Forecast Accuracy Report

November 2021

Review of the 2020 Demand, Supply and Reliability Forecasts

Important notice

PURPOSE

This Forecast Accuracy Report has been prepared consistent with AEMO's Reliability Forecast Guidelines and the AEMO Forecast Accuracy Reporting 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 2020 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 2021 unless otherwise indicated.

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VERSION CONTROL

Version	Release date	Changes
1	22 November 2021	Initial release

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 2021 *Forecast Accuracy Report* primarily assesses the accuracy of AEMO's 2020 *Electricity Statement of Opportunities* (ESOO)[1] for each region in the National Electricity Market (NEM). The report assesses the accuracy of forecast drivers and models of demand and supply that influenced the reliability assessments for the 2020-21 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, 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, 2020-21

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Energy consumption						All regions within 3%. Tasmania had the largest error, almost entirely explained by lower large industrial load.
Summer maximum demand						All mainland regions within distributions and consistent with forecast drivers. Outcomes in Tasmania and Victoria were in the very low end of the distributions, but driven by very mild weather and, in the case of Tasmania, lower large industrial load at time of the peak.
Winter maximum demand						Winter maximum demand outcomes in New South Wales, South Australia and Victoria above forecast distributions. The distribution of the initial year of the forecast horizon requires review.
Annual minimum demand						Due to under-forecast PV capacity, actual minimum demands in most regions were below the forecast distribution.
Demand Side Participation						Less demand side participation (DSP) than forecast observed in South Australia. This has been adjusted down in the 2021 forecast. Need for monitoring DSP for changes following introduction of 5-Minute Settlement and Wholesale Demand Response.
Installed generation capacity						New generator installations matched expectation, except in Victoria and New South Wales, where delays impacted availability compared with what was modelled.
Summer supply availability						Planned and unplanned outages in New South Wales, Queensland and Tasmania reduced availability against forecast, however units may simply not have been made available due to low levels of observed supply scarcity.

[1] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf.

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 most areas. In a difficult year, marked by the COVID-19 pandemic, strong La Niña influence on weather outcomes, and unexpected outages of baseload plants, it shows AEMO's forecasting process is robust.

A number of potential improvements have, however, been identified. Two areas stand out:

- Forecast uptake of distributed photovoltaics (PV) was under that observed, while forecast generation per megawatt (MW) from distributed PV was above that observed. The under-forecast of capacity significantly affected the minimum demand forecast, while the over-forecast of generation per MW offset that impact on forecast consumption[2]. AEMO has addressed these issues in the 2021 ESOO forecast (see Appendix A1), and will monitor this to ensure no further actions are needed ahead of producing the 2022 ESOO forecast.
- Three regions observed actual winter maximum demand outcomes above the 10% probability of exceedance (POE) forecast[3]. As this is not fully explained by weather outcomes, and given the last three winters in South Australia saw actuals above or at the 10% POE forecasts, AEMO will review the method for producing the starting points of the POE distribution.

The report also identifies the need for further analysis to better understand the observed variances of consumption and demand by customer segment. This will enable further analysis of the residual error in the consumption forecast, which can be quite significant, and build a better understanding of how these sectors are responding to economic conditions, decarbonisation challenges, and emerging technologies.

On the supply side, forecasts generally performed well, although with an emerging need identified to ensure the representation of weather accounts appropriately for the true diversity of potential weather outcomes.

While most forecast models have performed well, some of the inputs and assumptions have impacted forecast accuracy and should be monitored for potential improvements:

- The observed demand side participation (DSP) actuals aligned well with forecasts in most regions, where sufficient high price events occurred to allow reliable comparisons with forecasts. In South Australia, however, observed DSP was well below forecast, because the forecast relied on automatically calculated baselines which in many cases were set too high. AEMO identified and corrected this issue when the 2021 DSP forecast was produced. AEMO will monitor the new forecast for its performance, in particular in light of the October 2021 introduction of 5-Minute Settlement and Wholesale Demand Response, which may affect how industry consumers respond to price signals.
- New generation installations were high, but well aligned with forecasts for three NEM regions. However, both New South Wales and Victoria observed commissioning delays of large-scale wind and solar projects against provided timing, resulting in ~2,000 MW less installed capacity than forecast for February 2021 across both regions.
- Generator forced outage rates for coal-fired generators were mostly aligned with assumptions. On the highest demand days, planned and unplanned outages in New South Wales, Queensland and Tasmania did reduce availability compared to forecasts, although demand was not extreme at any point and generators could simply not have been made available as not required.

Improvement plan

Some of the observed differences between actuals and forecasts have affirmed changes already made to the forecast methodology for the 2021 ESOO, guided by observations in the 2020 *Forecast Accuracy Report*. The appendix to this report provides an update on these changes.

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[2] Distributed PV has little impact on summer and winter maximum demand, as it typically happens towards the early evening with little or no PV generating at the time.

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

Other differences have helped steer the direction for additional improvements to be implemented for the 2022 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 2022 are listed below.

Winter maximum demand forecast

As noted above, three NEM regions observed actual winter maximum demand outcomes above the 10% POE forecast, which cannot be explained by input drivers alone. AEMO will therefore review the methodology and further assess model inputs to see if improvements are required. Further investigation may reveal no changes are needed, but could also reveal underlying changes, for example changes in working and recreational habits following COVID-19, or increased usage of heaters following installation of rooftop PV, even after sunset[4]. Such issues could be transient or persistent and, depending on the investigation, should be accounted for in the forecast.

The issue could also exist for summer maximum demand, but has been masked by the very mild summer the NEM experienced in 2020-21.

Improved visibility and understanding of consumption patterns and trends

In the 2021 *Forecast Accuracy Report*, AEMO has added assessment of the accuracy of the large industrial load forecast, to improve understanding of what is driving differences between forecast and observed consumption. There is still more to be understood, and AEMO plans to investigate opportunities for a further breakdown of consumption, in particular into industry sectors, to gain better understanding of the reasons behind observed forecast variance and better guide future forecasting improvement initiatives. Just as important, a more detailed sectoral split will also allow better modelling of future decarbonisation scenarios.

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 2020 ESOO, AEMO used 10 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.

Improved auxiliary load forecast used to convert from “as generated” to “sent out” consumption

The auxiliary load forecast used to convert between as generated and sent out consumption in the 2020 ESOO was significantly higher than the auxiliary load observed. For the 2022 ESOO consumption and demand forecasts, AEMO will review the best source of auxiliary load forecast.

Tracking of emerging technologies

In addition to the improvement initiatives listed above, and the monitoring of inputs and assumptions explained earlier, AEMO will also be looking for data series 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 (VPP)), electric vehicles (EVs) and, longer term, the production of hydrogen from electricity.

Invitation for written submissions

Stakeholders are invited to submit written feedback on any issues related to the **improvement plan** outlined in this report. Submissions are requested by **5.00 pm (AEDT) Wednesday, 22 December 2021**. Submissions should be sent by email to energy.forecasting@aemo.com.au.

[4] Increased usage following investments in energy efficiency measures or other means to lower the cost of electricity often leads in an increase in consumption that erodes some of the savings. This is known as the “rebound” effect.

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Tables

Figures

1. Stakeholder consultation process

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

Section 8 of this report, the Forecast Improvement Plan, has been guided by assessment of the main contributors to forecast inaccuracies in the main body of this report. This consultation focuses 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 2022 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 values 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) Wednesday, 22 December 2021.**

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

Table 2 Consultation timeline

Consultation steps	Indicative dates
Forecasting Reference Group discussion of draft report	27 October 2021
Forecast Accuracy Report and Improvement plan published	22 November 2021
Submissions due on Improvement plan	22 December 2021
Final Forecast Improvement Plan published along with a Submission Response document	4 February 2022

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

2. Introduction

In accordance with National Electricity Rules (NER) clause 3.13.3A(h), AEMO must, no less than annually, prepare and publish on its website 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 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.

Specifically, this 2021 *Forecast Accuracy Report* assesses the accuracy of the 2020-21 demand and supply forecasts published in AEMO's 2020 NEM ESOO[6] and related products, in addition to the resulting reliability forecasts for each region in the NEM. The 2020 ESOO forecasts are the latest that can be assessed against a full year of subsequent actual observations.

The introduction of the reliability forecast under the Retailer Reliability Obligation (RRO) rules in 2019 increased the importance of forecast accuracy. To assess if the methodologies applied were fit for purpose, AEMO commissioned an external review of its forecast accuracy assessment methodology by the University of Adelaide[7]. Recommendations arising from the review were adopted by AEMO where practicable to increase the depth and breadth of its forecast accuracy reporting, and have formed the basis of AEMO's forecast accuracy reporting methodology, which AEMO consulted on in the first half of 2020[8].

2.1 Definitions

Any assessment of accuracy is reliant 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.

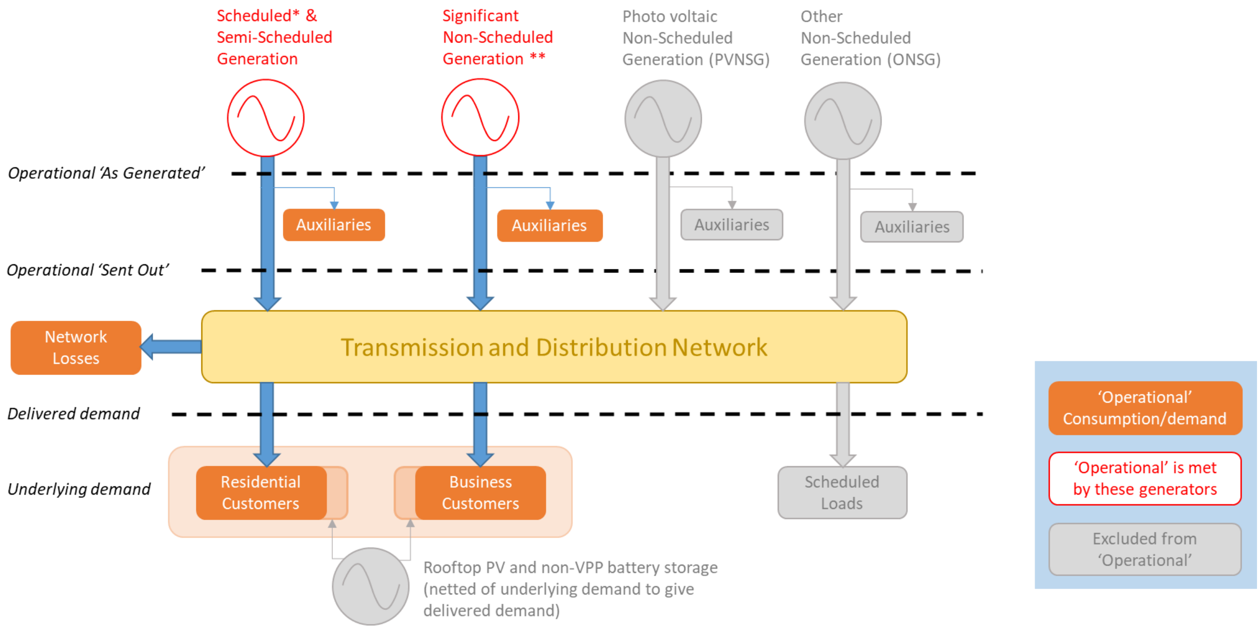
Figure 1 shows the demand definitions used in this document.

[6] 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/2020-nem-electricity-statement-of-opportunities.

[7] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/review-of-forecast-accuracy-metrics-report.pdf.

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

Figure 1 Demand definitions used in this document



* Including injection from grid-scale storages and VPP from aggregated behind-the-meter battery storage

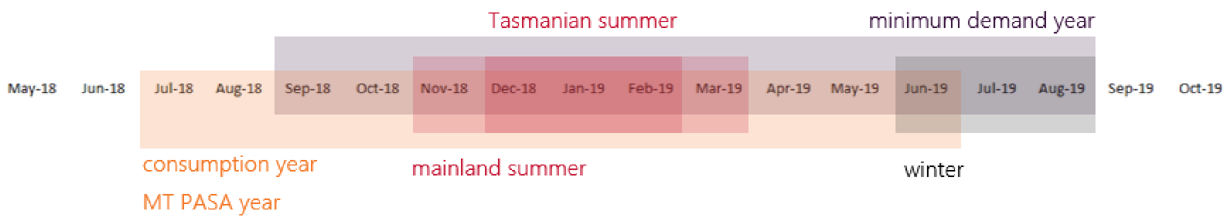
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

Seasonal definitions

For consistency, data and methodologies of actuals are the same as those used for the corresponding forecasts in the 2020 ESOO. This means:

- An energy consumption year is aligned with the financial year, being July to June inclusive.
- 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 presented in the report are calculated in line with AEMO's Forecast Accuracy Methodology[9]:

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

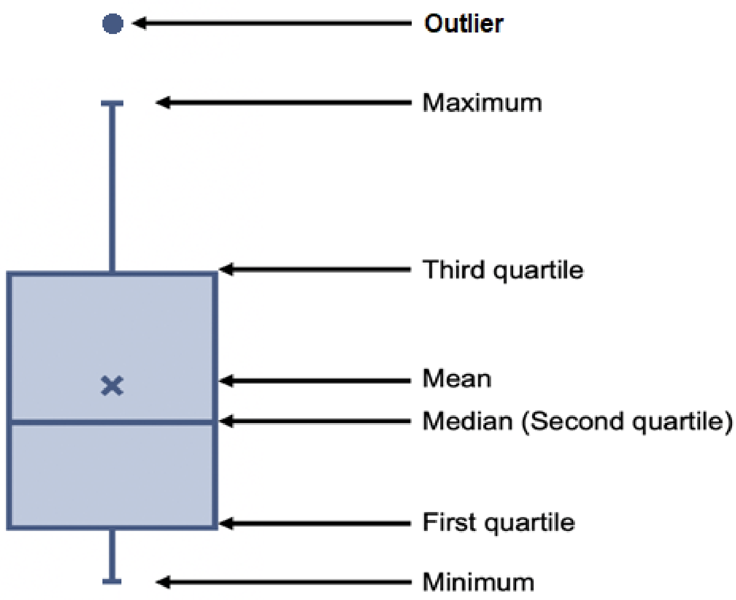
Using this approach, a negative percentage error indicates an under-forecast compared to actuals, where a positive error is an over-forecast. Specifically, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

Box plots

Within this report, some figures use box plots to illustrate the forecast accuracy. A box plot (sometimes also referred to as 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, 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 within this report



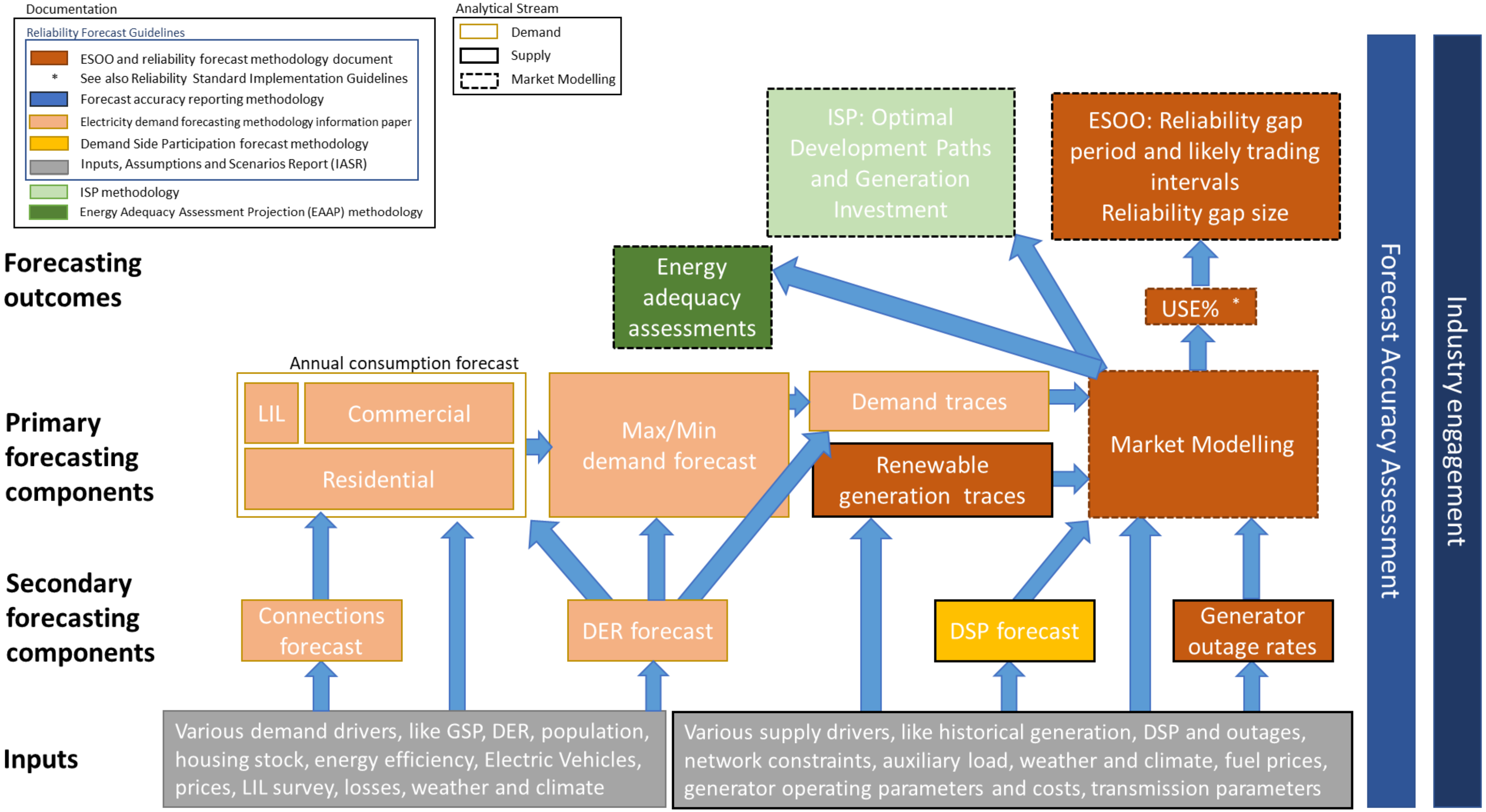
2.2 Forecast components

Production of AEMO's high-level outputs requires multiple sub-forecasts to be produced and appropriately integrated; these are called forecast components. Figure 4 shows the forecast components leading to AEMO's reliability forecast and the methodology documents (see colour legend) explaining these processes in more detail[10].

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

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

Figure 4 Forecasting components



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.

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 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 rooftop 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.

The scenarios used for the 2020 ESOO are summarised in Table 3.

Table 3 Key scenarios drivers used in the 2020 ESOO

Consultation steps	Scenarios			Sensitivities		
	Slow Change	Central	Step Change	Central Downside	Central Downside, High DER	Central Downside, high DER + Industrial closures
Demand drivers						
Economic growth and population outlook	Slower growth	Central	Higher growth	Central (Downside)[A]	Central (Downside)[A]	Central (Downside)[A]
Energy efficiency improvements	Low	Moderate	High	Moderate	Moderate	Moderate
Demand Side Participation	Low	Moderate	High	Moderate	Moderate	Moderate
DER uptake						
Distributed PV	Low	Central	High	Central	High	High
Battery storage	Low	Central	High	Central	High	High
EV uptake	Low	Central	High	Central	Central	Central
COVID-19 settings						
Restrictions time period	15-18 months	6-9 months	6-9 months	15-18 months	15-18 months	15-18 months
Business	Slow recovery	Moderate recovery	Quick recovery	Slow recovery	Slow recovery	Slow recovery
Industrial	Closures of at-risk industrial facilities	Limited impact	Limited impact	Limited impact (U-shaped recovery)[B]	Limited impact (U-shaped recovery)[B]	Early closures (L-shaped recovery)[B]
Max demand offset[C]	Lower	Central	Upper	Central	Upper	Central
Min demand offset[C]	Lower	Central	Upper	Central	Lower	Lower

A. A downside economic outlook provided by economic consultants BIS Oxford, based on second wave of contagion and slower recovery. See the 2020 *Inputs, Assumptions and Scenarios Report* (IASR) for more details.

B. The terminology used by economists for recession shapes denotes the type of recovery owing to the shape of the economic data during a recession. The U-shape refers to an energy usage downturn that has a visible trough, but recovers to trend. The L-shape refers to a more severe downturn in energy consumption that does not return to growth.

C. The maximum demand and minimum demand offsets were based on statistical analysis undertaken by AEMO in April to -May 2020, estimating the likely reduction in demand at time of typical summer maximum, winter maximum, and annual minimum demand. These estimates had a considerable uncertainty. To account for this, AEMO used the upper, central, and lower end of the estimated range of outcomes as indicated in the table.

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.
- Energy efficiency and appliance mix.
- EVs.

The 2020 NEM 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, three scenarios were therefore developed to illustrate a range of possible pathways: Slow Change, Central, and Step Change. To account for the additional uncertainty associated with the response to COVID-19, additional sensitivities were provided.

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 2020 NEM ESOO incorporated consultant forecasts for Gross Domestic Product (GDP), Gross State Product (GSP), and Household Disposable Income (HDI).

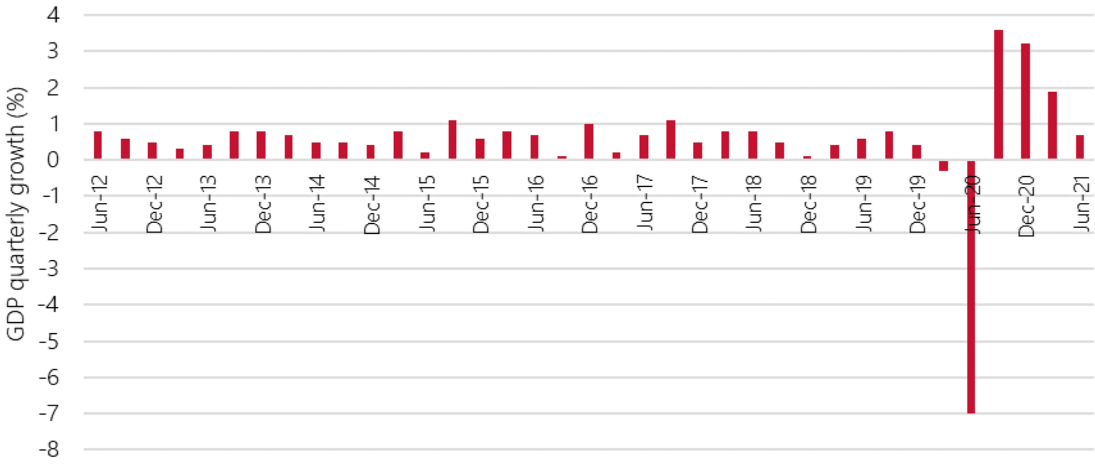
For 2020-21, annual GDP was forecast to decline by 2.2% in the Central scenario, where severe restrictions on activity were expected to remain in place until at least Q1 of 2021. Similar to GDP, GSP and HDI growth across the NEM regions were forecast to decline in the Central scenario by an average 2.6% and 2.9% respectively in 2020-21.

At the time of the forecast, vaccinations were yet to be developed and approved, and as a result international border closures were anticipated to be in place for some time longer. An average annual growth rate of 3.5% p.a. was forecast over the first 5 years of the forecast period, propped up by strong growth projections for 2021-22 as restrictions were expected to ease and economic activity normalised. GSP and HDI were also expected to see moderate growth within that period.

In contrast to the forecast, actual GDP increased in 2020-21 by 1.4%, with the short-term negative growth effects of the pandemic less severe than initial expectations. The actual quarterly GDP growth is shown in Figure 5[11].

[11] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2021, available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release#data-download – accessed 14 October 2021.

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



All things being equal, slower economic growth would lead to lower electricity demand than forecast. However, the sector in which the economic activity slows can affect energy consumption significantly due to differences in energy intensity[12] between sectors. As lockdowns and social distancing measures predominantly affected business activity in the Service (including hospitality, tourism, and retail) and Construction sectors[13], low economic growth does not necessarily result in similar reductions in electricity consumption.

As seen, overall, the consumption forecast expected a decline for the 2020-21 financial year, and contrary to this, the economy rebounded, which will partly explain why actual consumption for the year was higher than forecast. Without a more detailed sectoral breakdown of consumption, the actual impact on forecast accuracy cannot be determined. For this reason, a more detailed sectoral breakdown has been included as part of this year's Forecast Improvement Plan (see section 8.2.3).

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 the Australian Bureau of Statistics (ABS) and are shown in Table 4. As the ABS only updates reported growth in new dwellings every census (every five years), the short-term trend of National Metering Identifier (NMI) growth from the AEMO database is used for the short-term forecasts for preparation of the 2020 ESOO forecast.

Table 4 Connections forecast for 2020-21 and actuals for 2020-21

Region	2020 forecast for 2020-21 (no. of customers)	Actual for 2020-21 (no. of customers)	Difference (%)*
NSW	3,492,531	3,511,560	-0.5%
QLD	2,032,903	2,032,755	0.0%
SA	789,277	794,327	-0.6%
TAS	251,790	254,337	-1.0%
VIC	2,661,080	2,695,431	-1.3%
NEM	**9,227,581**	**9,288,410**	**-0.7%**

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

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

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

In response to the slowdown in immigration due to COVID-19 restrictions put in place at the time of the preparation of the 2020 ESOO, AEMO significantly reduced its forecast growth in connections. In the end, growth in new connections did not reduce, as construction remained stronger than expected[14] , so adding new connections at a higher rate than forecast. In general, the actual number of connections is still aligned 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

To define actual rooftop PV installed capacity in the 2020 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.

The central scenario outlooks initially provided by CSIRO[15] and Green Energy Markets (GEM)[16] assumed short term growth in installations similar to the trajectory of actual growth as it appeared at the time. The forecasts were refined while COVID-19 evolved and restrictions were put in place worldwide. It was expected that the economic uncertainty and job losses resulting from the lockdowns would lead to a reduction in spending in general, including high capital cost investments like rooftop PV.

AEMO's 2020 ESOO Central forecast, based on the average of the CSIRO and GEM forecasts, therefore resulted in a reduction in distributed PV forecast near term compared to the trend seen up to that point. As it was appreciated that the outcomes were very uncertain, a number of sensitivities were considered, including the Central Downside – High DER scenario, which assumed a lesser reduction in short term uptake.

The differences between forecasts and actuals by region are highlighted in Table 5, showing this for the Central scenario, which was the main forecast adopted for the 2020 ESOO, and the Central Downside – High DER scenario, which was found to more closely match what became reality, at least when it came to investments in rooftop PV.

For all NEM regions, rooftop PV was under-forecast in 2020, with the largest variation seen in New South Wales followed by Queensland. 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.

However, the 2020 *Forecast Accuracy Report*[17] indicated that the normalised profiles for PV generation per MW of installed capacity might be overestimating forecast generation. Discussion with the provider revealed that an improved profile was available, which better accounted for cloud cover and aerosols in the atmosphere. The revised normalised generation profiles were used in the 2021 ESOO, but the 2020 ESOO still used the old ones, which over-forecast generation across a year significantly by underestimating the impacts of cloud cover and aerosols on generation. This affected annual consumption forecasts , countering the issues seen with under-forecasting the capacity in most regions. At NEM level, the combined impact on consumption was therefore only a 0.3% over-forecast (see Table 8 in Section 4) despite the percentage difference between actual and forecast PV uptake being much larger (see Table 5).

As daytime minimum demand events typically happen on days with full sun, the update of normalised generation profiles for rooftop PV have had no real impact on minimum demand. For maximum demand, generation at time of peak demand is typically small in late afternoon/early evening, so the impact there was

[14] Australian Bureau of Statistics: Building Activity Australia (June 2021 release). Available at: https://www.abs.gov.au/statistics/industry/building-and-construction/building-activity-australia/latest-release Accessed: 28th October 2021

[15] See CSIRO, 2020 projections for small-scale embedded technologies: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf.

[16] See Green Energy Markets (GEM), 2020 projections for distributed energy resources: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf.

[17] See: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2020.pdf.

minimal too. The impacts associated with under-estimation of installation growth on maximum and minimum demand are covered in Section 5.

Table 5 Rooftop PV and PV non-scheduled generation (PVNSG) installed capacity comparison by region, as at 30 June 2021 (MW)

As installed at 30 June 2021		NSW	QLD	SA	TAS	VIC
Rooftop PV	Estimated actual (MW)	4,006	4,067	1,662	195	2,896
	Central forecast (MW)	3,160	3,433	1,447	179	2,608
	Downside – High DER forecast (MW)	3,151	3,410	1,439	181	2,777
	Central forecast error (%)	-21%	-16%	-13%	-8%	-10%
	Downside – High DER forecast error (%)	-21%	-16%	-13%	-7%	-4%
PVNSG	Estimated actual (MW)	270	209	176	3	276
	Central forecast (MW)	277	207	186	4	202
	Downside – High DER forecast (MW)	344	210	209	4	220
	Central forecast error (%)	3%	-1%	6%	19%	-27%
	Downside – High DER forecast error (%)	27%	0%	19%	21%	-21%
Total	Central forecast error (%)	-20%	-15%	-11%	-8%	-11%
	Downside – High DER forecast error (%)	-18%	-15%	-10%	-7%	-6%

Actuals are based on AEMO's latest actual data as of 19 September 2021.

PV non-scheduled generation (PVNSG) is a much smaller market compared to rooftop PV. As shown in the table, PVNSG was over-forecast in all regions, except for Victoria, which had a significant under-forecast. For all regions but Victoria, that leads to a slightly lower percentage error for distributed PV combined. The generation per installed MW of PVNSG was also over-estimated, driven mainly by inaccurate assumptions about the DC to AC ratio for these installations. This led to PVNSG forecast generation being overestimated in all regions (less so in Victoria, where capacity installed was under-forecast), as seen in Section 4.

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 in percent of this generator's dispatch. These auxiliary load percentages are provided to AEMO by participants.

The difference in auxiliary load between the 2020 ESOO forecast and the actual reported in the NEM is approximately 1.0% (see Table 8 in Section 4). It is the largest source of variance in the consumption forecast. About half the impact is due to higher auxiliary load factors used when developing the 2020 ESOO forecast, compared to the most recent ones provided by participants, which have been used to estimate the actual auxiliary load.

The other part of the variance is due to differences between forecast dispatch of thermal generators in the 2020-21 financial year versus how these generators were actually dispatched in the year. Many things can influence actual dispatch, such as growth in rooftop PV generation, and the Callide C4 incident[18] in May 2021, which also changed dispatch of coal-fired generation in Queensland in the weeks that followed.

3.5 Network losses

Network losses are the energies 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 transmission or distribution 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 are used as best estimate of the actuals for 2020-21. These are generally lower than what was assumed at the time the 2020 ESOO was made, in particular for distribution losses in the larger NEM regions, as shown in Table 6.

Table 6 Estimated network loss factors

	Transmission loss factor		Distribution loss factor	
	Applied to 2020 forecast	Used to estimate actual for 2020-21	Applied to 2020 forecast	Used to estimate actual for 2020-21
New South Wales	2.30%	2.40%	4.25%	4.22%
Queensland	2.56%	2.58%	4.76%	4.64%
South Australia	2.54%	2.79%	6.43%	7.31%
Tasmania	2.90%	2.78%	4.01%	4.76%
Victoria	1.92%	1.79%	4.88%	4.77%

Using the latest reported network losses as estimates for 2020-21 contributed to 0.2% variance for the NEM in the 2020 ESOO forecast (see Table 8 in Section 4). Looking at individual regions, the biggest impacts are in South Australia, where higher loss factors contributed to 1% forecast variance (from actual estimated losses higher than forecast) while lower loss factors in Victoria contributed to 0.9% forecast variance (from actual estimated losses lower than forecast).

[18] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf.

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 2015 to 2020, for each region, relative to history. Most recent forecasts have been somewhat similar; however, the forecasts in 2018 to 2020 generally projected lower growth rates compared to earlier years.

