# Forecast Accuracy Report

**December 2020**

Review of the 2019 Demand, Supply and Reliability Forecasts

# Important notice

## PURPOSE

This Forecast Accuracy Report has been prepared consistent with AEMO's Interim 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 2019 Electricity Statement of Opportunities (ESOO) and its predecessors for the National Electricity Market (NEM).

This publication has been prepared by AEMO using information available at 31 August 2020.

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## VERSION CONTROL

| Version | Release date | Changes |
|---|---|---|
| 1 | 2 December 2020 | |

# 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 2020 Forecast Accuracy Report primarily assesses the accuracy of AEMO's 2019 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 influence the reliability assessments for the 2019-20 financial year, in particular the summer.

Table 1 summarises the assessment of forecasting accuracy discussed within. Given the varying nature of each component and forecast, quantitative metrics are not always feasible. This qualitative summary should be read considering the following:

- 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, 2019-20**

| Forecast Component | NSW | QLD | SA | TAS | VIC | Comments |
|---|---|---|---|---|---|---|
| Drivers of demand | Orange | Yellow | Orange | Green | Yellow | Installed PV capacity significantly above forecast in most regions. A new methodology has already been developed and used in the 2020 ESOO to better capture recent PV sales history in forecasts. |
| Energy consumption | Green | Green | Orange | Yellow | Green | South Australian consumption more than 3% lower than forecast, though at least half of the deviation from forecast is explained by input drivers. Tasmania also lower than forecast driven by lower large industrial loads (LIL). |
| Summer maximum demand | Green | Green | Green | Orange | Green | All mainland regions sit well within distributions and are consistent with forecast drivers. Tasmania is at the very low end of the distribution, driven by lower LIL than forecast. |
| Winter maximum demand | Green | Green | Orange | Yellow | Green | Winter maximum demand in South Australia is above forecast distribution. Likely due to change in consumption behaviour due to COVID. Tasmania lower than forecast driven by LIL. |
| Annual minimum demand | Green | Yellow | Yellow | Orange | Green | Due to under-forecast PV capacity, actual minimum demand in Queensland and South Australia fell below forecast distribution. Tasmania was low as well, but driven by LIL rather than PV. |
| Demand Side Participation | Yellow | Green | Green | Green | Yellow | New South Wales and Victoria had responses from loads that had not been considered in the forecast, underestimating the DSP response in New South Wales in particular, less so in Victoria. |
| Installed generation capacity | Green | Green | Green | Green | Yellow | New generator installations matched expectation, except in Victoria where delays impacted availability compared with what was modelled. |
| Summer supply availability | Green | Yellow | Green | Green | Green | Planned and unplanned outages in Queensland reduced availability against forecast, which was accommodated due to the total volume of dispatchable capacity available in the region. |

The report highlights the impact that distributed photovoltaics (PV) can have on consumption, maximum and in particular minimum demand, and the resulting need for AEMO to have more visibility of the most recent PV uptake trends. The newly developed distributed energy resources (DER) register data will be a key enabler

[1] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities/2019-nem-electricity-statement-of-opportunities.

for this. The report also identifies the need for further analysis to better understand the observed variances of consumption and demand by customer segment. On the supply side, the forecasts generally performed well with only minor improvements identified.

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.

While most forecast models have performed well, some of the inputs and assumptions have impacted forecast accuracy. These can be summarised below:

- Rooftop PV and PV non-scheduled generation (PVNSG) actuals were above the 2019-20 forecast in all regions, totalling 1,807 MW more capacity installed than forecast across the NEM. This resulted in actual operational consumption and, in particular, minimum demand being lower than forecast in most regions.
- Actual economic activity was not well aligned with forecast, due to the impacts of domestic and international measures to minimise the spread of COVID-19 from late March 2020 onwards, which significantly reduced economic activity. While some business electricity consumption was reduced as a consequence, residential consumption increased, and the net impact for the last quarter of the financial year was relatively minor.
- DSP actuals aligned well with the forecast in most regions but, in both New South Wales and Victoria, DSP responses were seen from loads that had not been considered in the forecast, underestimating the DSP response for New South Wales in particular. These newly observed responses from select loads have been considered for the 2020 ESOO forecast, following consultation on DSP methodology in the first half of 2020.
- New generation installations were aligned with the forecast for most regions, however Victoria observed commissioning delays against provided timing. For summer 2019-20, there was 1,241 MW less installed capacity than expected in Victoria. These delays had the potential to impact reliability, however, were accommodated due to high availability from brown coal-fired generators during hot periods.
- Generator forced outage rates for coal-fired generators continued to worsen but were mostly aligned with assumptions, except for New South Wales black coal-fired generators, which performed worse than expected. An updated methodology used in the 2020 ESOO now uses participant and consultant forecasts of forced outage rates to better capture trends in performance and maintenance.
- Outage rates on inter-regional transmission elements were higher than assumed, primarily due to bushfire impacts on Victoria to New South Wales transmission elements, and destructive wind gusts and asset failure impacts on Victoria to South Australian transmission elements.

