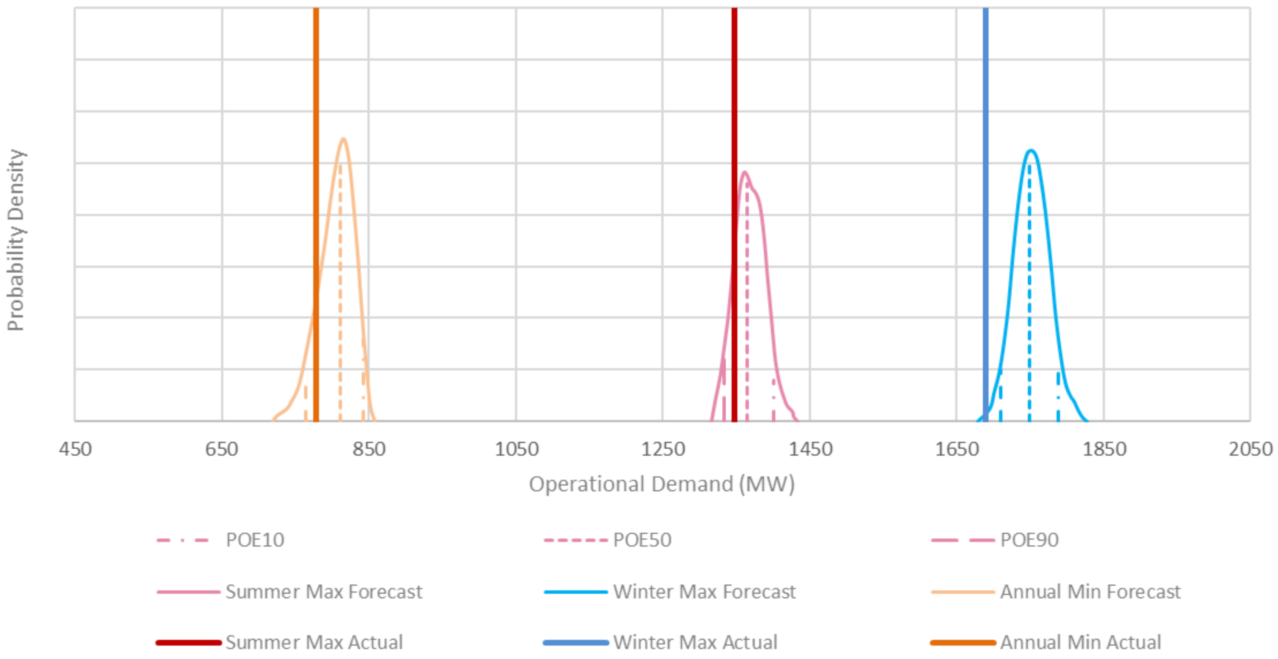


Table 20 Tasmania 2021-22 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Mon, 21 February 2022, 07:00	Tue, 7 June 2022, 18:30	Tue, 9 November 2021, 12:30
Temperature* (°C)	12.7	5.3	17.1
Max temperature (°C)	18.8	7.6	18.3
Min temperature (°C)	10.6	4.1	8.8
Losses (MW)	56	78	35
NSG output (MW)	29	75	89
Rooftop PV output (MW)	16	0	103
Sent out (OPSO)	**1,348**	**1,689**	**779**
Auxiliary (MW)	12	19	7
As generated (OPGEN)	**1,360**	**1,708**	**786**

* Hobart (Ellerslie Road) 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).

Demand in Tasmania is different from the mainland regions in two ways. First, Tasmania is consistently winter peaking; that is its annual maximum demand is driven by winter heating load rather than summer cooling loads. Also, Tasmania is influenced to a much larger extent by LIL operations, and weather (such as temperature) has a 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 Tuesday 7 June 2022 at 18:30 NEM time, with a temperature of 5.3°C recorded at Hobart (Ellerslie Road).

- Maximum demand was slightly below expectations, being below the 90% POE in the simulations by approximately 20 MW.
- Tasmania experienced a winter maximum demand event on the day with the second lowest daily maximum temperature (7.6°C). Compared to the day with the lowest daily maximum temperature, 18 July 2022, the maximum event day has a narrower temperature (3.5°C) range, windier with a maximum daily windspeed of 31.3 km/h, and rainier with maximum precipitation of 6.6 mm. All these conditions drive up heating load.
- Simulation outcomes were weighted towards occurring during a weekday evening in June to August. The evening peaks are typically driven by heating homes, hot water (showers) and cooking. The actual time of maximum demand event was consistent with the simulation.
- The temperature at the time of maximum demand event was at the higher end of the simulation outcomes. Considering that it was cold across the entire day, it was not unexpected.
- Occurring after sunset, PV generation was zero at the time of the observed maximum demand.
- LILs at time of peak were 713 MW, whereas the forecast had a 50% POE value of 765 MW (10% POE was 796 MW, and the 90% POE was 733 MW). The outcome being below the 90% POE value mostly explains why the actuals fell just below the 90% POE. AEMO will review the calculated distribution of LILs at time of peak demand.

Summer maximum demand occurred on Monday 21 February 2022 at 07:00 NEM time, with a temperature of 12.7°C recorded at Hobart (Ellerslie Road).

- The observed demand fell between 90% POE and 50% POE outcome, within expectations.
- 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.
- LILs at the time of summer maximum were at 726 MW, lower than the median for a 90% POE outcome (734 MW).
- Simulation outcomes were weighted towards occurring on a weekday and in December to February, which is consistent with the Monday 21 February occurrence. Similarly, PV generation at time of maximum was within expectations.

Figure 27 Tasmania simulated input variable probability distributions with actuals

Annual minimum demand occurred on Tuesday 09 November 2021 at 13:30 local time, when the temperature was 17.1°C. Tasmania is particularly affected by industrial activity, and as such minimum demand is inherently volatile.

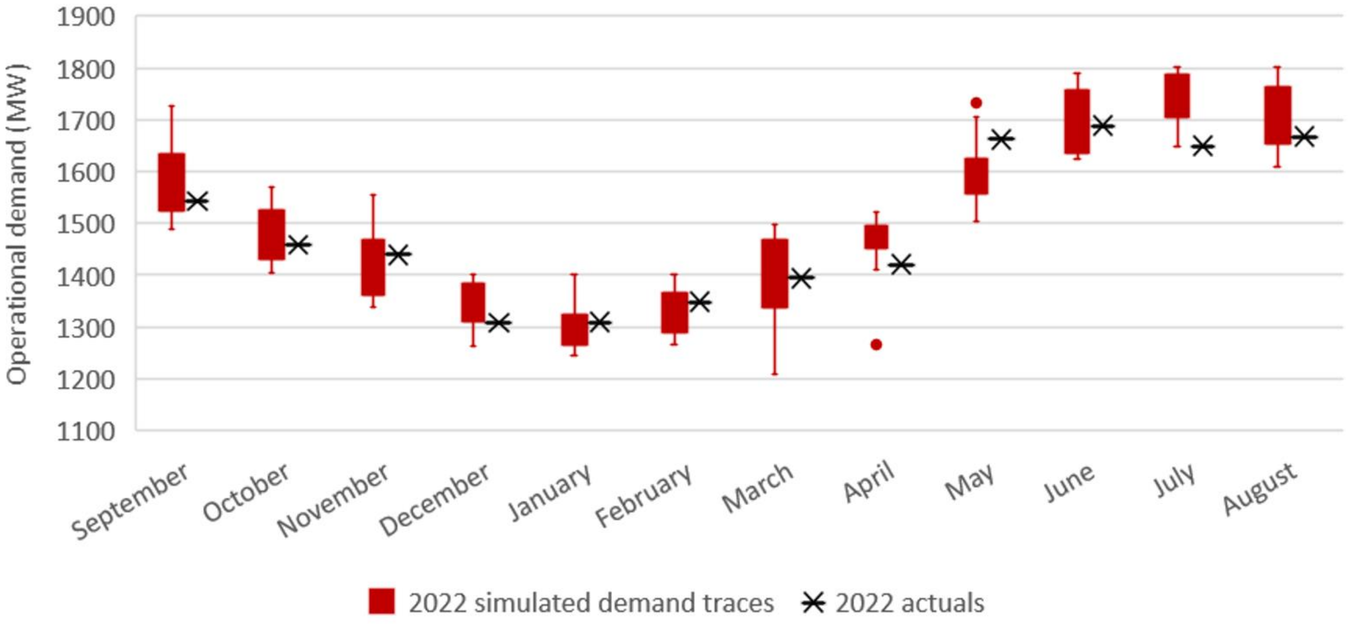
- The annual minimum demand fell between 50% POE and 90% POE, within expectations.
- Minimum demand was forecast to most likely occur in the middle of the day, subsequently with moderate temperatures and moderate PV generation. Each of these actuals fell well within expectations.

- The simulations projected minimum demand most likely to be in October or November, in alignment with the actual outcome.
- Simulation outcomes were weighted towards occurring on the weekend, while the actual minimum demand event happened on Tuesday.
- The overall LIL demand at the time of minimum demand event was 487 MW, slightly under 526 MW, which is the forecast median for 90% POE demand. This is another reason to review the LIL contributions at time of peak. This may also explain why the minimum fell on a Tuesday rather than during the weekend as projected.

Monthly maximums

The box plot in Figure 28 shows the range of monthly demand maximums for the 2022 simulated demand traces for 10% POE and 50% POE annual forecasts. All Actual monthly maximums fell within the simulated ranges.

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 21.

Figure 29 Victoria demand with extreme events identified

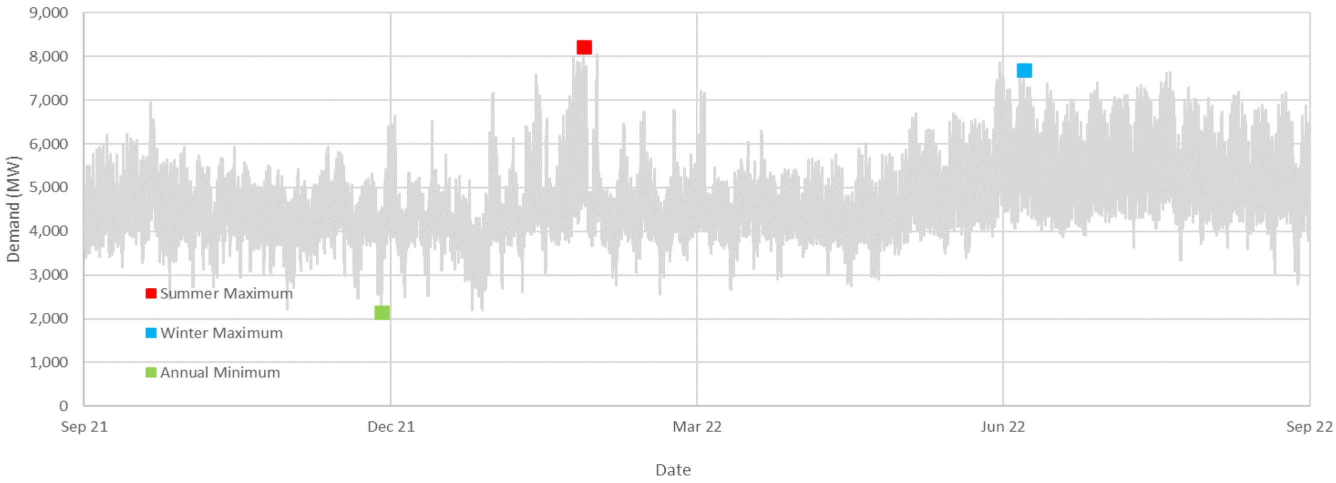


Figure 30 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. Summer maximum and annual minimum fell within forecast expectations, but the winter maximum demand outcome exceeded the forecast 10% POE. The likely reasons are discussed below.

Figure 30 Victoria simulated extreme event probability distributions with actuals

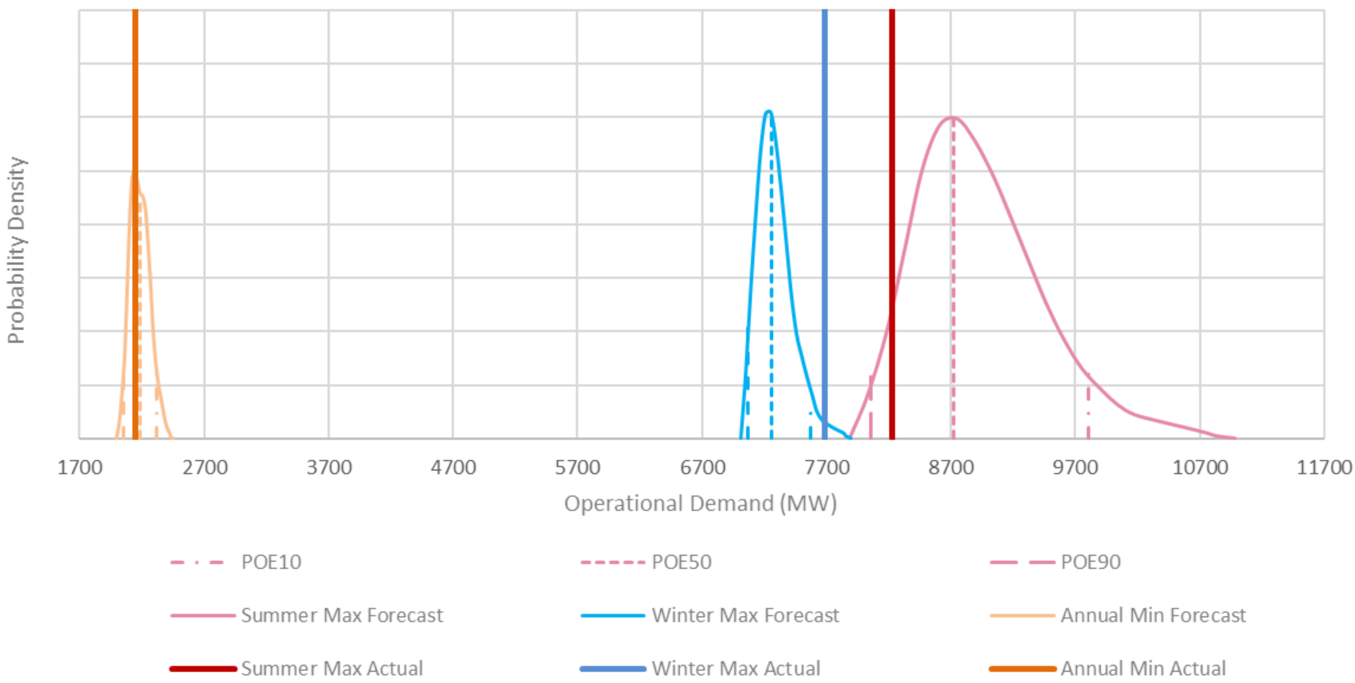


Table 21 Victoria 2021-22 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Thu, 27 January 2022, 18:00	Tue, 7 June 2022, 18:00	Sun, 28 November 2021, 13:00
Temperature* (°C)	31.0	9.7	20.1
Max temperature (°C)	32.3	11.4	21.6
Min temperature (°C)	21.2	7.3	10.0
Losses (MW)	521	487	117
NSG output (MW)	207	135	350
Rooftop PV output (MW)	283	0	2,172
Sent out (OPSO)	**8,225**	**7,683**	**2,148**
Auxiliary (MW)	374	328	185
As generated (OPGEN)	**8,599**	**8,011**	**2,333**

* 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).

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 Thursday 27 January 2022 at 17:00 NEM time. At the time of maximum demand, Melbourne (Olympic Park) recorded a temperature of 31.0°C, with an earlier daily maximum temperature of 32.3°C.

- The actual maximum demand was between 50% POE and 90% POE forecast.
- The maximum demand did not coincide with the hottest day in summer. However, being one of the hottest days, it had a narrow temperature range (11.1°C) so it was warm from the beginning of the day, as well as relatively high dew point ranging between 18.2°C and 20°C, which lowers the efficiency of evaporative cooling which is otherwise popular in the state and therefore increases the use of traditional air conditioners.
- The simulation outcomes were weighted towards the maximum demand event happening on a weekday in January in the late afternoon to early evening period. All of these are consistent with the actual maximum demand event.
- The temperature at the time of maximum demand was at the lower end of the simulation outcome range. It is not unexpected as Victoria experienced a mild summer driven by the La Niña climate cycle, and the resulting demand outcome was therefore also in the lower end of the range.
- Actual PV generation was at the lower end of simulated outcomes, with an actual of 283 MW at time of maximum demand, compared to a simulation range between 0 MW and 1,600 MW (although typically no more than 1,000 MW).

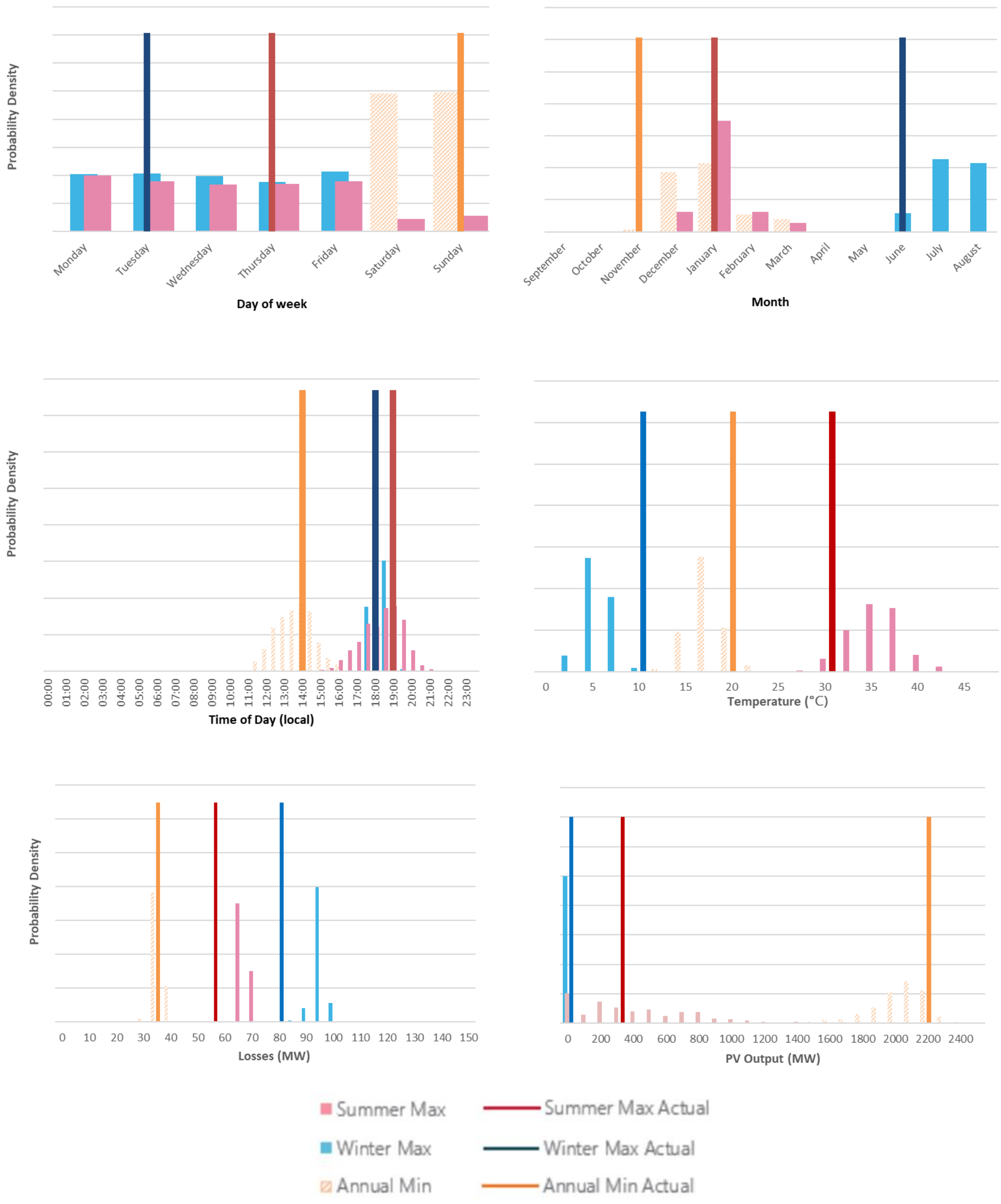
Winter maximum demand occurred on Tuesday 7 June 2022 at 18:00 NEM time, with a temperature of 9.7°C recorded at Melbourne (Olympic Park).