Figure 6 Recent annual energy consumption forecasts by region

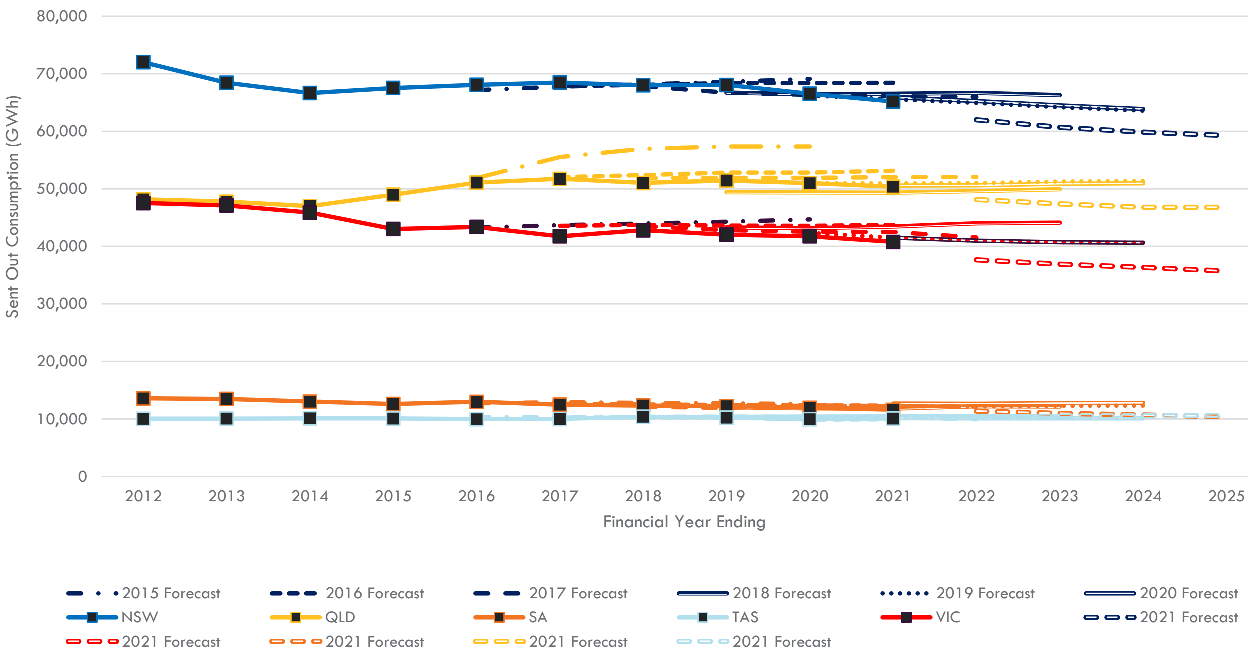


Table 7 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using the percentage error calculation outlined in Section 2.1.

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

One-year ahead annual operational consumption accuracy (%)	2016 NEFR forecast of 2016-17	2017 ESOO forecast of 2017-18	2018 ESOO forecast of 2018-19	2019 ESOO forecast of 2019-20	2020 ESOO forecast of 2020-21
New South Wales	-1.0%	-0.3%	-2.0%	-0.5%	-1.0%
Queensland	0.6%	1.7%	-3.9%	0.0%	-2.4%
South Australia	1.0%	-1.5%	-1.5%	2.6%	-0.3%
Tasmania	2.4%	-0.3%	1.2%	2.2%	2.4%
Victoria	4.3%	1.7%	3.0%	1.4%	-1.6%
NEM	1.0%	0.6%	-1.2%	0.4%	-1.3%

As Table 7 shows, in the last five years, the percentage errors for the individual regions have been within ±3% (with two exceptions, in 2016-17 for Victoria following the extended Portland Smelter outage, and in 2018-19 for Queensland, mostly driven by variance in liquified natural gas [LNG] loads). The NEM weighted average has had a percentage error within ±1.5%.

Table 8 shows the sources of variance for the 2020-21 consumption forecast of the NEM. This shows that the largest sources of error relate to over-forecast of generator auxiliary loads followed by cooling degree days, which were lower than forecast due to a strong La Niña summer[19].

Table 8 NEM operational energy consumption forecast accuracy by component

Category	2020 Forecast (gigawatt hours [GWh])	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	3,988	3,249	22.8%	0.4%
Heating Degree Days	6,409	6,866	-6.7%	-0.2%
Connections Growth	453	668	-32.2%	-0.1%
Large Industrial Loads	44,664	44,678	0.0%	0.0%
Rooftop PV	14,278	13,885	2.8%	0.2%
PV non-scheduled generation	2,014	1,442	39.7%	0.3%
Other non-scheduled generation	4,617	4,639	-0.5%	0.0%
Network losses	10,952	10,644	2.9%	0.2%
Operational sent-out	**175,717**	**178,030**	**-1.3%**	**-1.2%**
Auxiliary load	10,403	8,616	20.7%	1.0%
Operational as-generated	**186,120**	**186,645**	**-0.3%**	

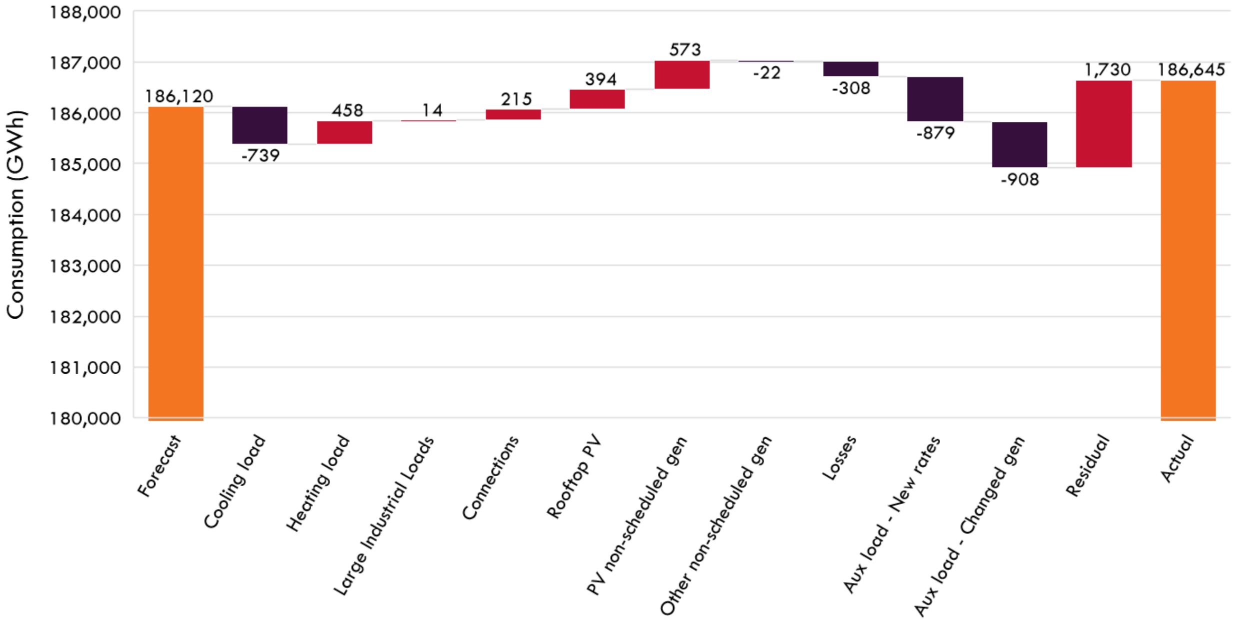
Figure 7 shows this graphically and highlights that the residual variance (the variance that is not explained by any of the measured components) is small, equating to 1,730 gigawatt hours (GWh) for operational as-generated consumption. Any impact of COVID-19 not accounted for through variations in connections growth or rooftop PV installations would be included in this residual. This includes the impact of the economic growth.

As component variances may net out at NEM level, care should be taken in making conclusions without checking region-specific variances. The rest of this section details the regional breakdown of these components. In summary:

- Cooling degree days were below forecast in all mainland states,driven by the mild weather caused by the La Niña.
- Large industrial loads were under-forecast in New South Wales but over-forecast in Tasmania.
- Changes to network loss factors (see Section 3.5) in particular caused differences in Victoria and South Australia.
- Generator auxiliary loads were overestimated in Queensland and Victoria.

[19] Bureau of Meteorology: "What is La Niña and how does it impact Australia?", available at http://www.bom.gov.au/climate/updates/articles/a020.shtml.

Figure 7 NEM operational as generated energy consumption variance by component



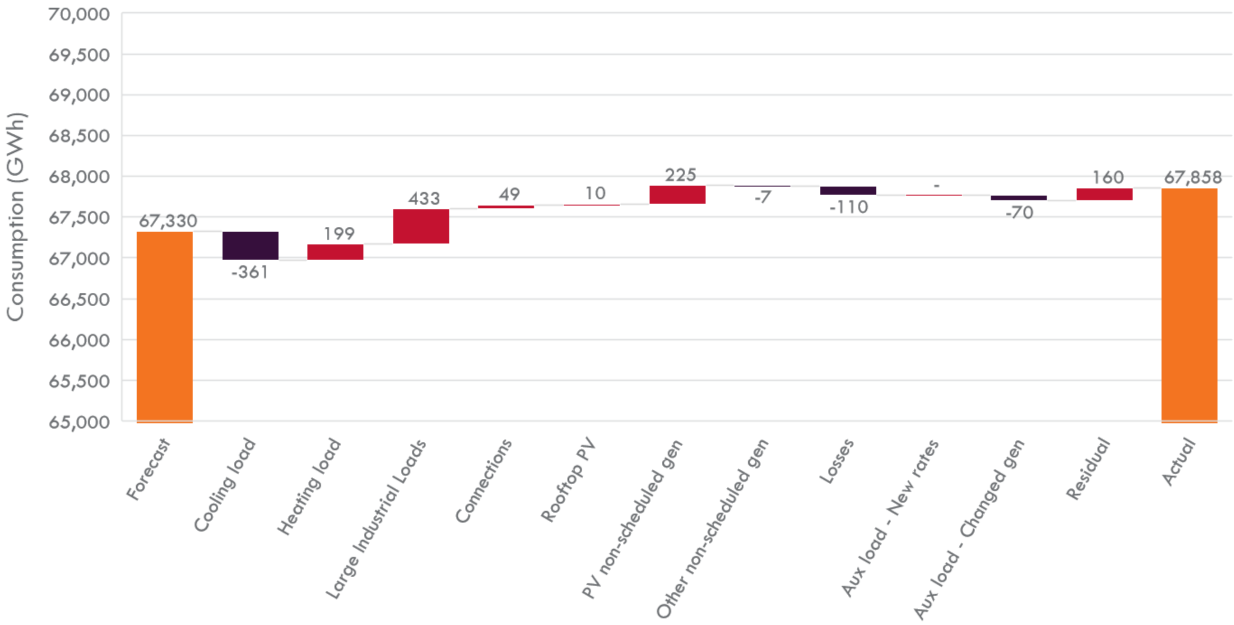
4.1 New South Wales

Operational as generated energy consumption for New South Wales in 2020-21 was above the Central forecast, leading to a percentage error of -0.8%. Table 9 and Figure 8 demonstrate the forecast accuracy by component. Summer cooling degree days were well below forecast, driven by the mild weather caused by the La Niña. Winter heating degree days were slightly higher than the median used in the forecast. The largest inaccuracy driver was an under-forecast of large industrial loads. Other differences were minor. Overall, the model for New South Wales has performed well, with the residual being 160 GWh (or -0.2%) as per Figure 8.

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

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	1,474	1,113	32.4%	0.5%
Heating Degree Days	2,296	2,495	-8.0%	-0.3%
Connections Growth	177	226	-21.8%	-0.1%
Large Industrial Loads	14,458	14,891	-2.9%	-0.6%
Rooftop PV	4,189	4,178	0.3%	0.0%
PV non-scheduled generation	634	409	55.1%	0.3%
Other non-scheduled generation	1,562	1,569	-0.5%	0.0%
Network losses	3,968	3,858	2.8%	0.2%
Operational sent-out	**64,518**	**65,178**	**-1.0%**	**-1.0%**
Auxiliary load	2,812	2,680	4.9%	0.2%
Operational as-generated	**67,330**	**67,858**	**-0.8%**	

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



4.2 Queensland

Operational as generated energy consumption for Queensland in 2020-21 was just 0.1% above forecast. There was a much bigger difference for operational sent-out consumption, with actual consumption 2.4% above forecast. Table 10 and Figure 9 show the forecast accuracy by component, highlighting that the biggest difference was auxiliary load. This was mostly attributable to the change in source for auxiliary rates as explained in Section 3.4.

The differences for the other measured components were generally small, with LNG the largest. It should be noted that the components generally caused an over-forecast, while consumption overall was under-forecast, leaving a residual of 1,582 GWh (equal to -3.0%) as per Figure 9.

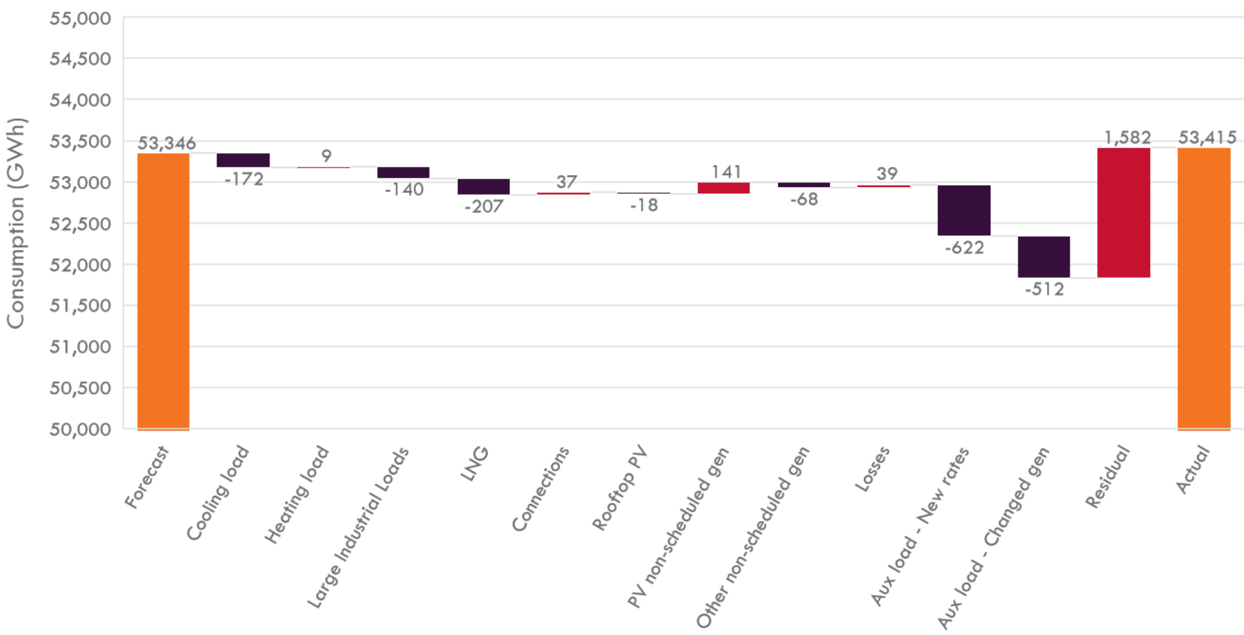
AEMO will seek to understand the causes of the residual difference by improving its ability to break down consumption into sectors in the future.

Table 10 Queensland operational energy consumption forecast accuracy by component

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	1,722	1,550	11.1%	0.3%
Heating Degree Days	482	491	-1.9%	0.0%
Connections Growth	109	146	-25.3%	-0.1%
Large Industrial Loads	13,957	13,817	1.0%	0.3%
LNG	6,718	6,511	3.2%	0.4%
Rooftop PV	4,743	4,761	-0.4%	0.0%
PV non-scheduled generation	506	365	38.8%	0.3%
Other non-scheduled generation	1,642	1,710	-4.0%	-0.1%

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Network losses	2,776	2,814	-1.4%	-0.1%
Operational sent out	**49,160**	**50,363**	**-2.4%**	**-2.3%**
Auxiliary load	4,186	3,052	37.1%	2.1%
Operational as generated	53,346	53,415	0.1%	

Figure 9 Queensland operational as generated energy consumption variance by component



4.3 South Australia

Operational as generated energy consumption for South Australia in 2020-21 was in line with the forecast, being just 0.1% above the Central forecast. Table 11 and Figure 10 demonstrate the forecast accuracy by component.

The largest inaccuracy drivers were an over-forecast of PV non-scheduled generation followed by an under-forecast of network losses.

The estimated actual for PVNSG was lower than forecast, mainly due to changes in assumed generation per megawatt of capacity. The new estimates better reflect the observed injection into the grid taking into account (AC/DC power ratio) and efficiency of panels and inverters.

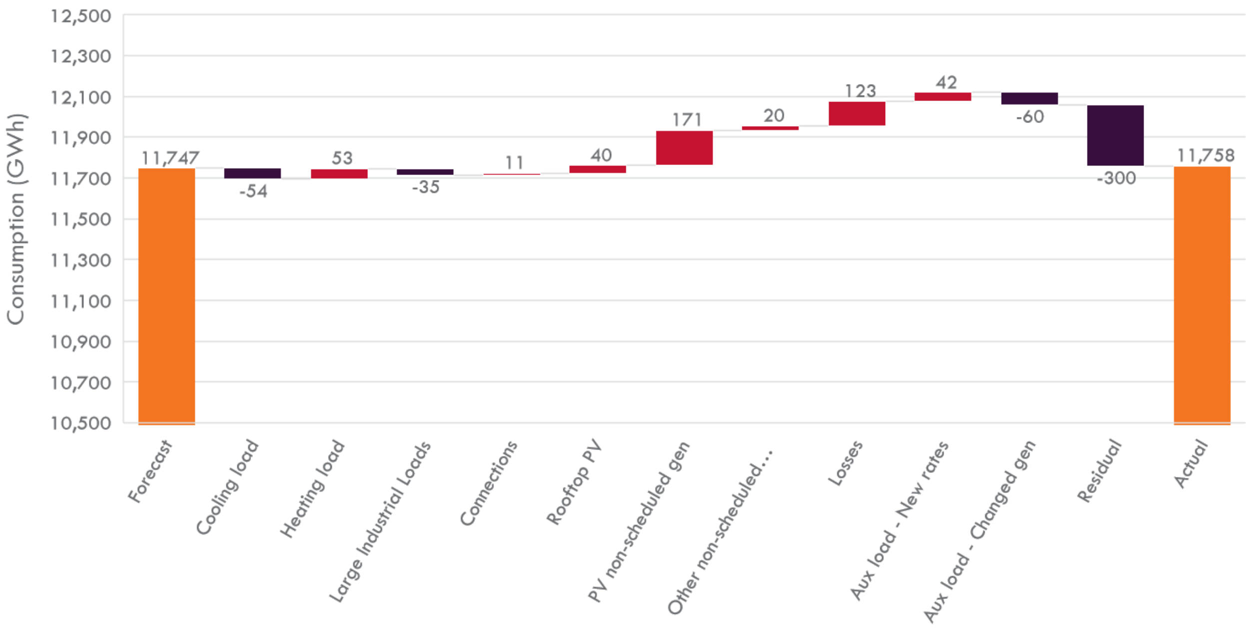
The observed difference for network losses is driven by the increase in reported loss factors for both transmission and distribution losses (see Section 3.5).

Most of the assessed components have moved in the same direction, leaving a residual variance of -300 GWh (2.5%) as shown in Figure 10. It is within what AEMO considers reasonable for a region. Without further sectoral breakdown, AEMO cannot assess the cause of the observed residual. AEMO is proposing to look into the possibility for a better sectoral breakdown in its forecasting improvement plan.

Table 11 South Australia operational energy consumption forecast accuracy by component

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	334	280	19.2%	0.5%
Heating Degree Days	639	692	-7.6%	-0.4%
Connections Growth	19	30	-37.1%	-0.1%
Large Industrial Loads	3,255	3,220	1.1%	0.3%
Rooftop PV	1,968	1,928	2.1%	0.3%
PV non-scheduled generation	442	271	63.1%	1.5%
Other non-scheduled generation	88	69	29.2%	0.2%
Network losses	897	1,020	-12.1%	-1.0%
Operational sent out	**11,584**	**11,614**	**-0.3%**	**-0.3%**
Auxiliary load	163	144	12.7%	0.2%
Operational as generated	**11,747**	**11,758**	**-0.1%**	

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



4.4 Tasmania

Operational as generated energy consumption for Tasmania in 2020-21 was below the Central forecast by 2.6%. Table 12 and Figure 11 demonstrate the forecast accuracy by component.

The largest source of inaccuracy was an over-forecast of large industrial loads, followed by an under-forecast of network losses.

The over-forecast of large industrial loads was mainly due to a partial outage of one of the region's largest loads towards the end of the financial year.

For network losses, the under-forecast was driven by a revised distribution loss factor, which is higher than the one used when the forecast was made (see Section 3.5).

Together with the other measured components, this leaves a residual of zero as per Figure 11. Subject to input variable correction, the model for Tasmania has performed well.

Table 12 Tasmania operational energy consumption forecast accuracy by component

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	0	0	0.0%	0.0%
Heating Degree Days	669	688	-2.7%	-0.2%
Connections Growth	13	28	-54.0%	-0.1%
Large Industrial Loads	6,284	5,996	4.8%	2.8%
Rooftop PV	217	194	12.0%	0.2%
PV non-scheduled generation	7	4	86.4%	0.0%
Other non-scheduled generation	448	497	-9.9%	-0.5%
Network losses	511	543	-5.9%	-0.3%
Operational sent out	**10,346**	**10,100**	**2.4%**	**2.4%**
Auxiliary load	107	88	21.4%	0.2%
Operational as generated	**10,453**	**10,188**	**2.6%**	

Figure 11 Tasmania operational as generated energy consumption variance by component

4.5 Victoria

Operational as generated energy consumption for Victoria in 2020-21 was above the Central forecast by 0.4%. Table 13 and Figure 12 demonstrate the forecast accuracy by component.

The largest inaccuracy driver was an over-forecast of auxiliary load, followed by network losses. The former was partly due to a change in data source for auxiliary load, as explained in Section 3.4. The latter was driven by a minor decrease in both transmission and distribution loss factors reported to AEMO, as covered in Section 3.5.

Also, while the installed PV capacity was under-forecast for Victoria, forecast PV generation was above the estimated actual. This is mainly due to a change in the generation per megawatt estimated used by AEMO for rooftop PV, as provided by AEMO's consultant. The new values better reflect generation on partially cloudy days and have been calibrated against a panel of ~20,000 actual rooftop PV installations. This new generation estimate has been used from the 2021 ESOO onward.

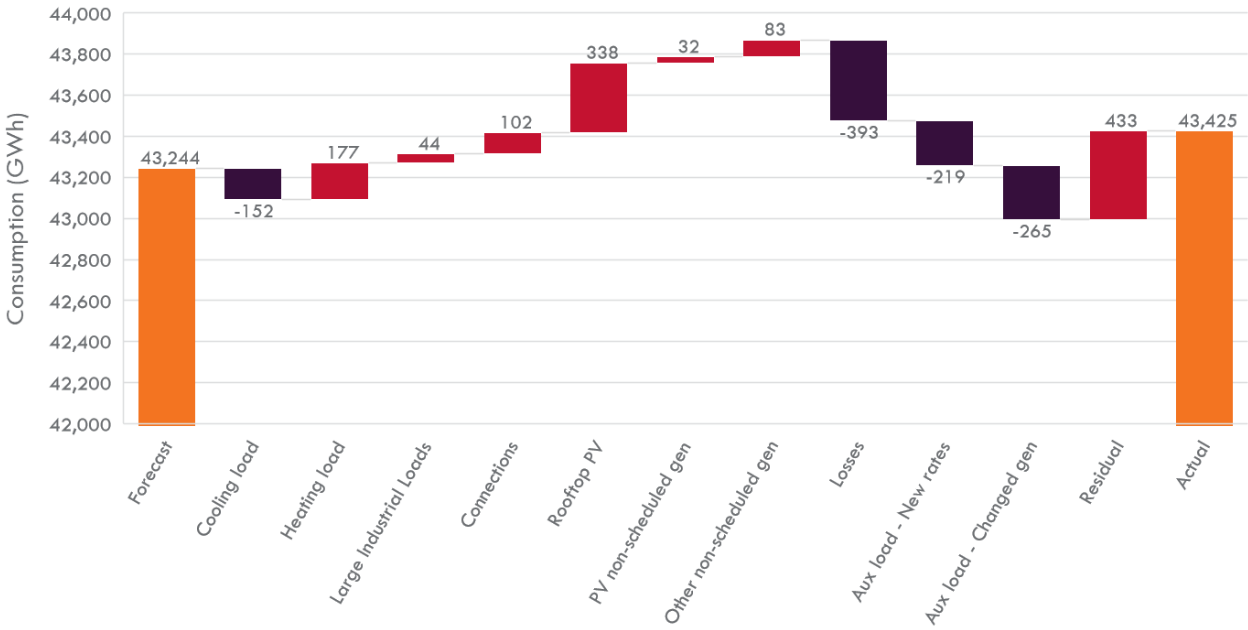
Accounting for the other measured elements, this leaves a moderate residual of 433 GWh (or -1%) which may, in part, be attributable to COVID-19 restrictions.

Subject to input variable correction, the model for Victoria has performed adequately.

Table 13 Victoria operational energy consumption forecast accuracy by component

Category	2020 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	458	305	49.9%	0.4%
Heating Degree Days	2,322	2,500	-7.1%	-0.4%
Connections Growth	135	237	-43.2%	-0.2%
Large Industrial Loads	6,711	6,755	-0.7%	-0.1%
Rooftop PV	3,162	2,824	12.0%	0.8%
PV non-scheduled generation	425	394	8.1%	0.1%
Other non-scheduled generation	877	795	10.4%	0.2%
Network losses	2,801	2,408	16.3%	0.9%
Operational sent out	**40,109**	**40,774**	**-1.6%**	**-1.5%**
Auxiliary load	3,135	2,651	18.3%	1.1%
Operational as generated	**43,244**	**43,425**	**-0.4%**	

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 coincident 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 rooftop PV is offsetting consumption.

Unlike the consumption forecast, which is a point forecast (single value), 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[20].

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 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[21].

5.1 Extreme demand events in 2020-21

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.

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[20] 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.

[21] 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.

Comparing actual observed demand with forecast values can only be done if on the same basis, so some adjustments to actual demand are necessary. 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 2020-21 occurred on 22 February 2021. Being a forecast hot day, Energy Queensland activated its PeakSmart controlled air-conditioner program, reducing demand by an estimated 52 MW. Due to high prices that evening, there were also load reductions in response to prices, although that happened after maximum demand had been reached.

5.1.1 Summer 2020-21 maximum demand events

Table 14 shows the summer maximum demand periods for NEM regions in 2020-21, with Queensland being the only region where an adjustment was required (see above).

Table 14 Summer 2020-21 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	Sat, 28 November 2020 17:00	12,546	375	12,171	-	-	12,171
QLD	Mon, 22 February 2021 18:00	9,473	433	9,040	52	-	9,092
SA	Thu, 18 February 2021 19:00	2,830	48	2,782	-	-	2,782
TAS	Thu, 17 December 2020 07:30	1,321	13	1,308	-	-	1,308
VIC	Mon, 11 January 2021 17:00	8,411	341	8,070	-	-	8,070

5.1.2 Winter 2021 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. AEMO found the maximum demand outcomes for both New South Wales and Queensland needed adjustment, as high wholesale prices triggered load reductions at some large industrial loads. The other regions had relatively low prices during the maximum demand events and no adjustments were necessary.

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

Table 15 Winter 2021 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	Thu, 10 June 2021, 18:00	13,007	415	12,592	305	-	12,897
QLD	Wed, 21 July 2021, 19:00	8,162	384	7,778	123	-	7,901
SA	Thu, 22 July 2021, 18:30	2,628	45	2,583	-	-	2,583
TAS	Sun, 25 July 2021, 18:30	1,698	19	1,679	-	-	1,679
VIC	Tue, 20 July 2021, 18:00	7,972	366	7,606	-	-	7,606

5.1.3 Annual 2020-21 minimum demand events

AEMO has reviewed the minimum demand events. For Queensland, the minimum demand event is excluding 25 May 2021, where load shedding following the Callide incident caused a minimum demand just under the natural minimum, which occurred Saturday 17 July 2021[22]. In Tasmania, several events caused by Basslink trips and resulting tripping of large industrial loads on the island have also been excluded[23]. The natural minimum in Tasmania occurred instead overnight, when one of the major industrial loads was taking an overnight outage for a large portion of its load. Otherwise, the minimum demand days were quite typical, either being Sundays or Christmas day. All regions but Tasmania reached their lowest minimum demand levels since the beginning of the NEM due to growth in PV capacity.

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, 11 April 2021, 13:00	5,310	167	5,143	-	-	5,143
QLD	Sat, 17 July 2021, 12:30	3,839	266	3,573	-	-	3,573
SA	Sun, 11 October 2020, 12:30	300	7	293	-	-	293
TAS	Mon, 8 February 2021 02:00	857	6	851	-	-	851
VIC	Fri, 25 December 2020, 13:00	2,529	216	2,313	-	-	2,313

[22] As per Section 2.1, minimum demand is assessed on a season year basis (September to August)

[23] During Basslink trips, when Tasmania is importing, a Frequency Control System Protection Scheme (FCSPS) trips load at some of Tasmania's major industrial sites. This happened on 29 November 2020, 9 February 2021, and 13 March 2021, and in all cases caused the observed minimum demand to dip below the natural minimum recorded 8 February 2021.

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 2021. 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

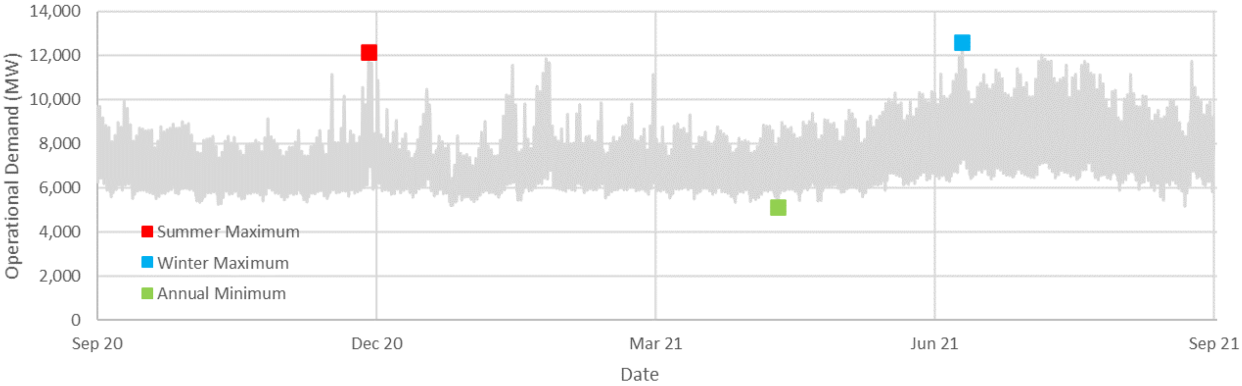


Figure 14 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and customer behaviour. The minimum and summer maximum demand events fell well within their respective forecast distributions, while the adjusted winter maximum demand event fell above the forecast 10% POE.