## Improvement plan

Some of the observed differences between actuals and forecasts have affirmed changes already made to the forecast methodology for the 2020 ESOO, guided by observations in the 2019 Forecast Accuracy Report. The appendix to this report provides an update on these changes.

Other differences have helped steer the direction for additional improvements to be implemented for the 2021 forecasts to improve forecast accuracy in the first five years of the reliability forecast relied upon for the RRO, and for use in the 2022 ISP. The priority improvements proposed for 2021 are listed below.

### Improved PV forecasts

Rooftop PV and PVNSG continues to be installed at a rapid rate, and discrepancies between forecast and actual uptake remains a material driver of consumption and demand forecast inaccuracy, in particular affecting AEMO's minimum demand forecasts.

For its 2020 forecasts, AEMO acquired expert PV uptake forecasts from multiple consultants, yet short-term trends in installations and output are still problematic. AEMO intends to work on improving the visibility of recent uptake. Focus is to get better estimates of actual number of installations and changes to the rate of uptake, for example through the use of DER register data, and to ensure recent trends are reflected in the forecasts.

AEMO will also review the daily and seasonal profile of PV generation associated with a given level of installed PV capacity, to ensure the contribution at time of maximum and minimum demand is calibrated to observed outcomes.

### Improved visibility and understanding of consumption patterns and trends

Consumption patterns change over time as consumers change the way they use energy in response to factors like COVID-19, or adoption of technologies like PV, battery storage and electric vehicles.

To improve understanding of consumption and demand drivers and trends, AEMO plans to focus on using smart meter data to estimate the split between business and residential consumption, and compare consumption trends for customers with and without PV systems. This will help verify and potentially improve existing models for residential and business consumption, and provide a tool for better understanding the reasons behind observed forecast variance and better guide future forecasting improvement initiatives.

In addition, variability of consumption by large industrial loads during minimum demand periods will be reviewed to ensure it is appropriately reflected in the minimum demand forecasts.

### Better visibility of forecast maximum demand within a year

The report shows comparisons of observed monthly maximum demand and the maximum demand of the traces used in the ESOO and Medium Term Projected Assessment of System Adequacy (MT PASA) modelling. There are some misalignments as the traces are not made to match forecast maximum demand outside summer and winter months. To give stakeholders visibility of the forecast range of maximum demand in shoulder months, AEMO will improve how it calculates and publishes more granular forecast data, in particular the forecasts published as part of the MT PASA process.

### Wind generation trace development

Analysis of availability of renewable generation sources showed examples of reduced wind farm output during high temperatures over the summer, which resulted in an unexpected reduction in supply availability.

As result of climate change[2] this may happen more frequently in the future. As installed wind capacity increases across the NEM, capturing the relationship between modelled wind generation and high temperatures is becoming more important.

AEMO intends to develop and implement a new wind generation model that will produce more realistic traces in the presence of high temperatures or wind speeds for the 2021 forecasts.

### Improved modelling of inter-regional transmission elements forced outages

AEMO's current process for calculating forced outage rates on inter-regional transmission elements uses available outage history only. This does not capture the potential correlation between high demand and network outage risks, as both are highly driven by weather. Weather conducive for bushfires and high wind gust events is identifiable in the historical weather traces used in forecasts, and AEMO will use this to develop network forced outage simulations that better reflect the compound risk associated with the potential coincidence with high demand events.

### 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) Friday, 15 January 2021**. Submissions should be sent by email to energy.forecasting@aemo.com.au.

[2] See for instance https://www.climatechangeinaustralia.gov.au/en/.

# Contents

# Tables

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# 1. Stakeholder consultation process

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

Section 8 of this report, the Forecast Improvement Plan, has been guided by the assessment of the main contributors to forecast inaccuracies. The process underlying the forecast accuracy assessment in this report was consulted on from April to October 2020 in the Forecast Accuracy Reporting Methodology consultation[3]. This consultation focuses on the initiatives outlined in the Forecast Improvement Plan only, and not the FAR methodology.

The finalised Forecast Improvement Plan is to the extent possible to be implemented prior to AEMO developing reliability forecasts to be published in the 2021 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 for 2021 ESOO or beyond?**

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) Friday, 15 January 2020.**

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

**Table 2 Consultation timeline**

| Consultation steps | Indicative dates |
|---|---|
| Forecasting Reference Group discussion of draft report | 28 October 2020 |
| Forecast Accuracy Report and Improvement plan published | 2 December 2020 |
| Submissions due on Improvement plan | 15 January 2021 |
| Final methodology improvements updated and published in existing methodology documents along with a Submission Response document | 12 February 2021 |

[3] At https://aemo.com.au/en/consultations/current-and-closed-consultations/forecast-accuracy-report-methodology.

[4] 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 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM). The objective of this transparency is to build confidence in the forecasts produced

To meet this requirement, AEMO has prepared this forecast accuracy report for a broad set of demand, supply, and reliability forecast components.

Specifically, this 2020 Forecast Accuracy Report assesses the accuracy of the 2019-20 demand and supply forecasts published in AEMO's 2019 NEM ESOO[5] and related products, in addition to the resulting reliability forecasts for each region in the NEM. The 2019 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 the forecast accuracy. To assess if the methodologies applied were fit for purpose, AEMO commissioned an external review of its forecast accuracy assessment methodology undertaken by University of Adelaide[6]. Recommendations arising from the review were adopted by AEMO where practicable to increase the depth and breadth of its forecast accuracy reporting, and has formed the basis of AEMO's forecast accuracy reporting methodology, which AEMO consulted on in the first half of 2020[7].