- The maximum demand fell above the 10% POE, although not by much.
- Victoria had its winter evening peak in 2022 on one of the coldest days of the season with a very small temperature range, a daily maximum temperature of 11.4°C and a daily minimum of 7.3°C. The temperature is towards the top end of the simulated range, so there should have been relatively less need for heating. The demand outcome above the forecast 10% POE is therefore unexpected, and AEMO will review its forecast

models and look further into reasons for why demand otherwise was so high. For example, the high gas prices at the time may have caused more to use electric heating, where they have the choice.

- 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.
- The actual maximum demand event fell on a Tuesday at 18:00, matching the simulation outcome of event more likely to happen on a weekday, in late afternoon to early evening.
- Given the timing, PV generation was 0 MW at the time of the maximum demand event, consistent with the simulation outcomes.

Figure 31 Victoria simulated input variable probability distributions with actuals



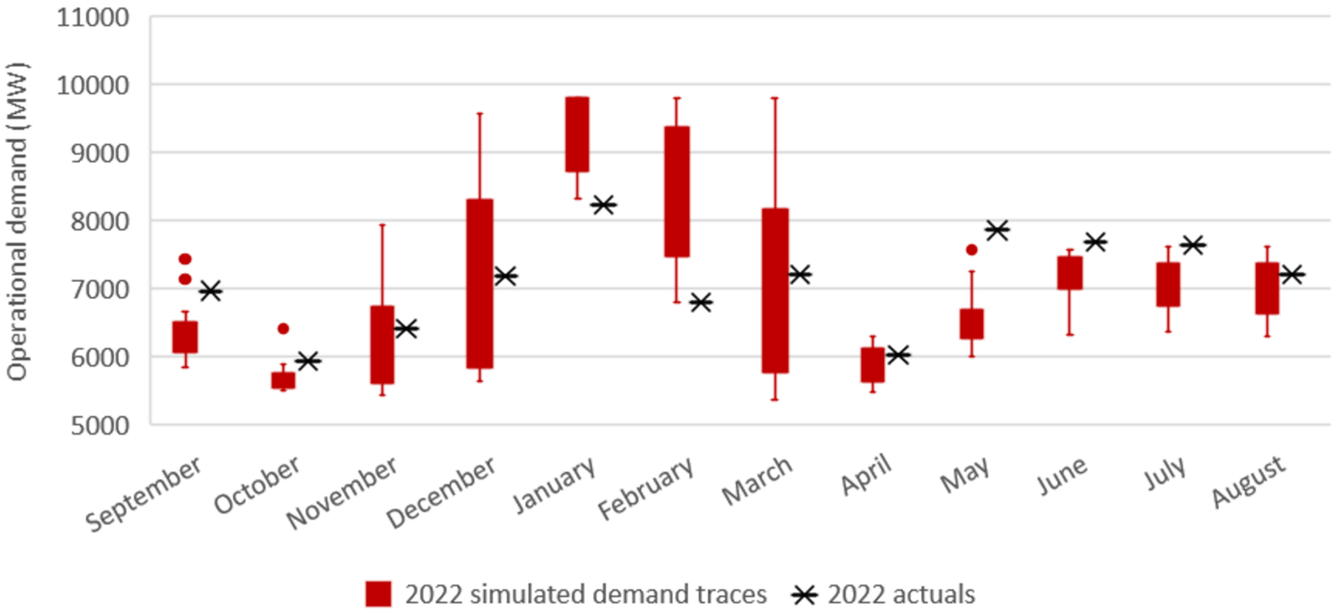
Annual minimum demand occurred on Sunday 28 November 2021 at 13:00 NEM time, when the temperature was 20.1°C. This is the third year where minimum demand has during the day rather than overnight.

- The actual minimum demand fell right below the 50% POE, consistent with the simulation outcomes.
- The minimum demand event happened in late November, on the early side of the forecast months, between late November to early March.
- Simulation outcomes were weighted towards a minimum event over the weekend in the late morning to early afternoon period, consistent with the Sunday 14:00 occurrence.
- PV generation at time of minimum was at the upper end of the distribution, which is consistent with the prevailing weather conditions on the day.

Monthly maximums

The box plot in Figure 32 shows the range of monthly demand maximums for the 2022 simulated demand traces for 10% POE and 50% POE annual forecasts. Monthly maximum demand in January is slightly below the simulated range, and monthly maximum demand in May and June are slightly above the simulated range. The June winter maximum demand event above forecast 10% POE explains why that month was over, and will be addressed through further analysis of the modelling. May had a significant cold snap towards the end with temperatures in Melbourne 5°C lower than normal. This outcome will be reflected in next year's traces.

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



6 Supply forecasts

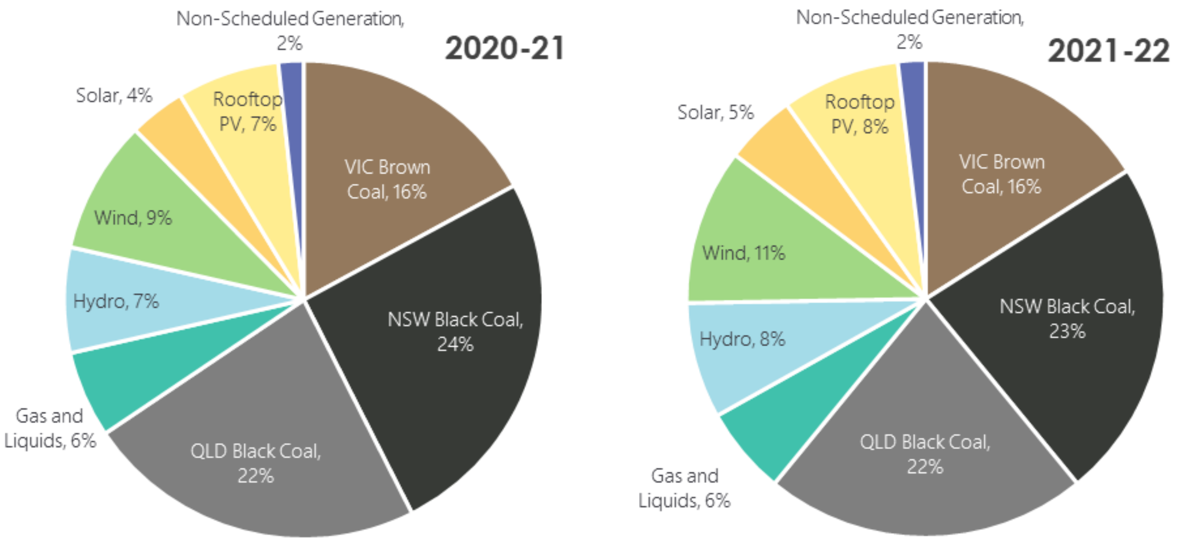
Generation supply in the NEM comes from a variety of locations and fuel sources, as shown in Figure 33. Black and brown coal remain the largest source, while solar, wind, and rooftop PV continue to show the largest increase in energy supply proportion between 2020-21 and 2021-22.

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 closed cycle gas turbines, diesel generators, and other similar peaking plant.

Figure 33 NEM generation mix by energy, including demand side components, 2020-21 and 2021-22



Supply availability is an important input in reliability studies, given that supply outages are a key driver of USE estimates during peak demand periods. Supply forecasts are therefore assessed by the degree to which capacity availability estimated in the 2021 ESOO matched actual generation availability.

There are numerous reasons why actual supply availability 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 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 (VRE) generators may fall outside the forecast simulation range.
- Generation curtailment due to constraints representing system security and network limitations.

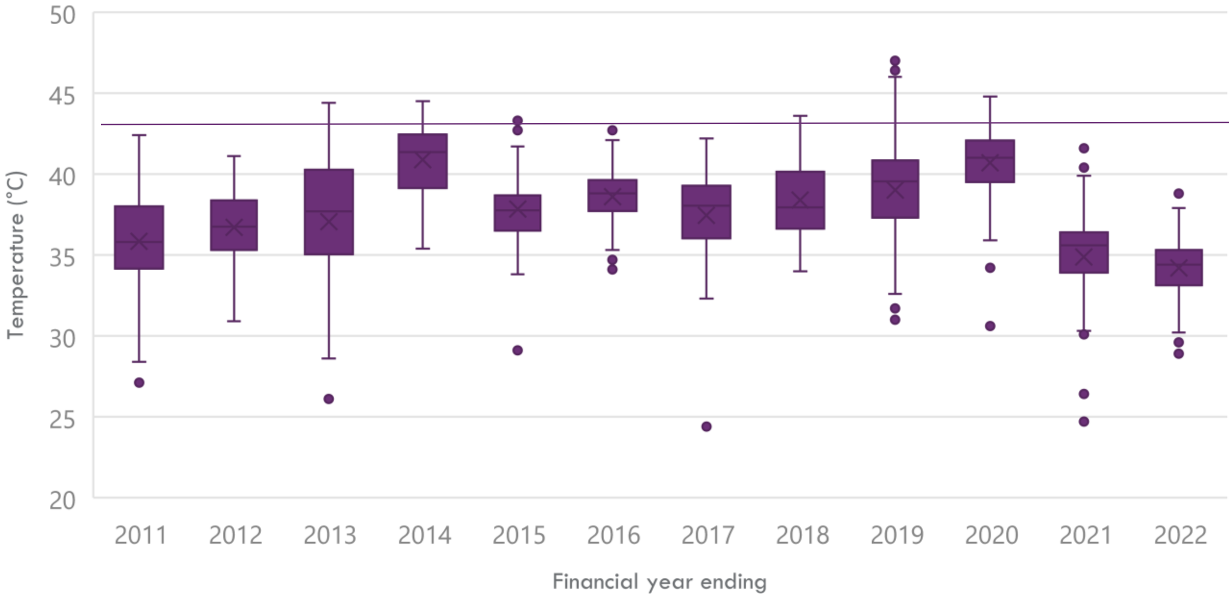
Consistent with the Forecast Accuracy Report Methodology[24], AEMO implements and publishes a variety of metrics to assess supply forecast accuracy. For each region, AEMO assesses the accuracy of generator commissioning and decommissioning schedules, then assesses supply availability, comparing actual 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 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 a range, showing the variation between the 2.5th and 97.5th percentile of the forecast simulations used.

The weather observed in summer 2021-22 was particularly 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)[25]. Figure 34 shows a box plot[26] of the temperature range of the identified 40 hours in each of the last 12 years in South Australia as well as the reference temperature of 43°C in South Australia. Weather in other regions followed a similar pattern. Without such high temperatures and the associated equipment derating, actual supply availability is expected to exceed forecast availability.

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



[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.

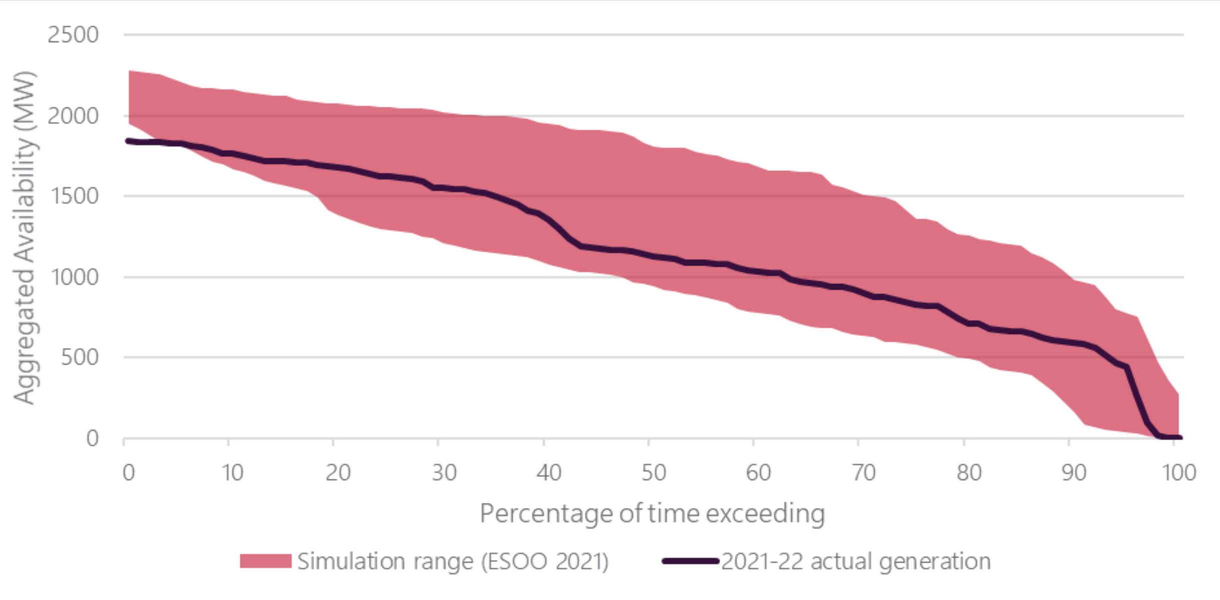
[25] AEMO's Generation Information dataset provides each regional summer rating temperature as part of its Background Information. Queensland has a reference temperature of 37°C, but all other mainland NEM regions exceed 40°C, with South Australia being the highest at 43°C.

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

Example supply availability interpretation

Figure 35 shows an example graph of supply availability, using New South Wales' large-scale solar generators as an example. The graph compares simulated availability 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 2021 ESOO simulated aggregate availability of this generation class for 80 intervals (40 hours) from the top 10 hottest days. This availability is expressed as a range, showing the variation between the 2.5th and 97.5th percentile of the forecast simulations.

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



The 2021 ESOO simulated range, shown in red, demonstrates that aggregate solar output was expected to be as high as 2,300 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 sits within the simulated range during the high temperature days of interest. Similar to the simulated range, output was shown to range between 1,800 MW and 0 MW. In this example, actuals aligned with the simulated range in most cases, with only a small divergence during high solar production, which was likely due to constraints representing system security and network limitations.

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

- Delays in commissioning new generators, compared to participant-provided dates, meant that availability of new capacity was below expectation throughout summer 2021-22.
- Given the observed mild weather, actual supply availability should have exceeded the simulated range (as high temperatures reduces the thermal efficiency); however, in both New South Wales and Queensland, observed supply availability was below the simulated range. This was caused by higher levels of planned and

unplanned outages than forecast, as well as potential generator decommitment through the periods of interest due to low levels of observed supply scarcity.

- Generator forced outage rates for black coal-fired generators continued to increase in Queensland, but other regions/fuel types were mostly aligned with forecast assumptions.

6.1 New South Wales

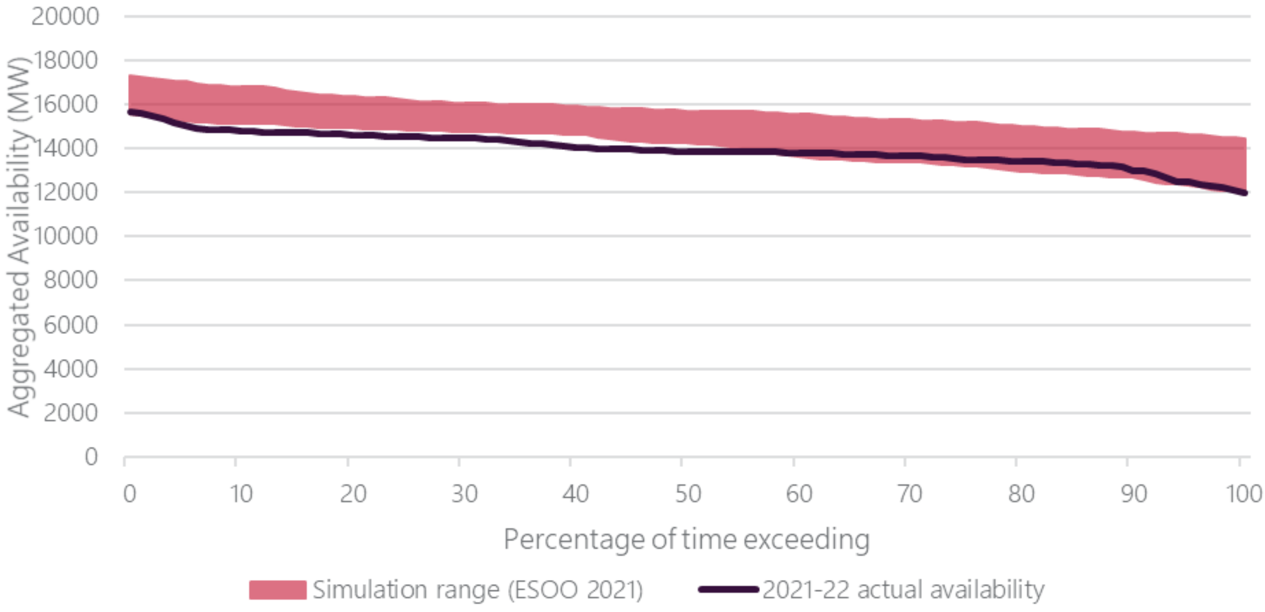
AEMO collects generation information reported from generator participants on the commissioning, decommissioning, and the capacity of individual generating and integrated resource systems. Table 22 shows how the information was implemented in the 2021 ESOO, compared to actual generator characteristics for February 2022. Two generators that were not forecast to be operating in the 2021 ESOO began commissioning ahead of schedule and were able to provide generating capacity through summer. This generation helped to offset the impact of commissioning delays of another seven generators. Additionally, the Hunter Valley Gas Turbine, which was included in the 2021 forecast, has since withdrawn. As a result, 175 MW less capacity was available last summer than was forecast.

Table 22 Forecast and actual generation count and capacity, February 2022

New South Wales	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	44	4,452	42	4,577	-125	-3%
Non-VRE generation/storage	50	14,731	52	14,781	-50	0%
All generation	94	19,183	94	19,358	-175	-1%

Figure 36 shows total summer availability for New South Wales for its highest temperature periods. While mild weather should result in high availability, actual availability was in the lower end of the simulation range. This was mostly due to lower output of renewable generation and lower availability of the black coal fleet.

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



Black coal

Unplanned outage rates for black coal-fired generation in New South Wales have decreased in 2022 from previous highs. Figure 37 shows the equivalent full unplanned outage rate, considering partial, full, and long duration outages. The outage rate in 2021-22 improved against 2020-21, which was consistent with the 2021 ESOO projection. The 2021 ESOO projection was based on participant submissions that forecast improved performance.