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

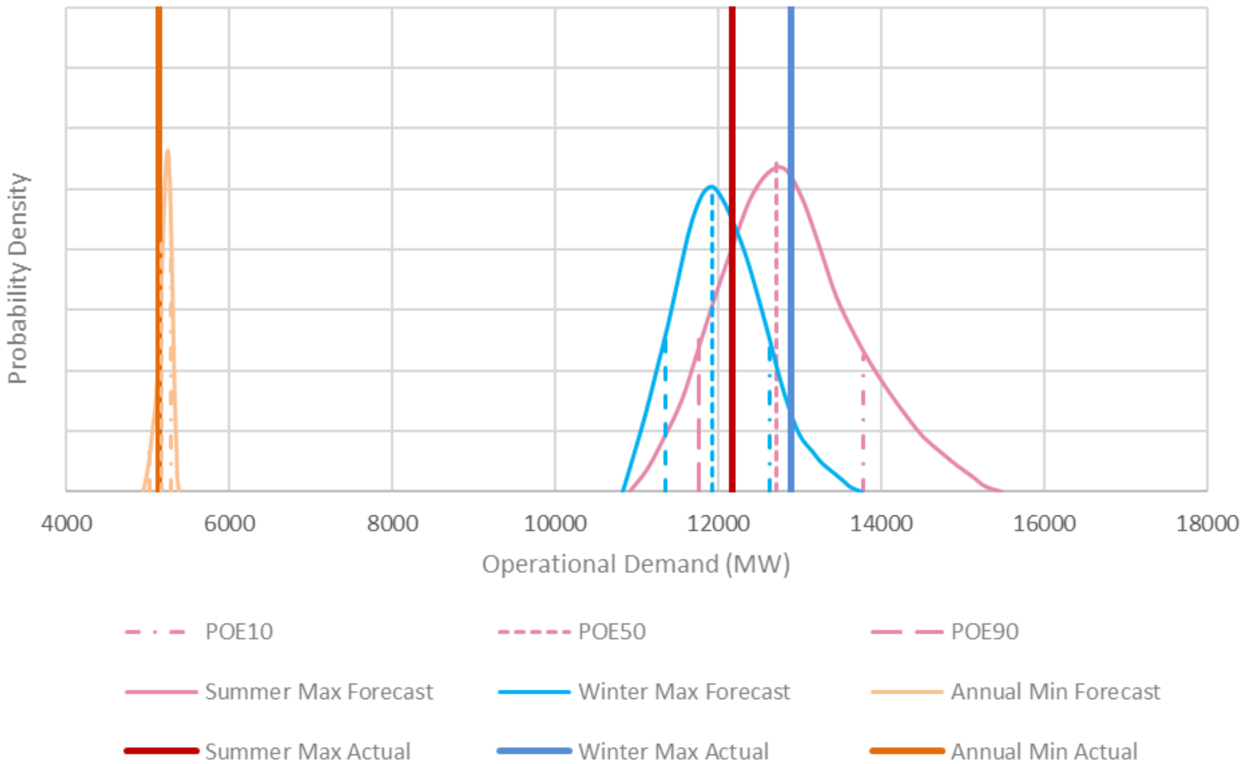


Table 17 New South Wales 2021 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Sat, 28 November 2020, 17:00	Thu, 10 June 2021, 18:00	Sun, 11 April 2021, 13:00
Temperature* (°C)	39.2	8.2	18.2
Max temperature (°C)	41.5	9.6	18.2
Min temperature (°C)	19.1	2.2	12.0
Losses (MW)	747	787	289
NSG output (MW)	233	244	314
Rooftop PV output (MW)	**362**	**0**	**2,114**
Sent out (OPSO)^	**12,171**	**12,592 adjusted to 12,897**	**5,143**
Auxiliary (MW)	375	415	167
As generated (OPGEN)^	**12,546**	**13,007 adjusted to 13,312**	**5,310**

* Bankstown Airport weather station. For more information please see Section 3.3.2 of the IASR (https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf).
^Winter maximum demand is adjusted to include a firm adjustment of 305 MW.

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 Saturday 28 November 2020 at 17:00 NEM time. At the time of maximum demand, Bankstown recorded a temperature of 39.2°C with a daily maximum of 41.5°C.

- Overall, summer maximum demand was within forecast expectations.
- New South Wales experienced a few days with particularly high daily maximum temperatures towards the end of November. The summer maximum demand event coincided with the day of the highest daily summer maximum temperature. Temperatures were high throughout this day, with a temperature of 28.1°C by 09:00, before reaching a temperature of 41.5°C by 15:00. At 15:00, the cloud coverage was at a monthly low, with the resulting heat driving up cooling load. The temperature at the time of this maximum demand event was within the distribution of the simulated temperature outcomes at time of maximum demand.
- Simulation outcomes were weighted towards occurring in late January/early February, which is slightly inconsistent with the November occurrence. The summer weather was, however, unusual overall, driven by the La Niña event, which caused a very mild summer across most of Australia. In that light, it is not surprising that the peak fell early, as there were not intense heat waves in mid-summer, which normally cause the maximum demand events. The summer maximum demand event falling on a Saturday goes against the simulations, with most of these events occurring on weekdays in simulation; this is mainly due to the extreme weather conditions experienced on this day compared to other days in the mild summer.
- PV generation at time of maximum demand sits within the forecast PV generation distribution. While there was stronger than forecast growth in PV installed capacity, a maximum demand time at 17:00 reduces the impacts of stronger PV installed capacity on PV generation.

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

Winter maximum demand occurred on Thursday 10 June 2021 at 18:00 NEM time, with a temperature of 8.2°C recorded at Bankstown. The maximum temperature of the day was only 9.6°C, which was the lowest recorded in June for several weather stations. The minimum temperature on the day was just 2.2°C.

- The observed maximum demand fell just above the 10% POE forecast, while the adjusted actual (accounting for DSP) fell above the 10% POE. Given the extreme cold temperatures throughout the day, this is within expectations.
- Maximum demand peaked at 18.00 NEM time, well after sunset. Hence, PV generation was zero at time of maximum demand.
- The forecast expected a later winter peak sometime in July, when heating loads are normally significantly higher, but in this year, the day with the lowest temperatures fell in June.

Annual minimum demand occurred on Sunday 11 April 2021 at 13:00 NEM time, when the temperature was 18.2°C.

- Actual minimum demand was just under the 50% POE, occurring mid-day for the first time. This is in line with the forecast expectations driven by the forecast uptake of rooftop PV capacity.
- Simulation outcomes were weighted towards occurring in summer months, which is contrary to the Sunday 11 April 2021 occurrence. The monthly distribution does extend into Autumn and because of the stronger than forecast growth in PV installed capacity, an April observation is not unexpected.

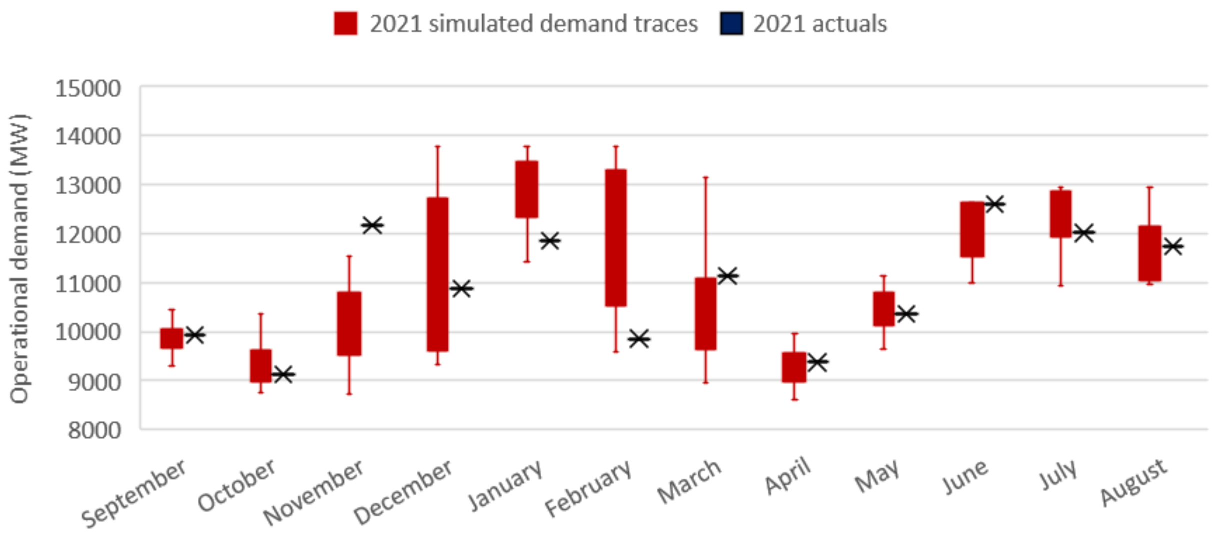
Monthly maximums

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 10 reference years (2011-20), 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 used in the demand traces, it is reasonable that a limited number of actuals may fall outside the range of monthly maximums of operational demand in these demand traces. COVID-19 impacts could be another explanation for actuals falling outside the range.

The box plot in Figure 16 shows the range of monthly demand maximums for the 2021 simulated demand traces for 10% POE and 50% POE annual forecasts. With the exception of November, actual monthly maximums all fell within the simulated ranges. The November maximum demand event ended up being the maximum demand event for the entire summer and is shown as an outlier compared to the range from the 10 reference years.

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

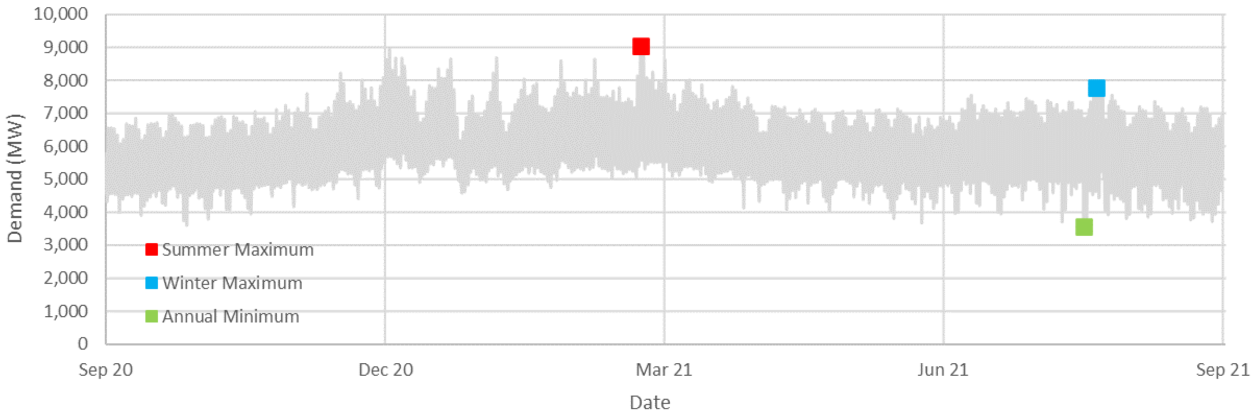


Figure 18 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. Both maximum demand events fell in the middle of their respective forecast distributions. The minimum demand event fell well below the forecast distribution because of the stronger than forecast growth in PV installed capacity (see Table 5) and the timing of the minimum event being during the middle of the day.

Figure 18 Queensland simulated extreme event probability distributions with actuals

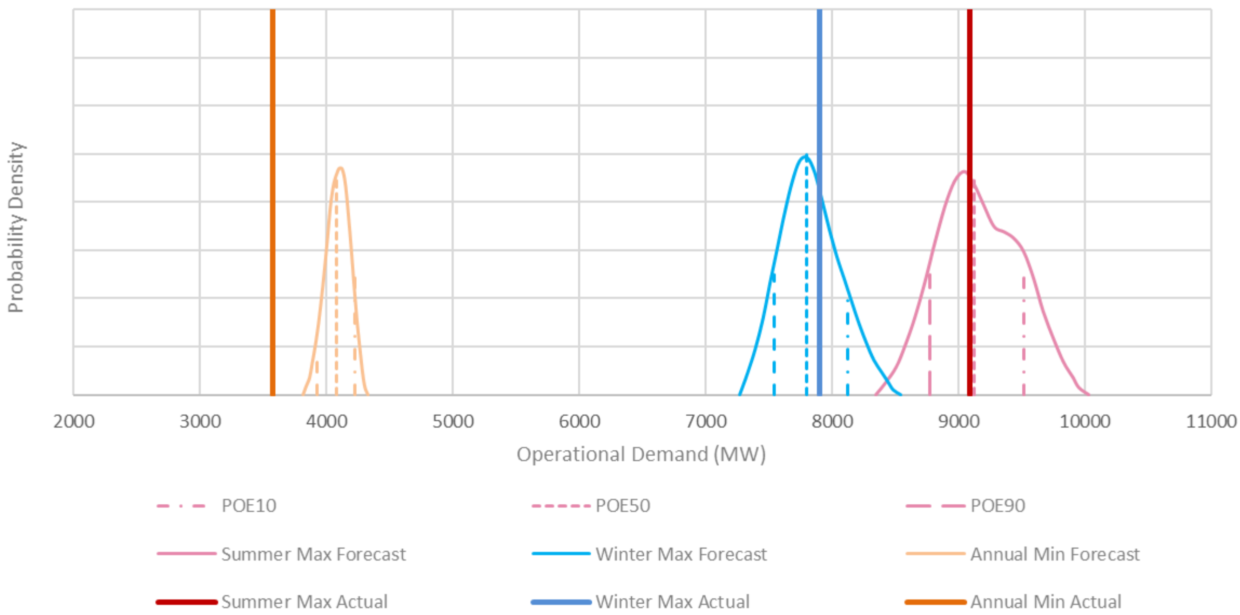


Table 18 Queensland 2020 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Mon, 22 February 2021, 18:00	Wed, 21 July 2021, 19:00	Sat, 17 July 2021, 12:30
Temperature* (°C)	27.9	11.3	20.3
Max temperature (°C)	34.2	17.1	21.0
Min temperature (°C)	20.9	7.9	11.0
Losses (MW)	553	470	183
NSG output (MW)	223	259	324
Rooftop PV output (MW)	163	0	2,396
Sent out (OPSO)^	**9,040 adjusted to 9,092**	**7,778 adjusted to 7,901**	**3,573**
Auxiliary (MW)	433	384	266
As generated (OPGEN)^	**9,473 adjusted to 9,525**	**8,162 adjusted to 8,285**	**3,839**

* 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 52 MW, while winter maximum demand include a firm adjustment of 123 MW potential adjustment.

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 Monday 22 February 2021 at 18:00 NEM time. At the time of maximum demand, Archerfield recorded a temperature of 27.9°C with an earlier daily maximum of 34.2°C.

- Maximum demand was within forecast expectations for the conditions on the day. However, Queensland had a seasonal maximum temperature of 34.5°C on Sunday 7 February 2021 that did not result in the summer maximum demand event, due to the typical lower demand on Sundays. Maximum demand events are more likely in January and February, as humidity is typically higher. Also, at the end of summer, due to heat fatigue, consumers are more likely to use their air-conditioners.
- Queensland, like most of Australia, was driven by milder temperatures caused by the La Niña event last summer, which was reflected in the peak demand event. The temperature at time of maximum demand was in the low range of simulated temperature outcomes, which ranged from 24°C to 42°C with a median of 33°C. Based on temperature alone, an actual maximum demand between 50% and 90% POE would be expected.
- Actual PV generation was at the lower end of simulated outcomes, with an actual of 163 MW at time of maximum demand, compared to a simulation median of 303 MW and a range of outcomes between 0 MW and 1,867 MW. Total PV capacity for Queensland was under-forecast, with an actual 4,067 MW of installed capacity as at 30 June 2021 compared to a forecast of 3,433 MW, which likely pushed the timing of the maximum demand event to later in the day.
- Simulation outcomes were weighted towards occurring during the week and in January/February, which is consistent with the Monday 22 February 2021 occurrence.

Figure 19 Queensland simulated input variable probability distributions with actuals

Winter maximum demand occurred on Wednesday 21 July 2021 at 19:00 NEM time. Temperature at the time was 11.3°C at Archerfield.

- The conditions on the winter maximum demand day suggest the forecast distribution to be accurate, with the observed maximum very close to a 50% POE.

- The day was the coldest winter day for the season (based on daily maximum temperature of 17.1°C). All PV generation had ceased by the 19:00 peak. The time of day, day of week, and month of year for the peak were all well within the simulation outcomes.
- Simulation outcomes were weighted towards occurring on a weekday, consistent with the occurrence on Wednesday 21 July 2021.

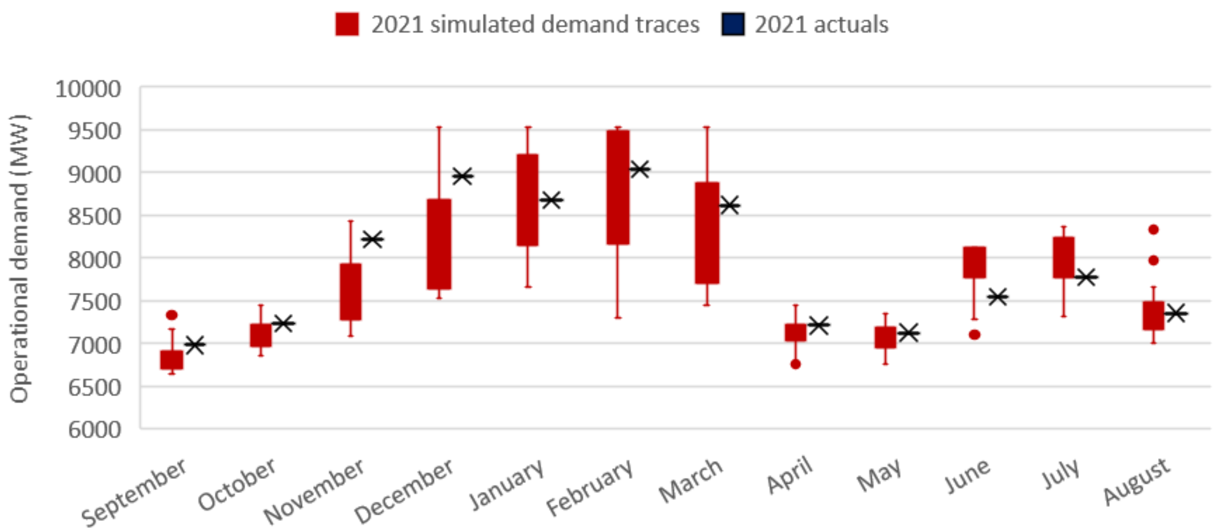
Annual minimum demand occurred in winter on Saturday 17 July 2021 at 12:30 NEM time, when the temperature was 20.3°C.

- Minimum demand was lower than forecast expectations.
- Prevailing conditions on the day were very similar to the conditions at time of the annual minimums in the two previous years.
- Actual minimum demand fell well below the 90% POE, with simulated temperature outcomes at time of minimum demand ranging between 15°C and 30°C. PV generation at time of minimum demand was 2,239 MW, sitting significantly above the distributional mode of roughly 1,900 MW. As explored earlier, the PV installed capacity forecast was under-forecast by around 340 MW, which accounts for most of the error in the forecast.
- Simulation outcomes were weighted towards occurring on the weekend and in August, although some occurrences appear in July, which is consistent with the Saturday 17 July 2021 occurrence.

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. Actual monthly maximums all fell within the simulated ranges.

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

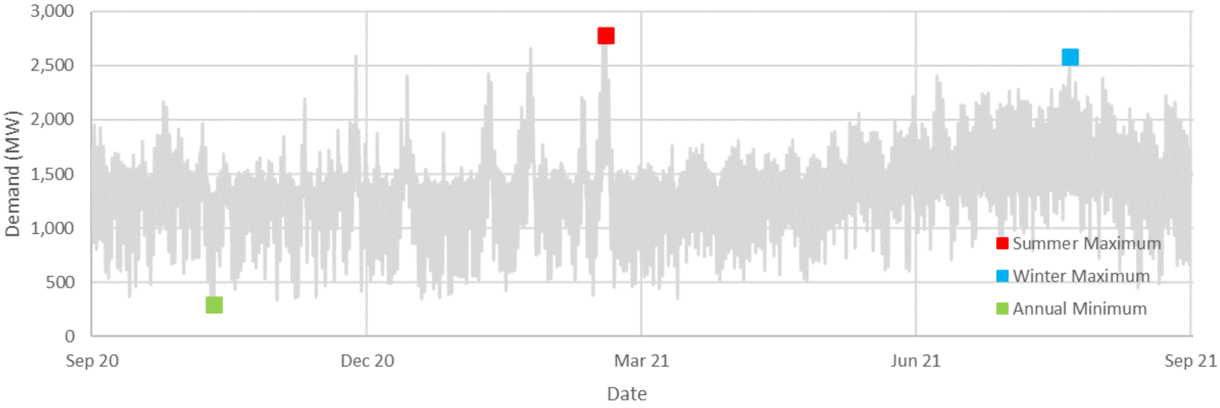


Figure 22 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The actual summer maximum demand event fell well within forecast distributions, while both the winter maximum and the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

Figure 22 South Australia simulated extreme event probability distributions with actuals

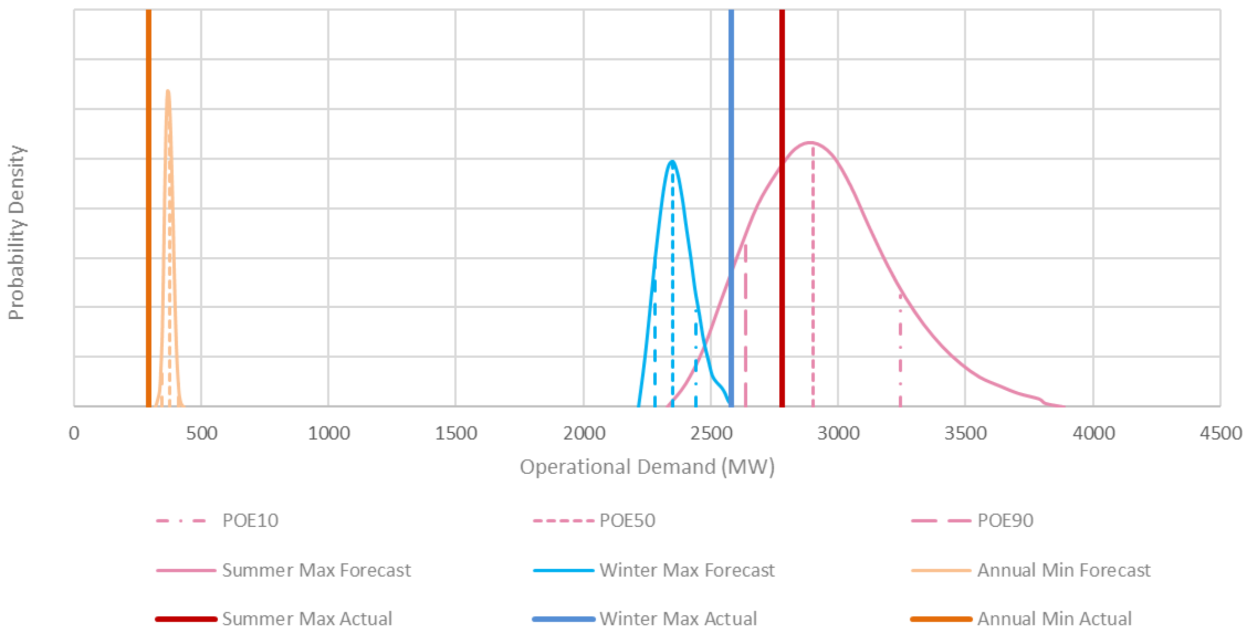


Table 19 South Australia 2020 extreme demand events

Event	**Summer maximum**	**Winter maximum**	**Annual minimum^**
NEM Date and time	Thu, 18 February 2021, 19:00	Thu, 22 July 2021, 18:30	Sun, 11 October 2020, 12:30
Temperature* (°C)	34.5	8.3	22.0
Max temperature (°C)	36.4	10.0	23.8
Min temperature (°C)	27.2	6.0	7.5
Losses (MW)	262	253	13

Event	Summer maximum	Winter maximum	Annual minimum^
NSG output (MW)	56	9	112
Rooftop PV output (MW)	82	0	985
Sent out (OPSO)	**2,782**	**2,583**	**293**
Auxiliary (MW)	48	45	7
As generated (OPGEN)	**2,830**	**2,628**	**300**

* From 1 August 2020 measurements use the Adelaide (West Terrace) weather station, BOM station 023000. For more, 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).
^At time of the minimum demand event, a VPP trial operated batteries thereby increasing the demand approximately by 5 MW (https://aemo.com.au/newsroom/news-updates/vpp-third-knowledge-sharing-report). This has not been included as official adjustment in this *Forecast Accuracy Report*, but AEMO will consider making adjustments for minimum demand in future versions.

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

Maximum demand occurred in summer on Thursday 18 February 2021 at 19:00 NEM time with a temperature of 34.5°C recorded at Adelaide (West Terrace).

- The conditions on the day of the maximum demand event indicate that the event should be between a 50% POE and 90% POE, consistent with what was observed.
- The temperature at the time of the maximum demand was in the lower end of the forecast temperature distribution, which ranged from 33.5°C to 47°C.
- PV output at the time of maximum demand was just in the higher end of the PV forecast distribution, which ranged from 0 MW to 615 MW with a median value of 63 MW.
- Simulation outcomes were weighted toward a weekday maximum and in January/February, consistent with what was observed.

Winter maximum demand occurred on Thursday 22 July 2021 at 18:30 NEM time, with a temperature of 8.3°C recorded at Adelaide (West Terrace).

- For the third year in a row, South Australia set a new record high winter maximum demand, the previous record being 2,539 MW (sent out) set on 7 August 2020.
- The day on this year's winter maximum demand event, Thursday 22 July 2021, had the lowest daily maximum temperature on record for many weather stations in South Australia[24].
- The timing of the peak meant that rooftop PV did not contribute to lower demand at the time.
- Simulation outcomes were weighted towards occurring on a weekday, typically in July, which is consistent with the occurrence on Thursday 22 July 2021.
- South Australia has had a very stable winter maximum demand historically, but it is noticeable that it has now set new record high demand three years in a row. While the weather on 22 July 2021 did support a demand in the high end of the range, other factors may also be at play, which supports further analysis. It could be a consequence of more people spending evenings at home following COVID-19 and thus consuming more power for heating. But as higher than forecast winter maximum demands have been observed before COVID-19 too, other drivers could be at play. For example, it could be a consequence of the high ownership of rooftop PV in the state, where owners may be less concerned about electricity bills and heating homes more at time of peak than previously. The forecast improvement plan will look further into this.

[24] See Bureau of Meteorology – Monthly Climate Summary for South Australia, July 2021, at http://www.bom.gov.au/climate/current/month/sa/archive/202107.summary.shtml.

Figure 23 South Australia simulated input variable probability distributions with actuals

Annual minimum demand occurred on Sunday 11 October 2020 at 12:30 NEM time, when the temperature was 22.0°C; this is a typical temperature for such events, requiring little cooling or heating demand.

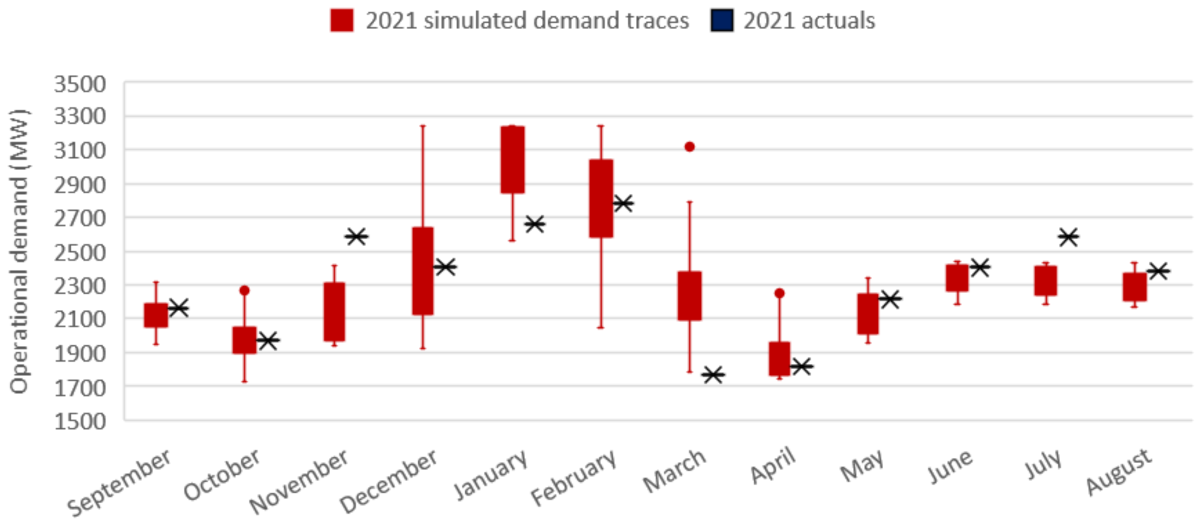
- South Australian minimum demand has been occurring mid-day for a number of years, with minimum demand reducing year on year in response to growth in installed rooftop PV capacity. Last year's minimum demand (sent out) for South Australia was 447 MW, compared to 293 MW this year.

- Actual PV installed capacity was 1,463 MW at the time of minimum demand, which is well above the forecast value of 1,392 MW and resulted in the actual PV generation just above the forecast distribution of PV generation at time of minimum demand.
- Weather conditions on the day were conducive to high PV generation, with low temperatures, low humidity, and no cloud cover. Actual normalised PV generation at time of minimum demand was 67.4%, consistent with other high PV generation days.
- Simulation outcomes were weighted towards occurring on the weekend and during the October/December period, which is consistent with the Sunday 11 October 2020 occurrence.

Monthly maximums

The box plot in Figure 23 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 during July fell above the ranges formed by the traces, due to the reference years being scaled to 10% and 50% POE demands, which as noted were lower than the actual observed. There was an additional observation outside the monthly ranges formed by the traces, with the very hot November weather that caused the summer maximum demand in New South Wales also affecting South Australia. Note that the 2020-21 weather year was included as reference year in the 2021 ESOO (and related processes like MT PASA and EAAP), which widen the range of monthly maximums considered for South Australia in more recent studies.