## 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.
- All times mentioned are NEM time – Australian Eastern Standard Time (UTC+10) – not local times, 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.
- Terms used in this report are defined in the glossary.

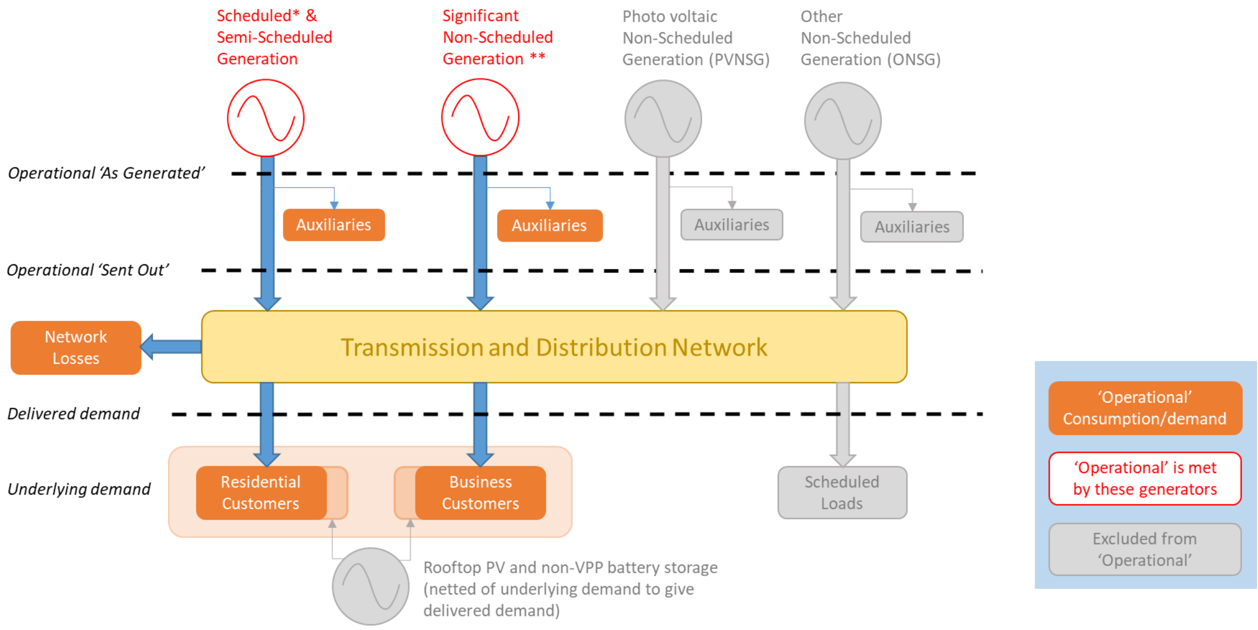
Figure 1 shows the demand definitions used in this document.

[5] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities/2019-nem-electricity-statement-of-opportunities.

[6] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecastmetricsassessment_uoa-aemo.pdf.

[7] 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.

**Figure 1 Demand definitions used in this document**

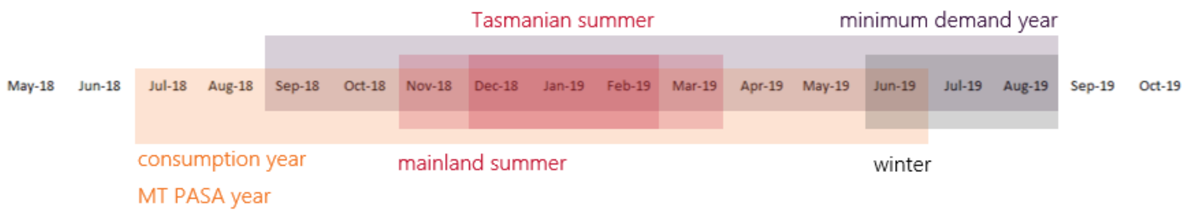



* Including VPP from aggregated behind-the-meter battery storage
** For definition, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

For consistency, data and methodologies of actuals are the same as those used for the corresponding forecasts in the 2019 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**