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

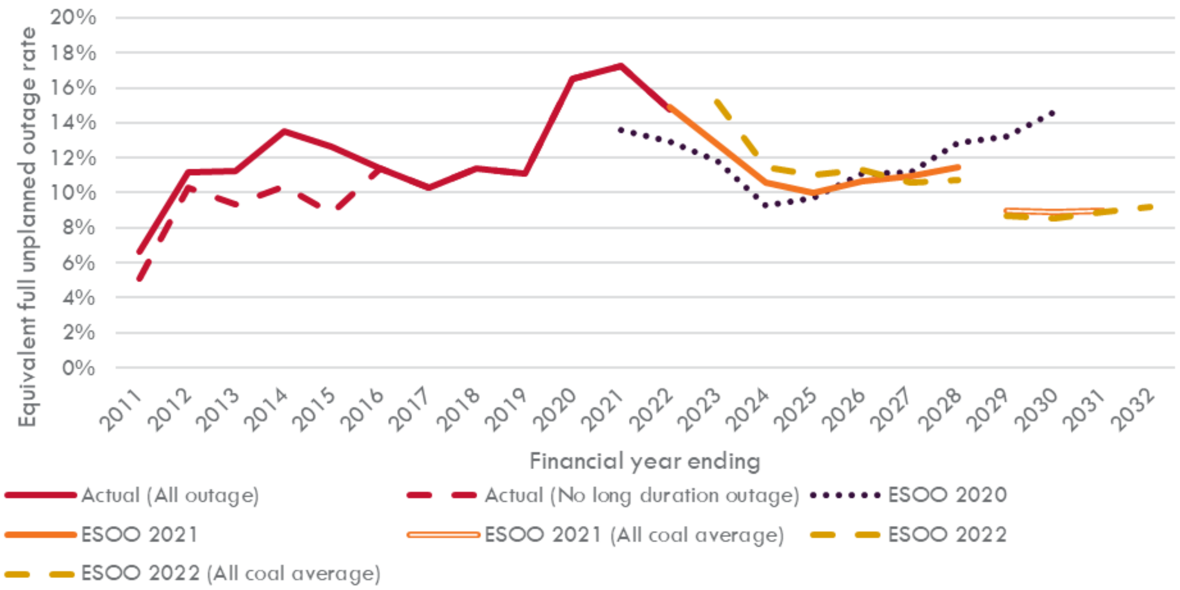
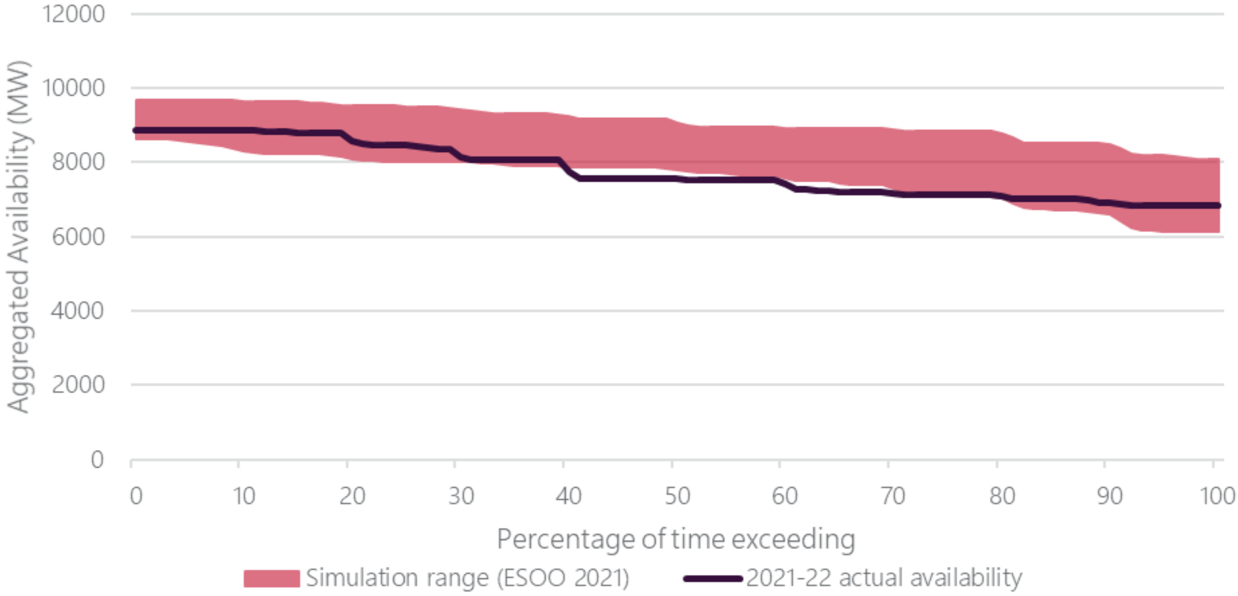


Figure 38 shows that actual availability for New South Wales black-coal generators over the top 10 hottest days was mostly in the lower end of the 2021 ESOO simulated range. Given the mild weather and consistent equivalent full unplanned outage rate projections, it would be expected that the availability to be in the higher end of the simulated range, however the outage of a key unit and lower-than-expected availability ratings caused the overall availability to be at the lower side of the expected range.

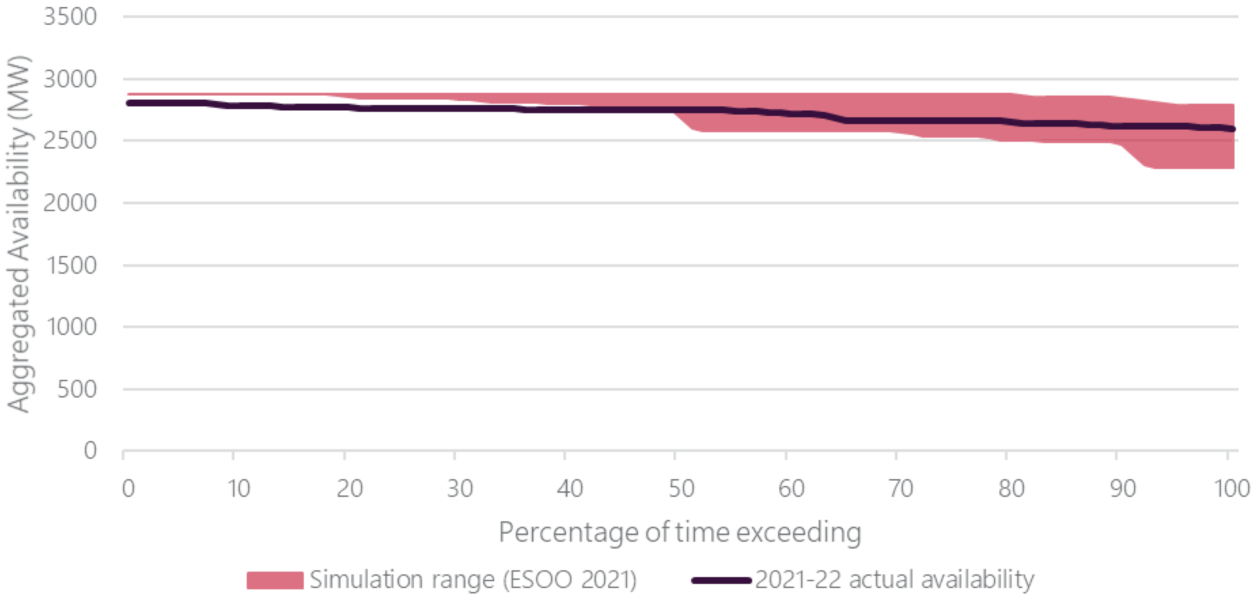
Figure 38 New South Wales black coal supply availability for the top 10 hottest days



Hydro

Figure 39 shows the supply availability for New South Wales hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2021-22, the observed availability was within, or lower than, the 2021 ESOO simulated range. Actuals are slightly below the simulated range at the top end, primarily due to hydro generators either providing availability below the seasonal ratings or having planned outages over the observed period.

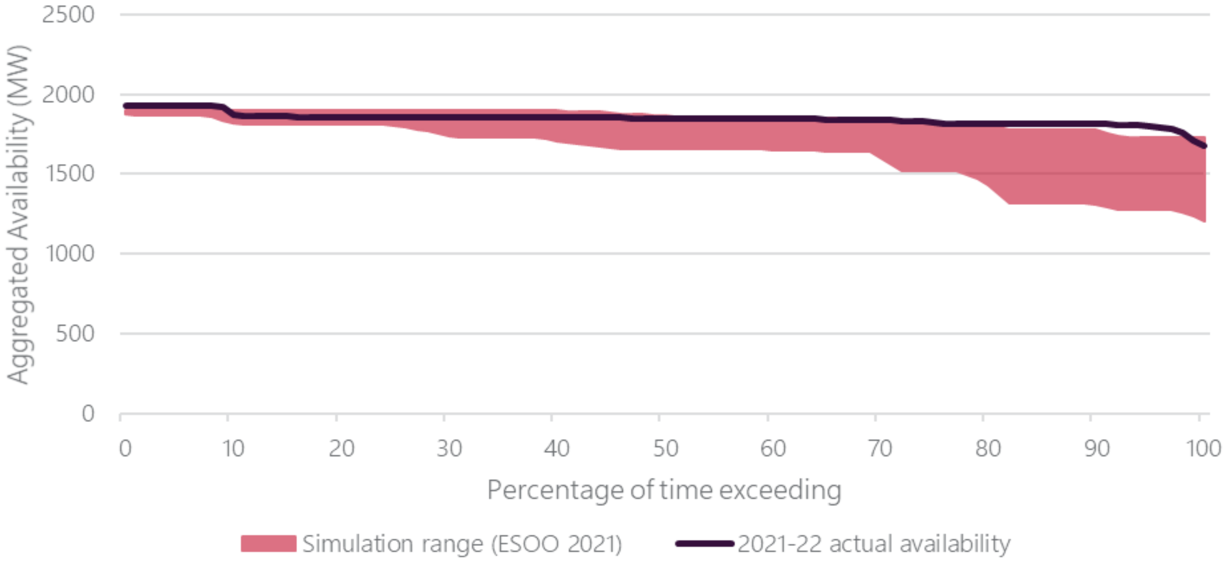
Figure 39 New South Wales hydrogeneration supply availability for the top 10 hottest days



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 2021-22, the observed availability was at the higher end of the 2021 ESOO forecast range, consistent with expectation given the mild weather observed, despite the absence of the Hunter Valley Gas Turbine.

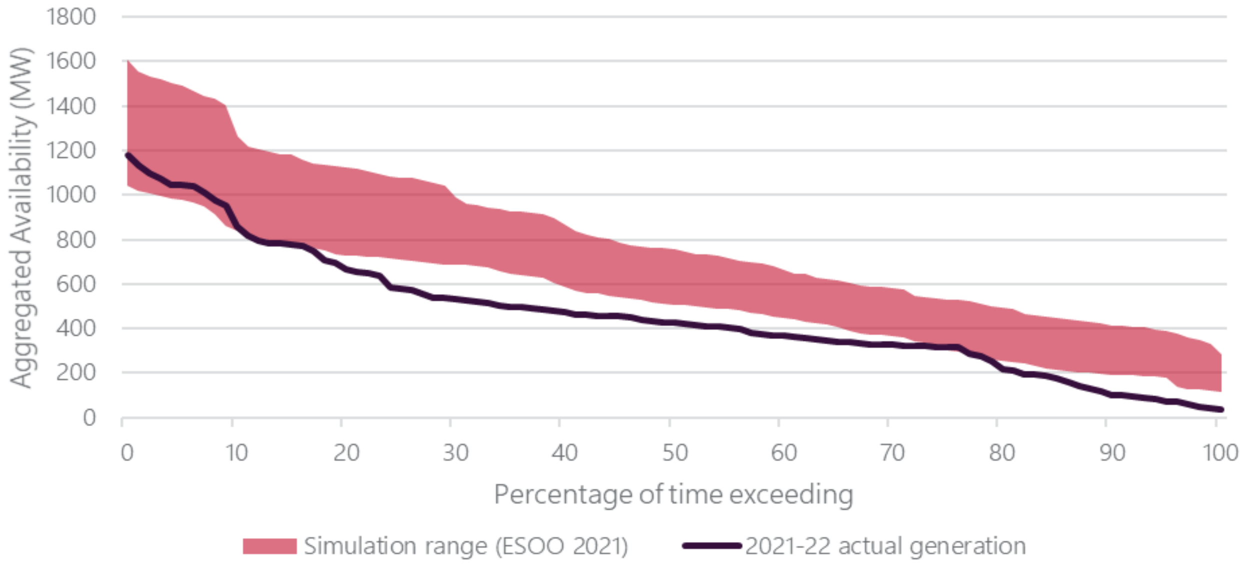
Figure 40 New South Wales gas and liquid supply availability for the top 10 hottest days



Wind

Figure 41 shows the 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 below the 2021 ESOO simulated range. The lower than anticipated output is mainly due to the delays in two generators becoming fully operational during summer 2021-22, which accounted for 183 MW less availability than forecast.

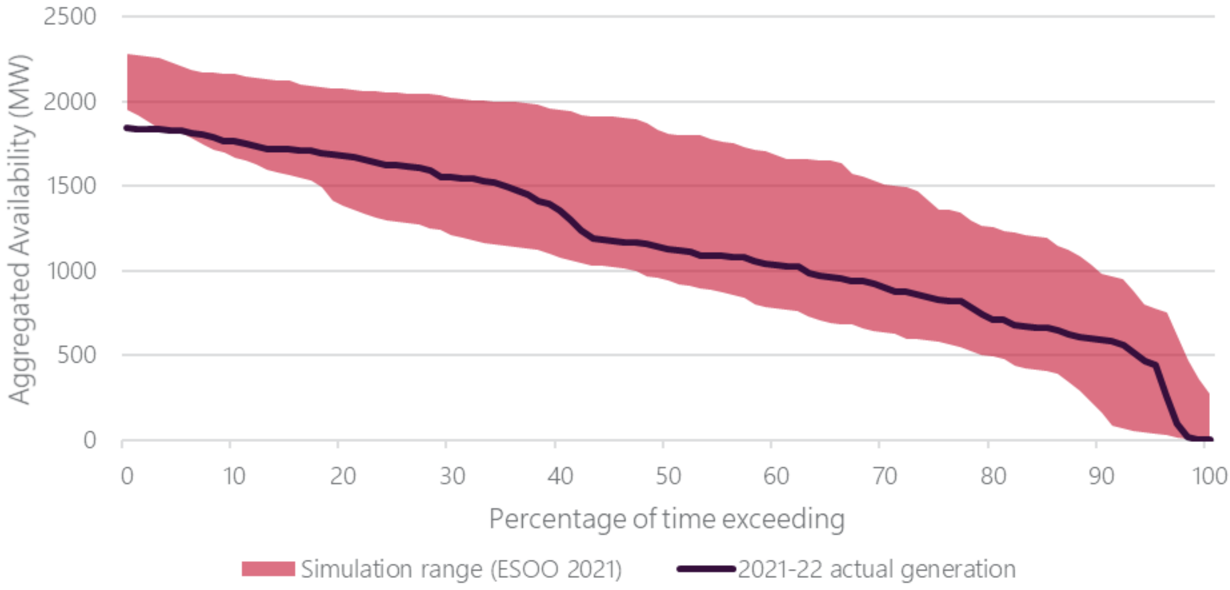
Figure 41 New South Wales wind supply availability for the top 10 hottest days



Large-scale solar

Figure 42 shows the supply availability for New South Wales large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated availability in the 2021 ESOO. The observed output was mostly within the simulated range. Actual generation may have been lower due to the curtailment of several generators during these periods.

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



6.2 Queensland

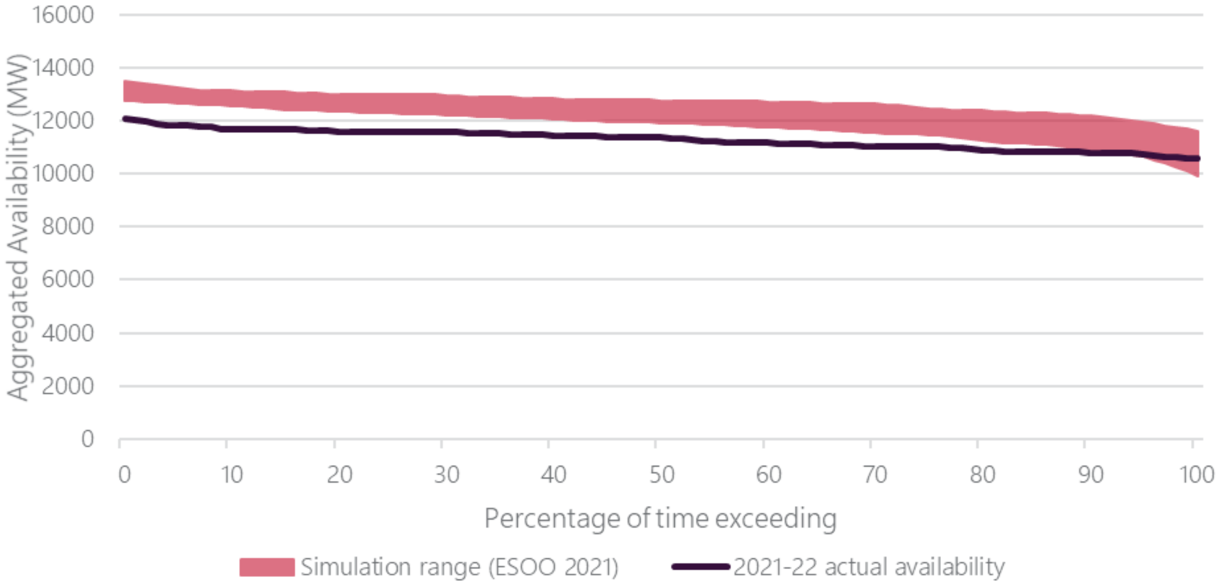
Table 23 shows how participant provided generation information was implemented in the 2021 ESOO, compared to actual generator characteristics for February 2022. In comparison to forecast, four solar projects were not fully operational while two solar projects had not begun commissioning. In total, 321 MW less solar capacity was available compared to the 2021 ESOO forecast.

Table 23 Forecast and actual generation count and capacity, February 2022

Queensland generation	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	29	2,373	31	2,694	-321	-14%
Non-VRE generation/storage	55	12,401	55	12,401	0	0%
All generation	84	14,774	86	15,095	-321	-2%

Figure 43 shows total summer availability for Queensland's highest temperature periods. Actual availability was mostly below, or towards the lower end of, the simulation range. The lower than forecast availability was due to project commissioning delays, lower than expected gas-fired unit availability, and planned maintenance of some coal-fired units.

Figure 43 Queensland supply availability for the top 10 hottest days



Black coal

The equivalent full unplanned outage rate of black coal-fired generation in Queensland in 2021-22 was higher than in 2020-21. The 2021 ESOO forecast, based on participant submissions, under-estimated this outcome by a significant amount, as shown in Figure 44. The main cause for this difference was long duration outages. The 2022 ESOO forecast provided by participants shows an increased equivalent full unplanned outage rate for black coal-fired generation compared to the 2021 ESOO forecast.

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

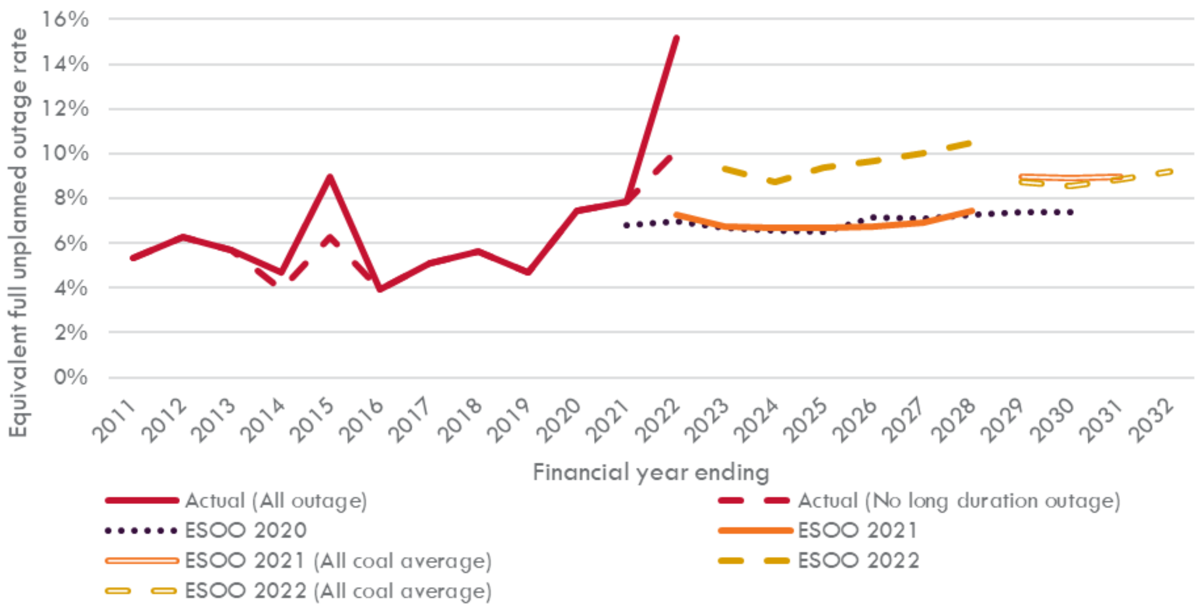
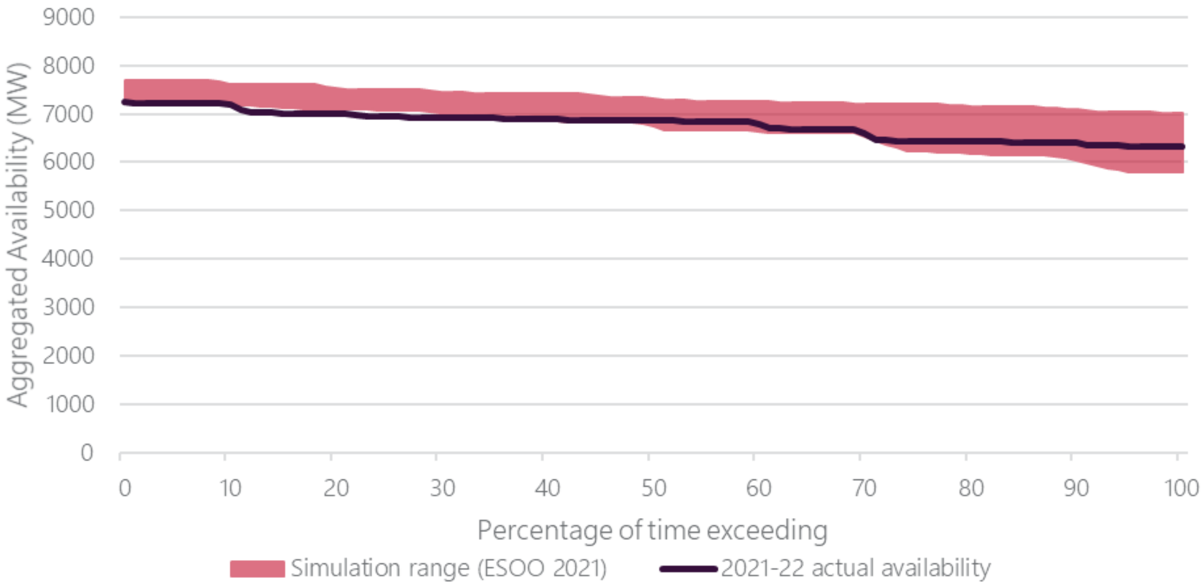


Figure 45 shows the supply availability for Queensland black coal generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly within the 2021 ESOO simulated range. The increased forced outage rate lowered the actual availability, while mild weather had little positive impact because the hot day derating for the Queensland black coal fleet is only 2% lower than the typical summer rating. A significant number of planned maintenance outages were also carried out in the observed periods, possibly due to the relative low risk of supply scarcity for the 2021-22 summer.