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

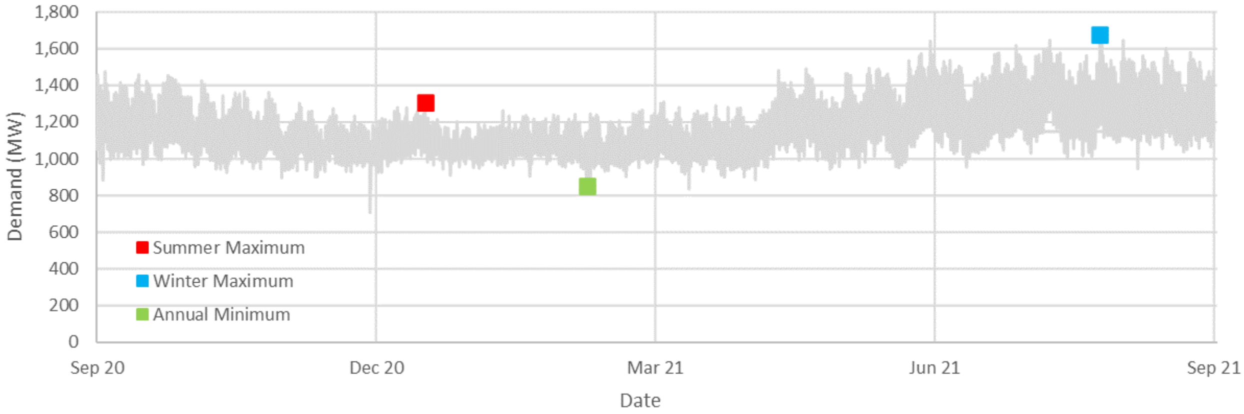


Figure 26 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. All minimum and maximum demand events fell towards the lower end of their respective forecast probability distributions,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

Figure 26 Tasmania simulated extreme event probability distributions with actuals

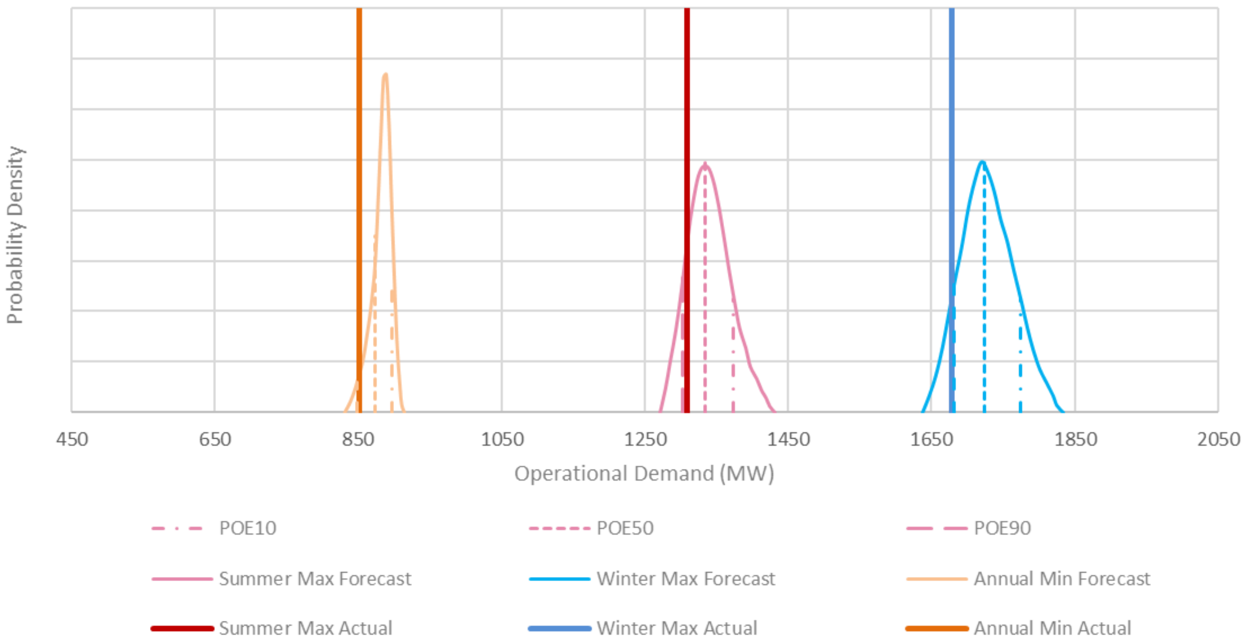


Table 20 Tasmania 2020 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Thu, 17 December 2020, 07:30	Sun, 25 July 2021, 18:30	Mon, 8 February 2021, 02:00
Temperature* (°C)	11.7	4.5	12.9
Max temperature (°C)	15.9	7.6	20.0
Min temperature (°C)	11.2	4.5	11.8
Losses (MW)	68	123	39

Event	Summer maximum	Winter maximum	Annual minimum
NSG output (MW)	25	67	46
Rooftop PV output (MW)	7	0	0
Sent out (OPSO)	**1,308**	**1,679**	**851**
Auxiliary (MW)	13	19	6
As generated (OPGEN)	**1,321**	**1,698**	**857**

* 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).

Figure 27 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows. 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 what large industrial loads were doing at time of the extreme demand outcomes, and weather (such as temperature) has a relatively smaller impact.

Maximum demand occurred in winter on Sunday 25 July 2021 at 18:30 NEM time, with a temperature of 4.5°C recorded at Hobart (Ellerslie Road).

- Tasmania experienced an unusual winter maximum demand event this year, being on a Sunday evening, driven largely by heating load following the day with the lowest daily maximum temperature (7.6°C).
- Simulation outcomes were weighted towards occurring during the morning on a weekday and in the June/August period. The morning peaks are typically driven by low overnight temperatures and the resulting morning peak from heating homes, hot water (showers) and cooking.
- The mentioned lowest observed daily temperature in years however caused an evening peak instead; as with little warmth accumulated during the day, evening heating demand was significant enough to make this the maximum demand event, even though it was also a Sunday.
- Occurring after sunset, PV generation was zero at time of the observed maximum demand.
- Large industrial loads at time of peak were 740 MW, whereas the forecast had a 50% POE value of 759 MW (10% POE was 782 MW, and the 90% POE was 736 MW). The outcome being just above the 90% POE value, along with the fact it was Sunday, mostly explains why the actuals fell just below the 90% POE.

Summer maximum demand occurred on Thursday 17 December 2020 at 07:30 NEM time, with a temperature of 11.7°C recorded at Hobart (Ellerslie Road).

- The observed demand corresponds to just above a 90% POE outcome.
- Again 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.
- Simulated temperature outcomes were consistent with the actual observed temperature of 11.7°C. The actual fell in the top end of the simulated temperatures representing cold snap-driven summer maximums. An outcome near 90% POE is therefore reasonable.
- Large industrial loads at time of summer maximum were at 707 MW, midway between 720 MW (the median for a 50% POE outcome) and 696 MW (the median for a 90% POE outcome).
- Simulation outcomes were weighted towards occurring on a weekday and in late December/early January, which is consistent with the Thursday 17 December 2020 occurrence. Similarly, PV generation at time of maximum was within expectation.

Figure 27 Tasmania simulated input variable probability distributions with actuals

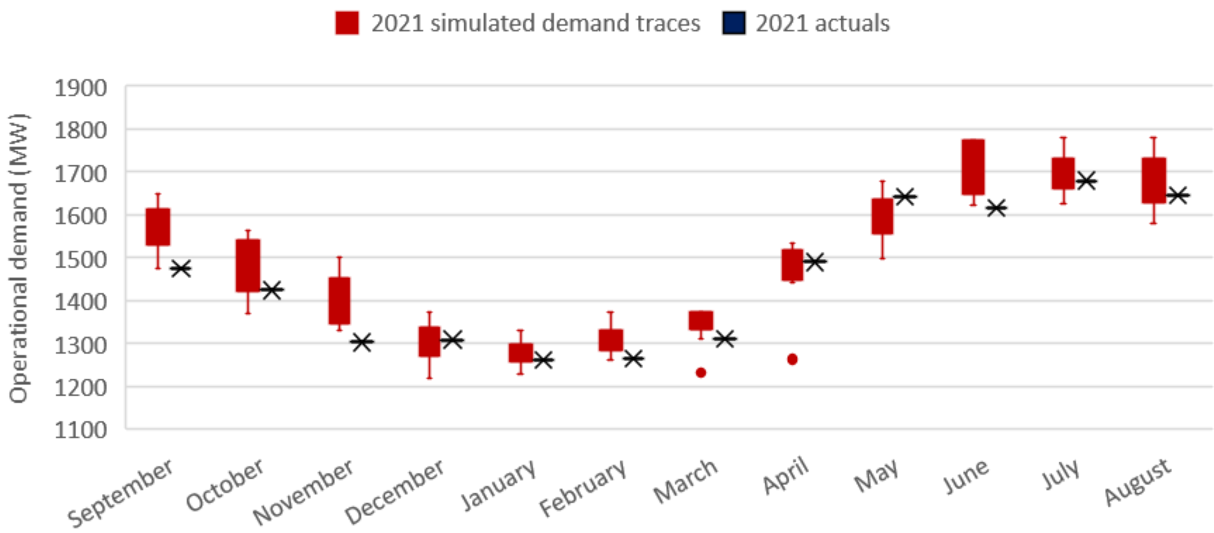
Annual minimum demand occurred on Monday 8 February 2021 at 02:00 local time, when the temperature was 11.6°C. Tasmania is particularly affected by industrial activity, and as such minimum demand is inherently volatile.

- A large industrial load was having a partial outage at that time, resulting in an overall large industrial load demand of 617 MW, slightly under 624 MW, which is the forecast median for 50% POE demand, while 594 MW is the forecast median for a 90% POE outcome. Due to the importance of large industrial loads for Tasmanian minimum demand, this suggests a minimum between a 50% POE and 90% POE outcome.
- Minimum demand was forecast to occur overnight, subsequently with moderate temperatures and no PV generation. Each of these actuals fell well within expectation.
- Simulation outcomes were weighted towards occurring on the weekend and in March. The occurrence in February (on the night following Sunday) is, however, within expectations.

Monthly maximums

The box plot in Figure 28 shows the range of monthly demand maximums for the 2021 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums mostly fell within the simulated ranges, although November (which was unusually warm[25] and did not bring any cold snaps which normally cause the November maximum demand events) is just under the range formed by the 10% POE and 50% POE traces. Had traces been available for 90% POE, it would most likely have fallen within that wider range. June is similarly under the range, with June being mild, and in particular night-time temperatures being higher than normal[26]. The inclusion of this 2020-21 reference year in the 2021 ESOO has improved the monthly distribution of possible maximum demand events.

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.

[25] See Bureau of Meteorology's Climate summaries at http://www.bom.gov.au/climate/current/month/tas/archive/202011.summary.shtml.

[26] See Bureau of Meteorology's Climate summaries at http://www.bom.gov.au/climate/current/month/tas/archive/202106.summary.shtml.

Figure 29 Victoria demand with extreme events identified

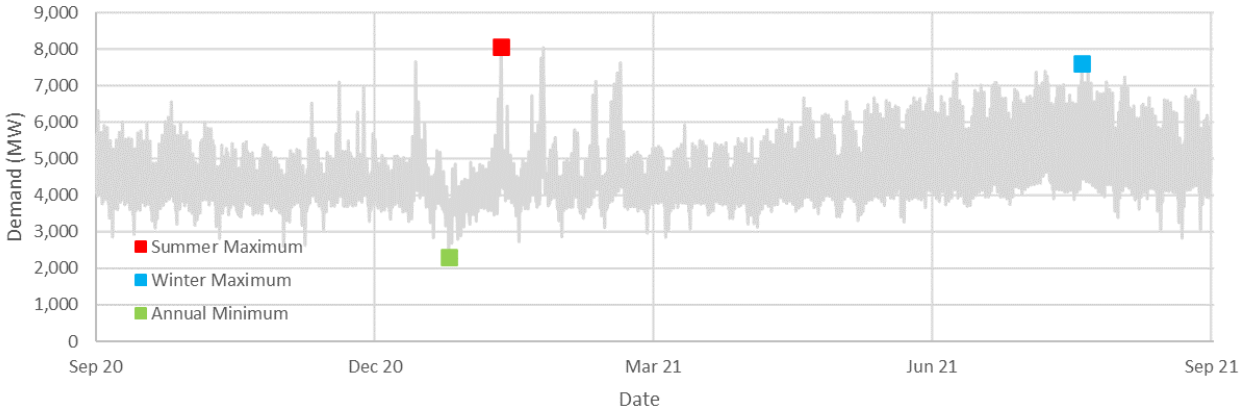


Figure 30 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. All demand events fell outside the 90% POE to 10% POE range. The likely reasons are discussed below.

Figure 30 Victoria simulated extreme event probability distributions with actuals

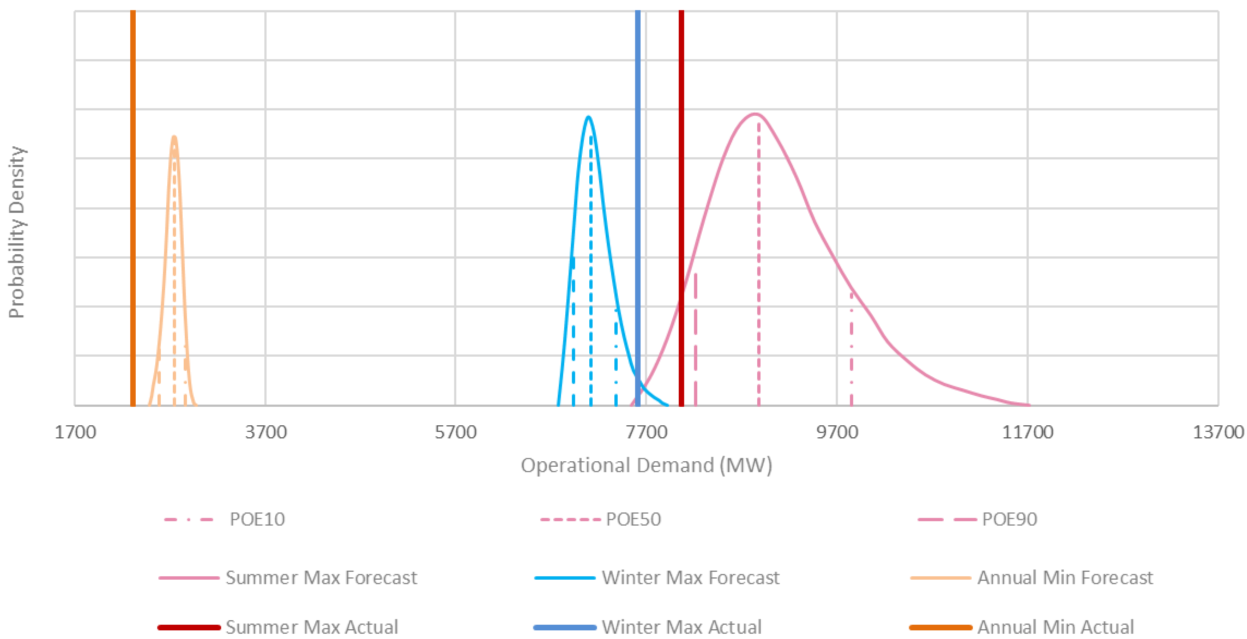


Table 21 Victoria 2020 extreme demand events

Event	**Summer maximum**	**Winter maximum**	**Annual minimum**
NEM Datetime	Mon, 11 January 2021, 17:00	Tue, 20 July 2021, 18:00	Fri, 25 December 2020, 13:00
Temperature* (°C)	35.4	8.8	18.3
Max temperature (°C)	36.0	11.6	19.3
Min temperature (°C)	19.5	6.7	13.3
Losses (MW)	499	489	123

Event	Summer maximum	Winter maximum	Annual minimum
NSG output (MW)	168	144	260
Rooftop PV output (MW)	524	0	1,653
Sent out (OPSO)	**8,070**	**7,606**	**2,313**
Auxiliary (MW)	341	366	216
As generated (OPGEN)	**8,411**	**7,972**	**2,529**

* 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 Monday 11 January 2021 at 17:00 NEM time. At the time of maximum demand, Melbourne (Olympic Park) recorded a temperature of 35.4°C, with an earlier daily maximum temperature of 36.0°C.

- The actual demand event was below the 90% POE forecast, most probably a reflection of the relatively low (for Melbourne) maximum temperature reached that day, with the La Niña causing very mild summer temperatures across most of Australia. Being rather early in January, not all business may have been back to full operation after the Christmas break.
- Two other days (Sunday 24 January and Monday 25 January) had daily maximum temperatures exceeding that observed on 11 January, with temperatures on 25 January peaking at 39.2°C and demand only a few megawatts below that seen on 11 January. Demand is likely not to have peaked on these days because Australia Day was on Tuesday 26 January, and many would have also taken 25 January off for an extended weekend.
- Victoria had three consecutive extreme weather days from Thursday 30 January 2020 to Saturday 1 February 2020, with temperatures only dropping to 21.5°C overnight into the Friday and 23.5°C into the Saturday. While the heatwave would suggest a very high maximum demand outcome, there was a cool change on Saturday afternoon that granted the state relief and reduced the severity of the event, resulting in the peak occurring on the Friday.
- PV normalised generation at time of peak was roughly 0.2 MW per MW of installed capacity, consistent with the observed time of the peak. As for most other regions, installed PV capacity was under-forecast, with the actual installed capacity at the time of maximum demand being 148 MW above forecast.
- Simulation outcomes were weighted towards occurring during weekdays and January. Typically demand in early January is lower due to the holiday season. The early January date for maximum demand is slightly inconsistent, but there were not many high temperature days in Victoria this summer.
- The demand outcome below the 90% POE follows two years in a row where summer maximum demand fell in the higher end of the forecast distribution. It highlights the uncertainty in Victoria's summer maximum demand forecast, where temperatures at time of peak can vary significantly from year to year.

Winter maximum demand occurred on Tuesday 20 July 2020 at 18:00 NEM time, with a temperature of 8.8°C recorded at Melbourne (Olympic Park).

- Victoria had its winter evening peak in 2020 on one of the coldest days of the season with a daily maximum temperature of 11.6°C and a daily minimum of 6.7°C. Simulated temperature outcomes ranged from 5°C to 15°C which, on the basis of temperature alone, would suggest a peak demand just below 50% POE.
- Simulation outcomes were weighted towards occurring during weekdays and in the July/August period, which is consistent with the actual occurrence.

Figure 31 Victoria simulated input variable probability distributions with actuals

Annual minimum demand occurred on Friday 25 December 2020 (Christmas Day) at 13:00 NEM time, when the temperature was 18.3°C. This is just the second year where minimum demand has occurred midday.

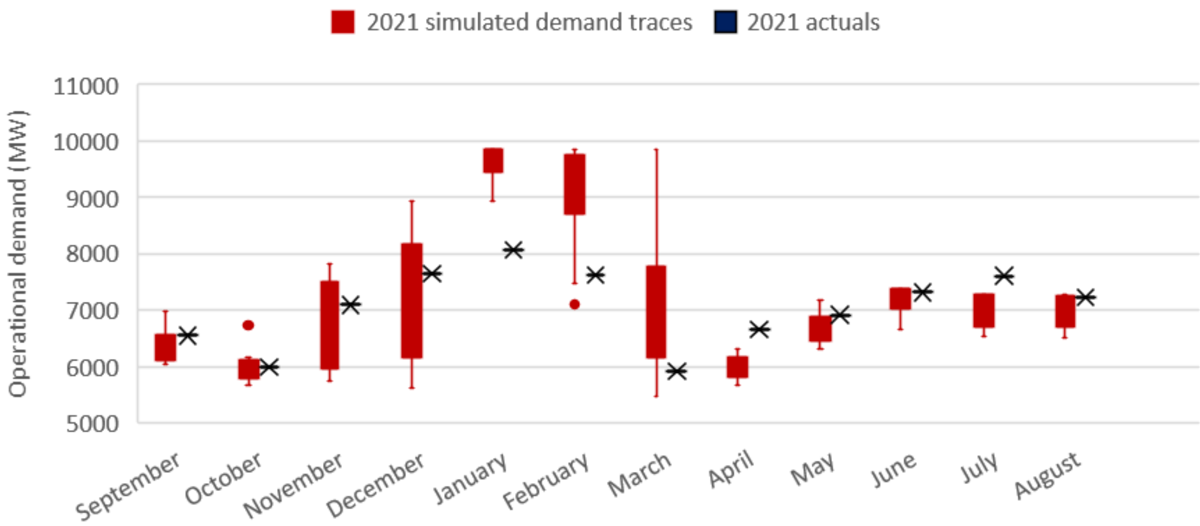
- Overall, the temperature alone would have suggested an outcome in the middle of the distribution. However, two other drivers had a significant higher impact, as discussed below.

- Minimums on Christmas Day tend to be particularly low when mild, sunny days coincide with this day. This happens very rarely (and can be seen as an outlier outcome). As result, the observed minimum was much lower than 50% POE.
- Also explaining this, 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 as well as the higher level of actual PV installations compared to forecast for Victoria.
- Simulation outcomes were weighted towards occurring on the weekend and in spring or autumn. Christmas Day occurrences are rare, and therefore do not show up in the distribution charts, but when they happen, they are typically very low, consistent with the Friday 25 December 2020 occurrence.

Monthly maximums

The box plot in Figure 31 shows the range of monthly demand maximums for the 2021 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums mostly fell within the simulated ranges. Due to the very mild summer with an actual maximum (occurring in January) below 90% POE, the shown January actual is of course below the range spanned by 10% and 50% POE traces. Similarly, with the winter maximum demand in July above 10% POE, the actual for that month is outside the range. April saw unusually warm weather in Victoria, with two consecutive days of temperatures above 30°C in Melbourne (Olympic Park) on 2 and 3 April 2021. It was the first time since 2005 this had happened[27]. As a result, the April actual is also above the simulated range.

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



[27] See Bureau of Meteorology's Climate summaries at http://www.bom.gov.au/climate/current/month/vic/archive/202104.melbourne.shtml.

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 have shown the largest increase in supply proportion between 2019-20 and 2020-21.

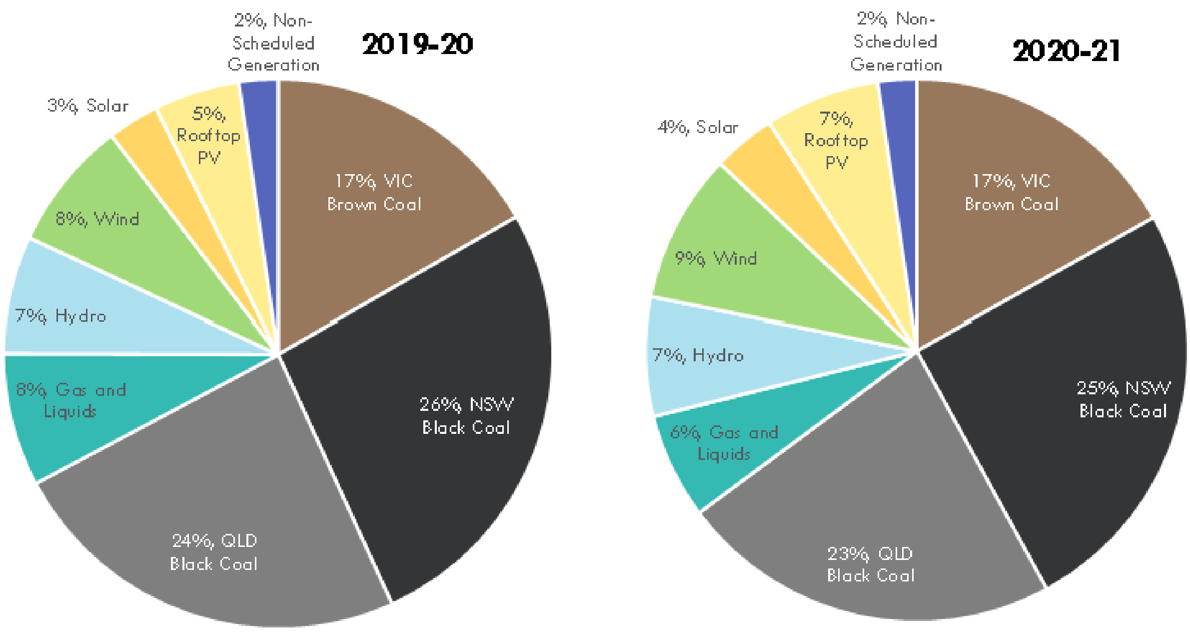
To assess the performance of supply forecasts, this section assesses:

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

Assessments have been prioritised for the major generation sources per region. For example, availability of coal generation is currently a larger contributor to the risk of unserved energy (USE) than solar generation. With the strong growth in grid-connected variable renewable generation, ~3200 MW were added between July 2020 and July 2021[28], wind and solar generator availability will contribute more to total forecast USE in the years to come.

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, 2019-20 and 2020-21



Supply availability is an important input in reliability studies, given it is commonly 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 2020 ESOO matched actual generation availability.

There are numerous reasons why actual supply availability may not match that forecast during peak periods of interest, including:

[28] 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.

- 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 are assumed not to occur in forecast.
- Weather resources for variable renewable energy (VRE) generators may fall outside the forecast simulation range.

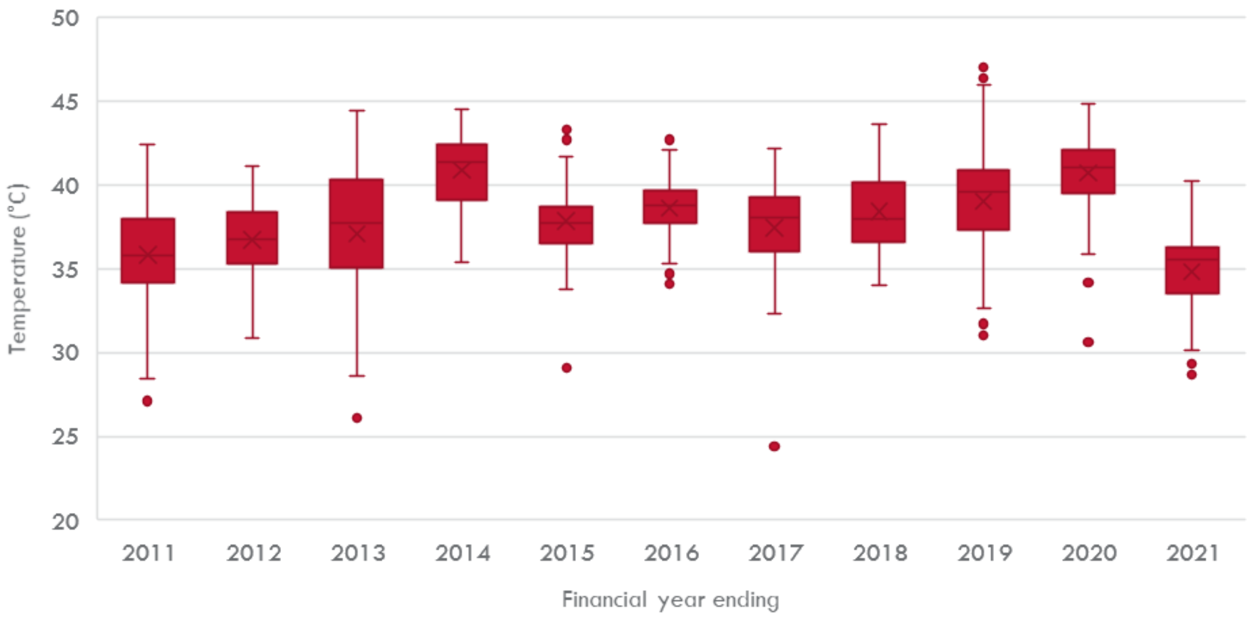
Consistent with the Forecast Accuracy Report Methodology[29], AEMO implements and publishes a variety of metrics to assess supply forecast accuracy. For each region, AEMO assesses the accuracy of generator commissioning and decommissioning schedules, then assesses supply availability, comparing actual 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. For the 2021 ESOO, AEMO updated the VRE trace methodology to better capture wind and solar generator performance. To demonstrate the impact of this trace change, simulated availability is shown for both methods.

The weather observed in summer 2020-21 was particularly mild, absent of the types of days considered in the development of generator peak summer ratings. Figure 34 shows a box plot[30] of the temperature range of the identified 40 hours in each of the last 11 years in South Australia noting weather in other regions followed a similar pattern. Without such high temperatures and the associated 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



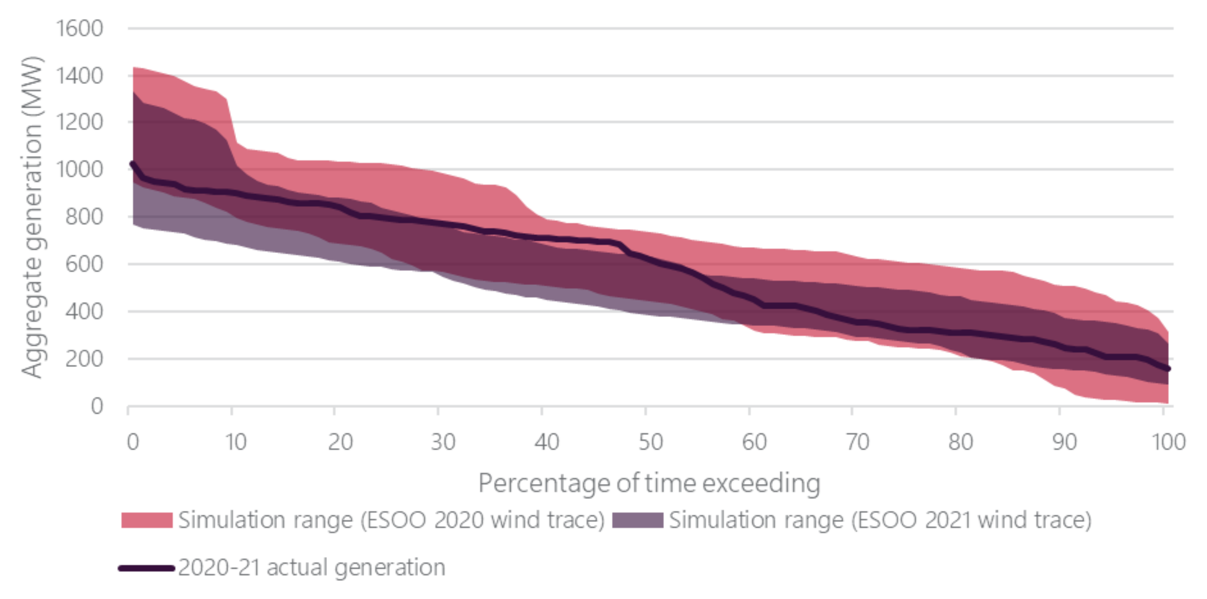
[29] Forecasting accuracy report methodology. See: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-accuracy-report-methodology/forecast-accuracy-reporting-methodology-report-aug-20.pdf

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

Example supply availability interpretation

Figure 35 shows an example graph of supply availability, using South Australian wind generators as an example. The graph compares simulated availability to actual availability from identified periods of each simulated, or actual year, ordered from highest to lowest availability. The red range shows the 2020 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 used. For the 2021 ESOO, AEMO updated the VRE trace methodology to better capture wind and solar generator performance. The purple range shows the range should the 2021 wind trace method have been applied in the 2020 ESOO.

Figure 35 Example simulated and actual supply (New South Wales wind generation)



In this example, the 2021 ESOO simulated availability is shown to be lower than the 2020 ESOO simulated availability in many intervals, due to the additional consideration for high wind and temperature impact. Actual (observed) supply remained high throughout these periods of interest due to the mild summer observed in 2020-21 with less instances of temperature derating. Actual supply was within the 2020 simulation range which did not consider temperature derating fully but slightly above the 2021 simulation range which did consider temperature derating. Given the intent of the simulations is to capture availability during high temperature periods, the results better align with the 2021 simulated range, despite the exceedance this unusually mild year.

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

- Delays in commissioning new generators, when compared to participant provided dates meant that availability of new capacity was below expectation throughout summer 2020-21. This was observed predominantly amongst new solar generators.
- Generator forced outage rates for black coal-fired generators continued to worsen in New South Wales and Queensland, but were mostly aligned with assumptions.
- Counter to expectation, given the mild weather, supply availability in both New South Wales and Queensland was below the simulated range. However, this did not result in reliability concerns due to

surplus dispatchable capacity and low maximum demand outcomes, and may have instead been caused by generator decommitment through the periods of interest due to low levels of observed supply scarcity.

- New wind trace methods were deployed for the 2021 ESOO to better capture the impact of high wind and temperature events. Both 2020 and 2021 methods were compared to actual output observed during summer 2020-21. Consistent with expectation, given the mild weather, actual output was towards the top, or above both simulated ranged in most regions.

6.1 New South Wales

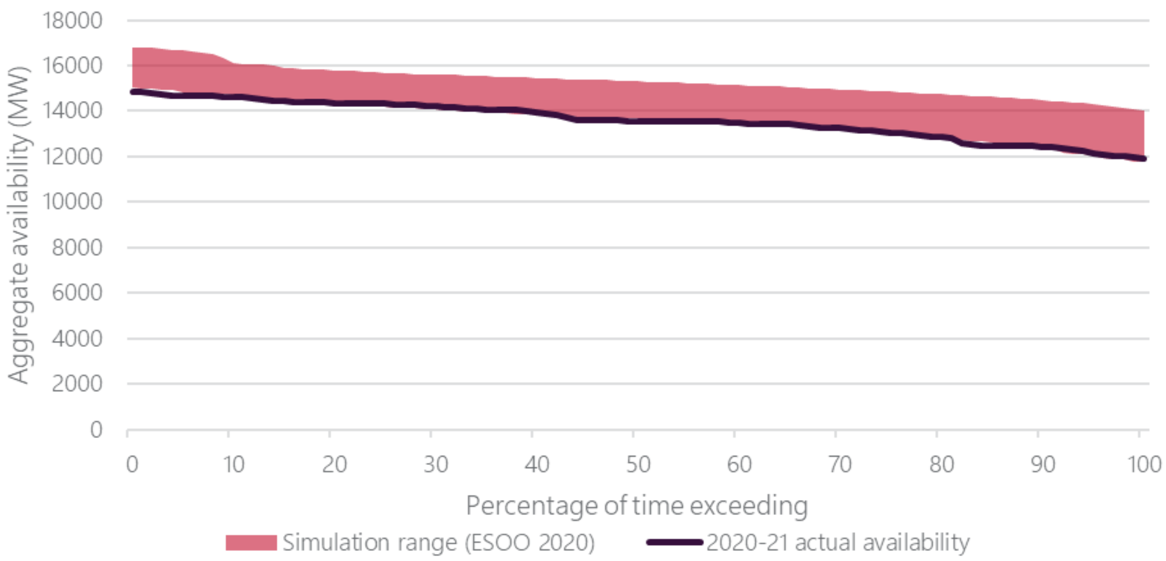
AEMO collects generation information reported from generator participants on the commissioning, decommissioning, and capacity of individual generators. Table 22 shows how the information was implemented in the 2020 ESOO, compared to actual generator characteristics for February 2021. While one generator began commissioning ahead of schedule, availability throughout the commissioning of numerous generators was below participant provided expectations. As a result, 776 MW of forecast available capacity was not actually available last summer.