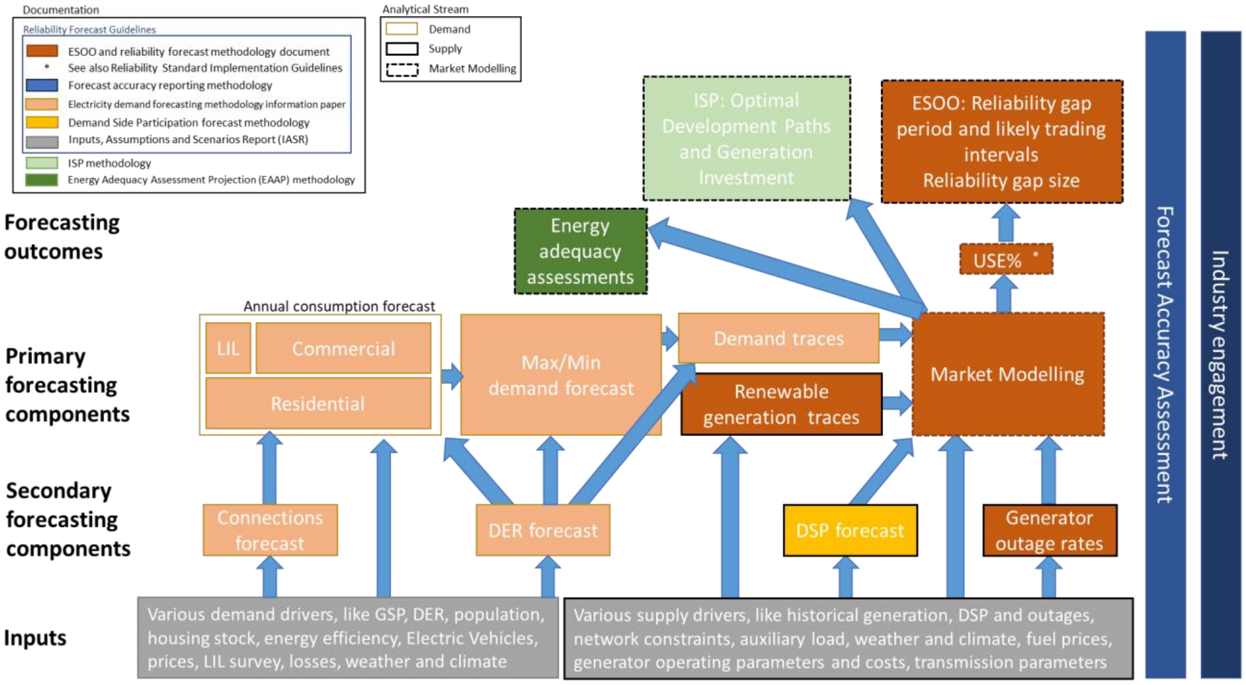

## 2.2 Forecast components

Production of AEMO's high level outputs requires multiple sub-forecasts to be produced and appropriately integrated, and these are referred to as forecast components. The figure below shows the forecast components leading to AEMO's reliability forecast and the methodology documents (see colour legend) explaining these processes in more detail[8].

[8] These documents are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

In this figure, 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.

**Figure 3 Forecasting components**




## 2.2.1 Assessability of forecast accuracy

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

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

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

As AEMO gains access to increasing proportions of 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 it is the case in for the 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 2019 ESOO are summarised in Table 3.

**Table 3 Key scenarios drivers used in the 2019 ESOO**

| Consultation steps | Slow Change scenario | Central scenario | Step Change scenario |
|---|---|---|---|
| **Economic growth and population outlook** | Low | Moderate | High |
| **Energy efficiency improvements** | Low | Moderate | High |
| **Demand Side Participation** | Low | Moderate | High |
| **Distributed PV uptake (rooftop plus PVNSG)** | Low | Moderate | High |
| **Battery storage uptake** | Low | Moderate | High |
| **EV uptake** | Low | Moderate | High |

# 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 2019 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.

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 year ahead forecasts. Input drivers that are suitable for accuracy assessment and comment are discussed in this section.

## 3.1 Macroeconomic growth

There are various macroeconomic indicators that form the basis of the scenario forecasts. The 2019 NEM ESOO Central scenario incorporated consultant forecasts between 2.6% and 4.0% p.a. average real growth in Gross Domestic Product (GDP) for the first five years of the forecast and 3.2% specifically for 2019-20. Instead, actual growth in GDP in 2019-20 fell 6.3%, the sum of the four quarters to June 2020 as shown in Figure 4[9].

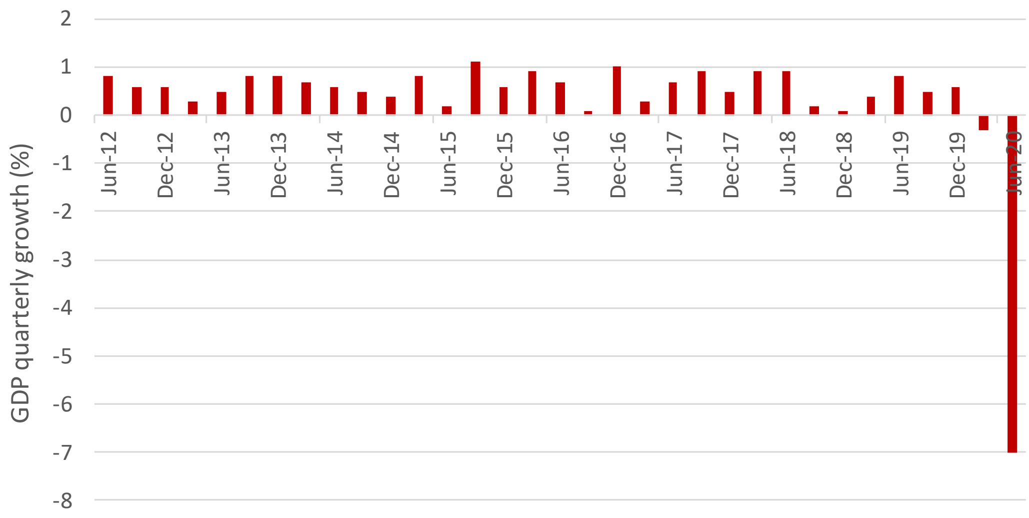
All things being equal, slower economic growth would lead to lower electricity demand than forecast. However, the specific sector in which the economic activity slows can affect the energy consumption significantly. In March 2020 the response by both federal and state governments during the unfolding COVID-19 pandemic has impacted electricity consumption, though not uniformly. Social distancing measures and restrictions in trading have resulted in declines in business activity of many small to medium enterprises (resulting in lower GDP) and subsequently lower energy consumption. At the same time, stay-at-home orders resulted in an increase in residential consumption.