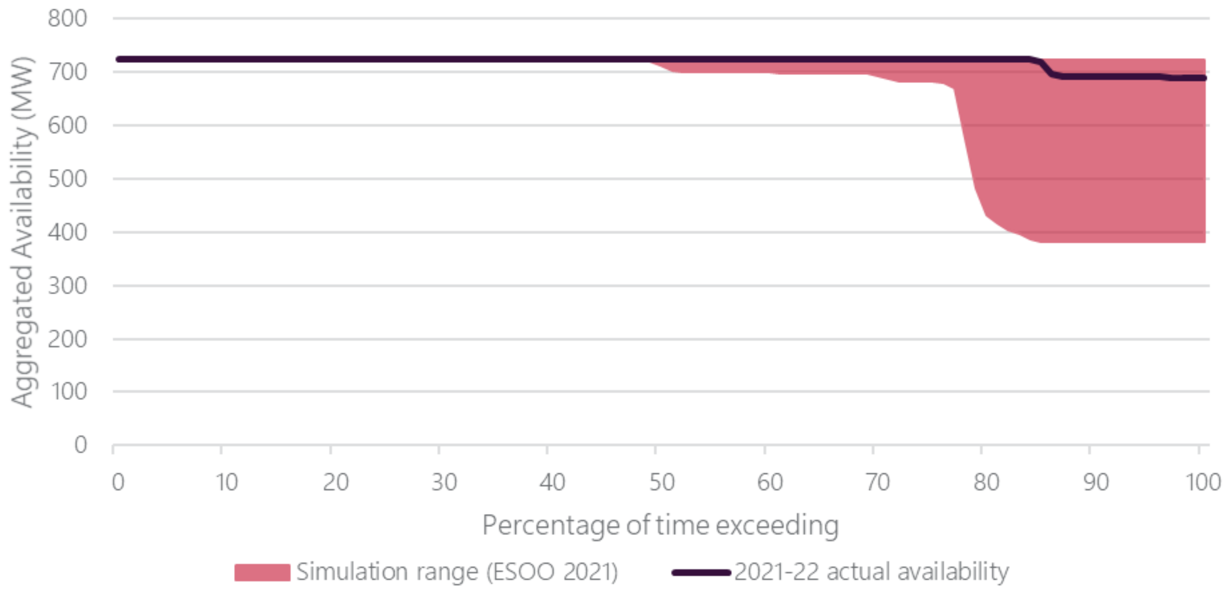
Figure 45 Queensland black coal supply availability for the top 10 hottest days



Hydro

Figure 46 shows the supply availability for Queensland hydro generators over the top 10 hottest days, comparing actual with simulated availability. The forecast performed as expected, as the observed availability was within, and towards the upper end of, the 2021 ESOO simulated range.

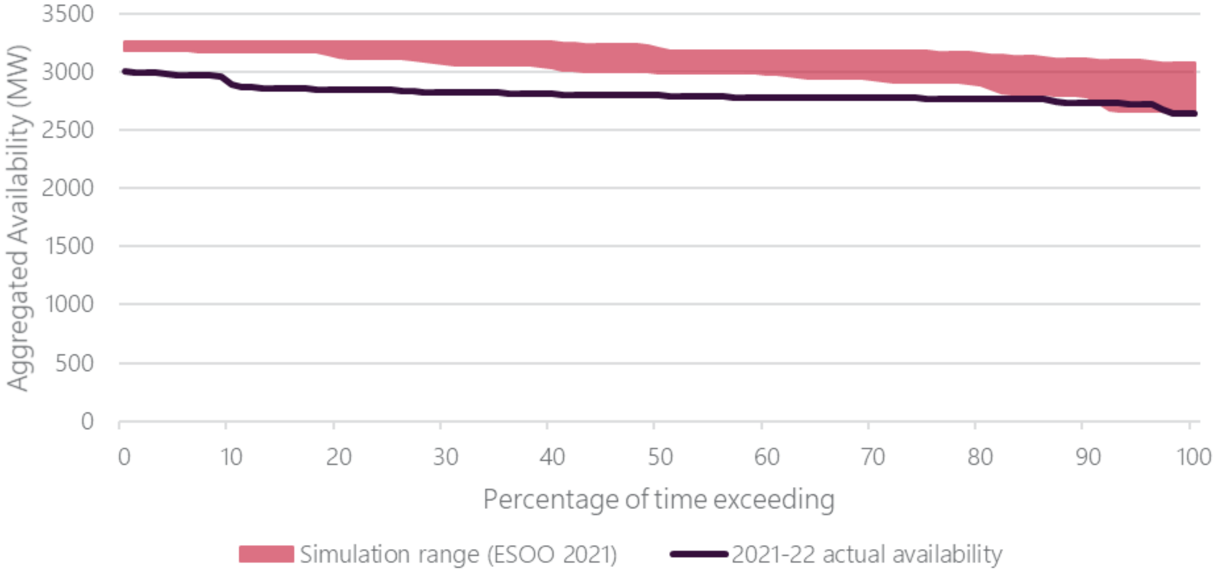
Figure 46 Queensland hydrogeneration supply availability for the top 10 hottest days



Gas and liquids

Figure 47 shows the supply availability for Queensland gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly lower than the 2021 ESOO simulated range, due mostly to planned outages.

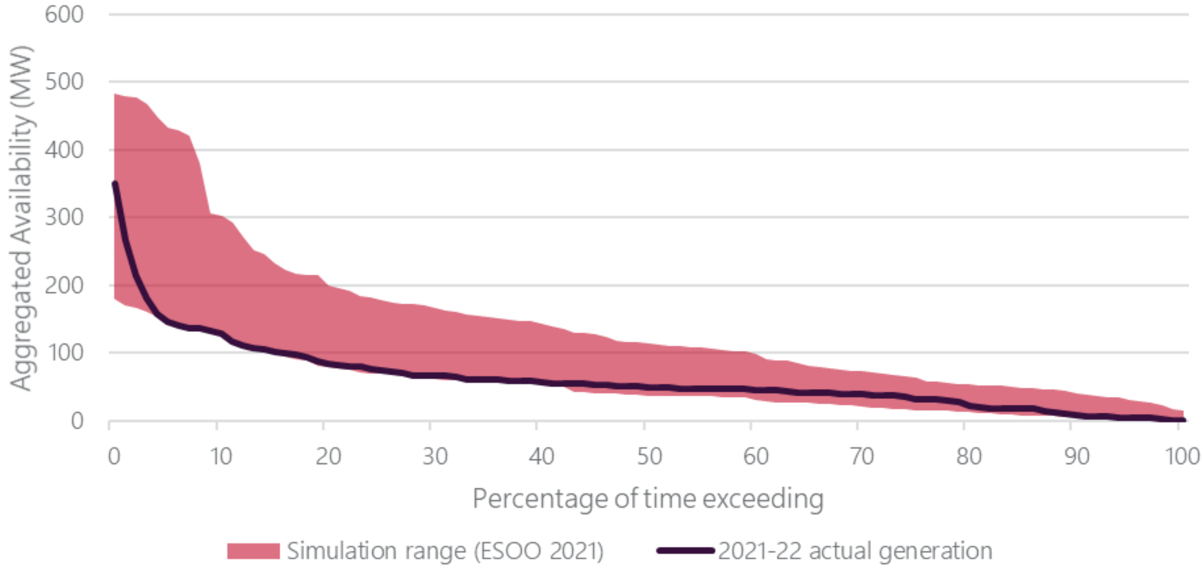
Figure 47 Queensland gas and liquids supply availability for the top 10 hottest days



Wind

Figure 48 shows wind generation supply for Queensland over the top 10 hottest days, comparing actual generation with the 2021 ESOO simulated availability range. The observed output was mostly in the lower end of the simulated range. The predominant reason seems to have been low wind speeds in periods of peak temperatures compared to the simulated weather conditions within the 2021 ESOO.

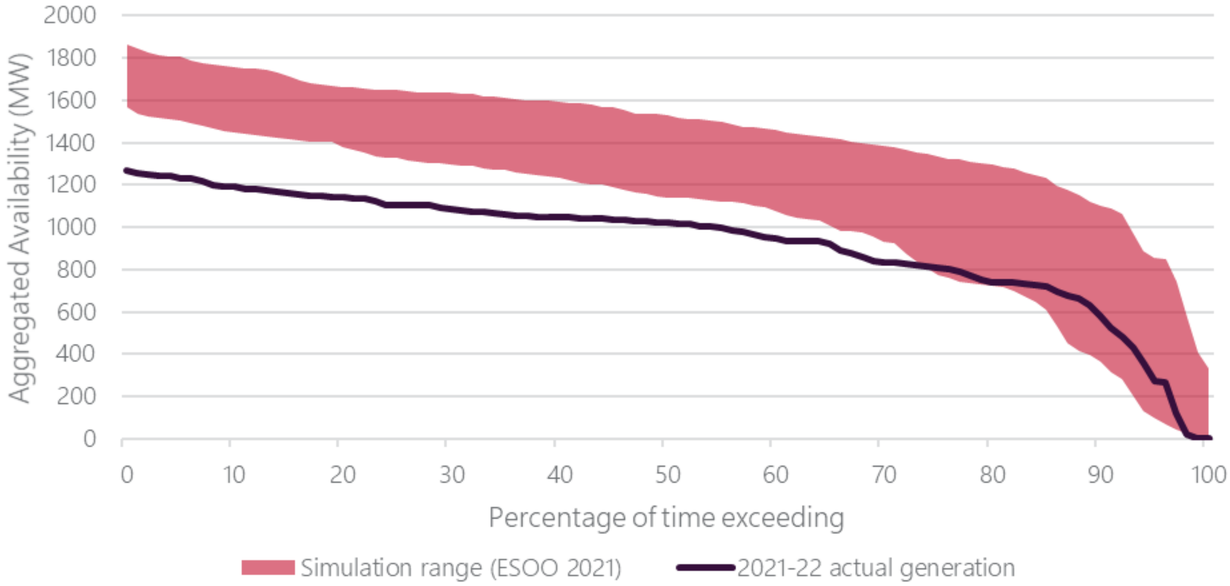
Figure 48 Queensland wind supply availability for the top 10 hottest days



Large-scale solar

Figure 49 shows the output of Queensland large-scale solar generators over the top 10 hottest days, comparing actual with 2021 ESOO simulated availability range. The actual generation was mostly below, or towards the lower end of, the simulated availability range, mostly due to late generator commissioning.

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



6.3 South Australia

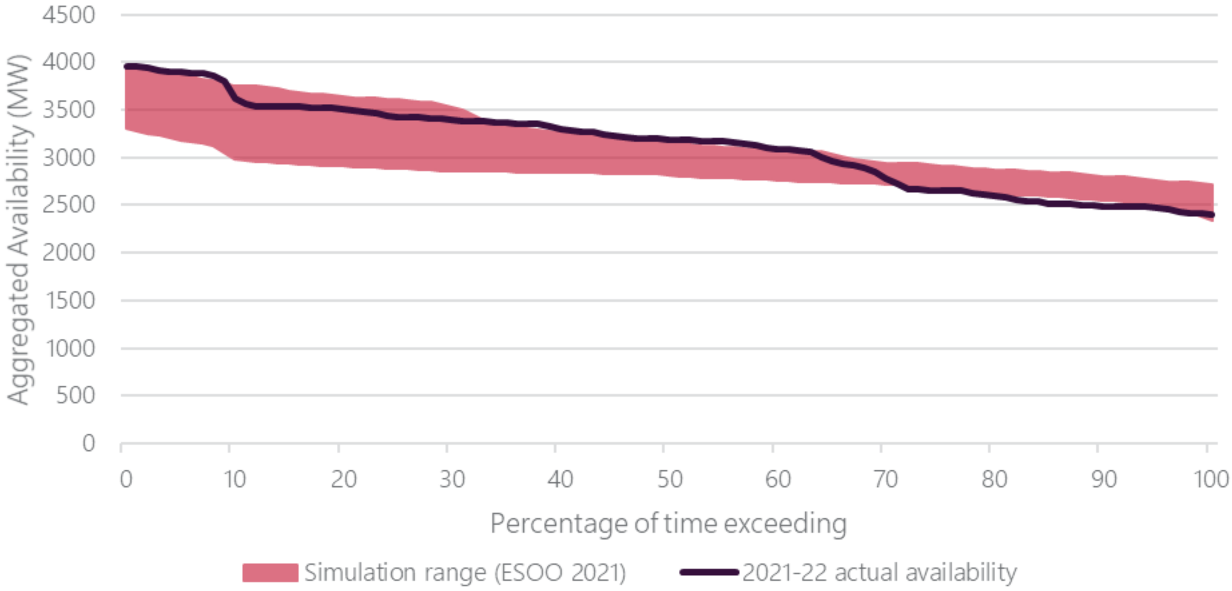
South Australian generation information, as reported by generator participants for the 2021 ESOO, is shown in Table 24 alongside actual generator characteristics in February 2022. Two new projects with longer than expected commissioning processes resulted in 49 MW less capacity than forecast.

Table 24 Forecast and actual generation count and capacity, February 2022

South Australia	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	30	2,443	30	2,492	-49	-2%
Non-VRE generation/storage	60	2,851	60	2,851	0	0%
All generation	90	5,295	90	5,344	-49	-1%

Figure 50 shows aggregate summer availability for South Australia during its highest temperature periods. Actual availability was mostly within and towards the upper end of the 2021 ESOO simulated range. This is attributed to greater wind capacity than expected and low levels of derating during a mild temperature year.

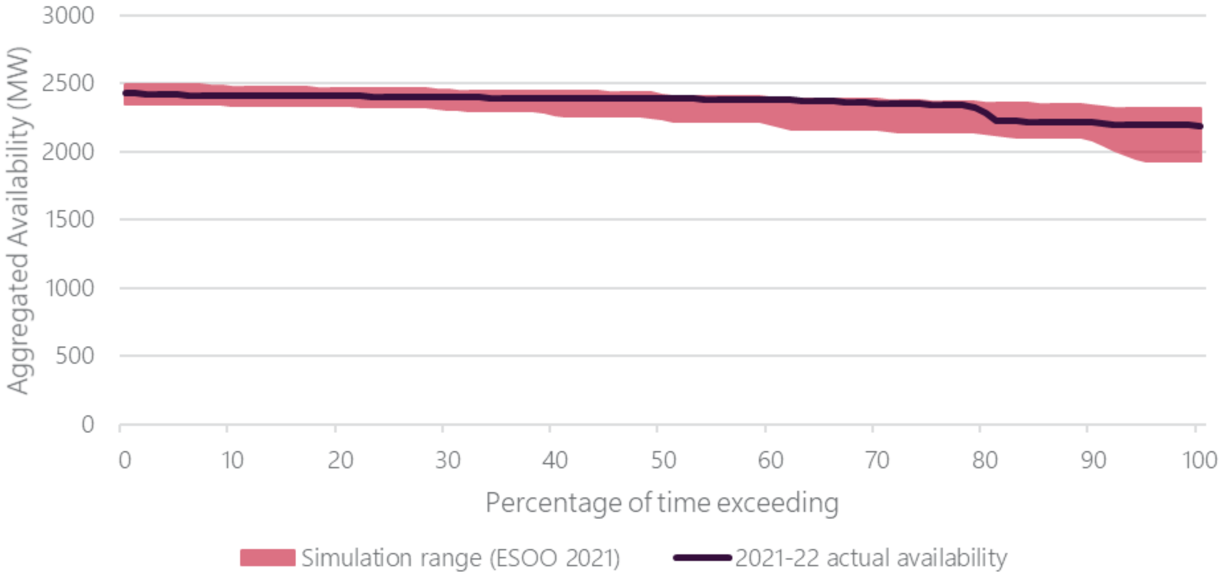
Figure 50 South Australia supply availability for the top 10 hottest days



Gas and liquids

Figure 51 shows that availability over the top 10 hottest days was mostly towards the upper end of the 2021 ESOO simulated availability. The mild temperatures observed should have resulted in actual availability above the top of the range, however actual availability was within the range. A relatively low rate of outages was observed during the top 10 hottest days.

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

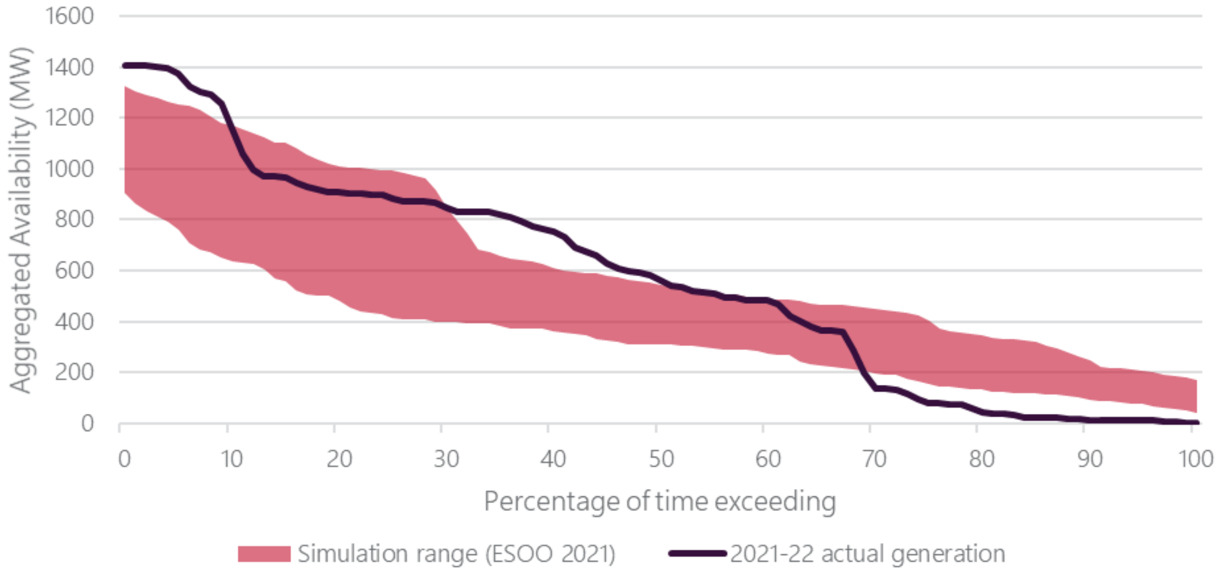


Wind

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 above the forecast range in the 2021 ESOO. The excursion from the simulated range is mainly due to a summer with mild temperatures in

2021-22. As per participant-provided information, many wind generators were modelled in the 2021 ESOO with a large capacity derating during peak temperatures. These high temperature events did not occur in 2021-22, causing the actual generation to be in the top end or above the simulated range.