Table 22 Forecast and actual generation count and capacity, February 2021

New South Wales	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	34	3,167	33	3,893	726	23%
Non-VRE generation/storage	51	14,691	53	14,741	50	0%
All generation	**85**	**17,858**	**86**	**18,634**	**776**	**4%**

Figure 36 shows total summer availability for New South Wales for the high temperature periods of interest. Despite the mild weather that should result in high availability, actual availability remains towards the lower end of, or below, the simulation range. The lower than forecast availability was primarily due to the delays of solar projects commissioning during summer 2020-21, and higher than expected forced outage rates during high temperature periods.

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 show an upward trend. Figure 37 shows the effective rates of unplanned outages, considering partial, full, and long duration outages. The outage rate in 2020-21 once again worsened against 2019-20, which was inconsistent with the 2020 ESOO projection. The 2020 ESOO projection was based on participant submissions that forecast improved performance. For the 2021 ESOO, participants have again submitted substantial improvements in the effective outage rate.

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

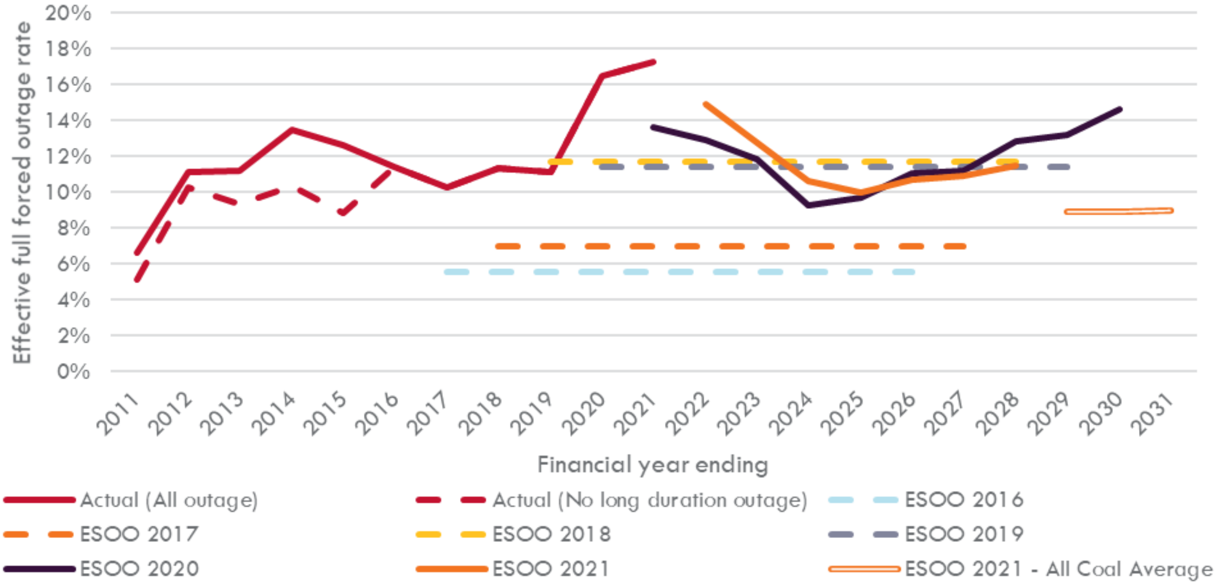
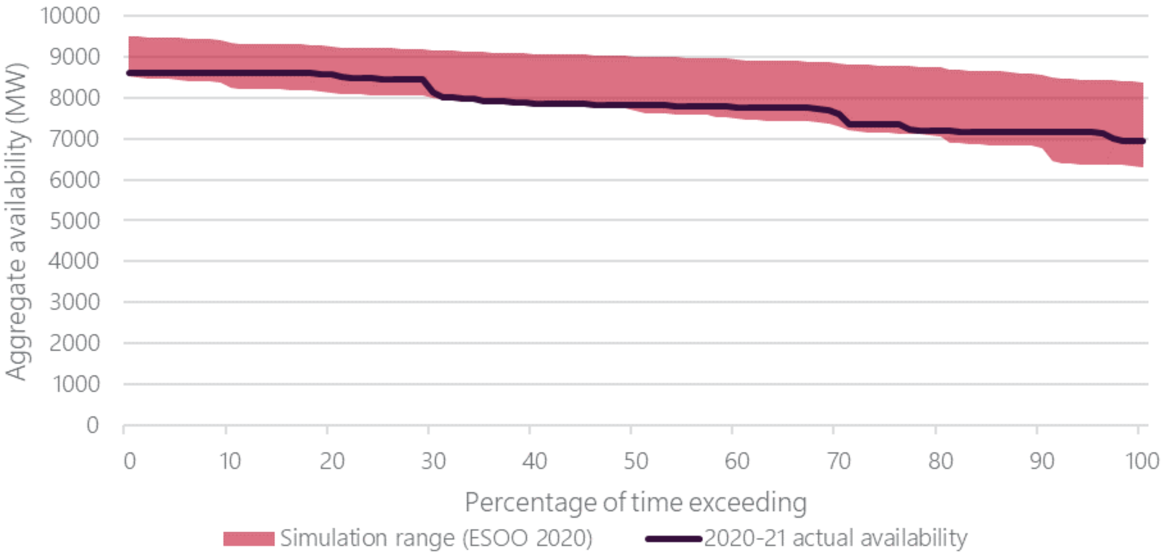


Figure 38 shows that actual availability for New South Wales black-coal generators over the top 10 hottest days was within, but towards the lower end of, the 2020 ESOO simulated range. Consistent with the mild weather, the actual availability of most generators was higher than expected due to the low levels of generator derating. However, the relatively low actual availability was driven by a single generator with regular prolonged outages.

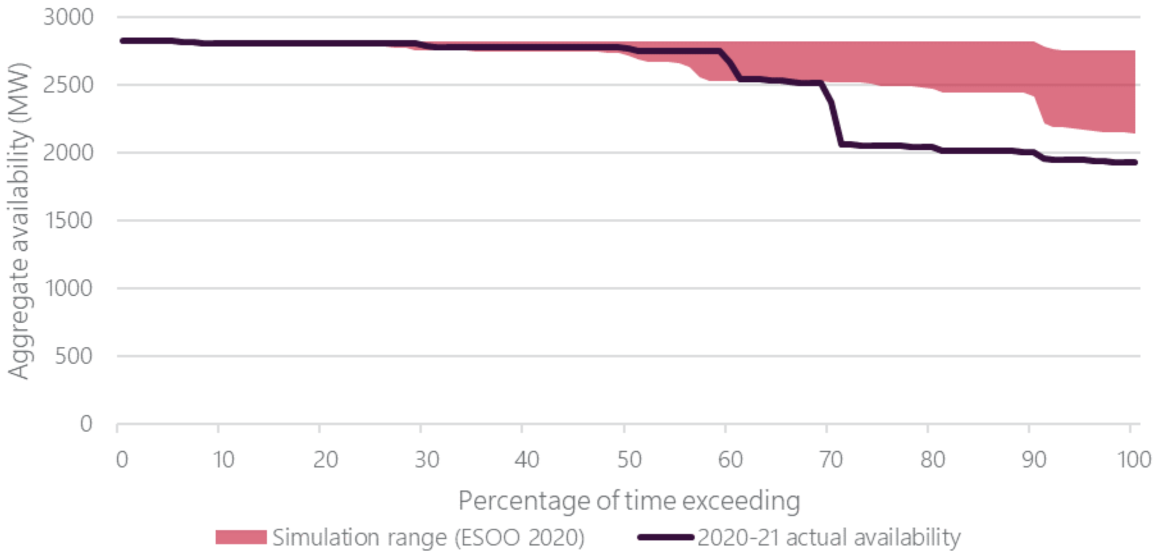
Figure 38 New South Wales black coal supply availability for the top 10 hottest days



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 2020-21, the observed availability was within, or lower than, the 2020 ESOO simulated range. The observed availability was lower than the 2020 ESOO simulated range on two of the top 10 hottest days, driven by outages on a number of units.

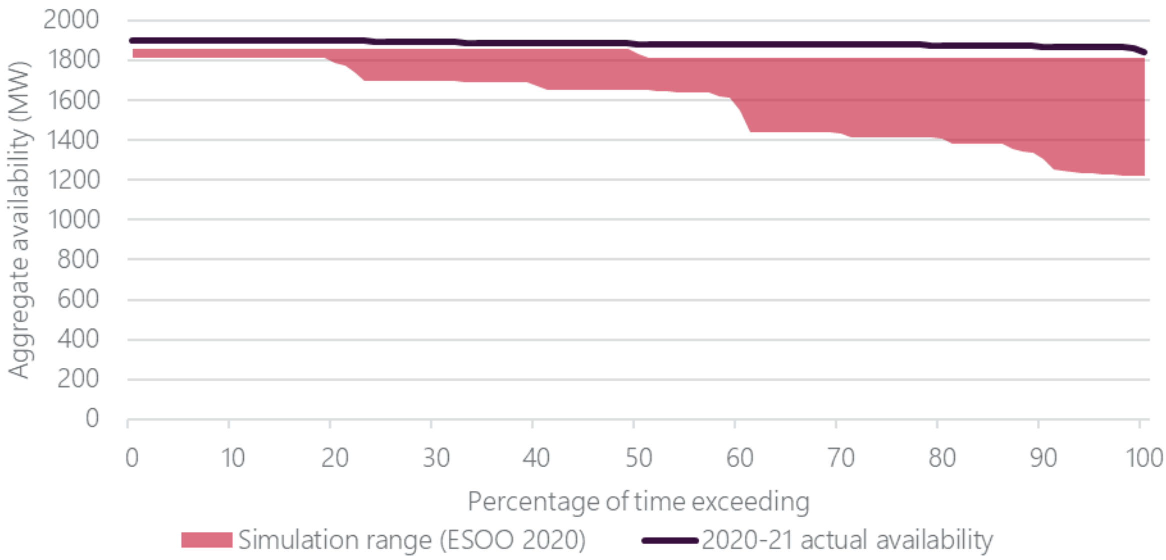
Figure 39 New South Wales hydrogeneration supply availability for the top 10 hottest days



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 2020-21, the observed availability was above the 2020 ESOO forecast, indicating that the generator fleet performed better than forecast during the observed mild weather last summer.

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

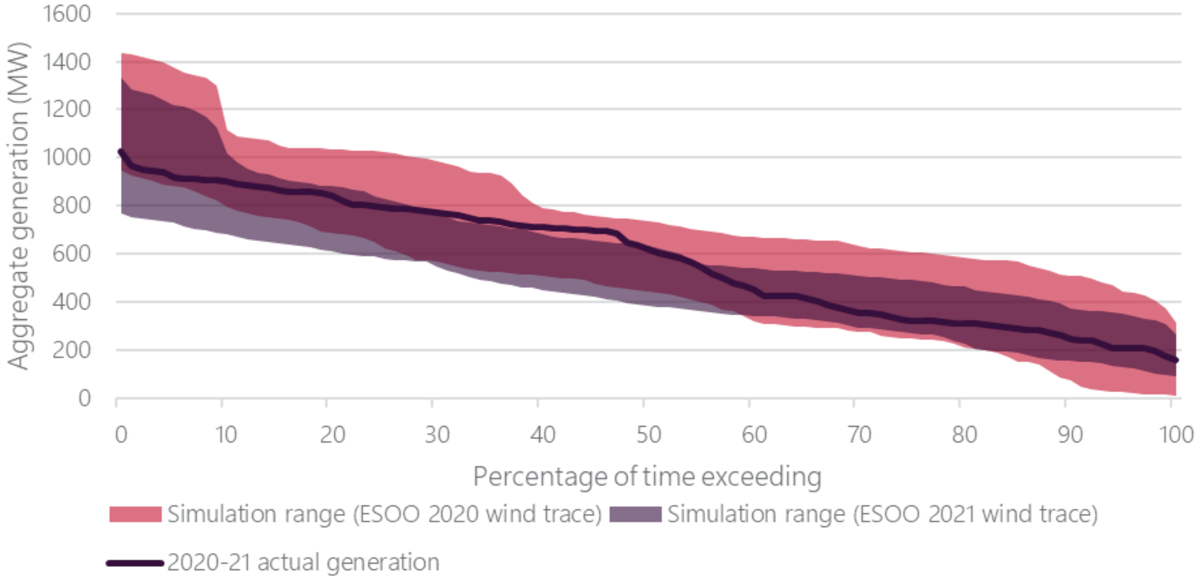


Wind

Figure 41 shows the aggregate generation for New South Wales wind generators over the top 10 hottest days, comparing actual with simulated output. The wind simulation method has changed for the 2021 ESOO, including use of new reanalysis data and resource-to-power conversion models[31]. Both simulation ranges are shown for comparison.

In 2020-21, the observed output was within, but towards the lower end of, the 2020 ESOO simulated range. The lower than anticipated output was due to the delays in generator full operation during summer 2020-21. The updated wind simulation method better captures high wind and high temperature derating events, but 2021 was a very mild summer, free from such weather events. Given the intent of the simulations is to capture availability during high temperature periods, the results better align with the 2021 simulated range, despite the exceedance.

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

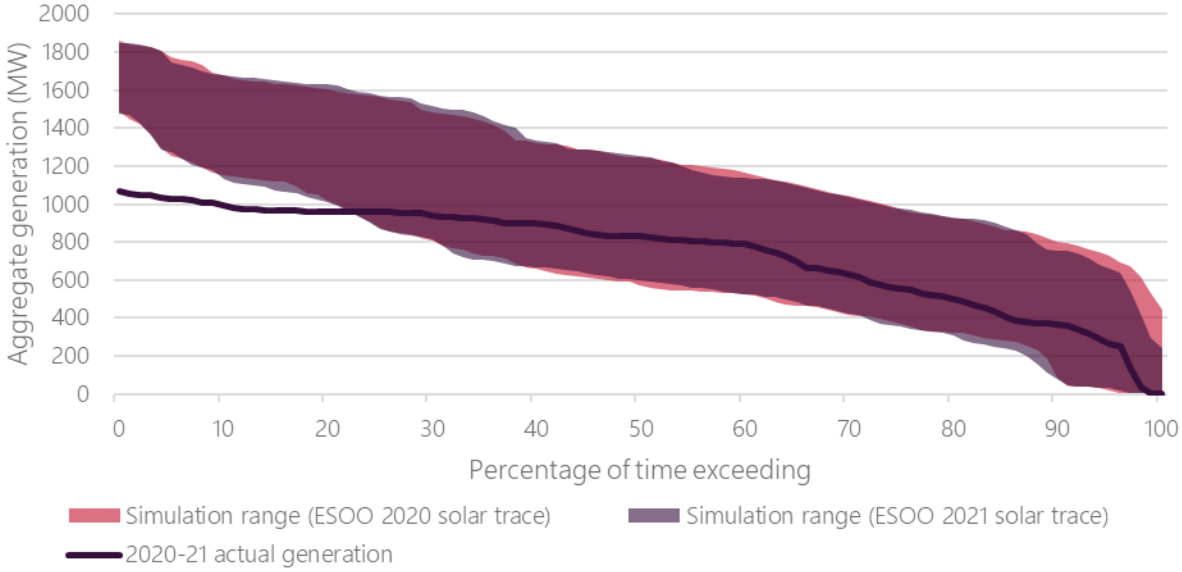


Large-scale solar

Figure 42 shows the supply availability for New South Wales large-scale solar generators over the top 10 hottest days, comparing actual with simulated availability using both 2020 ESOO and 2021 ESOO methods. In 2020-21, the observed availability was mostly within or below the 2020 ESOO simulated range. The lower than anticipated output was mainly due to the delays in generator full commissioning during summer 2020-21, and partially due to the curtailment of a few generators during high temperature periods.

[31] As flagged in the 2020 Forecast Improvement Plan, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-improvement-plan/forecast-improvement-plan-2020.pdf/.

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



6.2 Queensland

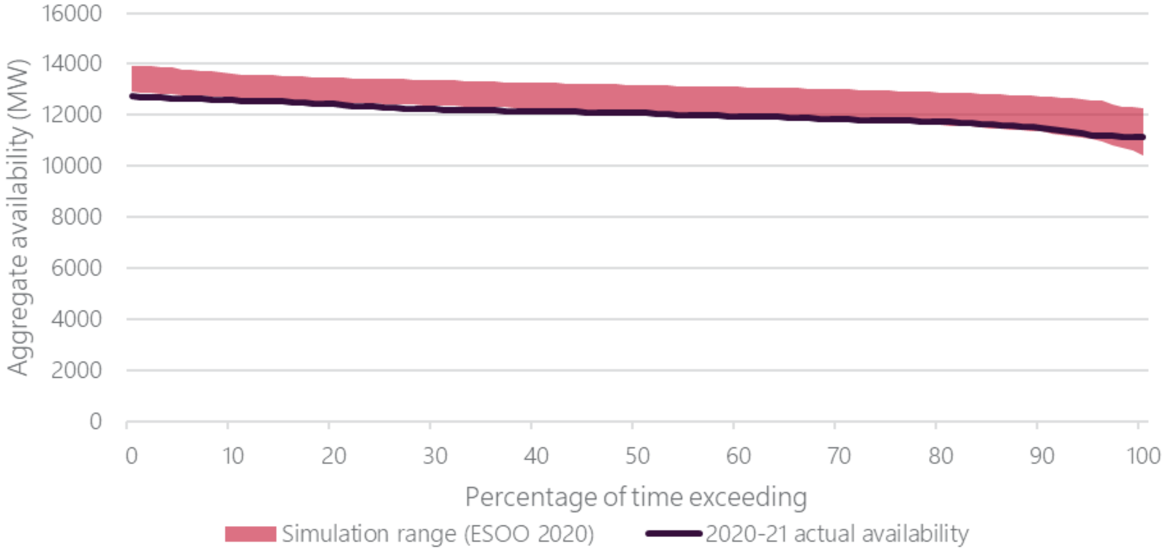
Table 23 shows how the Queensland generation information was implemented in the 2020 ESOO, compared to actual generator characteristics for February 2021. In aggregate, generators connected as projected, with one commissioned ahead of schedule, although available capacity was still behind schedule.

Table 23 Forecast and actual generation count and capacity, February 2021

Queensland generation	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	27	2,272	26	2,489	217	10%
Non-VRE generation/storage	55	12,355	56	12,389	34	0%
All generation	**82**	**14,626**	**82**	**14,877**	**251**	**2%**

Figure 43 shows total summer availability for Queensland high temperature periods of interest. Actual availability was mostly below, or towards the lower end of, the simulation range. The lower than forecast availability was primarily due to gas generator unavailability and solar curtailment, as explored in the technology aggregate sections below.

Figure 43 Queensland supply availability for the top 10 hottest days



Black coal

The effective full forced outage rate of black coal-fired generation in Queensland in 2020-21 worsened against 2019-20. The 2020 ESOO forecast, based on participant submissions, slightly under-estimated this outcome, as shown in Figure 44.

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

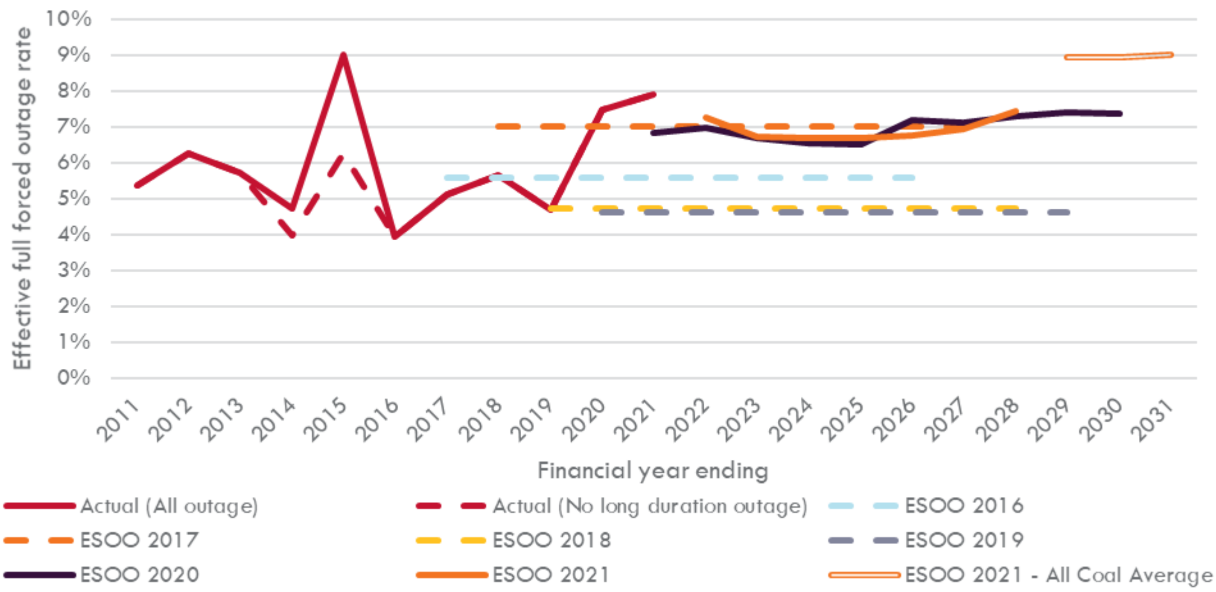
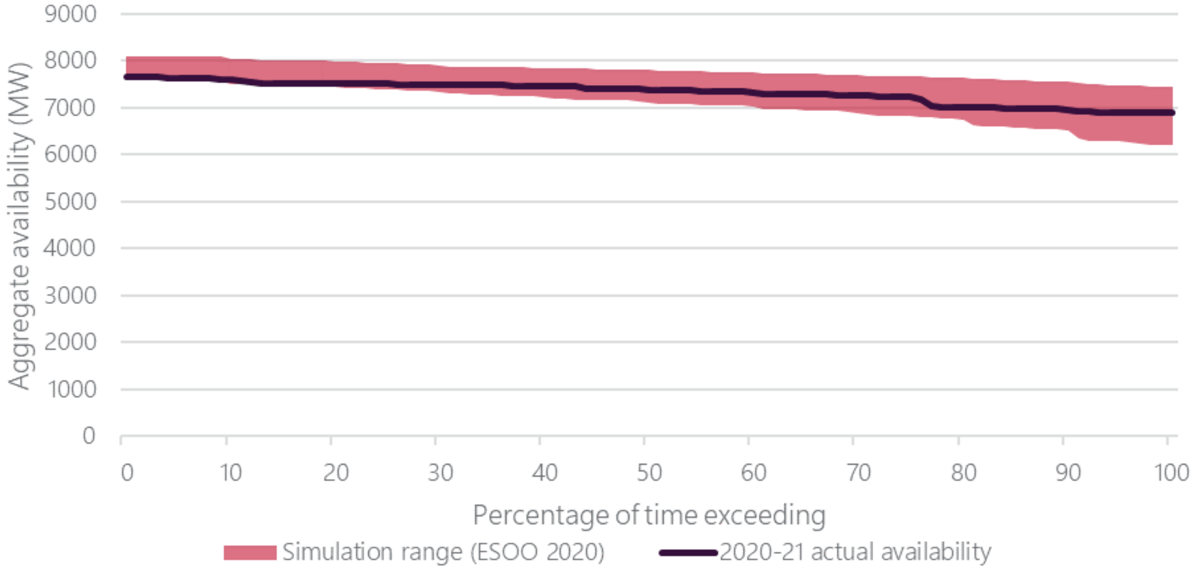


Figure 45 shows the supply availability for Queensland black coal generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was within the 2020 ESOO simulated range.

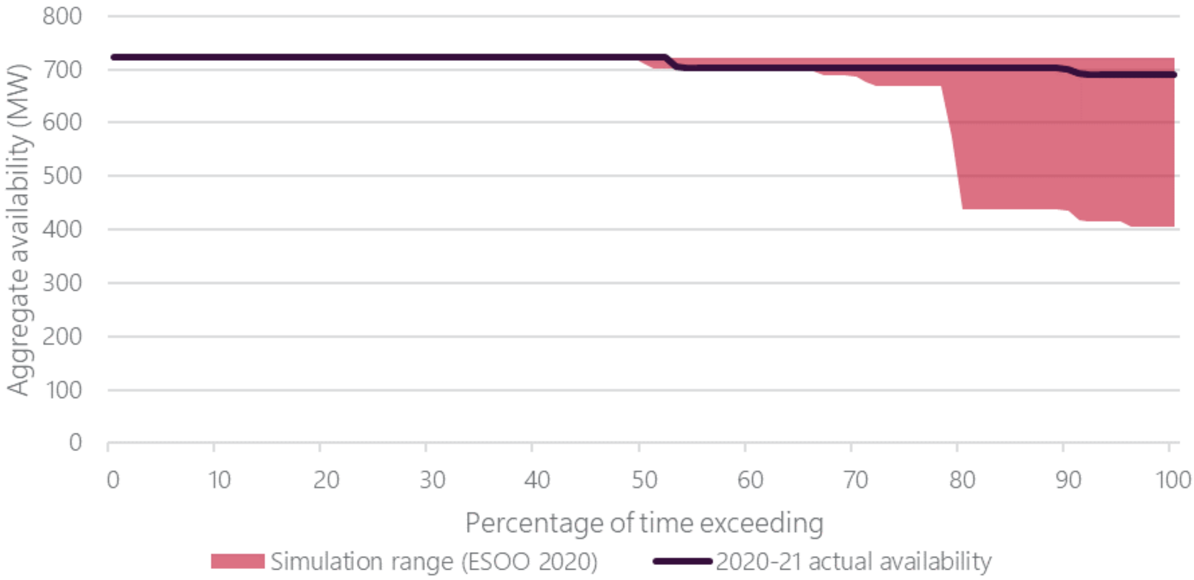
Figure 45 Queensland black coal supply availability for the top 10 hottest days



Hydro

Figure 46 shows the supply availability for Queensland hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was within, and towards the upper end of, the 2020 ESOO simulated range.

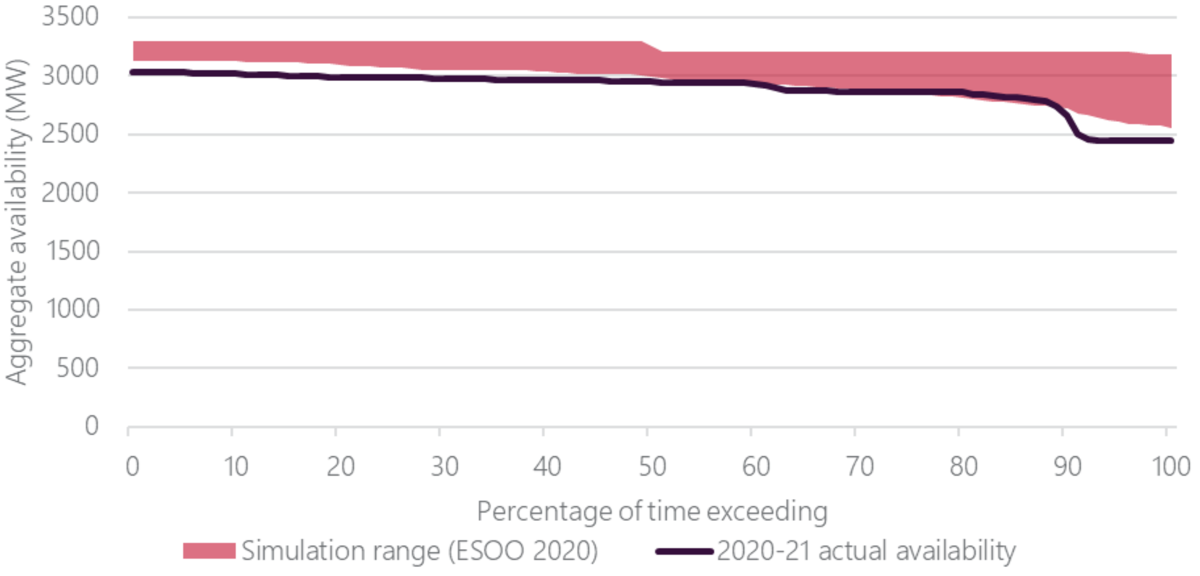
Figure 46 Queensland hydrogeneration supply availability for the top 10 hottest days



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. In 2020-21, the observed availability was mostly lower than the 2020 ESOO simulated range, due to the coincident unavailability of numerous units.

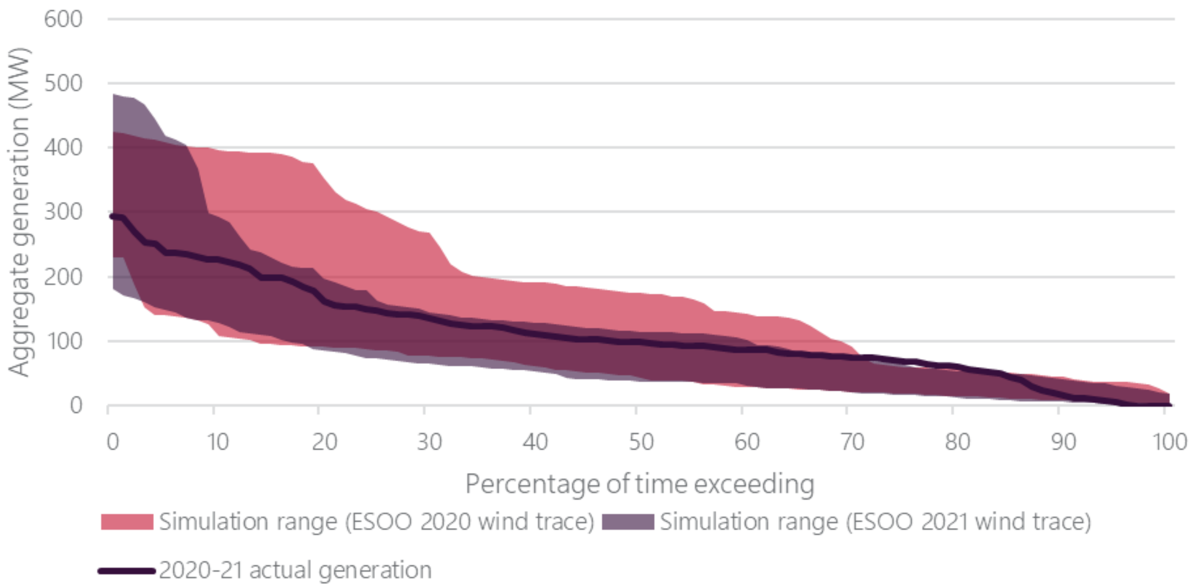
Figure 47 Queensland gas and liquids supply availability for the top 10 hottest days



Wind

Figure 48 shows wind generation supply for Queensland over the top 10 hottest days, comparing actual with simulated availability using both ESOO 2020 and 2021 approaches. In 2020-21, the observed output was mostly within both the 2020 ESOO and 2021 ESOO simulated ranges.