The impact on consumption in 2019-20 has been modest with industrial load broadly flat, and the downturn in commercial electricity consumption almost offset by residential load increases[10]. This is reflected in Section 4, where forecast and actual consumption matches reasonably well in most regions.

[9] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2020, available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release . Accessed 21 September 2020.

[10] Quarterly Energy Dynamics Q2 2020, Jul 2020, available at: https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q2-2020.pdf

**Figure 4 Macroeconomic growth rates, chain volume measures, seasonally adjusted**




## 3.2 Connections growth

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). 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 2019 ESOO forecast.

**Table 4 Connections forecast for 2019-20 and actuals for 2019-20**

| Region | Actual for 2019-20 (#) | 2019 forecast for 2019-20 (#) | Difference* (%) |
|---|---|---|---|
| New South Wales | 3,475,443 | 3,464,314 | -0.3% |
| Queensland | 2,009,359 | 2,015,430 | 0.3% |
| South Australia | 788,563 | 785,671 | -0.4% |
| Tasmania | 251,238 | 250,366 | -0.3% |
| Victoria | 2,646,207 | 2,633,118 | -0.5% |
| NEM | 9,170,810 | 9,148,899 | -0.2% |

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

In general, the actual number of connections aligned well with the forecast, and the contribution to the overall NEM consumption forecast variance is minimal (see Figure 8 in Section 4).

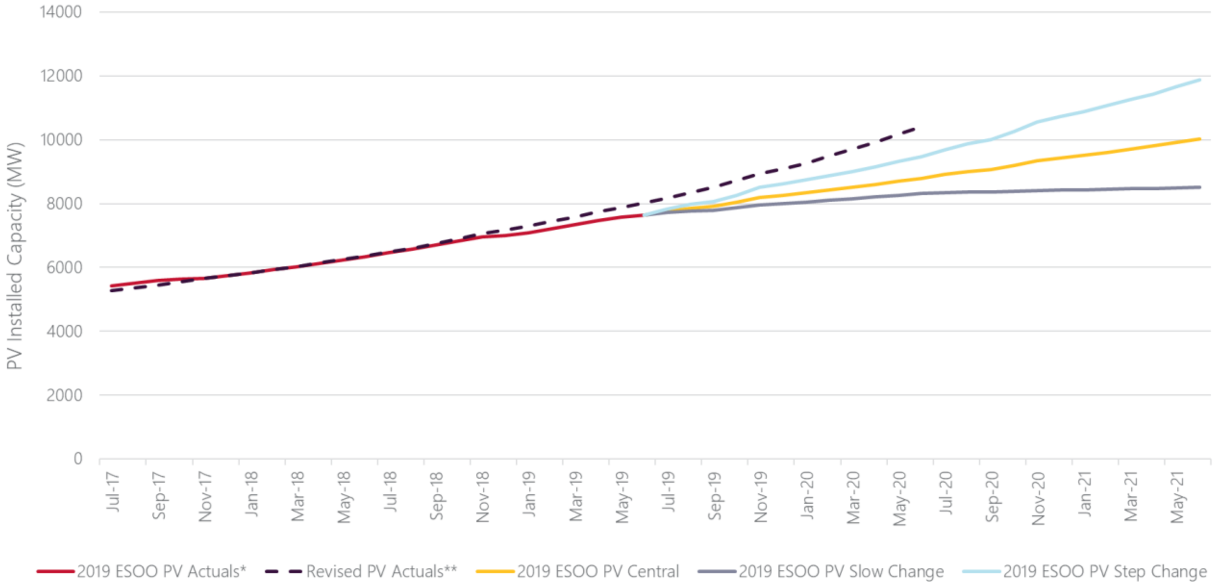
## 3.3 Rooftop PV and PV non-scheduled generation

To define actual rooftop PV installed capacity in the 2019 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 2019 ESOO Central scenario forecast provided by CSIRO[11] assumed short term growth in installations similar to the trajectory of actual growth as it appeared at the time.