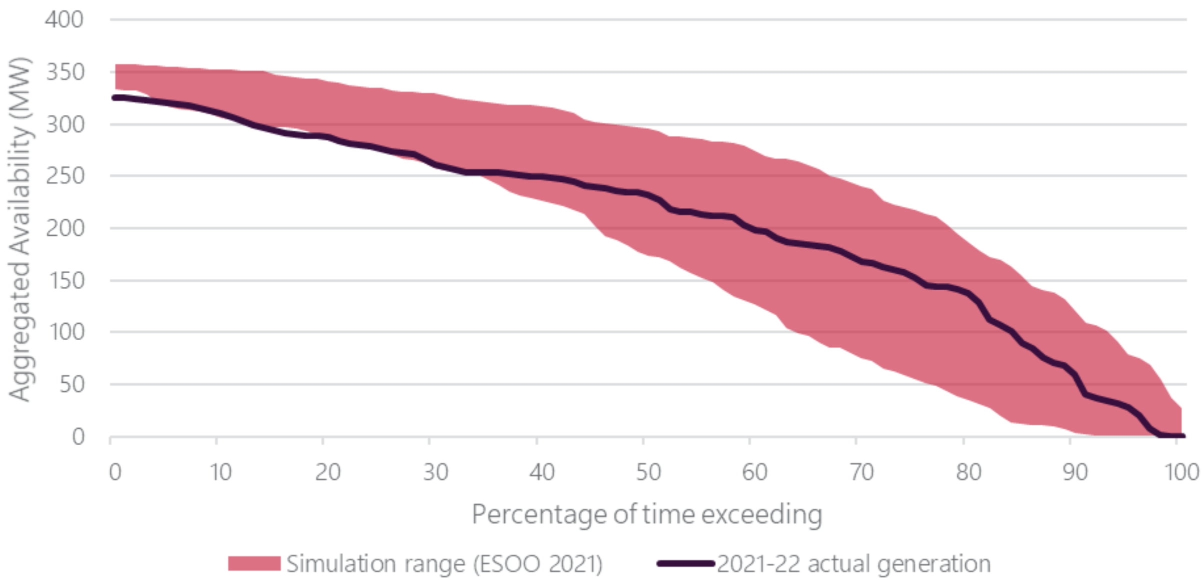
Figure 52 South Australia wind supply availability for the top 10 hottest days



Large-scale solar

Figure 53 shows the supply availability for South Australian large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated availability. In 2021-22, the observed availability was within the forecast range of the 2021 ESOO.

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



6.4 Tasmania

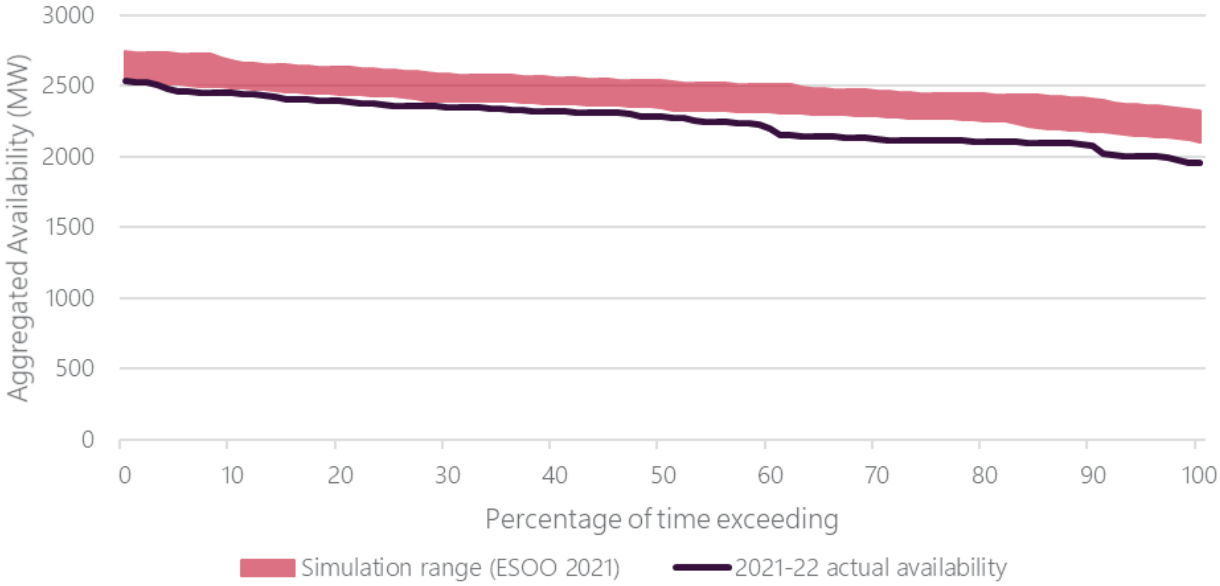
Table 25 shows how Tasmanian generation information was implemented in the 2021 ESOO, compared to actual generator characteristics for February 2022. In general, the assumed capacity in Tasmania in the 2021 ESOO was correct. While Tasmania is a winter-peaking region, the availability of surplus dispatchable hydro generation coupled with the availability of Basslink provides important support to the mainland during summer peak demand events.

Table 25 Forecast and actual generation count and capacity, February 2022

Tasmania	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	4	564	4	564	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 below the simulation range due to lower than expected hydro availability, as shown in the technology aggregate section below.

Figure 54 Tasmania supply availability for the top 10 hottest days

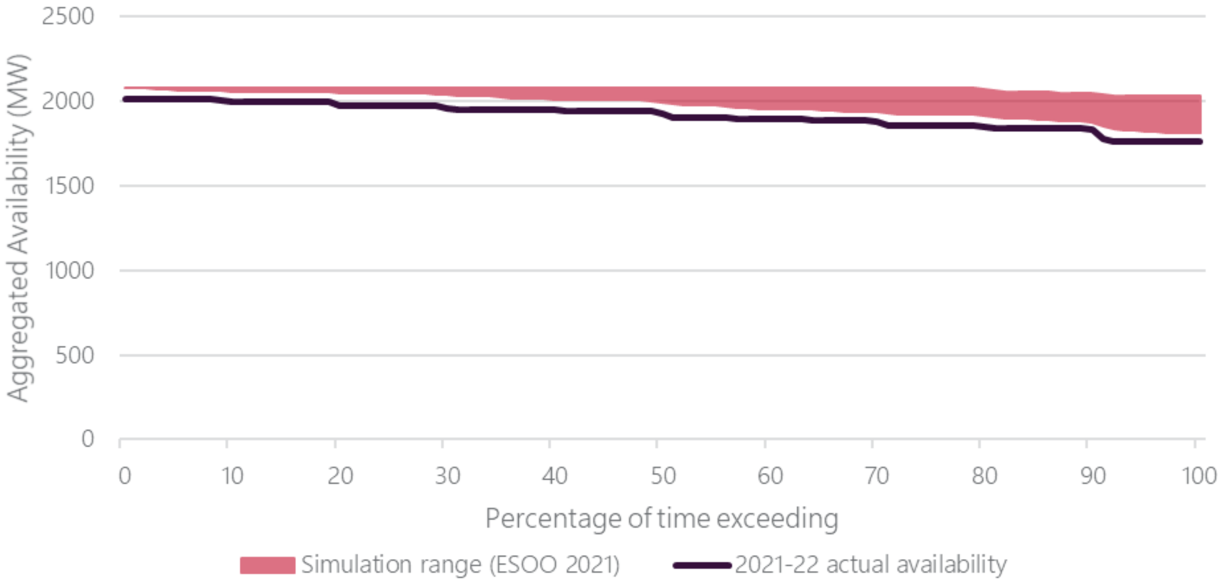


Hydro

Figure 55 shows the supply availability for Tasmanian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly below the lower end of the 2021 ESOO simulated range, due primarily to planned outages[27] of Tasmanian hydro generators during the observed period.

[27] Planned outages were not modelled in ESOO as per AEMO's Reliability Forecast Methodology.

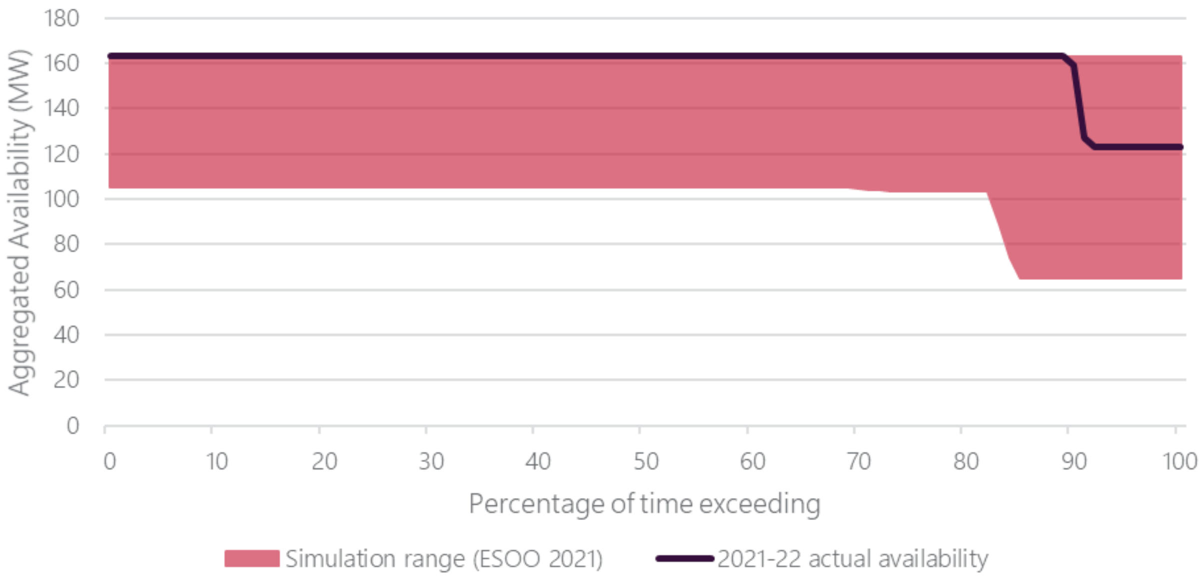
Figure 55 Tasmania hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 56 shows the supply availability for Tasmanian gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. The generators performed as expected in 2021-22, with the observed availability at the upper end of the 2021 ESOO simulated range.

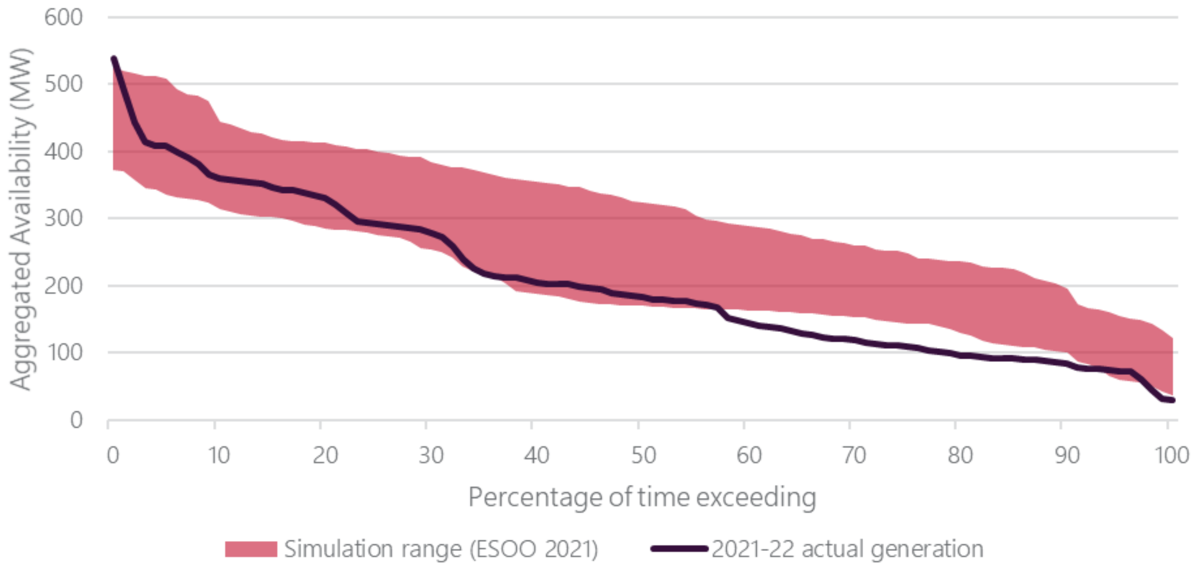
Figure 56 Tasmania gas and liquids supply availability for the top 10 hottest days



Wind

Figure 57 shows the output of Tasmanian wind generators over the top 10 hottest days, comparing actual generation with 2021 ESOO simulated availability. The observed output was spread across the forecast range, but being below the forecast range at times as well.

Figure 57 Tasmania wind output for the top 10 hottest days



6.5 Victoria

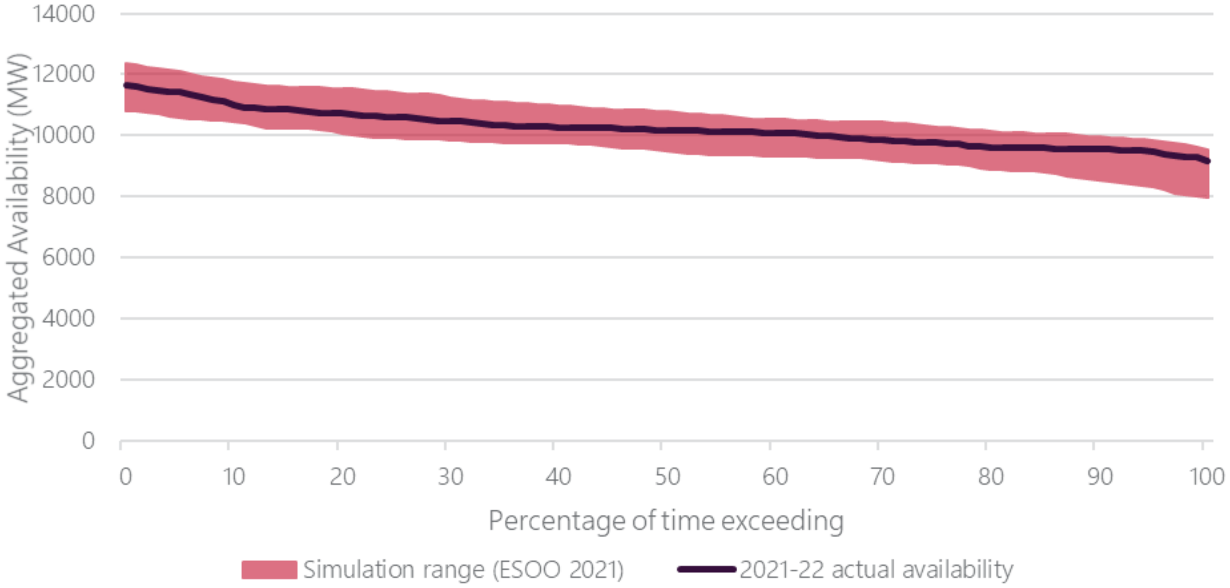
Victorian generation information, as reported by generator participants for the 2021 ESOO, is shown in Table 26 alongside actual generator characteristics for February 2022. In Victoria, numerous VRE projects were delayed compared to participant-provided information, resulting in substantially less generation availability than was forecast for summer 2021-22.

Table 26 Forecast and actual generation count and capacity, February 2022

Victoria	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	36	4,129	37	4,657	-528	-13%
Non-VRE generation/storage	68	9,548	68	9,548	0	0%
All generation	104	13,678	105	14,206	-528	-4%

Figure 58 shows aggregate summer availability for Victoria during its highest temperature periods. Actual availability was mostly within the 2021 ESOO simulated range. The higher than expected availability for brown coal, gas and liquids compensated for lower than expected renewable generation availability.

Figure 58 Victoria supply availability for the top 10 hottest days



Brown coal

Brown coal-fired generation in Victoria has experienced declining reliability over the last 10 years, as demonstrated through the equivalent full unplanned outage rate shown in Figure 59. The outage rate in 2021-22 was consistent with, but slightly higher than, the aggregate forecast included in the 2021 ESOO.

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

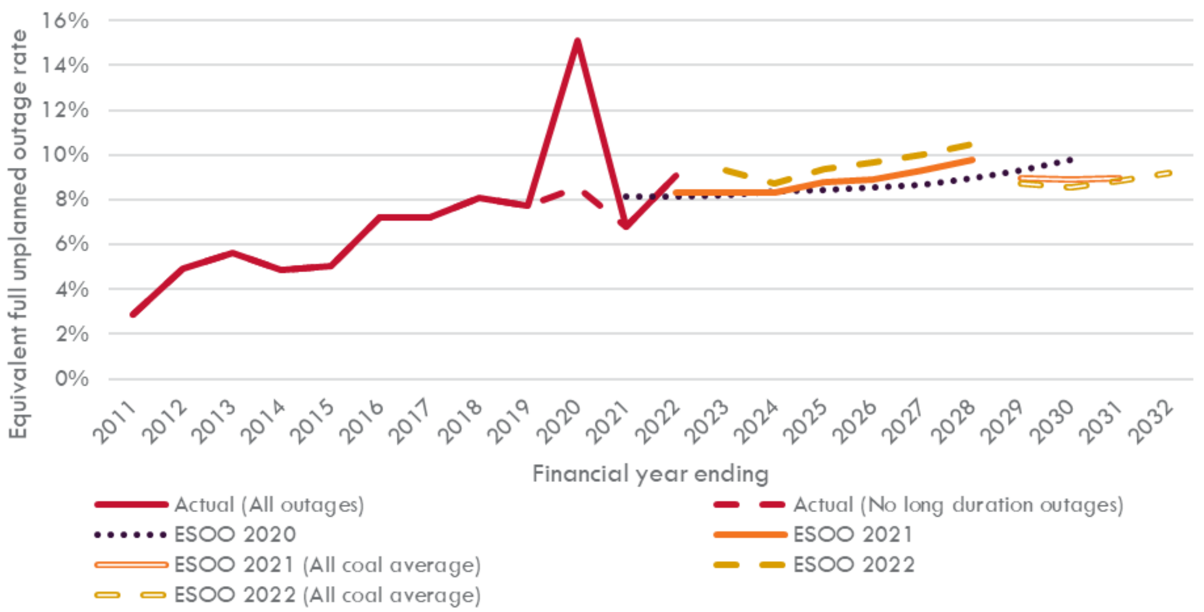
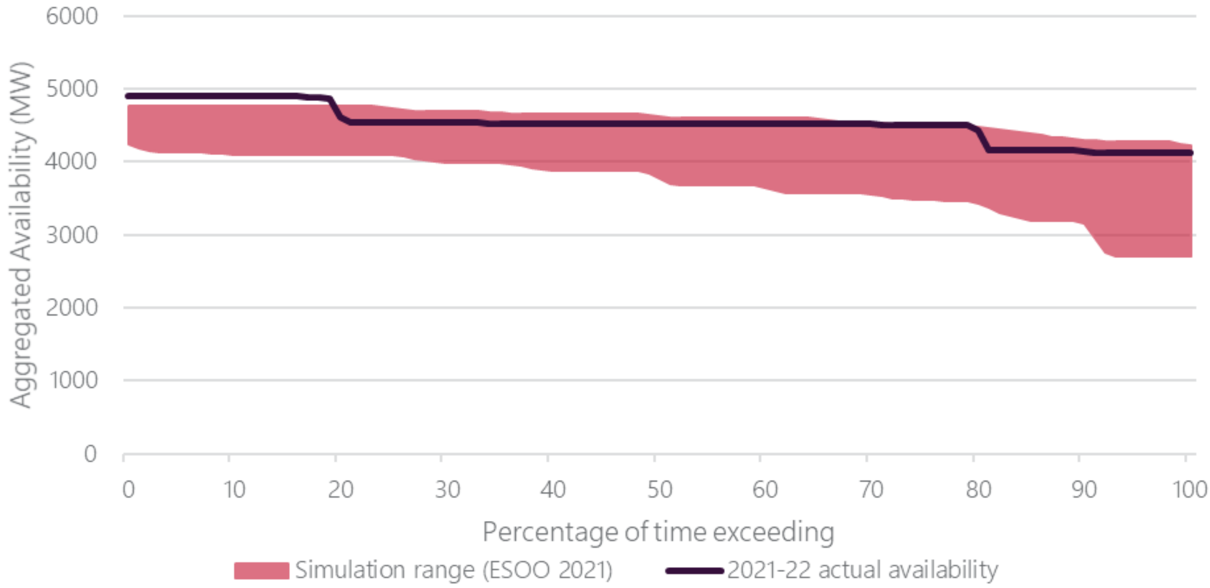


Figure 60 shows that availability over the top 10 hottest days for Victorian brown coal was above or within the range of simulated availability. The higher than forecast availability meets expectations, given the low levels of derating expected during a mild temperature year.