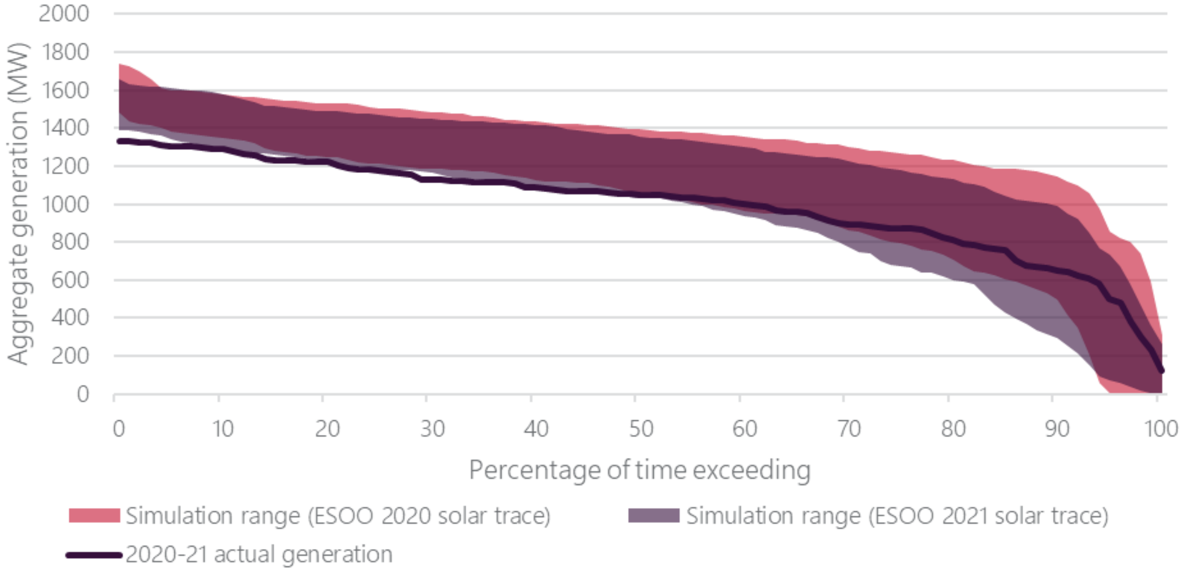
Figure 48 Queensland wind supply availability for the top 10 hottest days



Large-scale solar

Figure 49 shows the output of Queensland large-scale solar generators over the top 10 hottest days, comparing actual with simulated output, using both ESOO 2020 and 2021 approaches. In 2020-21, the observed availability was mostly below, or towards the lower end of, both simulated ranges. Generator commissioning was generally aligned with participant-provided schedules in Queensland. The predominant reason for excursion from simulated output ranges was curtailment due to constraints representing system security and network limitations.

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



6.3 South Australia

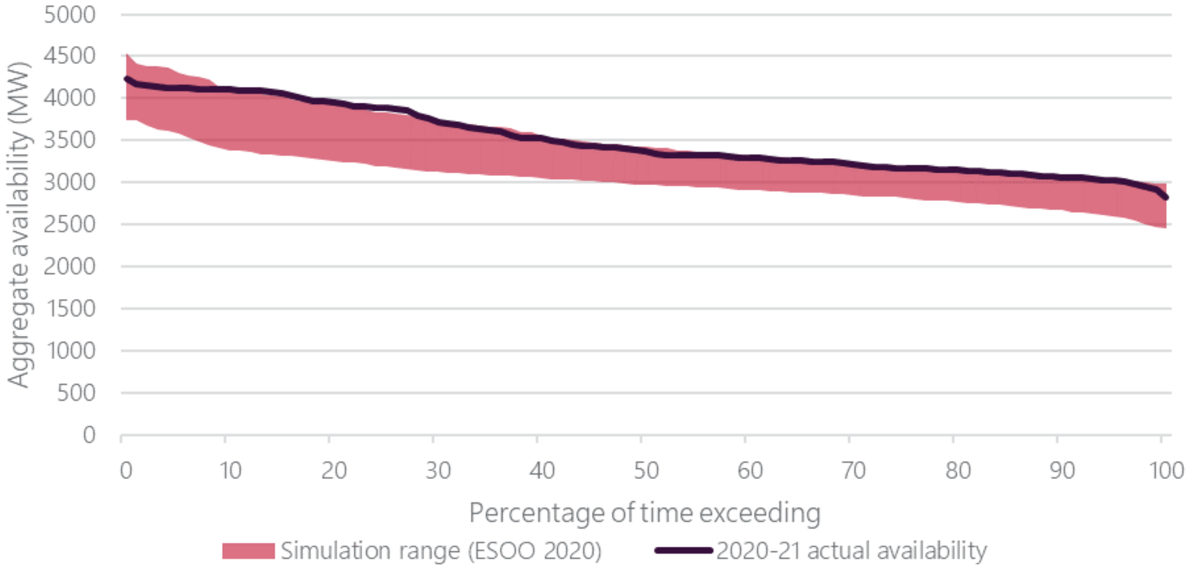
South Australian generation information, as reported by generator participants for the 2020 ESOO, is shown in Table 24 alongside actual generator characteristics in February 2021.

Table 24 Forecast and actual generation count and capacity, February 2021

South Australia	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	25	2,409	25	2,409	0	0%
Non-VRE generation/storage	62	3,256	62	3,256	0	0%
All generation	**87**	**5,665**	**87**	**5,665**	**0**	**0%**

Figure 50 shows aggregate summer availability for South Australia during the high temperature periods of interest. Actual availability was within, and towards the upper end of, the 2020 ESOO simulated range. This was attributed to the higher than expected gas availability and wind output, driven by the low levels of the derating during a mild temperature year.

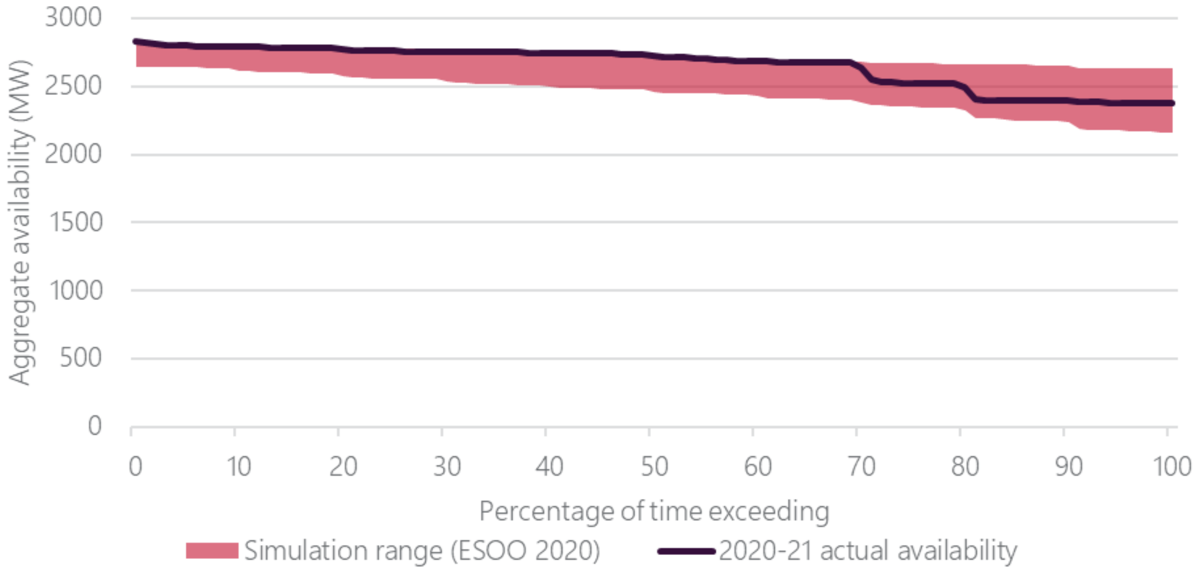
Figure 50 South Australia supply availability for the top 10 hottest days



Gas and liquids

Figure 51 shows that availability over the top 10 hottest days was mostly towards the upper end of 2020 ESOO simulated availability. The higher than forecast output was driven by less temperature derating throughout the mild summer, and a low rate of outages 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 with simulated output. In 2020-21, the observed output was mostly above the forecasting range in the 2020 ESOO. The excursion from the simulated range is due to the lower than expected temperature derating, which aligned with the relatively mild 2020-21 summer. This is confirmed by Figure 53, which shows the temperature and wind relationship for a South Australian location for the 40 hours sampled from the top 10 hottest days used for supply availability assessments. It indicates that the 2020-21 summer temperature was generally lower than other years, while the range of wind output was within the range historically observed.

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

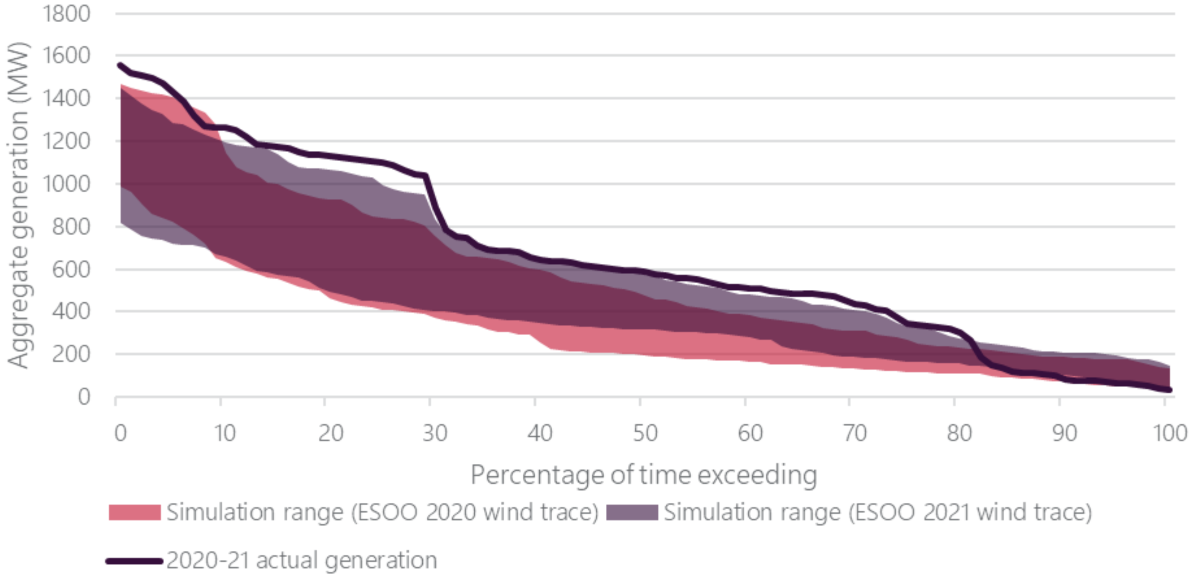
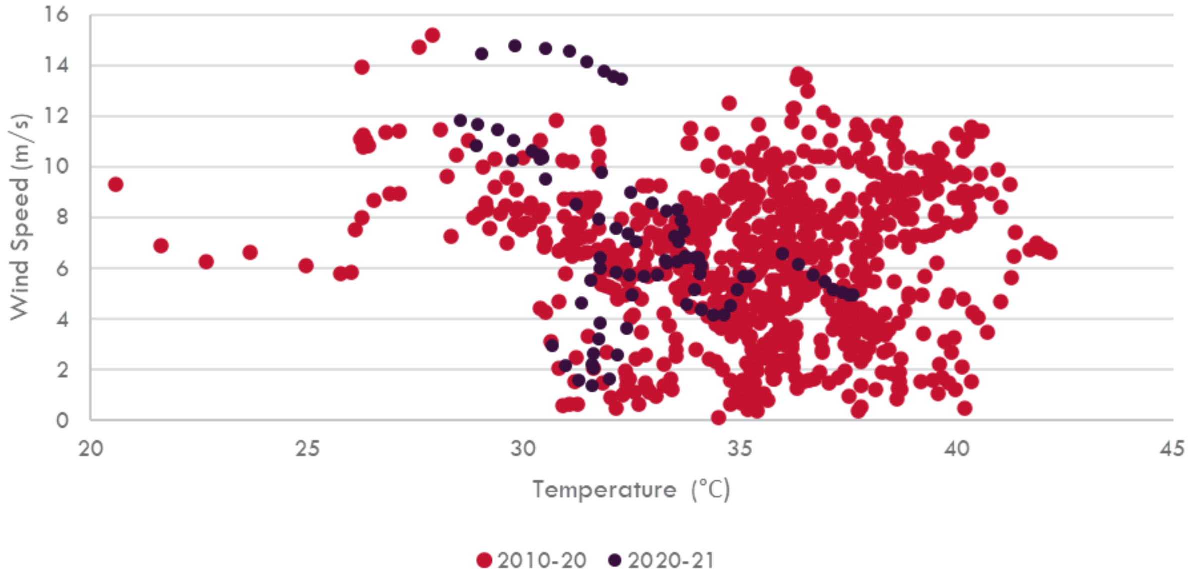


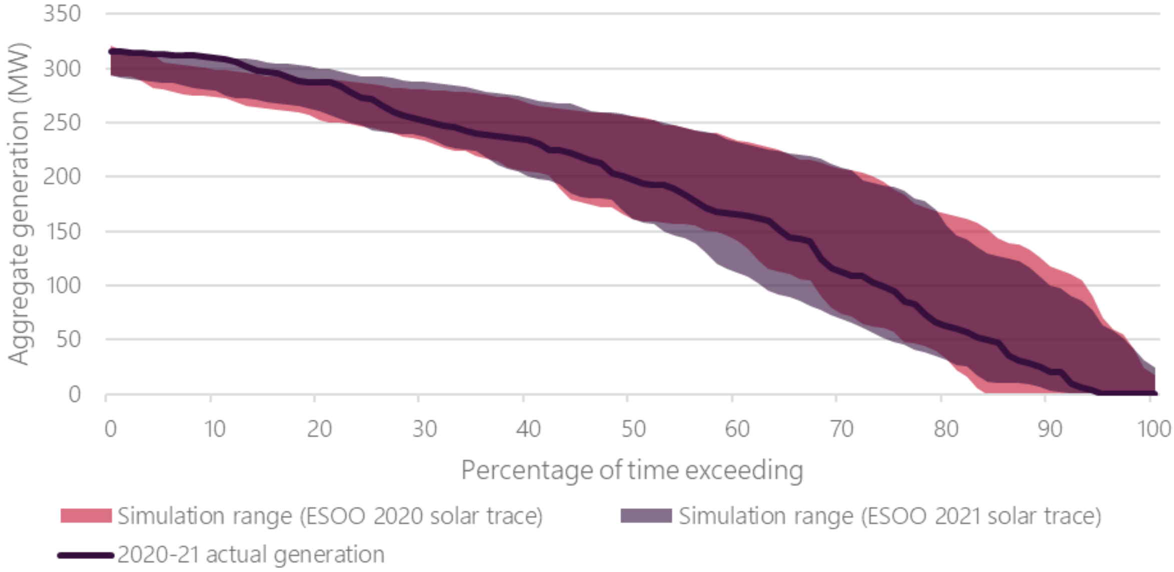
Figure 53 Scatter plot of temperature and wind speeds for the peak periods of 10 hottest day during South Australia summers



Large-scale Solar

Figure 54 shows the supply availability for South Australian large-scale solar generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was within the forecasting range in the 2020 ESOO.

Figure 54 South Australia large-scale solar supply availability for the top 10 hottest days



6.4 Tasmania

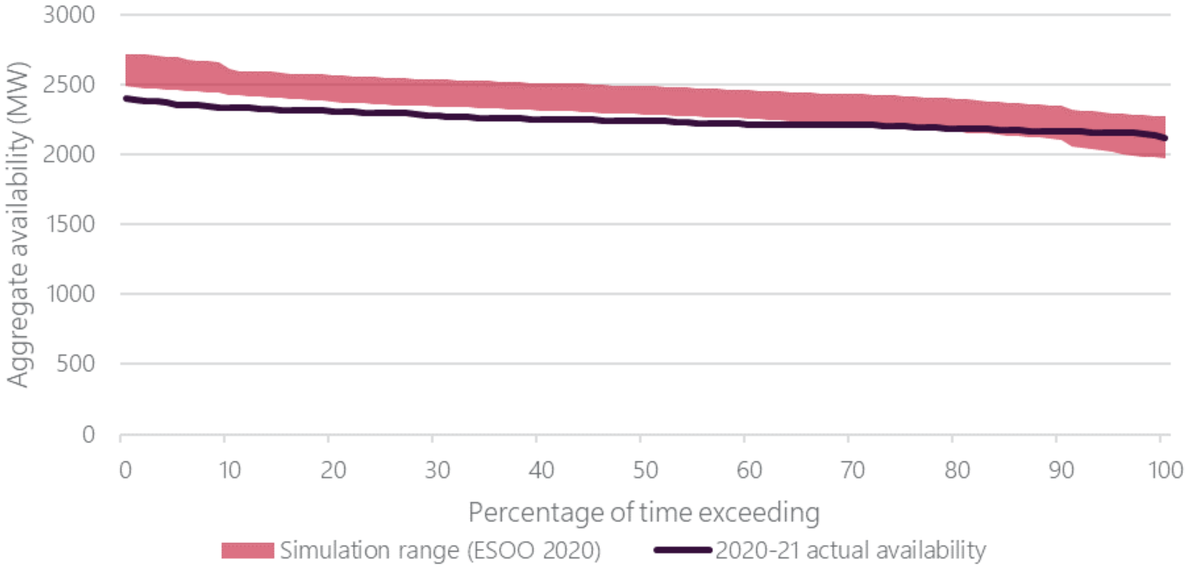
Table 25 shows how Tasmanian generation information was implemented in the 2020 ESOO, compared to actual generator characteristics for February 2021. In Tasmania, some generators that had indicated they would not be available during summer 2020-21 were actually available. While Tasmania is a winter-peaking region, the availability of surplus dispatchable hydro generation and the mainland support provided by Basslink limits the reliability risks during winter. This analysis therefore examines the availability of capacity during summer, when Tasmanian capacity may be valuable to support Victorian peak demand events.

Table 25 Forecast and actual generation count and capacity, February 2020

Tasmania	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	4	573	4	573	0	0%
Non-VRE generation/storage	49	2,348	48	2,265	-83	-4%
All generation	**53**	**2,921**	**52**	**2,839**	**-82**	**-3%**

Figure 55 shows total summer availability for Tasmania for the high temperature periods of interest. Actual availability was mostly below the simulation range, which was due to lower than expected hydro availability, as shown in the technology aggregate section below.

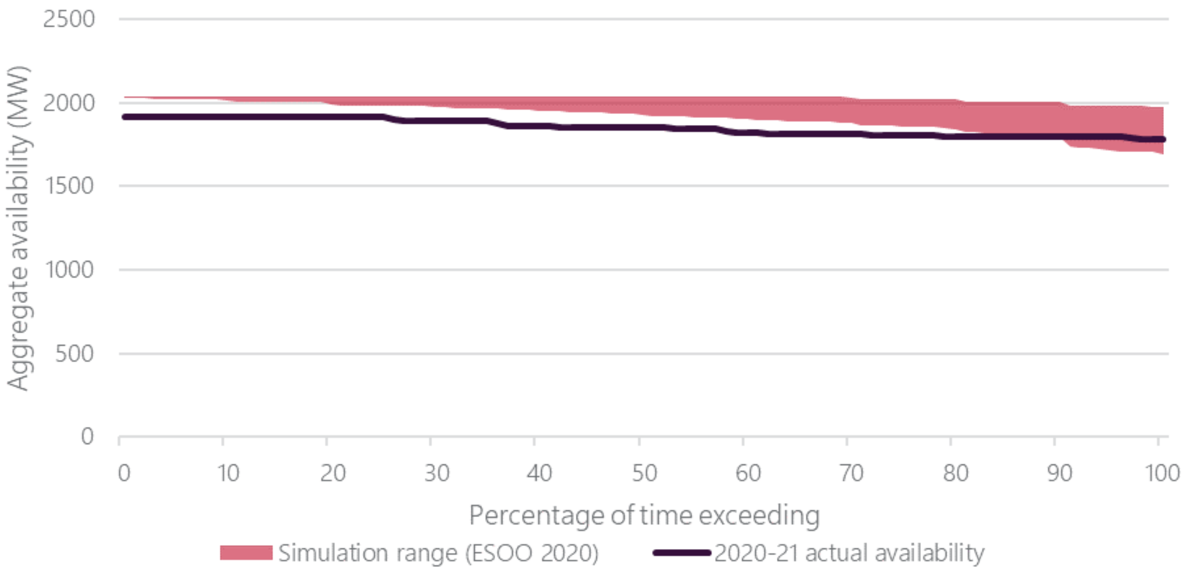
Figure 55 Tasmania supply availability for the top 10 hottest days



Hydro

Figure 56 shows the supply availability for Tasmanian hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was mostly below the 2020 ESOO simulated range. This was due to the higher rates of Tasmanian hydro generation unavailability during high temperature periods.

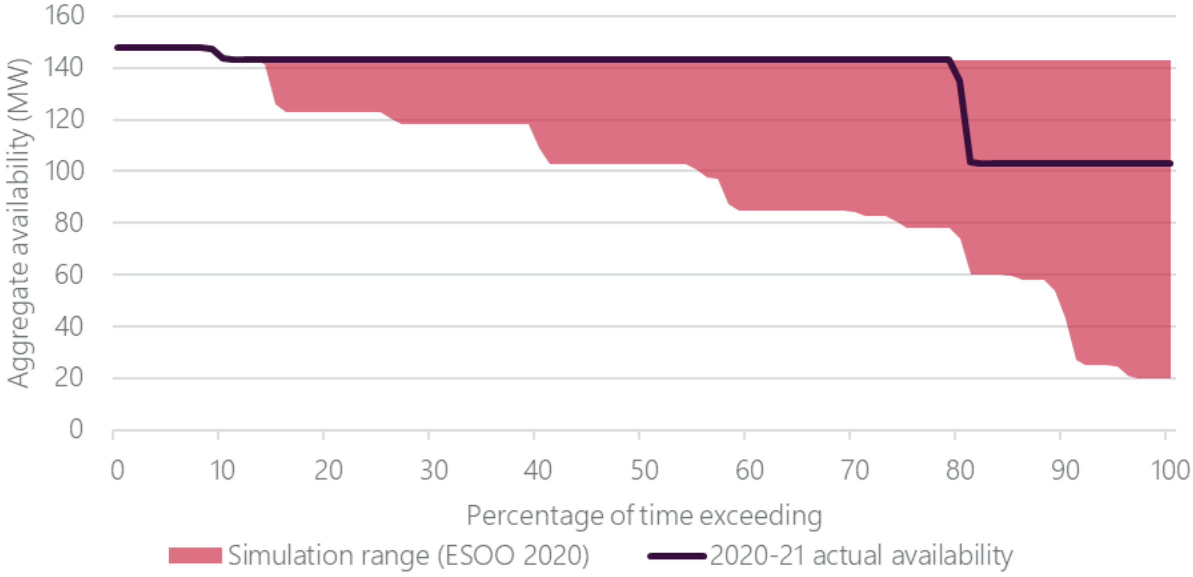
Figure 56 Tasmania hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 57 shows the supply availability for Tasmanian gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was mostly towards the upper end of the 2020 ESOO simulated range.

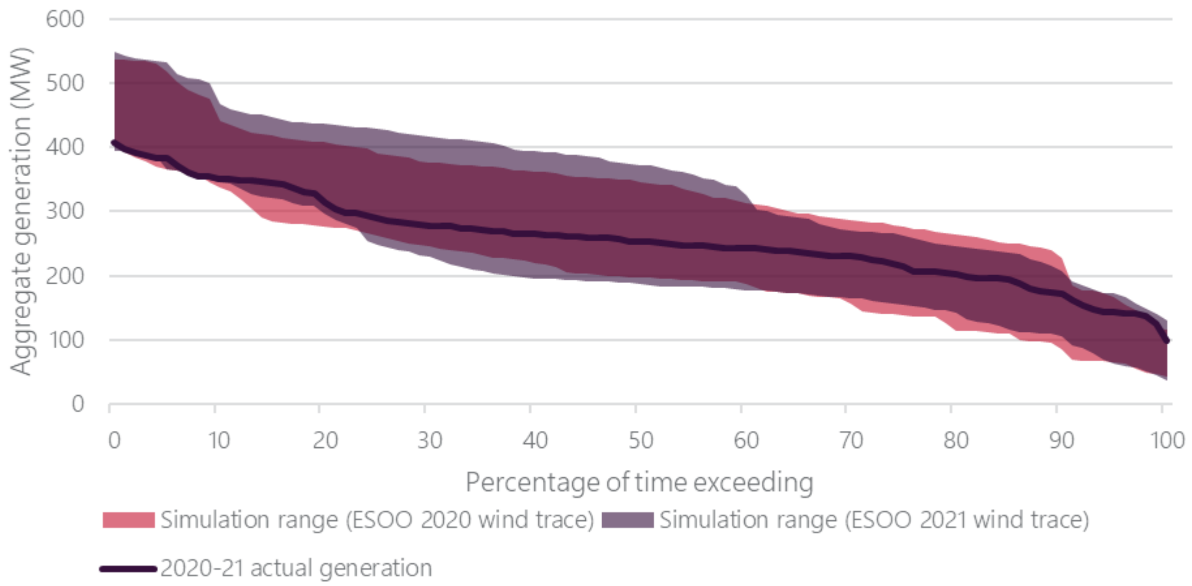
Figure 57 Tasmania gas and liquids supply availability for the top 10 hottest days



Wind

Figure 58 shows the output of Tasmanian wind generators over the top 10 hottest days, comparing actual with 2020 and 2021 ESOO simulated output. In 2020-21, the observed output was within the forecasting range of both the 2020 and 2021 ESOO.

Figure 58 Tasmania wind output for the top 10 hottest days



6.5 Victoria

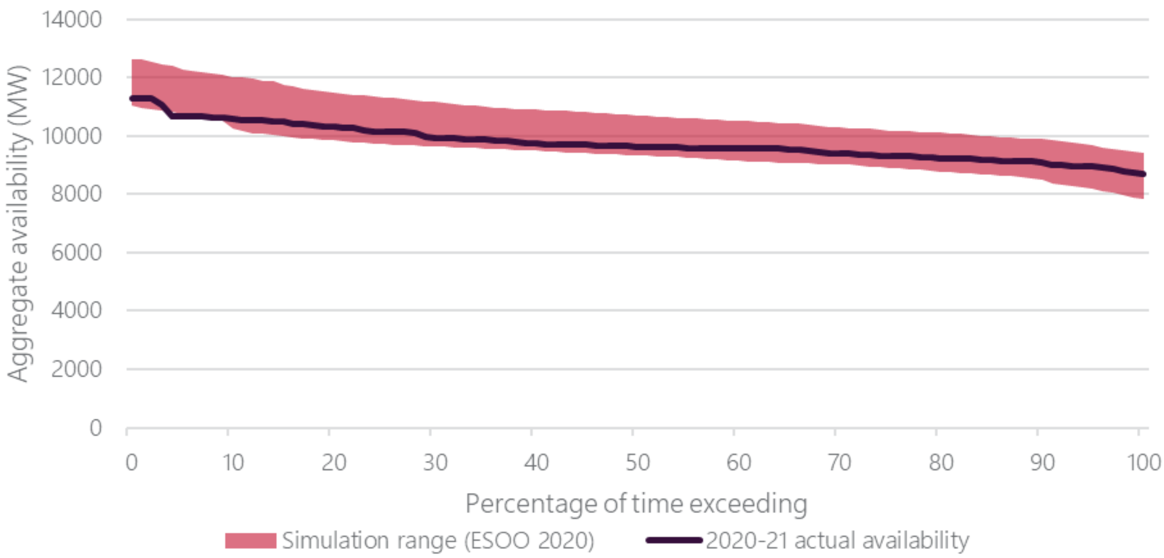
Victorian generation information, as reported by generator participants for the 2020 ESOO, is shown in Table 26 alongside actual generator characteristics for February 2021. In Victoria, numerous VRE projects were delayed compared to participant-provided information, resulting in substantially less generation availability than was forecast for summer 2020-21.

Table 26 Forecast and actual generation count and capacity, February 2021

Victoria	Facilities actually operating		Facilities forecast to operate		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	30	3,348	31	4,493	1,145	34%
Non-VRE generation/storage	67	9,469	67	9,469	**0**	**0%**
All generation	**97**	**12,817**	**98**	**13,962**	**1,145**	**9%**

Figure 59 shows aggregate summer availability for Victoria during the high temperature periods of interest. Actual availability was mostly within the 2020 ESOO simulated range. This was attributed to the lower than forecast brown coal outage rate and higher than expected gas availability, which combined to offset the reduced availability observed among VRE projects.

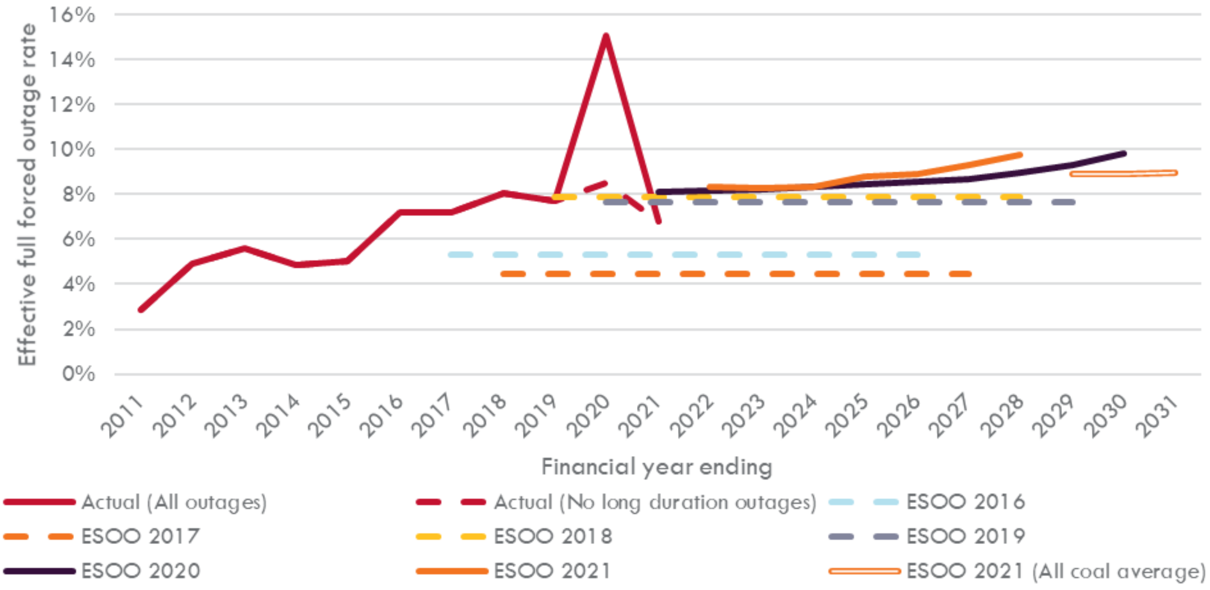
Figure 59 Victoria supply availability for the top 10 hottest days



Brown coal

Brown coal-fired generation in Victoria has experienced worsening reliability over the last 10 years, as demonstrated through the effective unplanned outage rate shown in Figure 60. The outage rate in 2020-21 was consistent but slightly lower than the aggregate forecast included in the 2020 ESOO.