Figure 5 compares the rooftop PV forecast for the 2019 ESOO scenarios (see Table 3 for definition) with the estimated actuals at the time the 2019 PV forecast was finalised in May 2019, and current revised actuals for the same period (as of 19 September 2020). As seen, the current revision (dashed line) is higher in mid-2019 than the estimated actuals were (red line) at the time the 2019 PV forecast was finalised. The figure highlights the inaccurate estimate of existing capacity of all three scenarios (June 2019) caused the starting point to be too low and didn't pick up an acceleration in installations at the time. Overall, the actuals therefore fell outside the range of rooftop PV installations assumed across AEMO's scenarios.

**Figure 5 NEM rooftop PV installed capacity comparison, 2017-21**




* As estimated in May 2019
** As estimated in September 2020

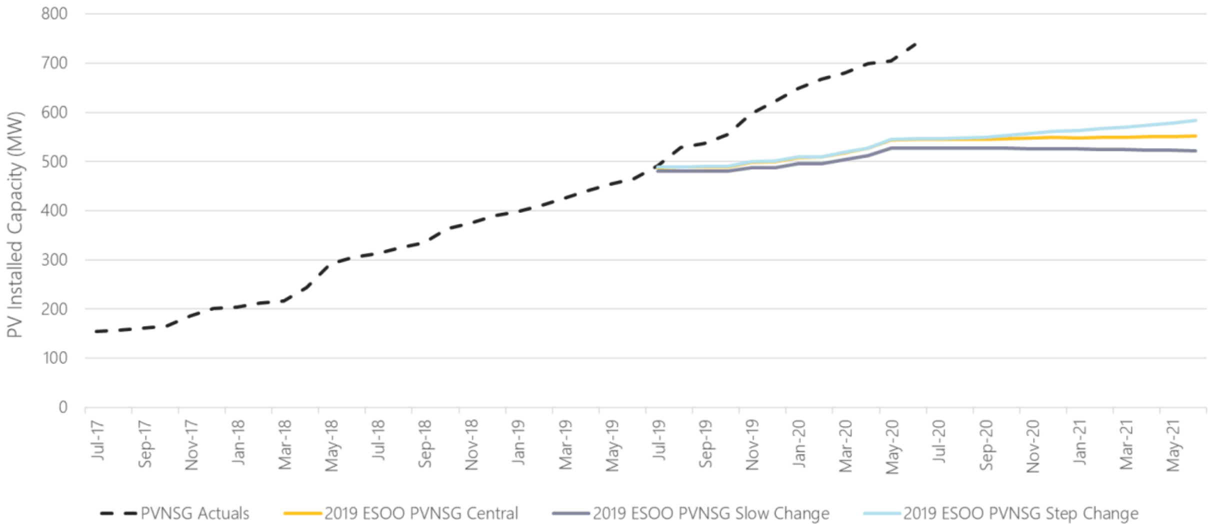
Figure 6 shows the PV non-scheduled generation (PVNSG) latest view of actuals[12] compared to the first two years of the 2019 PVNSG forecast. Note that unlike rooftop PV, there is no lag in reporting projects this size, so there is no difference between actuals estimated at the time of the 2019 ESOO and what is estimated today.

While the forecast starting point aligns well with the actuals at the time, the trajectory assumed a slowing uptake trend as Large-scale generation certificate (LGC) prices were forecast to fall over the short term lowering the economic advantage of new installations.

[11] For further information see CSIRO, 2019 Projections for Small Scale Embedded Technologies Report: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-projections-for-small-scale-embedded-technologies-report-by-csiro.pdf

[12] As estimated in September 2020.

**Figure 6 NEM PVNSG installed capacity comparison, 2017-21**




The differences between forecasts and actuals by region are highlighted in Table 5, showing this for the Central scenario, which was the main forecast discussed in the 2019 ESOO, and the Step Change scenario, which had the forecast closest to the observed actuals.

**Table 5 Rooftop PV and PVNSG installed capacity comparison by region, as at 30 June 2020 (MW)**

| | As installed at 30 June 2020 | NSW | QLD | SA | TAS | VIC |
|---|---|---|---|---|---|---|
| Rooftop PV | Estimated Actual (MW) | 3078 | 3387 | 1417 | 172 | 2356 |
| | Central Forecast (MW) | 2275 | 3052 | 1219 | 162 | 2087 |
| | Step Change Forecast (MW) | 2521 | 3235 | 1335 | 175 | 2203 |
| | Actual difference to Central forecast (%) | 35% | 9% | 16% | 6% | 13% |
| | Actual difference to Step Change forecast (%) | 22% | 5% | 6% | -2% | 7% |
| PVNSG | Estimated Actual (MW) | 213 | 192 | 137 | 2.5 | 191 |
| | Central Forecast (MW) | 180 | 182 | 60 | 6 | 116 |
| | Step Change Forecast (MW) | 180 | 183 | 61 | 6 | 116 |
| | Actual difference to Central forecast (%) | 18% | 5% | 128% | -58% | 64% |
| | Actual difference to Step Change forecast Difference (%) | 18% | 5% | 128% | -58% | 64% |
| Total | Actual distributed PV difference to Central forecast (%) | 34% | 10% | 22% | 4% | 16% |
| | Actual distributed PV difference to Step Change forecast (%) | 22% | 5% | 11% | -4% | 10% |

Actuals are based on AEMOs latest actual data as of 19 September 2020.