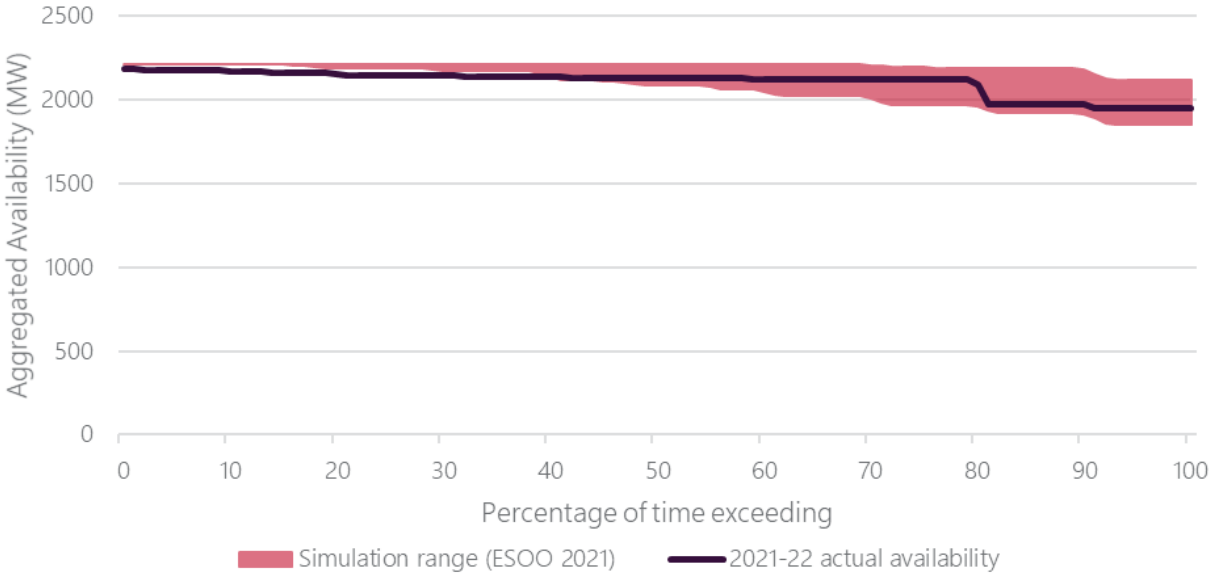
Figure 60 Victoria brown coal supply availability for the top 10 hottest days



Hydro

Figure 61 shows the supply availability for Victorian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly within the 2021 ESOO simulated range, as expected.

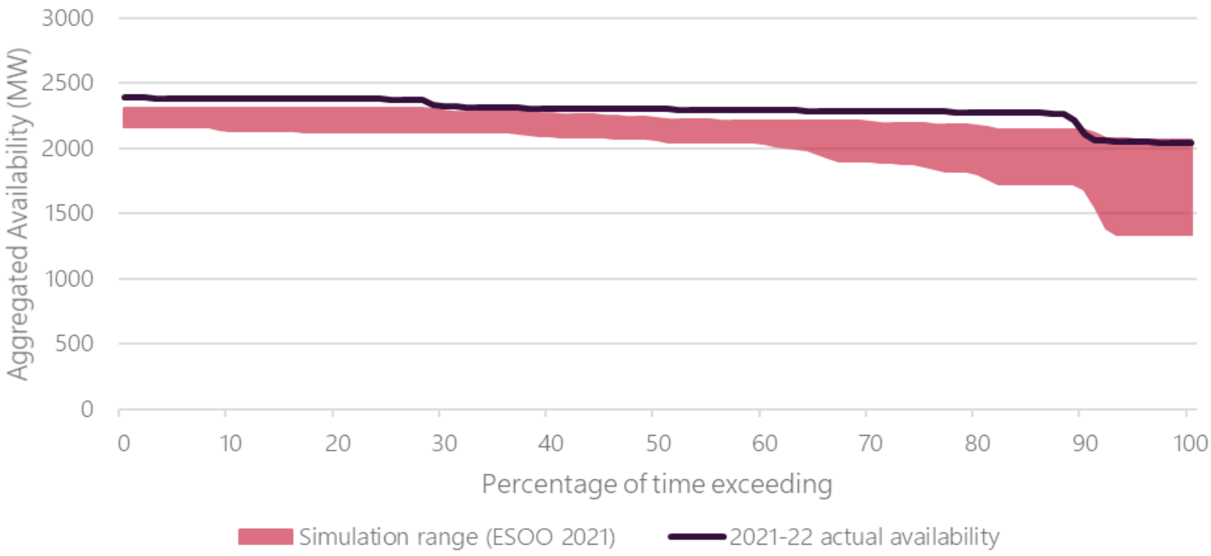
Figure 61 Victoria hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 62 shows that observed availability over the top 10 hottest days was entirely above the 2021 ESOO simulated availability. This was mainly due to low levels of temperature derating, as expected given the relatively low temperatures observed, and the lower than expected levels of forced outages.

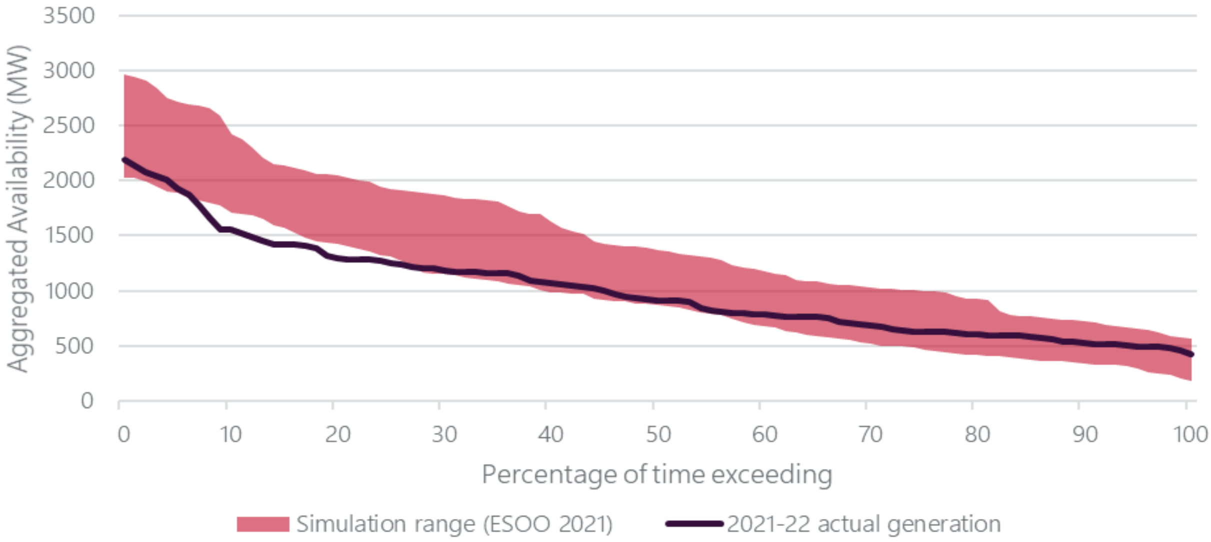
Figure 62 Victoria gas and liquids supply availability for the top 10 hottest days



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 below or towards the lower end of 2021 ESOO simulation range. The lower than expected output was predominantly due to delays in commissioning, compared to participant-provided information. These delays accounted for 479 MW less available capacity compared to what was forecast based on provided information.

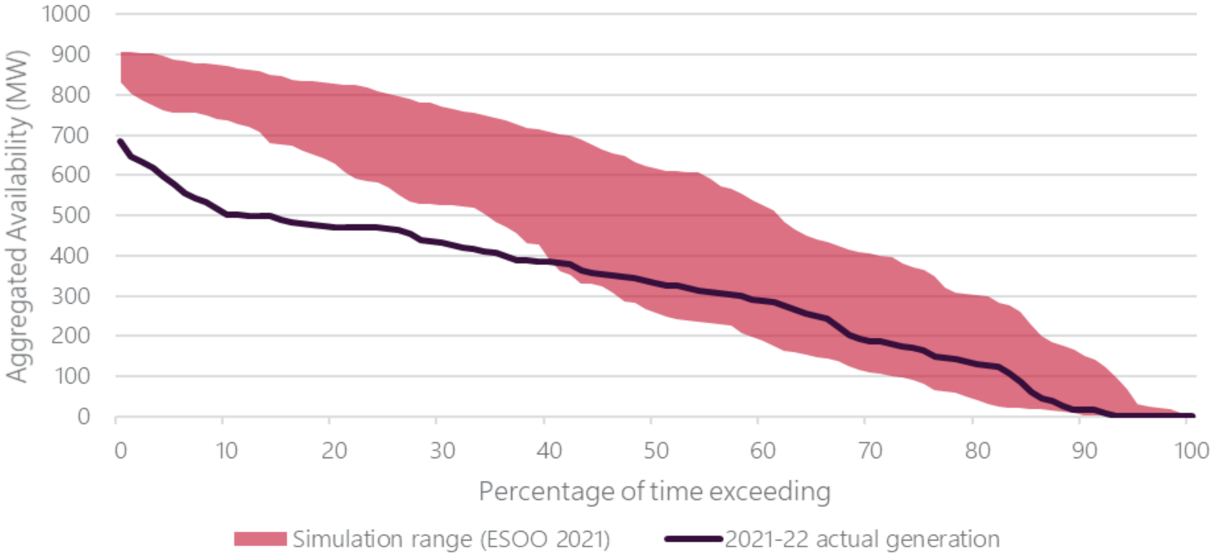
Figure 63 Victoria wind supply for the top 10 hottest days



Large-scale solar

Figure 64 shows aggregate output for Victorian large-scale solar generators over the top 10 hottest days, comparing actual generation with potential forecast availability range. The observed output was often below the 2021 ESOO simulation range. The lower than expected output seems predominantly due to outages 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 medium- to long-term reliability assessments (ESOO, EAAP and MT PASA) as well as the ISP. It 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 2021 ESOO was published along with the 2021 ESOO in August 2021; its accuracy is assessed in the following section.

Background

AEMO's DSP forecast methodology[28] estimates the demand response from LILs and any other market participants. The responses at a half-hourly level to various price triggers over the previous three years are aggregated to a regional response per event. The forecast aggregate response in a region for a particular trigger is then estimated as the 50th percentile of the recorded historical responses.

In addition to price response, additional load responses may operate during grid emergencies, typically when the system is in an actual lack of reserve (LOR2 or LOR3) state[29]. These programs operated by network service providers are generally only active in summer, causing the difference in forecast DSP between seasons.

Consistent with the DSP forecasting methodology, AEMO's 2021 DSP forecast excluded:

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

These items were excluded to avoid double-counting, as they are directly accounted for as a reduction in the maximum demand forecasts.

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

[29] 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.

AEMO's DSP forecast is used in processes to assess the need for reserves under the Reliability and Emergency Reserve Trader (RERT) framework[30], therefore AEMO has typically excluded all RERT resources in the DSP forecasts. However, it has been observed that sites that have been on the short-notice RERT panel, and not under a RERT contract, have been providing DSP responses voluntarily at times where RERT was not needed. AEMO's 2021 DSP forecast therefore included an additional DSP response from such sites, to reflect their likely contribution at times where RERT is not required. This additional response was only reflected in the forecast reliability response estimate.

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 2021-22 year compared to the 2021 forecast median response.
- Estimated DSP response during the regional maximum demand events against the forecast DSP reliability response.

DSP response by price trigger levels

The median price-driven DSP responses for different wholesale price triggers were assessed using 1 April 2021 to 31 March 2022 consumption data for the same list of DSP resources as the 2021 DSP forecast. This is compared to the forecast DSP responses that were based on consumption data from the three previous years (1 April 2018 to 31 March 2021). 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.

Comparison results are shown in Figure 65 through to Figure 69, and highlight that New South Wales and Queensland experienced the highest number of high price events, providing the greatest number of observations to contribute to the evaluation. The assessment was done for dates before the period of high prices in June 2022.

The 2021 forecasts for all regions except Tasmania include high estimations for Wholesale Demand Response (WDR)[31]. As of June 2022, WDR had only been dispatched in New South Wales and Victoria, and in lower quantities than forecast amounts compared to the 2021 DSP forecast. Partly because of the higher than actual WDR forecasts all regions except Queensland have forecast DSP higher than actual DSP.

In conclusion:

- Median observed actual responses in New South Wales were lower than forecast responses for all price triggers including and above $500/megawatt hour (MWh). For prices between $300/MWh and $500/MWh, the actual responses were higher than forecast. For the large difference between forecast and actual response above $5,000/MWh the fewer (fewer than 10) number of high price events should be noted, which means the

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

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

estimated actual response may not be statistically significant. Additionally, the 2021 forecast includes a higher than eventuated inclusion of WDR, which contributes to the higher than actual forecasts.

- In Queensland, a high number of price events across all price triggers contributes to Queensland having the most closely aligned actual and forecast DSP. For prices up to but not including $5,000/MWh, the actual response is slightly higher than the forecast response. For prices above $5,000/MWh, the estimated actual response is higher than the forecast response.
- For South Australia, the median values of the observed DSP responses are well under the forecast for prices above $500/MWh. For prices between $300/MWh and $500/MWh, the forecast and actual DSP are well aligned. Note that the estimated DSP excludes some very flexible loads in the region that respond daily to even minor price differences. The high frequency of responses from these very flexible loads means that the demand forecast already accounts for it, because historical load at these sites at time of peak demand generally has been low.
- Median forecast responses in Tasmania exceeded the actual responses, for all price triggers. There were fewer than 10 observations available for price triggers above $500/MWh, and there were no periods where the price was above $2,500/MWh.
- For Victoria, there were insufficient (fewer than 10) high price periods above $2,500 to do any validation of outcomes. For prices between $300/MWh and $500/MWh, the actual DSP was higher than forecast, and between $500/MWh and $1,000/MWh, the forecast was much higher than actual response.

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

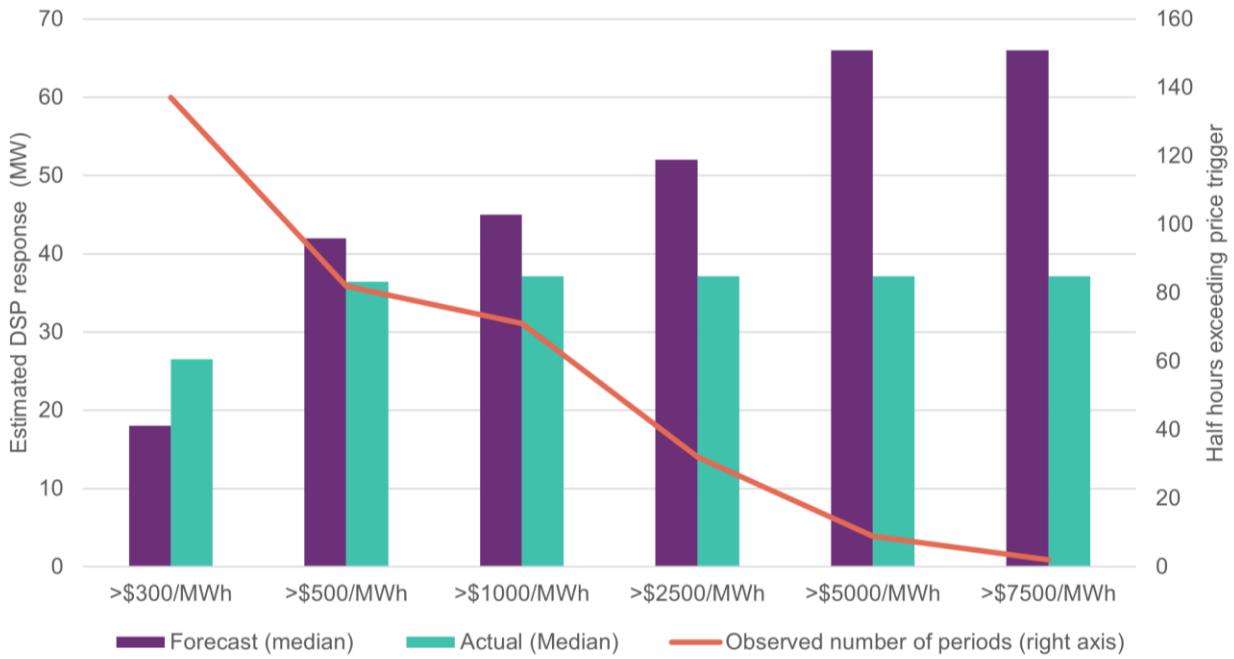


Figure 66 Evaluation of actual compared to forecast price-driven DSP in Queensland

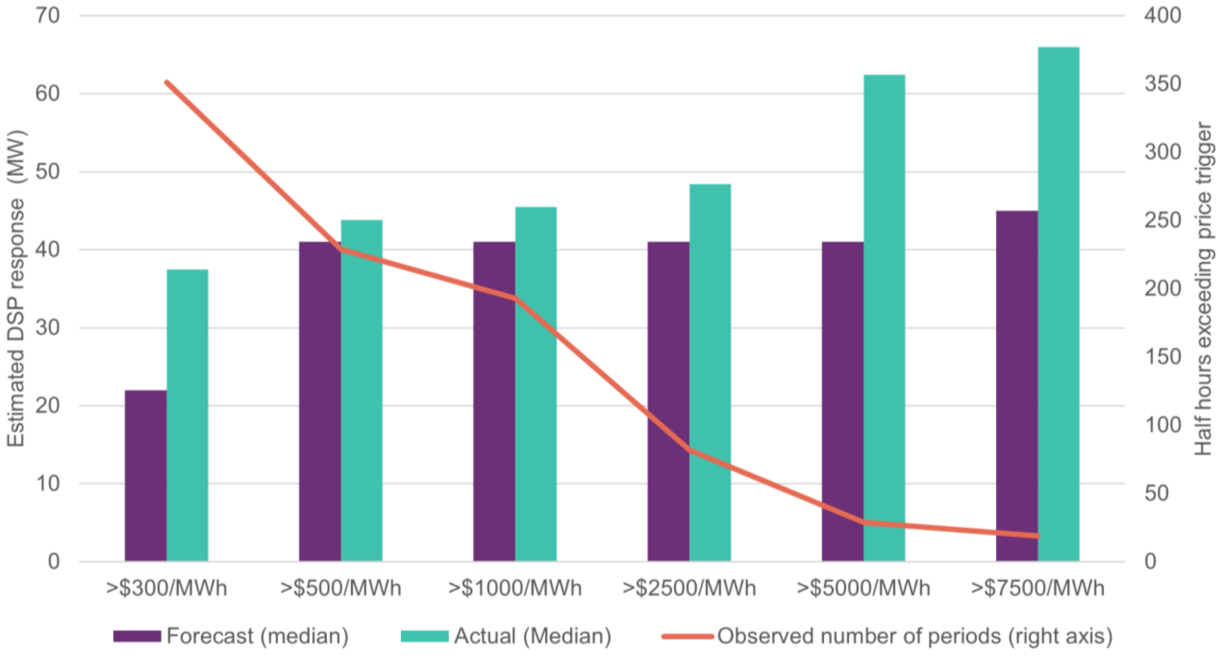


Figure 67 Evaluation of actual compared to forecast price-driven DSP in South Australia