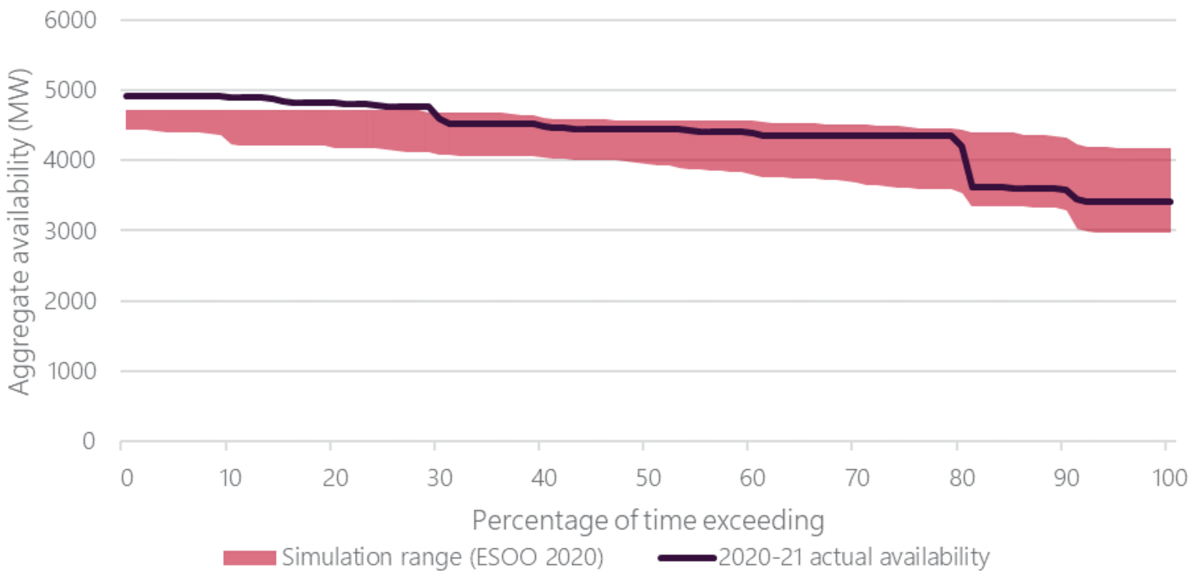
Figure 60 Victoria brown coal effective unplanned outage rates, forecasts including HILP outages



HILP: high impact, low probability

Figure 61 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 expectation, given the low levels of derating expected during a mild temperature year.

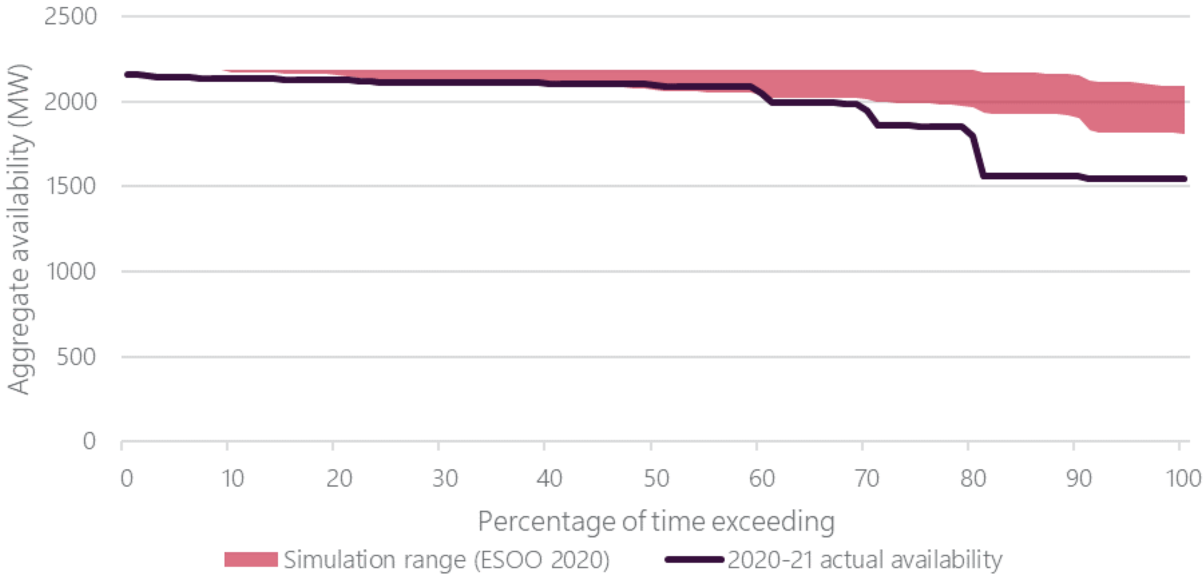
Figure 61 Victoria brown coal supply availability for the top 10 hottest days



Hydro

Figure 62 shows the supply availability for Victorian hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2020-21, the observed availability was mostly lower than the 2020 ESOO simulated range, predominantly due to unplanned outages during the identified high temperature periods.

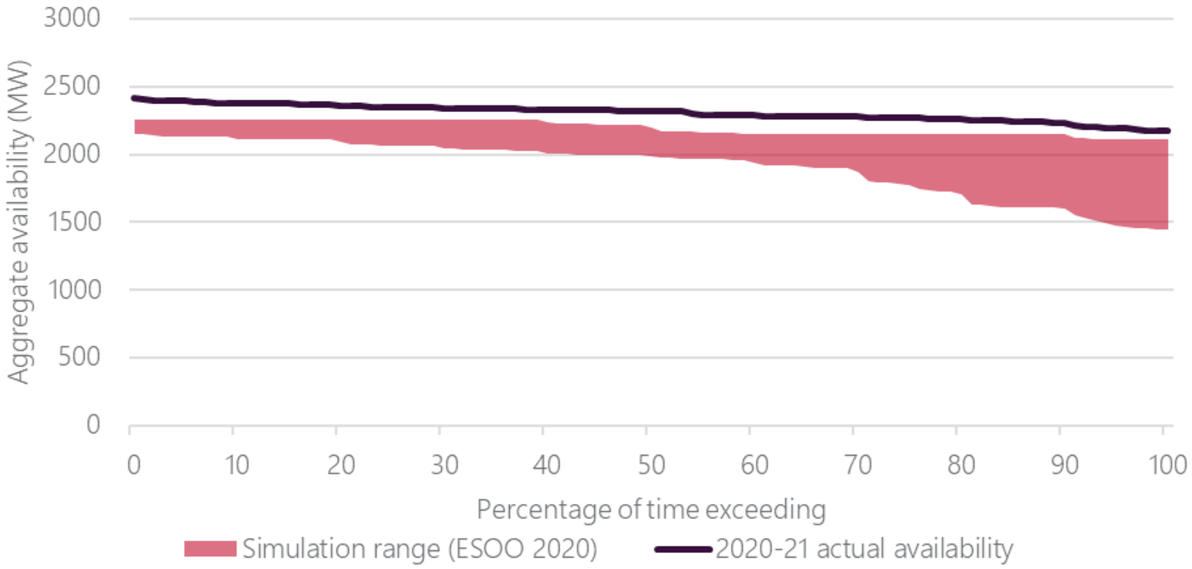
Figure 62 Victoria hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 63 shows that observed availability over the top 10 hottest days was entirely above the 2020 ESOO simulated availability. This was mainly due to low levels of temperature derating, as expected given the relatively low temperatures observed.

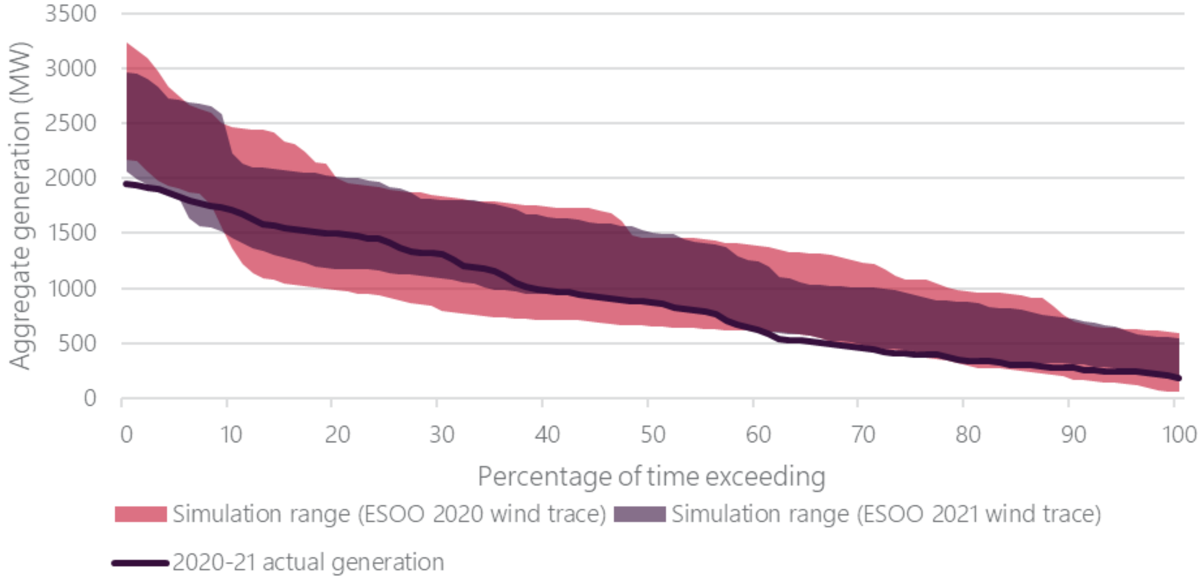
Figure 63 Victoria gas and liquids supply availability for the top 10 hottest days



Wind

Figure 64 shows the aggregate output for Victorian wind generators over the top 10 hottest days, comparing actual with simulated output. In 2020-21, the observed output was below or towards the lower end of both the 2020 and 2021 ESOO simulation ranges. The lower than expected output was predominantly due to delays in commissioning when compared to participant-provided information.

Figure 64 Victoria wind supply for the top 10 hottest days



Large-scale Solar

Figure 65 shows aggregate output for Victorian large-scale solar generators over the top 10 hottest days, comparing actual with simulated output. In 2020-21, the observed output was below both the 2020 and 2021 ESOO simulation ranges. The lower than expected output was predominantly due to delays in commissioning when compared to participant-provided information.

Figure 65 Victoria large-scale solar supply for the top 10 hottest days

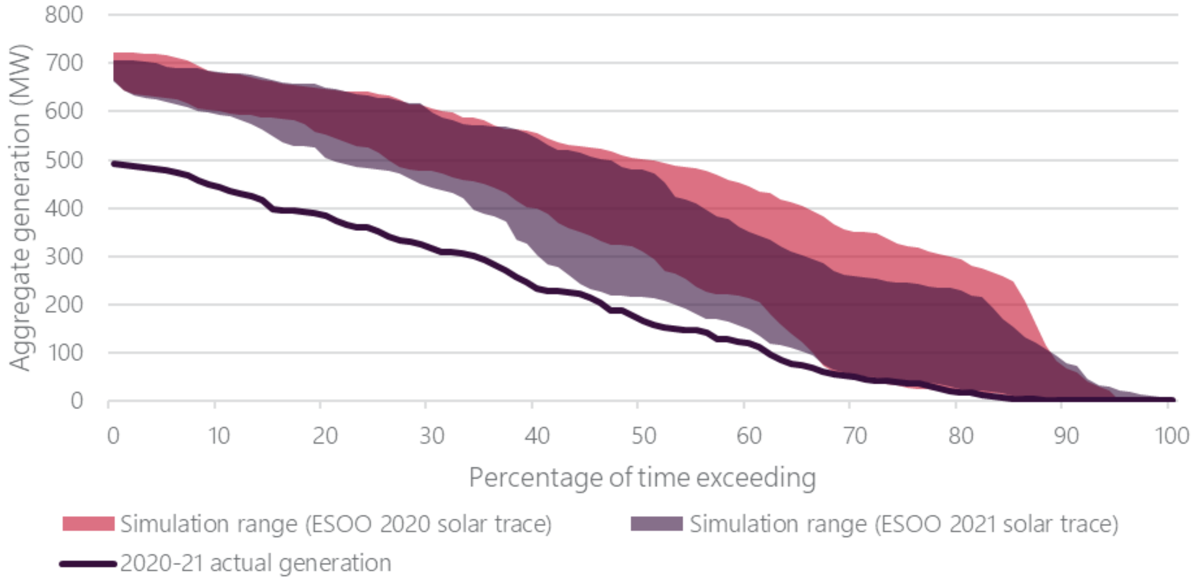
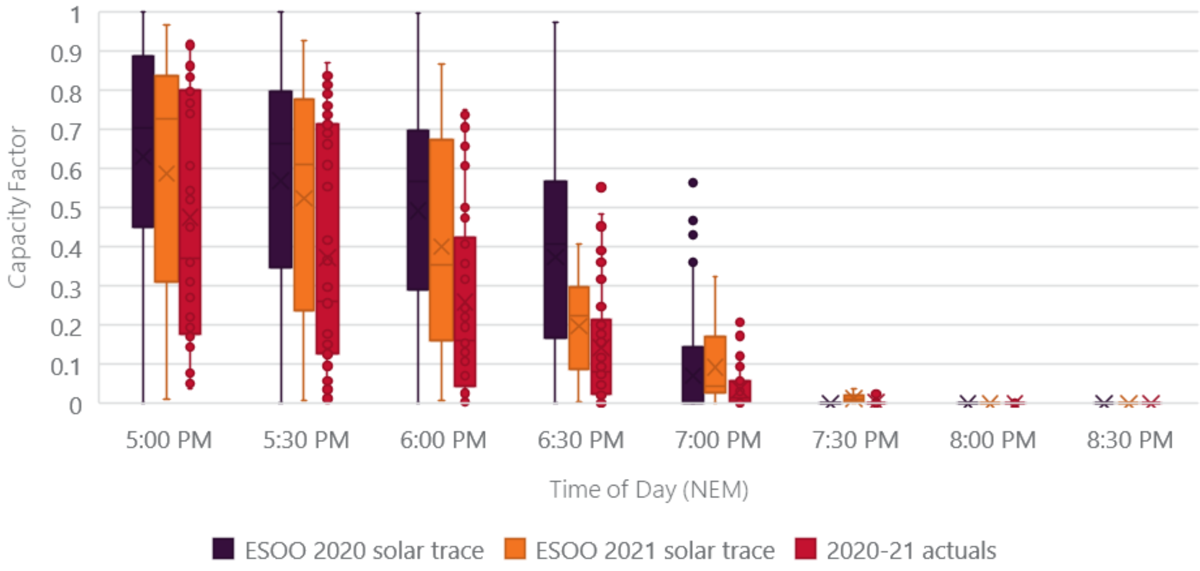


Figure 66 shows the box plot[32] of the solar generation capacity factor over the sunset periods of the top 10 hottest days, comparing actual with simulated solar traces. The solar trace used in the 2021 ESOO, which better incorporates current solar farm technical parameters, shows better alignment with the actual aggregate solar profile during these key intervals.

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

Figure 66 Box plot of Victoria solar capacity factor in solar traces compared with actuals for sunset time of 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 2020 ESOO was published along with the 2020 ESOO in August 2020; its accuracy is assessed in the following section.

Background

AEMO's DSP forecast methodology[33] estimates the demand response from large industrial loads and any other market participants. The responses at 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[34]. 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 2020 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.

AEMO's DSP forecast is used in processes to assess the need for reserves under the Reliability and Emergency Reserve Trader (RERT) framework[35], and 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-term RERT panel, and not under a RERT contract, have been providing DSP responses voluntarily at times where RERT was not needed.

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

[34] 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.

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

AEMO's 2020 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 (50^{th} percentile) observed DSP response for various wholesale price triggers during the 2020-21 year compared to the 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 2020 till 31 March 2021 consumption data for the same list of DSP resources as the 2020 DSP forecast. This is compared to the forecast DSP responses that were based on consumption data from the three previous years (1 April 2017 till 31 March 2020). 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 67 through to Figure 71 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.

In conclusion:

- Median observed actual responses in New South Wales were well aligned for lower price triggers. From prices >$2,500/megawatt hour (MWh) the median of actual DSP responses exceeds that of the forecast. It could be a result of the forecast being too low, although the number of occurrences of the price triggers is small (five or fewer for prices >$5,000/MWh), which is too few to reliably estimate the response. It should also be noted that the 2021 DSP forecast has been increased to 66 MW for the higher price bands, although this is mainly to account for Wholesale Demand Response.
- In Queensland, there was good alignment for price triggers up to including >$1,000/MWh. There were too few observations to reliably assess DSP responses for higher price levels. Note that this assessment excludes the Callide incident on 25 May 2021 and the subsequent higher prices. The responses appeared to be higher in the weeks following the event, in particular for peaking type non-scheduled generators. AEMO will monitor whether that level of response persists in this year.
- For South Australia, the median values of the observed DSP responses are well under the forecast across all price triggers. As noted in the 2021 DSP forecast[36], refinements of the baseline methodology showed that the 2020 DSP estimate for South Australia generally had been over-forecast. 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 mean that the demand forecast already accounts for it, because historical load at these sites at time of peak demand generally has been low.
- Median observed responses in Tasmania generally exceeded those forecast, although generally there were very few observations available (10 or fewer, and with no observations with prices >$5000/MWh). The few observations that were available included cases with Basslink outages during imports. This happened on

[36] See Appendix A6 in the 2021 ESOO: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf.

three occasions and triggered high prices and an automated tripping of load across some major loads. It is therefore believed that the higher than forecast level of response is mainly driven by observed load shedding, rather than voluntary DSP.

- For Victoria, there were insufficient high price periods to do any validation of outcomes.

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

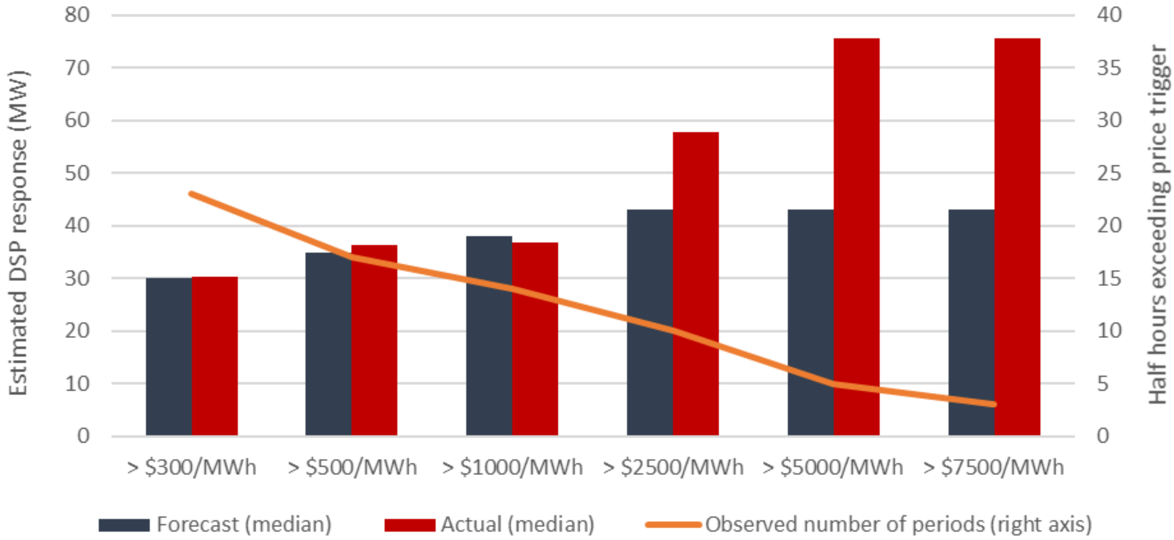


Figure 68 Evaluation of actual compared to forecast price-driven DSP in Queensland

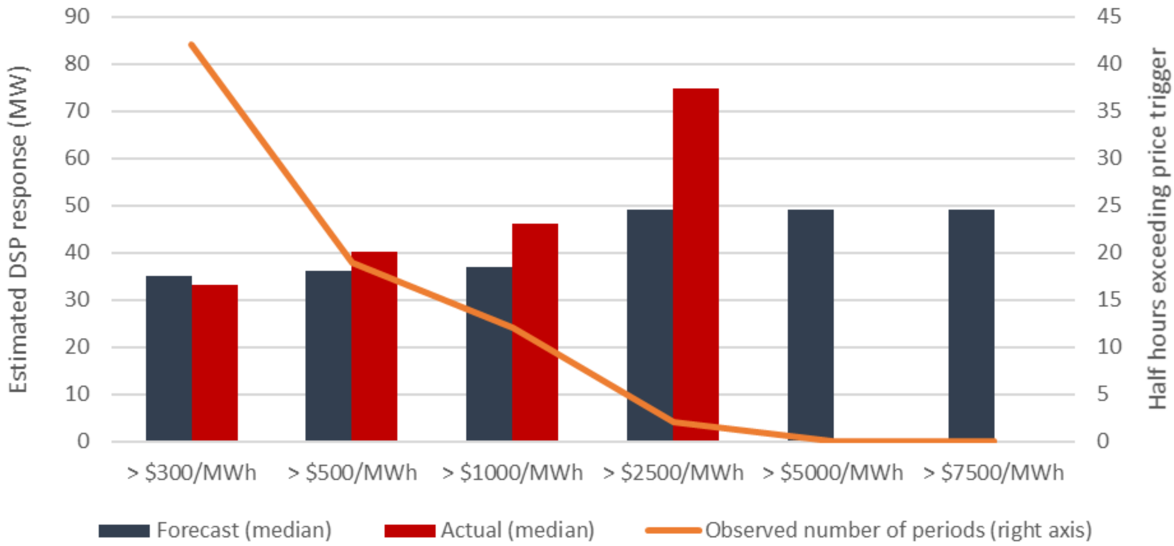


Figure 69 Evaluation of actual compared to forecast price-driven DSP in South Australia

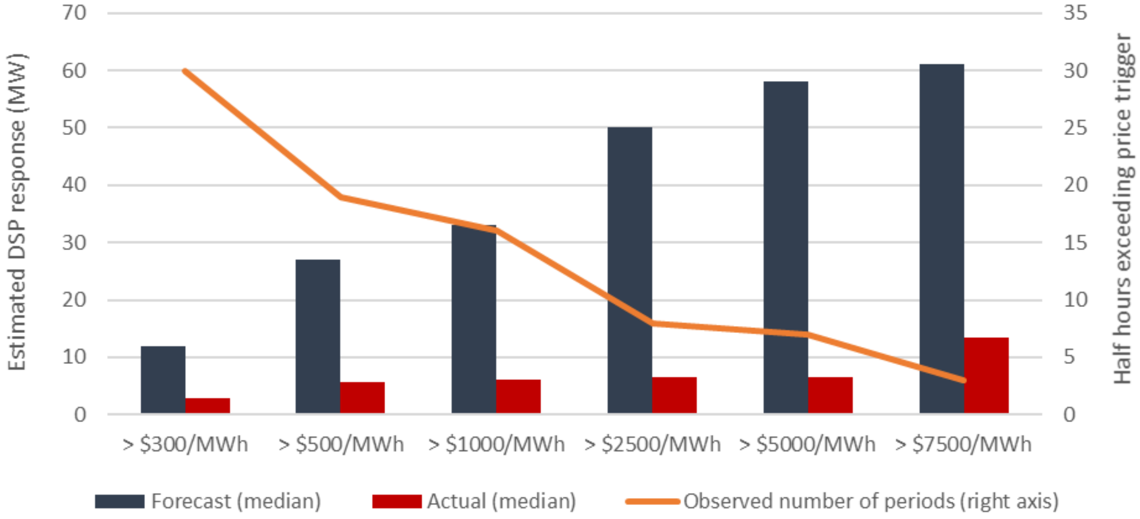


Figure 70 Evaluation of actual compared to forecast price-driven DSP in Tasmania

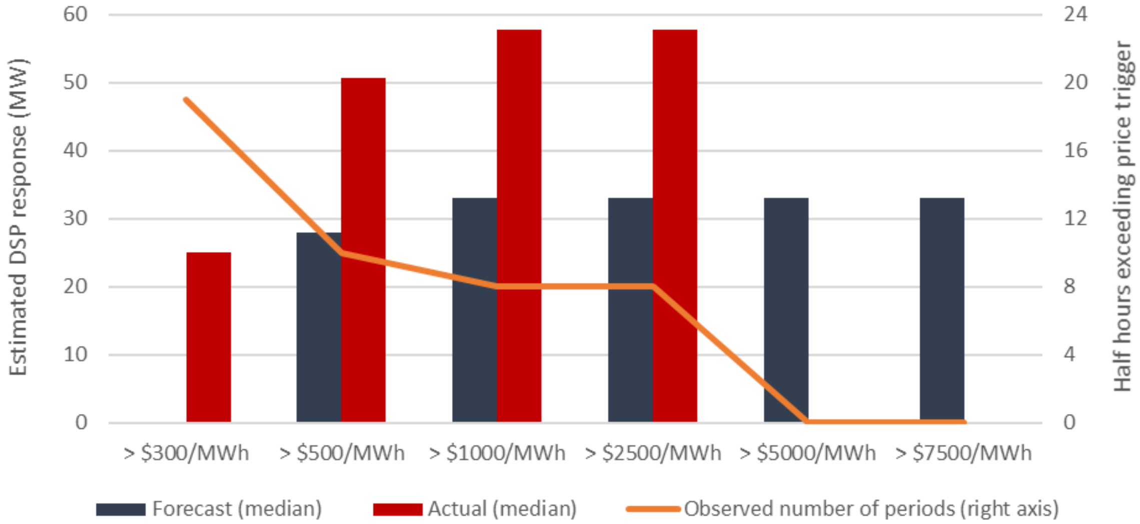
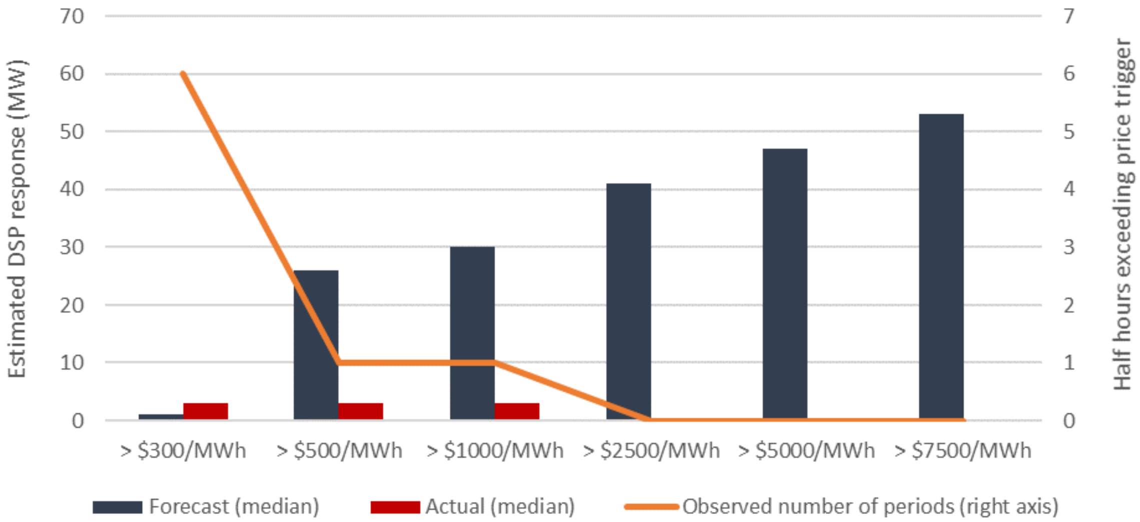


Figure 71 Evaluation of actual compared to forecast price-driven DSP in Victoria



DSP response during reliability events

The reliability response from the 2020 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 2019-20 summer

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Summer	285	102	61	33	200
Winter	285	49	61	33	175

For comparison, AEMO has assessed the amount of DSP for the peak demand days of the 2019-20 year:

- **New South Wales** – the region had its summer maximum demand on 25 November 2020. Prices were relatively low on the day and no DSP was observed. The winter maximum demand, however, exceeded that of summer and occurred on 10 June 2021. The region reached an actual LOR1 that day and the resulting high prices triggered 305 MW of observed DSP at time of peak, well in line with the reliability forecast[37].
- **Queensland** – the thresholds for LOR2 or LOR3 were not met during the summer. However, on the maximum demand day in summer, prices got close to $2,500/MWh and 62 MW of price-responsive DSP was observed[38]. Energy Queensland did also operate its controlled air-conditioner program on that day for an estimated combined response of 115 MW, which aligns well with the reliability forecast. Queensland entered an actual LOR3 on 25 May 2021 following the Callide incident. As a significant amount of load was shed as result of the incident, it has been impossible to estimate the voluntary response during the event. At time of the winter maximum demand on 21 July 2021, prices were high, peaking above $5,000/MWh just before the maximum was observed. AEMO has assessed that price-responsive DSP at time of peak reached 123 MW. This is substantially higher than forecast for winter, and AEMO will monitor whether DSP has increased following the large number of high-price events that followed the Callide incident.
- **South Australia** – this region had its 2020-21 maximum demand in the evening of 18 February 2021. Prices during the evening were well below $300/MWh and no DSP was observed. The winter maximum demand was reached on 22 July 2021. Demand was only ~200 MW less than the summer maximum demand, but also on this day prices remained below the price triggers and no DSP was observed.
- **Tasmania** – being winter peaking, Tasmania had its annual maximum demand on Sunday 25 July 2021. There were no LOR conditions and prices were moderate (below the $300/MWh trigger) and did thus not result in any observable price-driven DSP response.
- **Victoria** – the region experienced a very mild summer and its maximum demand was reached on 11 January 2021. Prices remained low and no network DSP was called on the day. The winter maximum was the highest observed since 2011, but also on that day, prices were below the $300/MWh trigger and no DSP was observed.

DSP forecast conclusions

Of the five NEM regions, only Queensland reached conditions similar to what the forecast DSP reliability response represents, though New South Wales was also close. It is observed that:

- In **New South Wales**, actual DSP response seems well aligned with the forecast reliability response.

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[37] A similar level of DSP response was also observed on a number of days in May, in no cases during actual LOR2 or LOR3 events. AEMO will consider if the adjustment currently applied only for the reliability response, should also be applied for the top bands of the price response estimates. It will have no impacts on the reliability forecast outcomes, but could have implications for any economic modelling using AEMO's assumptions.

[38] This response was observed an hour after the maximum demand period and thus did not affect the adjusted demand for summer maximum demand.

- In **Queensland**, the actual DSP response observed over summer seemed well aligned with forecast. DSP could unfortunately not be estimated following the Callide incident, where Queensland experienced both LOR2 and LOR3 conditions. Following the incident, there appears to have been more DSP than forecast in a number of high price periods, including on the day of the winter maximum demand. AEMO will monitor whether this higher level persists, and will account for this in the 2022 DSP forecast if needed.

7. Reliability forecasts

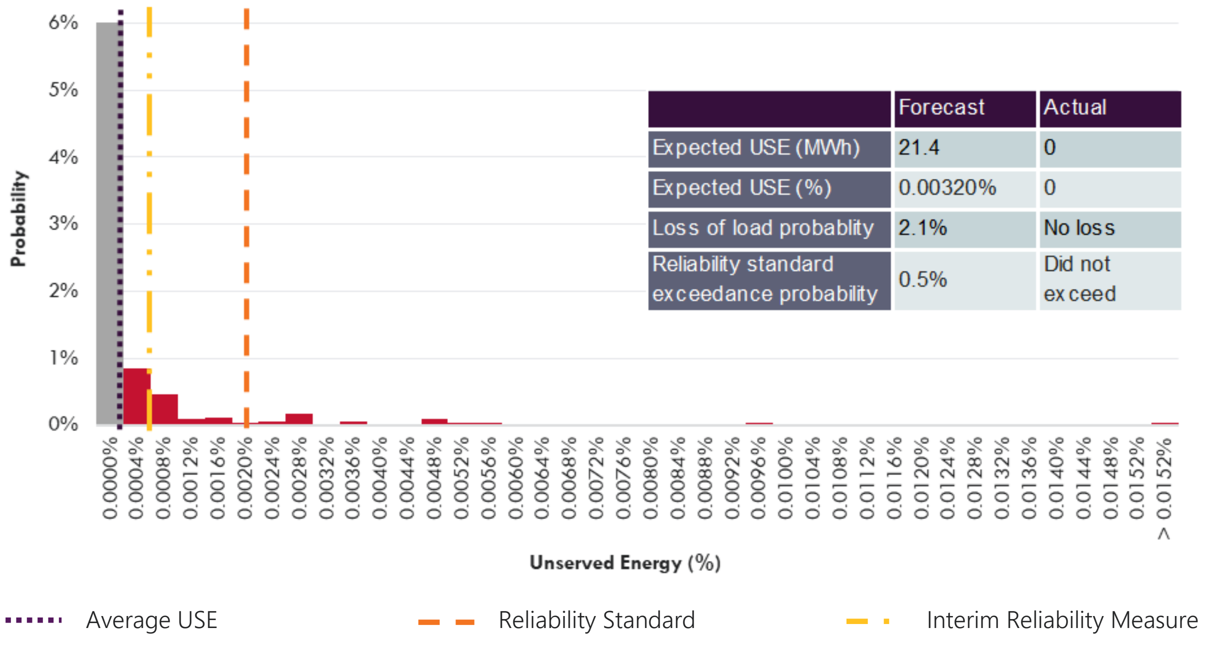
AEMO forecasts and reports on scarcity risk of generation supply availability, DSP, and inter-regional transmission capability, relative to demand. This forecast of supply scarcity risk is an implementation of the reliability standard[39] and Interim Reliability Measure (IRM)[40], with the expectation 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 2020-21.