For all NEM regions, rooftop PV was under-forecast in 2019, with the largest variation seen in New South Wales. As installed rooftop PV capacity is negatively correlated with operational consumption, maximum and in particular minimum demand, higher uptake typically lowers operational consumption and demand.

The impact of under-forecasting rooftop PV results in the variance between the 2019 ESOO consumption forecast and the actuals reported in the NEM of approximately 0.4% (see Figure 8 in Section 4). The impacts on maximum and minimum demand are covered in Section 5.

As shown in the table, PVNSG was also under-forecast in all regions, except for Tasmania.

Section 8 presents the improvements already implemented and additional initiatives considered to both improve the accuracy of the forecast near term and better reflect PV forecast uncertainty in the future.

## 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). Auxiliary loads are not directly measured and so are modelled with the assumption that they are equal to the difference between total generation as measured at generator terminals and the electricity that is sent out into the grid.

The difference in auxiliary load between the 2019 ESOO forecast and the actual reported in the NEM is approximately 0.5% (see Figure 8 in Section 4). It is the largest source of variance, though it is mostly due to higher than actual auxiliary load factors used when developing the 2019 ESOO forecast.

For the 2019 ESOO forecast (as with previous years) AEMO has used consultant estimates for these values. To improve accuracy (see the 2019 Forecast Improvement Plan), AEMO has in 2020 requested scheduled and semi-scheduled generators to self-report their typical auxiliary load percentage, which AEMO now uses in its modelling. The actual operational sent-out consumption for 2020 was calculated based on the new percentages, which differs significantly for some power stations in Queensland and Victoria. The reported differences are to a large extent a consequence of getting estimates of auxiliary load directly from generators. Using generator supplied auxiliary load factors going forward, should ensure better consistency year on year (no step change in assumptions) and is regarded as an improved estimate of auxiliary load and thus operational sent-out consumption/demand.

## 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. These are generally lower than what was assumed at the time the 2019 ESOO was made, in particular for distribution losses, as shown in Table 6.

**Table 6 Estimated network loss factors**

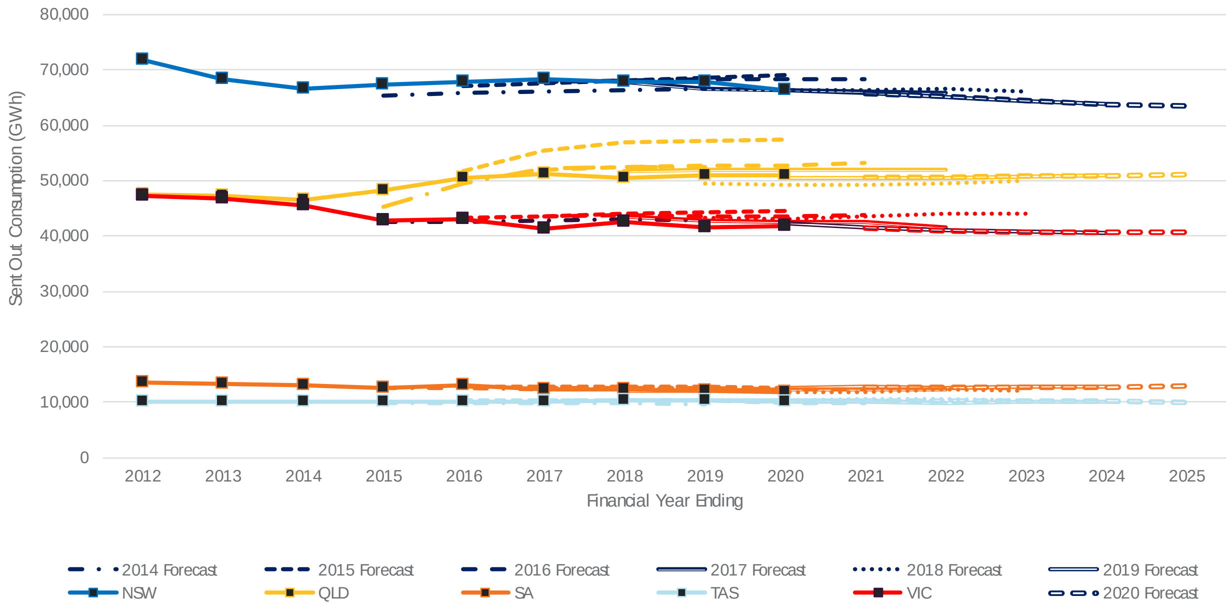
| | Transmission Loss Factor | | Distribution Loss Factor | |
|---|---|---|---|---|
| | Applied to 2019 forecast | Estimated actual for 2019-20 | Applied to 2019 forecast | Estimated actual for 2019-20 |
| **New South Wales** | 2.29% | 2.30% | 4.63% | 4.25% |
| **Queensland** | 2.58% | 2.56% | 4.80% | 4.76% |
| **South Australia** | 2.62% | 2.54% | 6.57% | 6.43% |
| **Tasmania** | 2.43% | 2.90% | 5.31% | 4.01% |
| **Victoria** | 2.62% | 1.92% | 5.12% | 4.88% |

Using the latest reported network losses as estimates for 2019-20, contributed to the third largest component in the variance in the 2019 ESOO forecast of approximately 0.4% in the NEM (see Figure 8 in Section 4).