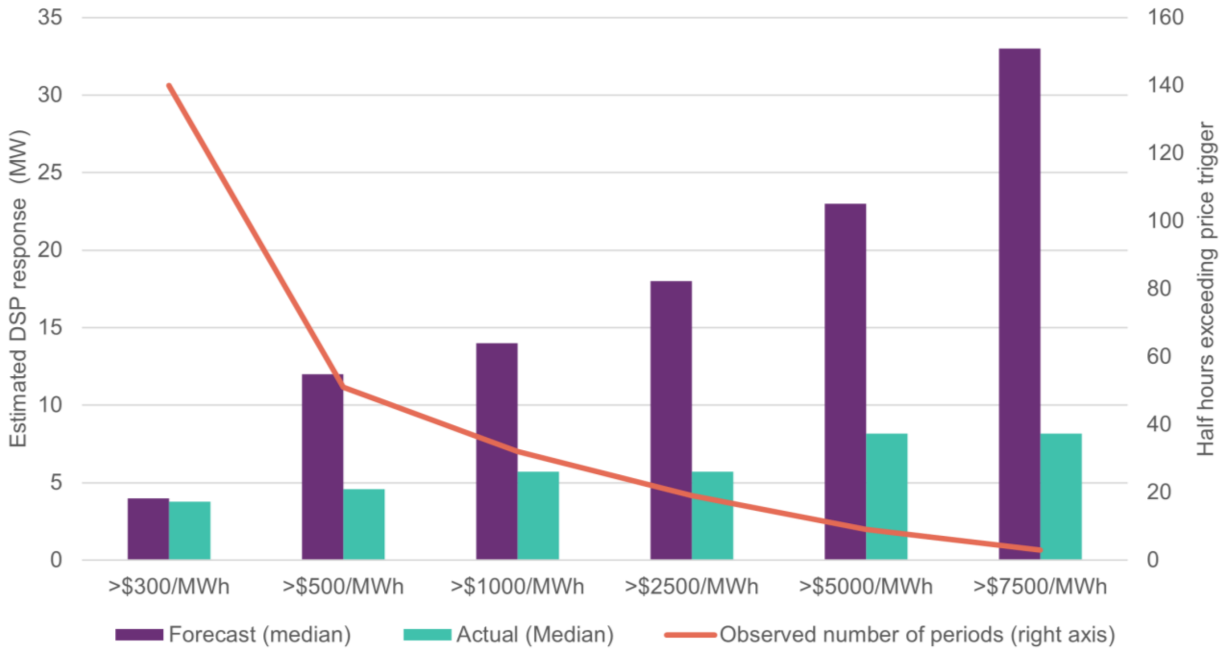


Figure 68 Evaluation of actual compared to forecast price-driven DSP in Tasmania

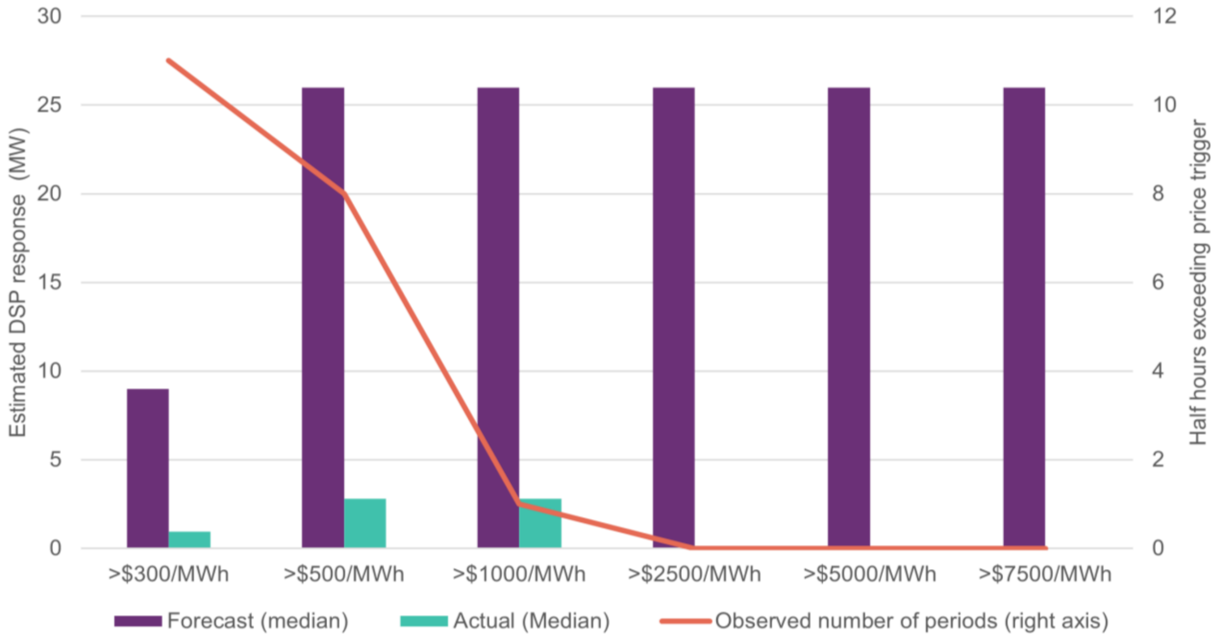
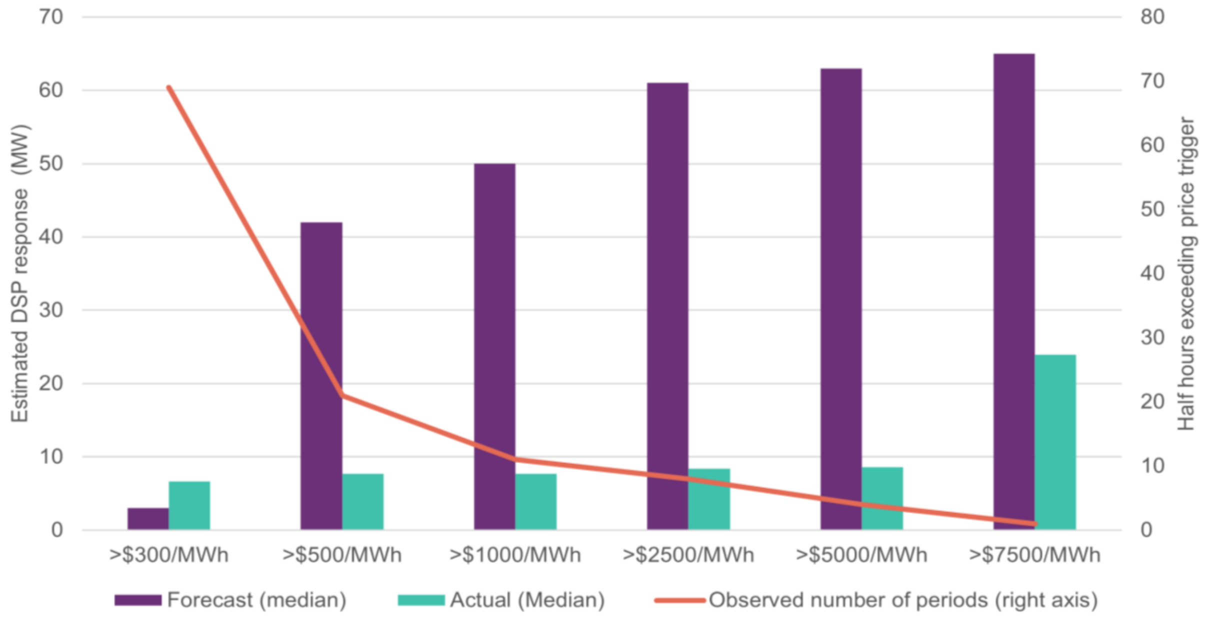


Figure 69 Evaluation of actual compared to forecast price-driven DSP in Victoria



DSP response during reliability events

The reliability response from the 2021 forecast is shown in Table 27. It represents the forecast DSP where the system is in an actual LOR2 or LOR3 state.

Table 27 Forecast reliability response in MW during LOR2 or LOR3 during 2021-22 summer and 2022 winter

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Summer	308	104	33	26	212
Winter	308	45	33	26	187

For comparison, AEMO has assessed the amount of DSP for the peak demand days of the 2021-22 year:

- **New South Wales** – the region had its summer maximum demand on 1 February 2022. Prices were relatively low on that day and no DSP was observed. The winter maximum demand was reached on 19 July 2022. Prices were above $500/MWh but given the wholesale prices were generally elevated across the winter; this was not sufficient to drive an observable price response.
- **Queensland** – the maximum demand day in summer was reached on 8 March 2022. Prices were very high, though having dropped slightly from the Market Price Cap the previous half hour. AEMO's assessment indicates 103 MW of price-responsive DSP, and no network DSP. The winter maximum demand was observed on 4 July 2023, which was a new all-time high winter maximum demand record for the region. Prices were high, above $1,000/MWh (having come down from reaching the market price cap an hour earlier). Demand dropped by approximately 100 MW when the prices increased in the afternoon, but remained at that lower level for the remainder of the day and well into the following day, even as prices came down. It was potentially price-driven DSP, but AEMO cannot rule out other explanations and has accordingly not made any adjustments to the observed maximum demand (as per Table 15).
- **South Australia** – the region had its summer 2021-22 maximum demand in the evening of 11 January 2022. Due to a very mild summer, observed demand was less than the forecast 90% POE demand and prices during the evening were generally low, with a brief spike around the peak. No DSP was observed on 11 January 2022. The winter maximum demand was reached on 22 August 2022. Demand was only about 80 MW less than the summer maximum demand, but prices remained below the price triggers and no DSP was observed.
- **Tasmania** – being winter peaking, Tasmania had its annual maximum demand on 7 June 2022. There were no LOR conditions, and while prices were just above the $300/MWh trigger, it did not result in any observable price-driven DSP response.
- **Victoria** – the very mild summer was also felt in Victoria, and its maximum demand was reached on 27 January 2022, only just above the forecast 90% POE demand. Prices remained low and no network DSP was called on the day. The winter maximum was reached on 7 June 2022 and was the highest observed since 2011. While prices were above the $300/MWh trigger, it stayed below the $500/MWh trigger, and the elevated prices observed for long periods during the winter meant that no DSP could be observed for that period specifically.

DSP forecast conclusions

Across all high price periods, actual estimated DSP was generally lower than forecast, apart from Queensland, where actuals were above forecast values. For New South Wales and Victoria, that was partly because of less WDR than forecast. In the southern states, the number of periods with prices above the higher price triggers was rather low, meaning that the estimated DSP response may not be statistically significant, and it is therefore not possible to draw any strong conclusions from the observations.

Of the five NEM regions, only Queensland had maximum demand events where prices had reached the upper price triggers. The observed DSP during summer aligned well with the forecast on that day, while there was some evidence of DSP during winter as well, although it cannot be ruled out that the observed reduction in demand was driven by other factors.

AEMO will continue to monitor DSP trends including any growth in WDR.

7 Reliability forecasts

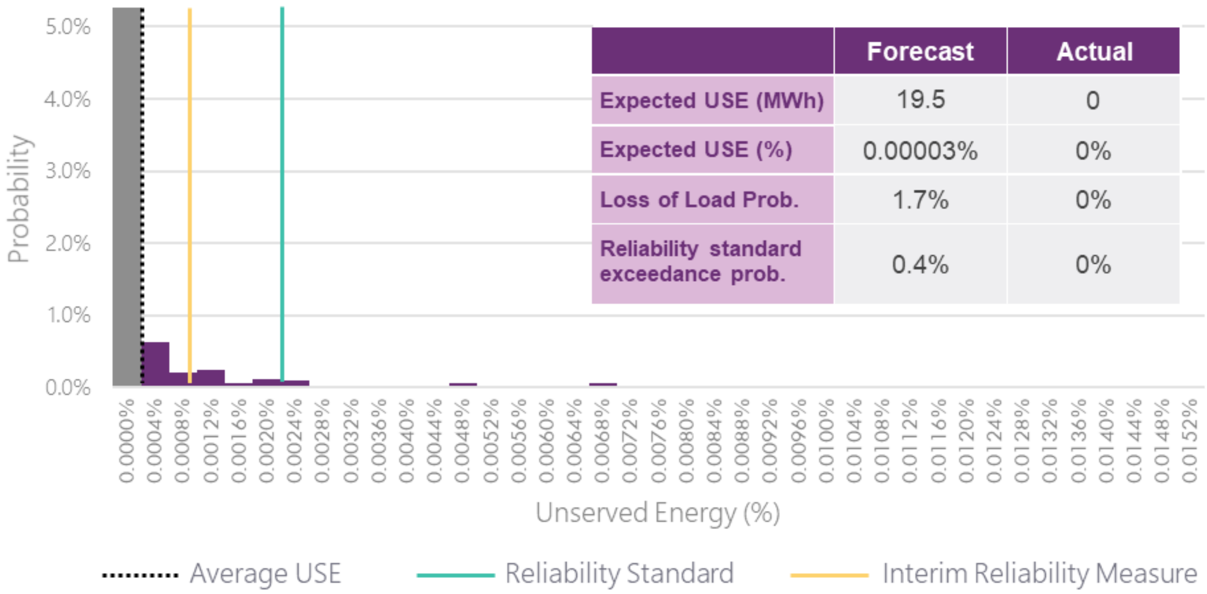
AEMO forecasts and reports on scarcity risk of generation supply availability, DSP, and inter-regional transmission capability, relative to demand. This forecast of supply scarcity risk is an implementation of the reliability standard[32] and Interim Reliability Measure (IRM)[33], with the expectation that the market will respond to avoid USE occurring. Further, in operational and planning timeframes, AEMO uses RERT and other operational mechanisms to avoid USE events where possible. No USE events occurred in 2021-22 in any region.

Reliability forecasts are not presented for the purposes of assessing forecast accuracy, but rather 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 in the 2021 ESOO. The probability of any loss of load was assessed at 1.7%.

Figure 70 New South Wales USE forecast distribution for 2021-22 summer



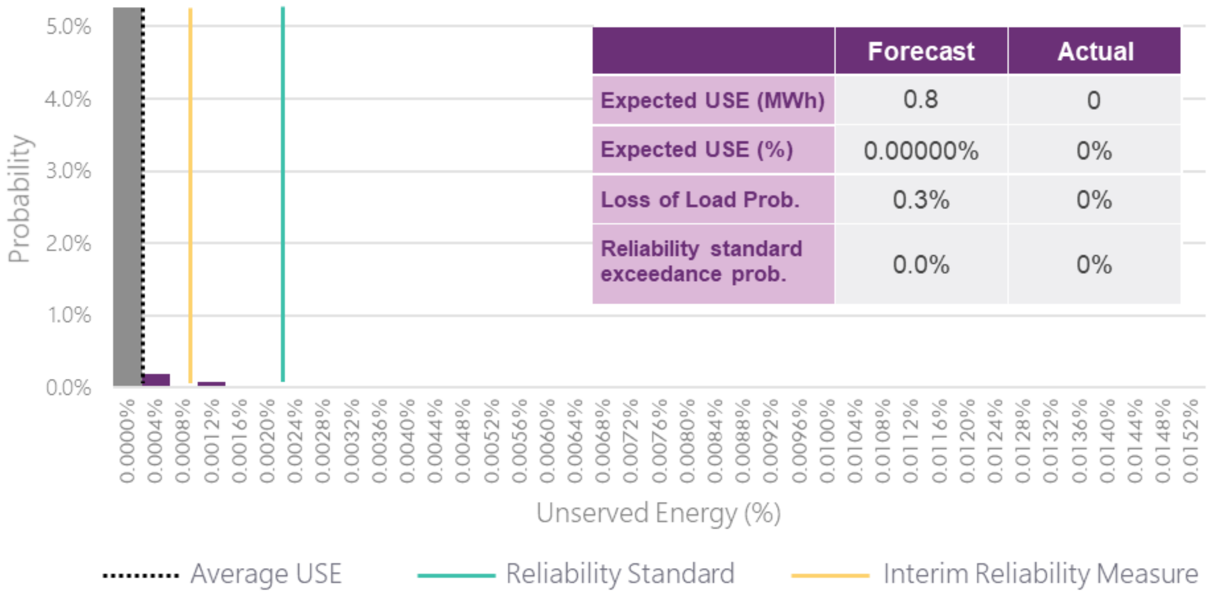
[32] The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

[33] The IRM is an interim reliability measure, agreed to at the March 2020 COAG Energy Council and introduced by the National Electricity Rules (Interim Reliability Measure) Rule 2020 published in November 2020, that sets a maximum expected USE of no more than 0.0006% in any region in any financial year. It supplements the existing reliability standard for a limited period of time and allows AEMO to procure reserves if the ESOO reports that this measure is expected to be exceeded. The National Electricity Rules (RRO trigger) Rule 2020 also allows the RRO to be triggered by a forecast exceedance of the IRM. AEMO prepared the reliability forecast against the existing 0.002% reliability standard and against the IRM of 0.0006%. For more information, see the ESB website at http://www.coagenergycouncil.gov.au/reliability-and-security-measures/interim-reliability-measures.

7.2 Queensland

Figure 71 shows the forecast distribution of USE in Queensland in the 2021 ESOO. The distribution shows that very minimal USE events were forecast by the simulations.

Figure 71 Queensland USE forecast distribution for 2021-22 summer

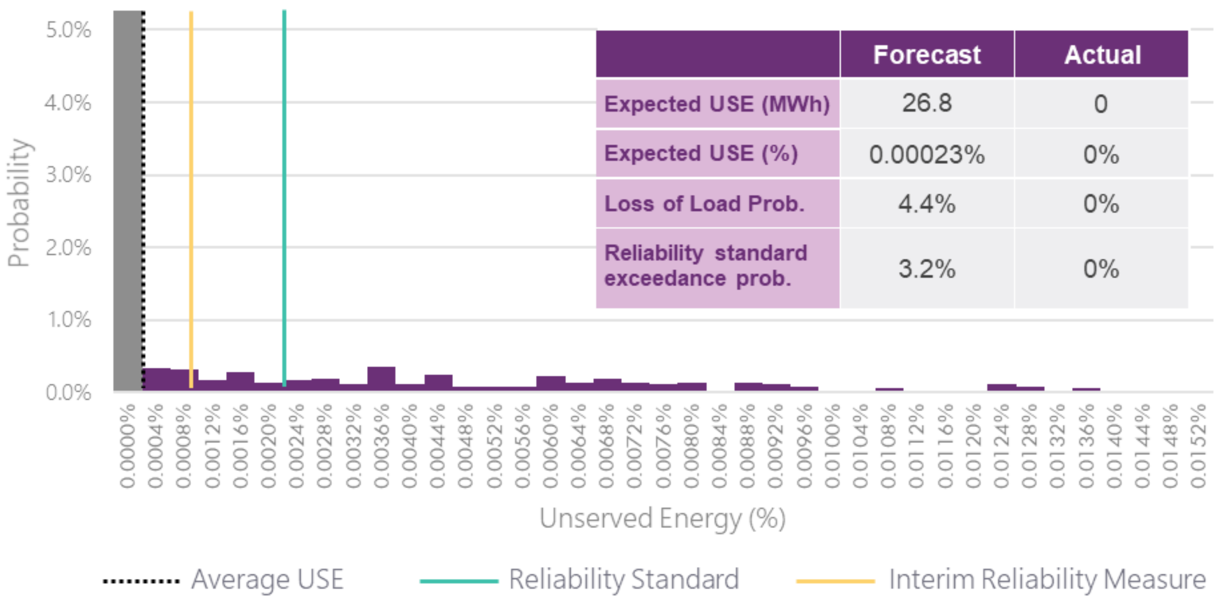


	Forecast	Actual
Expected USE (MWh)	0.8	0
Expected USE (%)	0.00000%	0%
Loss of Load Prob.	0.3%	0%
Reliability standard exceedance prob.	0.0%	0%

7.3 South Australia

Figure 72 shows the forecast distribution of USE in South Australia in the 2021 ESOO. It shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 4.4%.

Figure 72 South Australia USE forecast distribution for 2021-22 summer

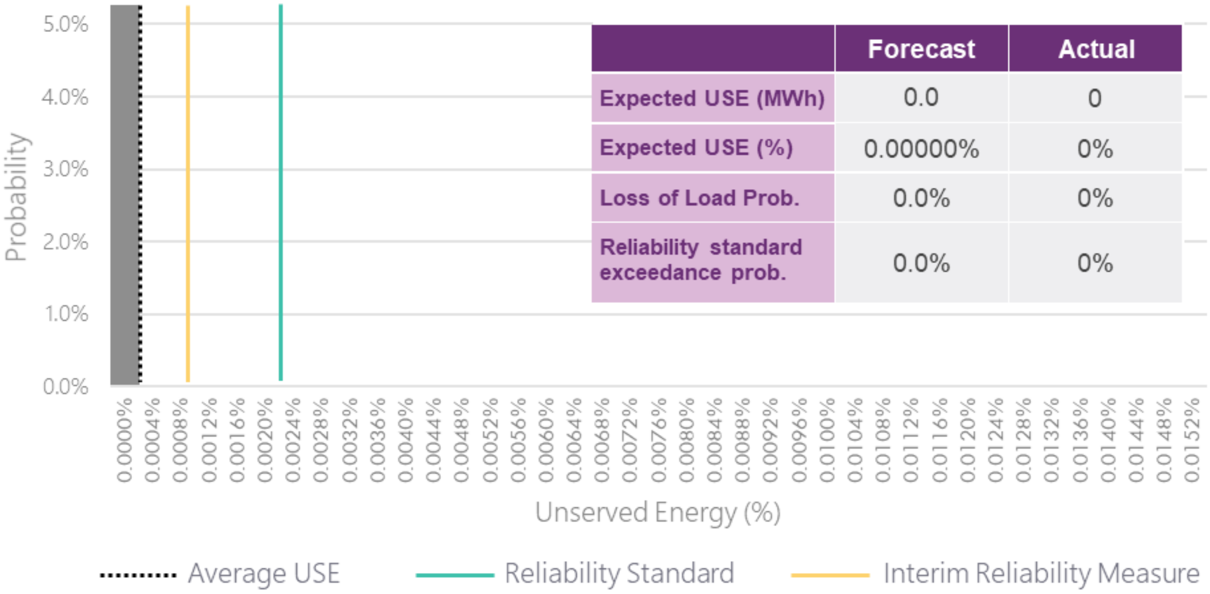


	Forecast	Actual
Expected USE (MWh)	26.8	0
Expected USE (%)	0.00023%	0%
Loss of Load Prob.	4.4%	0%
Reliability standard exceedance prob.	3.2%	0%

7.4 Tasmania

Figure 73 shows the forecast distribution of USE in Tasmania in the 2021 ESOO. The distribution shows that no USE events were forecast by the simulations.