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 72 shows the forecast distribution of USE in New South Wales in the 2020 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 2.1%. In 2020-21, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 97.9% of simulations.

Figure 72 New South Wales USE forecast distribution for 2020-21 summer



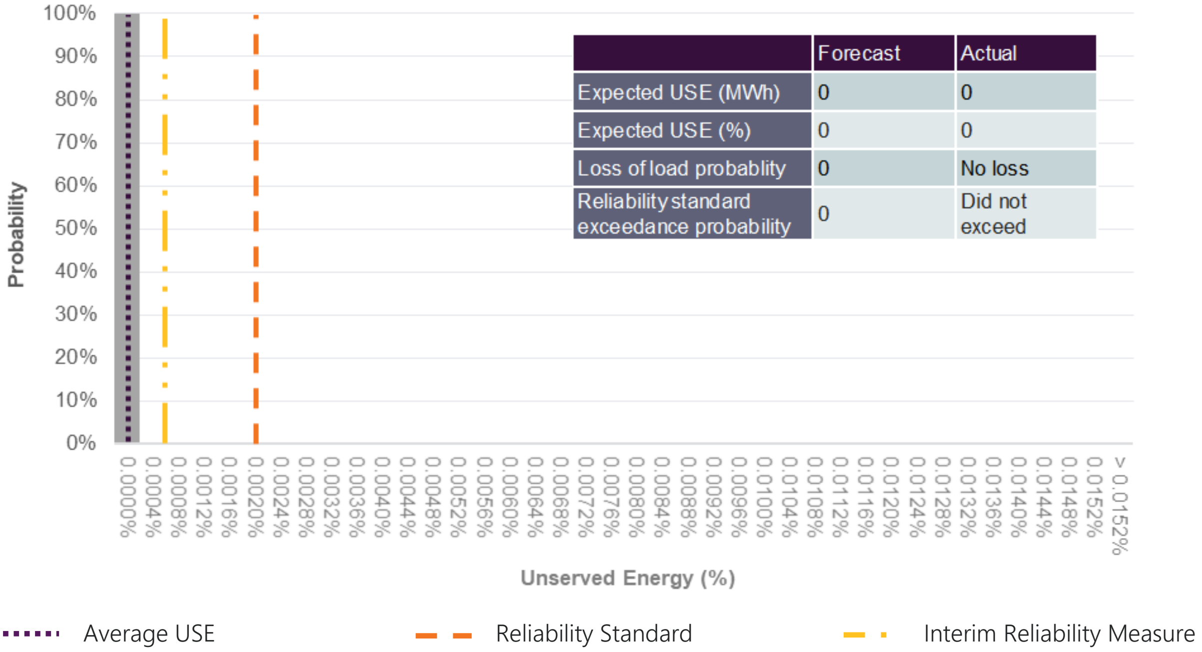
39 The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

40 The IRM is a new 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 73 shows the forecast distribution of USE in Queensland in the 2020 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2020-21, no USE in accordance with the reliability standard definition was observed, consistent with expectation.

Figure 73 Queensland USE forecast distribution for 2020-21 summer

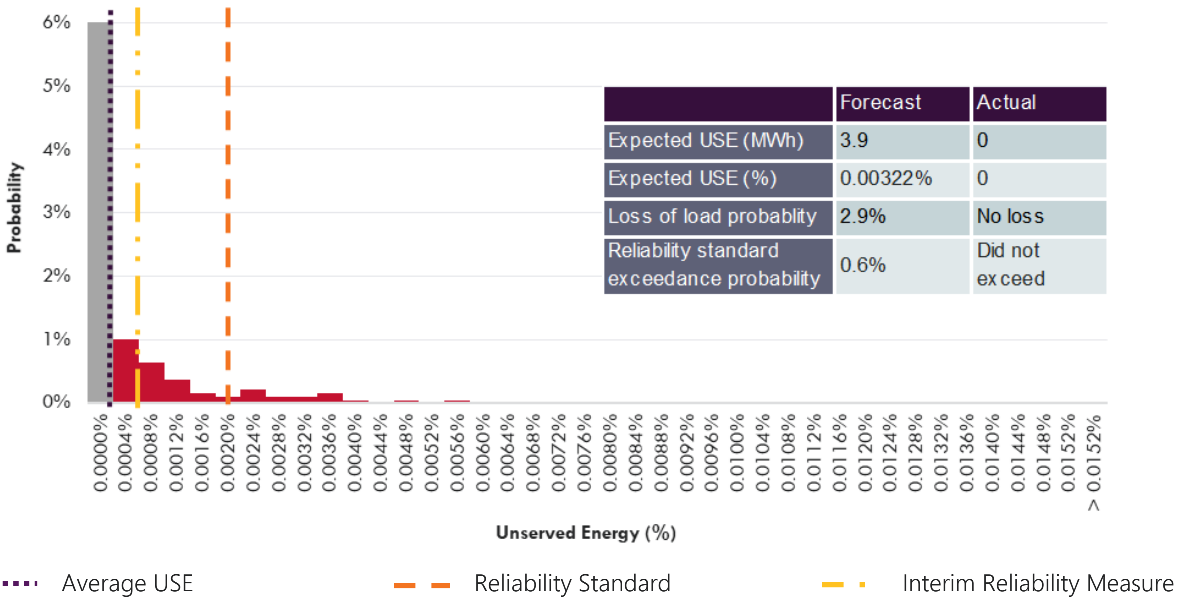


	Forecast	Actual
Expected USE (MWh)	0	0
Expected USE (%)	0	0
Loss of load probablity	0	No loss
Reliability standard exceedance probability	0	Did not exceed

7.3 South Australia

Figure 74 shows the forecast distribution of USE in South Australia in the 2020 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 2.9%. In 2020-21, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 97.1% of the simulations.

Figure 74 South Australia USE forecast distribution for 2019-20 summer

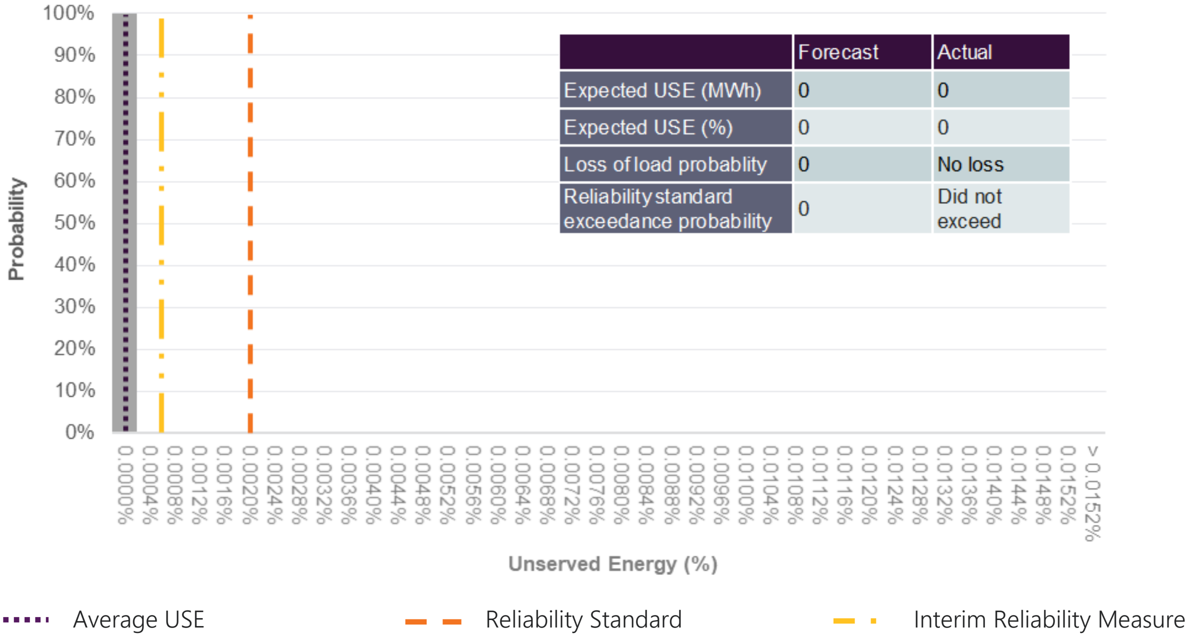


	Forecast	Actual
Expected USE (MWh)	3.9	0
Expected USE (%)	0.00322%	0
Loss of load probablity	2.9%	No loss
Reliability standard exceedance probability	0.6%	Did not exceed

7.4 Tasmania

Figure 75 shows the forecast distribution of USE in Tasmania in the 2020 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2020-21, no USE in accordance with the reliability standard definition was observed, consistent with the expectation.

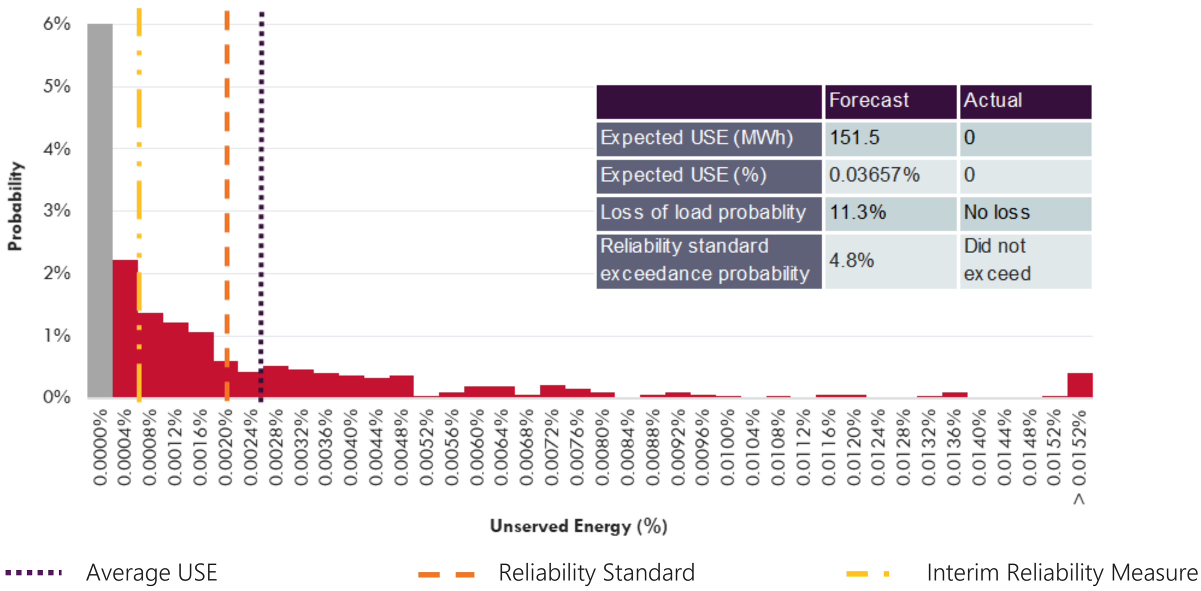
Figure 75 Tasmania USE forecast distribution for 2020-21 summer



7.5 Victoria

Figure 76 shows the forecast distribution of USE in Victoria in the 2020 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 11.3%. While there were some customers without power in 2020-21, the USE did not meet the definition of a system reliability incident. No load was lost as a reliability incident, an outcome predicted by 88.7% of simulations.

Figure 76 Victoria USE forecast distribution for 2020-21 summer



8. Improvement plan

AEMO acknowledges the importance of forecast accuracy to industry decision-making. The purpose of this annual *Forecast Accuracy Report* is to demonstrate accountability 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.

It should be noted that not all forecast improvements stem from the actions required 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 forecast accuracy issues found. 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 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 technological changes (such as EVs or battery storage systems). 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 2020 forecasts summarised in Section 8.1. Section 8.2 summarises the priority initiatives included in AEMO's 2021 Forecast Improvement Plan, while Section 8.3 outlines the research initiatives proposed to assist with the delivery of the 2021 Forecast Improvement Plan and future initiatives.

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 2020 forecasts – summary of findings

While most forecast models have performed well, some of the inputs and assumptions have impacted forecast accuracy. The issues driving proposed improvements in this year's Forecast Improvement Plan are summarised below:

- **Forecast winter maximum demand** – three regions observed actual winter maximum demand outcomes above the 10% POE forecast[41]. As this is not fully explained by weather outcomes, and given the last three winters in South Australia resulted in actuals above or at the 10% POE, AEMO will review the method for producing the starting points of the POE distribution.
- **Economic activity as driver for demand** – actual economic activity was significantly higher than forecast, as the economy rebounded following last year's constriction due to COVID-19, while another year of low economic growth had been forecast.
  - The report identifies the need for further analysis to better understand the observed variances of consumption and demand by customer segment. This will enable further analysis of the residual error in the consumption forecast, which can be quite significant, and build a better understanding of how these sectors are responding to the economic conditions and decarbonisation challenges.
- **Auxiliary load forecast** – the auxiliary load forecast used to convert between as generated and sent out consumption in the 2020 ESOO was significantly higher than the auxiliary load actually observed and should be reviewed.
- On the **supply side**, the forecasts generally performed well, although an emerging need was identified to ensure the representation of weather accounts appropriately for the true diversity of potential weather outcomes as VRE capacity increases at a rapid pace. A couple of assumptions to monitor were also noted:
  - New generation installations were high, but well aligned with the forecast for three of the NEM regions. However, both New South Wales and Victoria observed commissioning delays compared to participant-provided timing, resulting in ~2,000 MW less installed capacity than forecast for February 2021 across the regions.
  - Generator forced outage rates for coal-fired generators were mostly aligned with assumptions. On the highest demand days, planned and unplanned outages in New South Wales, Queensland and Tasmania did cause a reduced availability against forecast, although demand was not extreme at any point and, whilst not known, it is possible that generators may simply not have been made available as not required.

In addition, a number of observations on forecast variance have been noted, where the issue is expected to have been resolved with improvements already implemented in the 2021 ESOO, such as those identified in the 2020 Forecast improvement Plan initiatives. These observations include:

- The distributed PV forecast uptake was lower than what was observed, while forecast generation per MW was above the observed. The under-forecast of capacity significantly affected the minimum demand forecast, while the over-forecast of generation per MW reversed that impact on consumption. With the 2021 ESOO forecast, these issues have both been addressed, although AEMO will monitor this to ensure no further actions are needed ahead of producing the 2022 ESOO forecast.
- The observed DSP actuals aligned well with the forecast in most regions, where sufficient high price events occurred that allowed reliable comparison with forecasts. In South Australia, however, observed DSP was well below forecast, as the forecast relied on automatically calculated baselines, which in many cases were set too high. This was an issue identified and corrected when the 2021 DSP forecast was produced. AEMO will monitor the new forecast for its performance, in particular in light of the introduction of 5-Minute Settlement and Wholesale Demand Response in October 2021, which may affect how industry consumers respond to price signals.

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

For reference, Appendix A1 lists the improvements presented in the 2020 Forecast Improvement Plan along with a summary of implementation status of each of these initiatives, and any other improvements implemented for the 2021 ESOO.

Finally, it should be acknowledged that not all technologies can be tracked. Emerging technologies such as battery storage and EVs do not have robust data streams that reflect their uptake and usage, and thus the impacts on consumption and demand. Finding or building data sources that reflect this is important to assist in producing accurate forecasts, and to measure how forecasts differ from actual observations.

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 2021 Forecast Improvement Plan:

1. Review forecast maximum and minimum distribution of the initial year of the forecast horizon.
2. Review auxiliary load forecast used to convert from as generated to sent out consumption/demand.
3. Improve visibility of sectoral consumption.
4. Improve renewable generation and demand traces, including the quantity used, and their shape.
5. Monitor trends in:
   - Distributed PV uptake.
   - Generator commissioning and full commercial use dates.
   - Generator forced outage rates.
   - DSP, following the introduction of Wholesale Demand Response and 5-Minute Settlement.
6. Monitor emerging technologies' uptake and usage.

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

- 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 2022 ESOO forecast.
- The two **improve** actions have confirmed gaps exist and will seek to address these.
- **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.

8.2.1 Review initial year of forecast maximum and minimum demand distribution

Three NEM regions observed winter maximum demand outcomes above the 10% POE forecast, which cannot alone be easily explained by input drivers. As part of its ongoing review process, AEMO will review the methodology and further assess model inputs to see if improvements are required. 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 usage of heaters following installation of rooftop PV, even after sunset[42].

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

[42] Increased usage following investments in energy efficiency measures or other means to lower the cost of electricity often leads in an increase in consumption that erodes some of the savings. This is known as the "rebound" effect and will be investigated as part of the Forecasting Research Plan outlined in Section 8.3.

expressed as the 10%, 50% and 90% POE forecasts[43]. It may also reveal alternatives to use instead of the GEV model, and if so, testing will be undertaken to ensure the best approach is identified and consulted on ahead of use in the 2022 ESOO.

While the issue was identified for winter maximum demand, the issue could potentially also exist for summer maximum demand, but masked by the very mild summer the NEM experienced in 2020-21. The investigation will therefore cover both summer and winter maximum demand, as well as minimum demand, which uses a similar approach.

8.2.2 Review auxiliary load forecast

Following from the deviations between forecast and actual auxiliary load observed for the 2020 ESOO, AEMO will review the best source of auxiliary load forecast for the 2022 ESOO consumption and demand forecasts. The forecast should, for each scenario, be a good representation of expected thermal generator dispatch, taking into account unit availabilities and realistic bidding behaviour. Forecast values should be checked against historical trends for validation.

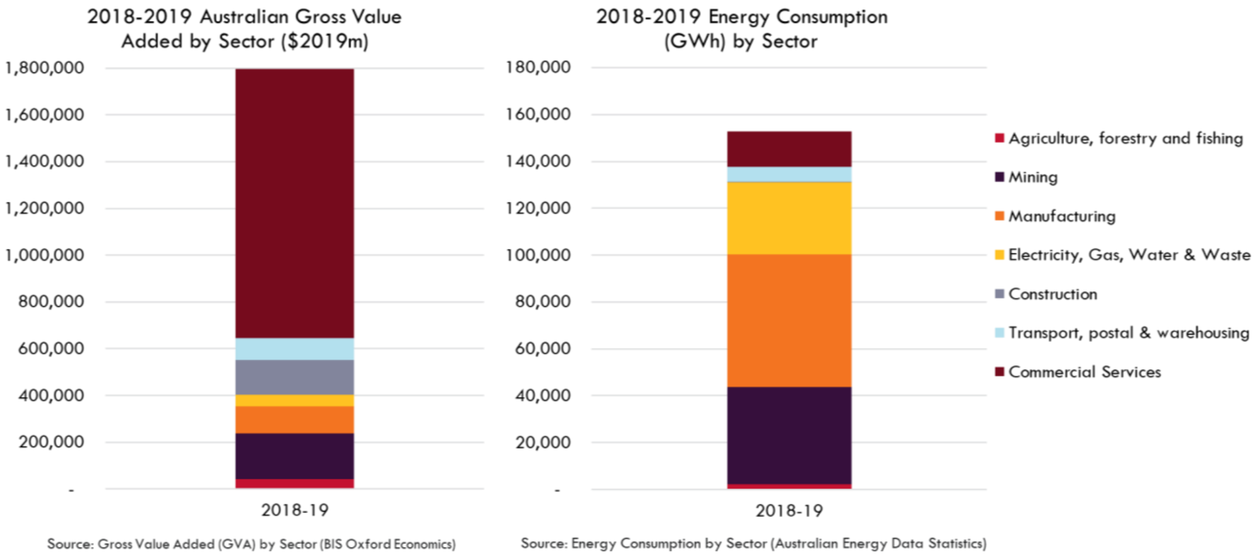
8.2.3 Improved visibility of sectoral consumption

In this 2021 *Forecast Accuracy Report*, AEMO has added assessment of the accuracy of the large industrial load forecast. This has improved the understanding of what is driving the differences observed between forecast and observed consumption. There is still more to be understood, and AEMO has planned 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.

The plan is to look for improved breakdown both of the existing large industrial load sector, but also the broader business mass market component of the forecast.

Some sectors, for example cement, have seen significant shifts in energy intensity (energy used per $ million value created) as resource-intensive inputs are increasingly imported rather than produced within Australia. An improved sectoral split will increase the visibility of such trends.

Figure 77 The value added to the economy and energy consumed varies significantly between sectors



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

Visibility of consumption at sector level 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).

It will also allow better integration with economy-wide modelling, such as integrated assessment models (IAM), which 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.

This work is supported by research undertaken through the National Energy Analytics Research (NEAR) program to improve the classification of metered customer load by industry sector, as outlined in Section 8.3.

8.2.4 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 2020 ESOO used 10 weather years to create demand reference years matching that weather, along with corresponding profiles for the generation from large scale wind and solar farms.

Need for more weather traces

The NEM is witnessing a rapid transformation of the generation fleet, with 3,200 MW of additional large-scale wind and solar projects generating by the end of July 2021 compared with the year before[44]. 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. Demand traces will need to be created for any new weather years.

MT PASA 10% POE daily and most probable daily peak load forecasts

Concurrent with this, AEMO is looking to revise the approach to develop the 10% POE daily peak load, and the most probable daily peak load forecasts published as a standalone component of the MT PASA process. These daily peak load forecasts are currently based on annual POEs scaled to give a monthly profile and account for the day types, but maintaining the characteristic that the profile itself would only be exceeded one in 10 years for a 10% POE daily peak forecast (and one in two years respectively for the most probably daily peak load).

The current design has caused some misunderstandings, with some stakeholders expecting the values to based on monthly POEs instead (adjusted for day types). This may be a more useful definition.

AEMO proposes that the daily peak load forecasts in future years are produced from monthly POE distributions instead, which may be more intuitive to use, while noting that these values will not match the seasonal POE targets used to develop the traces that are actually used in the ESOO and MT PASA.

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[44] 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.

8.2.5 Monitor for change in trends for key inputs

Within this report, a number of critical assumptions have been highlighted for additional scrutiny of trends to allow corrective action ahead of finalising the 2022 ESOO forecast, should that be necessary. These assumptions are outlined below.

Distributed PV uptake and generation

- Analysis of short-term installation trends. In particular, attention will be on whether there are impacts from the potential short-term price increase of panels and inverters as a result of global supply chain issues from increases in raw material costs, factory constraints in China, and global shipping issues.
- Continued review of the normalised PV generation profiles used to ensure the forecast generation per MW of installed PV capacity is within expectation.

Generator commissioning and full commercial use dates

- Continue to monitor trends in project completion (full commercial use) against dates in AEMO's Generation Information page.

Generator forced outage rates

- Continue to monitor trends in actual forced outage rates against those reported to AEMO by participants.

Demand Side Participation trends

- Monitor observed DSP against actuals to see if historical responses remain an accurate estimation of current level of DSP, following the introduction of Wholesale Demand Response and 5-Minute Settlement. Also review observed outcomes in Queensland and South Australia to investigate if recent changes observed are transient or sustained.

8.2.6 Monitor emerging technologies uptake and usage

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.

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, AEMO has been leading the EV Data Availability Taskforce under the Distributed Energy Integration Program (DEIP) Electric Vehicle Grid Integration Working Group[45]. This identifies EV data needs from an energy sector perspective, including registration data and the installation of charging infrastructure, alongside potential collection mechanisms and delivery options for this data. When it comes to understanding charging profiles, AEMO is following trials currently underway in Australia, which may provide new insight into how EV owners use and charge their vehicles.

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.

[45] See https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/ev-grid-integration-workstream/.

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 a known data and developing a new method using yet to be identified data.

AEMO has commissioned several forecasting-related research projects and been involved in some itself, utilising the expertise within the organisation and its unique access to energy market data.

In particular, AEMO has been an active part of the NEAR program[46]. NEAR is a collaboration between CSIRO, AEMO, and the Australian Government Department of Industry, Science, Energy and Resources (DISER) whose purpose is to bring together data from across the energy sector, establishing pathways for improved data publication and sharing, and executing research to unlock value from both existing and emerging data assets.

For the 2021-22 year, AEMO has identified the following opportunities for research to support its improvement plan:

- Sectoral modelling.
  - AEMO is leading a NEAR project whose purpose is 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 the 2022 ISP.
- Future load shape.
  - Understand changes in future load shape from technology uptake and usage. This overlaps with monitoring of emerging technologies as outlined in Section 8.2.6 and includes deriving understanding from meter data analysis, for example on the use of EV fast chargers.
  - AEMO is also involved in a NEAR project that assesses the extent to which households that have installed rooftop PV, consume more electricity than previously, given the reduction in their electricity bill. This increase in underlying consumption, known as the rebound effect, has seen some investigation at an annual level, but it could potentially explain growth in peak demand, if consumers with rooftop PV are shown to use more electricity on very cold (winter) or hot (summer) evenings, just before or around sunset.

These initiatives have been discussed at AEMO's Forecasting Reference Group (FRG) meetings.

[46] See https://near.csiro.au/.

A1. Status of 2021 ESOO improvements

The 2020 Forecast Improvement Plan was published in the 2020 *Forecast Accuracy Report*[47]. It proposed a number of improvements planned for the 2021 ESOO. For visibility of progress, each improvement is listed below along with a summary of feedback and the implementation status.

Table 28 Proposed improvements relevant to the 2021 ESOO

Improvement	Stakeholder feedback	Status
Improved PV forecasts Improved PV forecasts through better visibility of installed capacity and short-term trends in installations, as well as review of Solcast's normalised PV generation per MW profiles.	An update was provided at the July 2021 FRG.	**Implemented**. To address this subject, AEMO has: • Assessed quality of CER data, including use of DER Register data for validation. Improved recency of data (less lag between PV installations and registering by CER) has been observed leading to an improvement in the estimation of current capacity. • Increased usage of actual data in preference to estimated data. • Used updated normalised PV generation profiles – leveraging on improvements in satellite data and cloud/aerosol modelling.
Data analytics to improve understanding of trends and drivers Help verify the models for residential and business consumption and use more recent data. Improve the ability to explain forecast differences by increasing the understanding of sectoral or spatial trends, including changes driven by COVID-19.	Work on understanding COVID-19 impact on max/min demand was presented at the FRG on 5 May 2021. The 5 May 2021 FRG meeting also presented on hydrogen and electrification, which relates to understanding multi-sector couplings. A more comprehensive discussion on the multi-sector modelling was provided at the 30 June 2021 FRG meeting. A general update on the overall initiative was provided at the July 2021 FRG.	**Mostly progressed.** To address this subject, AEMO has: • Improved the estimate of residential/business consumption split for the 2021 ESOO based on sample smart meter data to supplement the older AER data. • Continued analysis of COVID-19 which showed little evidence of impact at time of max and min demand. • Improved tracking of large industrial loads to assess forecast accuracy and better representation of large industrial loads at time of minimum demand to reflect influence from large industrial loads. Additional initiatives (beyond what was outlined in the 2020 Forecast Improvement Plan) include: • Improved understanding multi-sector couplings, sectorial energy intensity trends including impacts of energy efficiency. • Metering analysis of data centre load growth.
Improve representation of the monthly max demand forecast distribution	A general update was provided at the July 2021 FRG.	**Partly implemented.** To address this subject, AEMO has: • Explored options to improve the shoulder seasons trace outcomes. Use of historical demand traces stretched to hit more targets would cause increasing distortion of

[47] 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 feedback	Status
AEMO noted examples of where monthly MT PASA traces reported in the 2020 *Forecast Accuracy Report* showed cases where actuals in shoulder seasons fell outside the range spanned by the reference years used. This is because the traces represent history (last nine years) rather than the forecast outcomes. AEMO should explore ways to better capture the range of maximum monthly demand outcomes across the sample of traces used.		the load shapes. Instead, AEMO has found that the issue is best addressed through use of synthetic demand traces, or more historical years. The inclusion of the 2020-21 reference year in future assessments will help to broaden the range of monthly outcomes in some regions. • Considered options for improving the 10% POE daily peak load, and the most probable daily peak load forecasts. This may best be done through publishing POEs that represents monthly POEs rather than seasonal POEs. AEMO will consult on this change as part of the 2021 Forecast Improvement Plan.
Improved wind generation traces Development of improved wind generation traces accounting for high wind and high temperature cut-offs.	A general update was provided at the July 2021 FRG. The wind traces were published with the 2021 ESOO model dataset – trace library.	**Implemented.** To address this subject, AEMO has developed an empirical machine-learning-based wind generation model, which accounts for both high wind and high temperature cut-offs in its calculation of half-hourly wind generation. If participants provided specific temperatures thresholds through the Generation Information process, the approach would account for those. The ESOO and Reliability Forecast Methodology* has been updated to reflect the new methodology.
Improve modelling of inter-regional transmission element outage risk The current method for capturing inter-regional transmission element outage risk is found appropriate for random outages. Updates should be made to capture trends in frequency or timing/coincidence when the outages are weather-driven.	Calculated transmission outage rates relevant for the weather dependent method was presented at the June 2021 FRG. A more general update was provided at the July 2021 FRG.	**Implemented**. To address this subject, AEMO has developed and implemented a methodology to model forced outages as a function of bushfire weather for the Dederang-South Morang and Dederang-Upper/Lower Tumut lines. As with other Forced Outages Rates (FOR), these values will be consulted on annually. The ESOO and Reliability Forecast Methodology* has been updated to reflect the new methodology. Furthermore, AEMO will seek data to improve the representation of transmission element outage risks through collaboration with network service providers.
Improved understanding of emerging technologies Investigate and if possible onboard data sources to track uptake and use of emerging technologies, such as battery storage and EVs.	A detailed presentation on the work on EVs was given at the July 2021 FRG, along with a more general update on the entire improvement plan.	**In progress**. To address this subject, AEMO has: • Worked with DNSPs to improve battery storage data in the DER-Register and through NEAR worked with CSIRO to develop the capability to identify battery storages (and other appliances) from smart meter data. • Continued leading the Electric Vehicle Data Availability Taskforce under the Distributed Energy Integration Program (DEIP) to identify data gaps for EVs in Australia. Additional initiatives (beyond what was outlined in the 2020 Forecast Improvement Plan) include: • Modelling of the hydrogen sector was introduced in the 2021 ESOO and relates to the multi-sector coupling work discussed in the second item of this table.

* 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
GWh	Gigawatt hour/s
MW	Megawatt
MWh	Megawatt hour/s
TWh	Terawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BOM	Bureau of Meteorology
CER	Clean Energy Regulator
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEIP	Distributed Energy Integration Program
DER	Distributed energy resources
DISER	Department of Industry, Science, Energy and 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

Abbreviation	Full name
HDI	Household Disposable Income
HIA	Housing Industry Association
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
MTTR	Mean time to repair
NEAR	National Energy Analytics Research
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
OPGEN	Operational demand 'As Generated'
OPSO	Operational demand sent-out
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
REZ	Renewable Energy Zone
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
STC	Small-scale Technology Certificate
USE	Unserved energy
VRE	Variable renewable energy