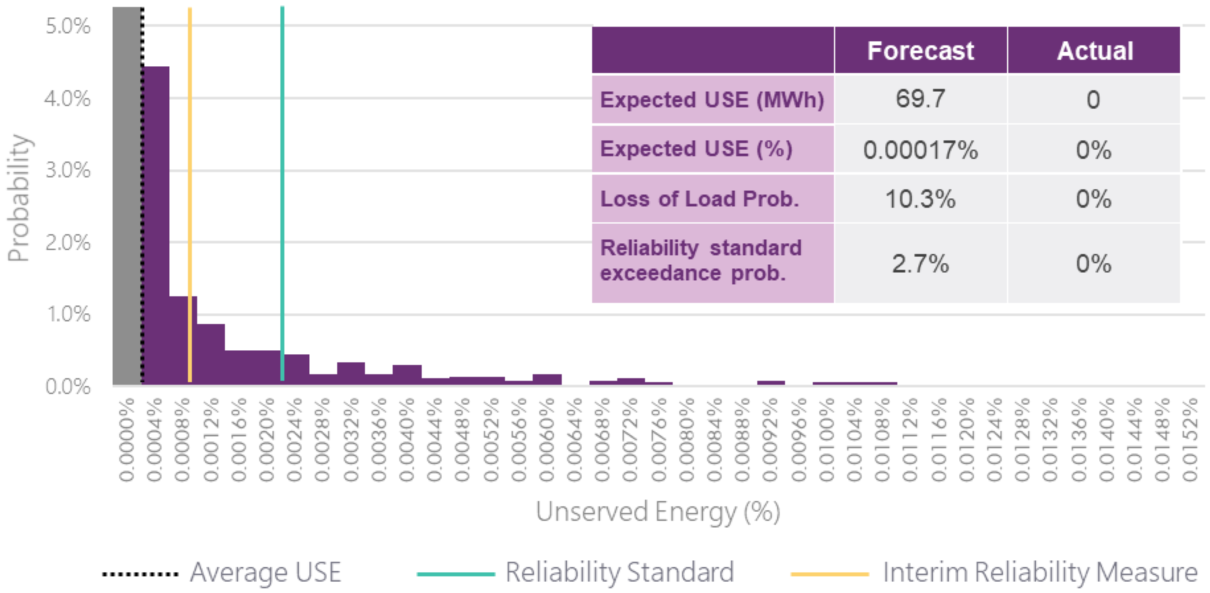
Figure 73 Tasmania USE forecast distribution for 2021-22 summer



7.5 Victoria

Figure 74 shows the forecast distribution of USE in Victoria in the 2021 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 10.3%.

Figure 74 Victoria USE forecast distribution for 2021-22 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 demonstrate forecast accuracy performance and provide transparency around areas where AEMO is focusing efforts to improve 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** – minor updates to forecasting models, data or assumptions to address identified forecast accuracy issues. While the *Forecast Accuracy Report* is prepared annually, forecast performance is tracked more regularly by AEMO and may drive other minor improvements to how inputs are sourced or models are calibrated 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. The RRO required a number of changes to AEMO's forecasting process. Similarly, the Actionable ISP has increased the focus on intra-regional transmission requirements over previous AEMO planning publications, driving a need for a higher spatial resolution to assess intra-regional power system needs.

AEMO's 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 2021 forecasts summarised in Section 8.1. Section 8.2 summarises the priority initiatives included in AEMO's 2022 Forecast Improvement Plan, while Section 8.3 outlines the research initiatives proposed to assist with the delivery of the 2022 Forecast Improvement Plan and future initiatives.

Appendix A1 lists the improvements presented in the 2021 Forecast Improvement Plan, along with a summary of the implementation status of each of these initiatives, and any other improvements implemented for the 2022 ESOO.

Consistent with the Forecasting Best Practice Guidelines, the minor improvements proposed in this Forecast Improvement Plan are being consulted on using a single stage consultation (as initiated by this document), while more material changes to the Forecasting Approach, for example due to regulatory changes, will use the forecasting best practice consultation procedures.

8.1 2021 forecasts – summary of findings

While forecast models have generally performed well, a number of potential forecasting improvements have been identified – in particular for the winter maximum demand, annual minimum demand and annual consumption forecasts. These issues are summarised below:

- The observed actual **winter maximum demand outcomes** were above the 10% POE forecast for two regions, Queensland and Victoria. This is consistent with what has been seen for other regions, in particular South Australia, in recent years and highlights that there is a need for further improvements to how the starting points of the forecast POE distributions are set (although for Queensland, the outcome is explained by very cold weather which also extended unusually far north into the state). Also, while the issues to date have generally related to actuals being above expectations, another region, Tasmania, had its actual winter maximum demand below the 90% POE forecast. This can be explained by lower than forecast demand from LILs. The forecast approach for LILs in Tasmania during maximum demand conditions should be reviewed.
- For **annual minimum demand**, three regions showed good alignment, while New South Wales' actual minimum demand was lower than the forecast distribution, and Queensland's actual minimum demand was above the forecast. With rooftop PV installations showing good alignment this year, the forecast model requires review. As the percentage error is on either side, with the actual above the forecast range in one region and under in the other, it may not be related to any single missing factor in the modelling, but this will be reviewed as well.
- **Annual consumption** had significant differences for three regions, New South Wales, Queensland and Victoria. This was identified through AEMO's ongoing monitoring process during the year and improved in the *Update to the 2021 ESOO* in April 2022. The amendments reduced the observed percentage errors, but some unexplained residuals remain, particularly in the LIL and ONSG component forecasts in some regions. There are potential benefits from better analysis of observed variances of consumption by customer segment. This will enable further analysis of the residual variance in the consumption forecast, and build a better understanding of how these sectors are responding to economic conditions, decarbonisation challenges, and uptake and use of emerging technologies.

On the supply side, including the consideration of DSP, discrepancies were noted for several supply forecasting inputs. Separate to the Forecast Improvement Plan, AEMO is consulting on reliability forecast guidelines and methodologies between October 2022 and April 2023[34], and has proposed methodology changes for several key topics. Observations relevant to this accuracy assessment include:

[34] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

- **Generator commissioning** did not match participant-provided information, resulting in 920 MW less capacity available in 2021-22 than was forecast. AEMO proposes to review the methodology for the treatment of new assets in forecasts.
- **Planned and unplanned outages** impacted supply availability for numerous regions and technologies. Given the mild temperatures observed, and the methodology used by AEMO regarding high temperature de-rating, actual supply availability in all regions should have been above simulation bounds. Planned and unplanned outages impacted supply availability in some of these cases, and hence AEMO proposes to review the methodology for collecting and forecasting random outage parameters.

8.2 Forecast improvement priorities for 2022

AEMO proposes the following priority initiatives, guided by the observations in the *Forecast Accuracy Report* listed above, for its 2022 Forecast Improvement Plan:

1. Improve renewable generation and demand traces, including the quantity used, and their shape.
2. Improve visibility of sectoral consumption.
3. Review forecast maximum and minimum distribution of the initial year of the forecast horizon.
4. Review large industrial load and other non-scheduled generation forecast components.
5. Monitor data availability of uptake and usage of emerging technologies.
6. Monitor demand side participation.

As noted above, the initiatives have been classified into review, improve or monitor:

- The two **improve** actions have confirmed gaps exist and will seek to address these. In both cases, the work is an extension of investigations initiated as result of the 2021 Forecast Improvement Plan and are longer term programs that are likely to continue into future Forecast Improvement Plans as well.
- The two **review** actions are meant to investigate the nature of the issues observed – first, to confirm that corrective actions are required, and if so to identify a suitable solution for the 2023 ESOO forecast.
- **Monitoring** is used where assumptions are known to be at risk of changing from historical outcomes, to ensure extra care is taken to validate assumptions ahead of the next ESOO. It is also used to track emerging technologies, where data streams for tracking are yet to be built.

The six initiatives are explained in the following sections.

AEMO will also produce connection point forecasts in regions where it does not duplicate work done otherwise, which have not been produced since 2020. This may lead to improved regional forecasts through the additional information collected through this process, and particularly may improve sub-regional forecasts, for instance for the ISP.

8.2.1 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, where the 2021 ESOO used 11 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 5,000 MW of additional large-scale wind and solar projects committed as of August 2022, while almost 5,000 MW of thermal capacity has announced withdrawal[35]. 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 through using more historical years (if the quality of the data is adequate) or alternatively, 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, and solar insolation at half-hourly resolution. Wind and solar generation profiles will be created based on this data, noting the new wind generation profiles also account for temperature cut-offs in generation.

Using more weather years will make it more likely the simulations account for 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 2023 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.

8.2.2 Improved visibility of sectoral consumption

AEMO commenced analysis of sectoral consumption as part of the 2021 Forecast Improvement Plan, supported by research undertaken through the National Energy Analytics Research (NEAR) program to improve classification of meter data. AEMO plans 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. This will help to identify opportunities for data and model improvements to reduce consumption forecast variance in the 2023 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 allow validation of consumption and trends against other data sources, such as the Australian Energy Statistics and National Greenhouse and Energy Reporting (NGER) and 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. 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.

[35] 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.

8.2.3 Review initial year of forecast maximum and minimum demand distribution

For Victoria, the observed winter maximum demand outcome was above the 10% POE forecast, which cannot alone be easily explained by input drivers. For minimum demand, the observed actual minimum in New South Wales was below the 90% POE forecast, while in Queensland it was above the 10% POE forecast. As part of its ongoing review process, AEMO will review the methodology and further assess model inputs to see if improvements are required.

In previous years, the focus has been on improving the inputs, with distributed PV forecasts in particular being an issue. With that improved, the cases above highlight a need to improve the model performance, so a review of the models used to set the starting points of the distribution should be undertaken, including whether additional weather variables like dew point can improve model performance. Further investigation may reveal no changes are required, but could also reveal underlying behavioural changes, for example change in working and recreational habits following COVID-19, or increase in use of reverse cycle air-conditions for heating or cooling following installation of rooftop PV, even after sunset. Customers may also have shifted flexible demand such as pool pumps and hot water load to the mid-day period, affecting minimum demand outcomes.

The investigation may lead to proposed changes for the Generalised Extreme Value (GEV) model used to set the starting point of the maximum and minimum demand distributions, which in the published forecast are expressed as the 10%, 50% and 90% POE forecasts[36]. It may also reveal alternatives to use instead of the GEV model; if so, testing will be undertaken to ensure the best approach is identified and consulted on ahead of use in the 2023 ESOO.

8.2.4 Review large industrial load and other non-scheduled generation forecast components

Both the LIL and ONSG forecast components should be reviewed in terms of both their impacts on consumption and their contributions at time of maximum and minimum demand:

- The LIL forecast was found to give a significant variance to the Tasmanian winter maximum demand, and contributed significantly to the consumption forecast residual in several regions. The latter is to a large extent explained by outages at major sites or delays of forecast expansions to their outputs. The review will show if anything can be done to mitigate those risks.
- ONSG also contributed materially to the consumption forecast residual. Given there is not a lot of installed ONSG capacity, it would be expected to have a smaller impact. The review will show if the forecast of ONSG can be improved, both for consumption and minimum demand.

8.2.5 Monitor data availability of uptake and usage of emerging technologies

For mature technologies, historical datasets exist that help build forecast models and validate the forecast outcomes. Emerging technologies, which may become widespread but have yet to see any large-scale uptake, cannot be based on history. Such technologies include battery storage and EVs.

To improve the understanding of consumer uptake of these technologies, AEMO has a number of initiatives to build knowledge that can help form assumptions, sense check the forecasting results, and track forecast accuracy.

[36] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf.

For batteries, AEMO is working with distribution network service providers (DNSPs) to improve knowledge of existing battery storage installations in the DER Register and investigating methodologies to identify the operating profiles of battery storage installations.

For EVs, the EV Council now provides good statistics of EV sales data, as vehicle sales reporting by all manufacturers has improved. AEMO will start to track its EV forecast using this data source.

In terms of usage, AEMO has a database of many fast-charging stations, which it has been using to analyse the usage profile of these chargers using interval metering data. This profile was used in the latest EV forecast. AEMO has also facilitated knowledge sharing sessions between industry partners involved in research of EV charging profiles.

Finally, AEMO is involved in work through the Energy Security Board (ESB) to track EV supply equipment (EVSE, meaning charging infrastructure), with standing data for EVSE installations that meet the criteria being determined to be collected in a data register similar to the DER Register[37].

Other emerging technologies and trends will be tracked as they start to mature and information about uptake and usage becomes available. This includes hydrogen and ammonia production technologies and fuel-switching away from reticulated gas to electricity where this is beneficial.

8.2.6 Monitor demand side participation trends

There was no history available with regards to use of WDR when the 2021 DSP forecast was made, and only limited data when the 2022 DSP forecast was developed. Since then, additional capacity has been registered and it is being used more frequently. AEMO will monitor how WDR is used compared to forecast, to guide any future updates of the DSP forecast.

8.3 Forecasting Research Plan

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.

For the 2022-23 year, AEMO has identified the following opportunities for research to support its improvement plan within two overall areas

- **Sectoral modelling – Improve understanding of sectoral consumption.** AEMO plans to continue research that commenced in 2021-2022 as part of a NEAR project to identify datasets that enable a finer breakdown of sectoral energy consumption, and allow AEMO's forecasting models to better account for sectoral consumption trends. This will also assist in aligning AEMO's forecasting models with economy-wide integrated assessment modelling approaches such as the multi-sectoral modelling used in scenarios developed for AEMO's broad forecasting and planning purposes, including the ISP. This will support the "Improved visibility of sectoral consumption" item from the proposed Forecast Improvement Plan (see Section 8.2.2).
- **Future load shape.**

[37] See https://www.datocms-assets.com/32572/1658376992-esb-electric-vehicle-smart-charging-issues-paper-final-for-publication.pdf.

– **Understand changes in future load shape from technology uptake and usage**: There is limited data available for usage (charge and discharge data) for battery storage systems (including VPP) and EVs. AEMO will continue to collaborate with industry participants and researchers doing research in EV charging and battery storage usage. This will help meet the objectives of the “Monitoring data availability of uptake and usage of emerging technologies” item from the improvement plan outlined in Section 8.2.5.

– **Investigate behavioural change impacts on consumption profiles:** AEMO identified the risk of maximum and minimum demand forecast errors if not accounting for behavioural change (see Section 8.2.3). Households that have installed rooftop PV may consume more electricity than previously, given the reduction in their electricity bill and less concern about electricity prices. This increase in underlying consumption, known as the rebound effect, has seen some investigation at an annual level, but it may potentially explain growth in peak demand too, if consumers with rooftop PV are shown to use more electricity on very cold (winter) or hot (summer) evenings, just before or around sunset. This was explored by CSIRO in the NEAR program in 2021-22, and AEMO will consider the findings and whether this can be extended to look further into impacts at time of minimum demand (have flexible loads been moved to operated there). AEMO will also consider how to measure and account for the impacts (on overall consumption and max/min demand) of behavioural change for customers with both rooftop PV and batteries, either internally or in partnership with others.

A1. Status of improvements proposed in 2021

The 2021 Forecast Improvement Plan was published in the 2021 *Forecast Accuracy Report*[38]. It proposed a number of improvements planned for the 2022 ESOO or beyond. For visibility of progress, each improvement is listed below along with a summary of feedback and the implementation status.

Table 28 Improvements outlined in the 2021 Forecast Improvement Plan

Improvement	Stakeholder engagement	Status
Review initial year of forecast maximum and minimum demand distribution AEMO noted examples of winter maximum demand outcomes that could not be explained fully by input drivers. Review of models and their inputs to be undertaken as part of ongoing review process.	Draft maximum/minimum demand forecasts were presented at the 29 June 2022 meeting of the Forecasting Reference Group (FRG). An update on PV rebound investigation done through the NEAR project was provided at the 27 July 2022 FRG.	**Mostly completed.** AEMO reviewed its maximum and minimum demand models when producing the 2022 ESOO forecast, taking into account the issues flagged in the 2021 *Forecast Accuracy Report*. • Refinements to the methodology have been considered, with an improved residual model potentially giving better forecast outcomes. AEMO will continue to explore this. • Higher than forecast outcomes observed for the 2019 and 2020 ESOO forecasts could be driven by changed daily consumption trends from owners of rooftop PV systems. A NEAR project provided an estimate of this impact in June 2022. AEMO will consider whether to apply this information in its forecasting processes as part of the 2022 Forecast Improvement Plan.
Review auxiliary load forecast AEMO to review the best source of auxiliary load forecast for the 2022 ESOO consumption and demand forecasts.		**Completed.** AEMO has moved to use a different source of auxiliary load forecast, which better reflects actual generator dispatch.
Improved visibility of sectoral consumption AEMO to investigate the opportunities for a further breakdown of consumption into specific industry sectors to gain a better understanding of the reasons behind observed forecast variance and guide future forecasting improvement initiatives.	An update was provided at the 27 July 2022 FRG. A series of updates was provided to NEAR project partners from Dec 2021 to June 2022.	**In progress.** AEMO has made reasonable progress with this priority initiative through the NEAR project. Progress to date includes: • Identification of suitable datasets that could assist with breaking down sectoral consumption. • Preliminary mapping of a significant number of business NMIs to Australian and New Zealand Standard Industry Classification (ANZSIC) codes • Development of an initial breakdown of sectoral consumption for both LIL and business mass market components. • Validation of sectoral consumption across datasets, including commercial data, NGER and AEMO's internal databases. While the NEAR project is complete, AEMO will continue work on this initiative as part of the 2022 Forecast Improvement Plan, focusing on improving NMI mapping to ANZSIC codes, and developing a plan to incorporate insights into AEMO's consumption forecast process.

[38] AEMO. 2020. Forecast Accuracy Report 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2020.pdf.

Improvement	Stakeholder engagement	Status
Improved and additional renewable generation and demand traces The growth in weather-dependent (wind and solar) generation capacity in the NEM increases the importance of weather when assessing future reliability outcomes. Using more weather years will make it more likely the simulations account for occasions where limited wind and solar resources could increase the risk of USE. Additional weather years should be matched with consistent demand years.	A presentation was provided at the 29 Sep 2021 FRG.	**In progress.** AEMO has uplifted the simulation code to be significantly faster, which enables the extra complexity from producing traces through the demand simulation process. Bootstrapping weather, which retains ENSO climate cycles, has been implemented. Review of other key subcomponents is in progress: the residual model, the LIL model and the ONSG model. The uplift of the latter two will be coordinated with the reviews of these components flagged in this 2022 Forecast Improvement Plan. AEMO will continue to deliver this as part of the 2022 Forecast Improvement Plan.
Monitor for change in trends for key inputs Monitor for changes in historical trends for: • Distributed PV uptake and generation • Generator commissioning and full commercial use dates • Generator forced outage rates • DSP trends	Draft generator forced outage rates were presented at the 29 June 2022 FRG. Draft DSP forecast was presented at the 29 June 2022 FRG.	**Ongoing process.** For the specific items: • Uptake of PV has shown good alignment over the last year as outlined in this report. • Generator commissioning dates are still imprecise in many cases and AEMO is presently consulting on changes to the implementation of the commitment criteria in this reliability studies as part of its overall Reliability Forecast Guidelines consultation. • The past year has highlighted continued issues as well as a need for an additional category for generator forced outage rates. This is also identified in the Reliability Forecast Guidelines consultation. • At the time the 2022 DSP forecast was produced, AEMO accessed the impact of WDR and 5-minute settlement. There were generally too few high-price observations during the 2021-22 summer to estimate the impact of these changes with any statistical significance.
Monitor emerging technologies uptake and usage Monitor and if possible onboard data sources to track uptake and use of emerging technologies, such as battery storage and EVs.	At the July 2022 FRG, presentations were given on: • Heatmap of DER and smart meter penetration • AEMO's EV fast charging analysis	**Ongoing process.** In particular, the following should be noted: • AEMO continues to work with DNSPs to improve battery storage data in the DER Register. • Through the ESB, AEMO is involved in scoping how EV supply equipment standing data can be collected. • EV sales data now available, which includes Tesla sales. This is of a quality that can be used to track forecast accuracy. • AEMO has undertaken research in the usage profile of EV fast charging stations to inform the 2023 Draft IASR. • AEMO has had knowledge sharing sessions with organisations running trials investigating EV charging behaviour.

* The ESOO and Reliability Forecast Methodology is available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/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
CER	Clean Energy Regulator
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
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
NER	National Electricity Rules
NMI	National Metering Identifier
OPGEN	Operational demand ‘As Generated’
OPSO	Operational demand sent-out

Abbreviation	Full name
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