# 4. Operational energy consumption forecasts

AEMO forecasts annual operational energy consumption by region on a financial year basis. Figure 7 shows central forecasts prepared from 2014 to 2019, 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 7 Recent annual energy consumption forecasts by region**




AEMO assessed annual consumption forecast accuracy by measuring the percentage difference between actual and forecast values of the published forecasts. This percentage error is calculated using the formula below:

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

This calculation of percentage error varies from previous forecast accuracy reports, following the approach outlined in the Forecast Accuracy Report Methodology[13]. Using this formula, for example, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

Table 7 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using this new percentage error calculation. In the last three years, the individual percentage error for the individual regions has remained below 4% and the NEM weighted average has had a percentage error less than 2%.

[13] 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.

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

| One-year ahead annual operational consumption accuracy (%) | 2015 NEFR forecast in 2015-16 | 2016 NEFR forecast in 2016-17 | 2017 ESOO forecast in 2017-18 | 2018 ESOO forecast in 2018-19 | 2019 ESOO forecast in 2019-20 |
|---|---|---|---|---|---|
| New South Wales | -1.2% | -0.8% | -0.1% | -1.8% | -0.3% |
| Queensland | 2.7% | 1.7% | 2.8% | -3.0% | 0.1% |
| South Australia | -1.6% | 1.6% | -0.8% | -0.8% | 3.2% |
| Tasmania | 3.6% | 2.5% | -0.1% | 1.3% | 2.3% |
| Victoria | 0.5% | 5.2% | 2.5% | 3.9% | 1.5% |
| NEM | 0.5% | 1.6% | 1.3% | -0.6% | 0.6% |

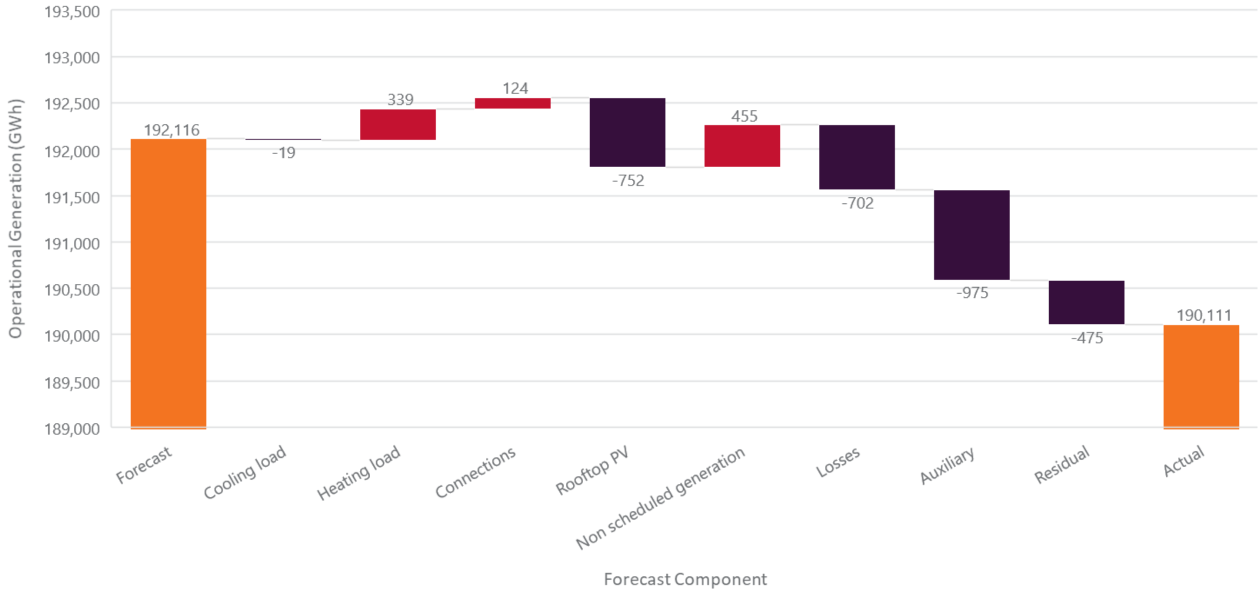
Table 8 shows the sources of variance for the 2019-20 consumption forecasts of the NEM. This shows that the largest sources of error relate to underestimates of rooftop PV generation, and overestimates of network losses and generator auxiliary loads, as discussed in Section 3.

**Table 8 NEM operational energy consumption forecast accuracy by component**

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | 3,559 | 3,540 | 0.5% | 0.0% |
| Heating Degree Days | 5,327 | 5,666 | -6.0% | -0.2% |
| Connections Growth | 685 | 809 | -15.4% | -0.1% |
| Rooftop PV | 11,312 | 12,064 | -6.2% | -0.4% |
| Small non-scheduled generation | 6,310 | 5,855 | 7.8% | 0.2% |
| Network losses | 11,427 | 10,725 | 6.5% | 0.4% |
| **Operational sent out** | **181,963** | **180,932** | **0.6%** | **0.5%** |
| Auxiliary load | 10,153 | 9,178 | 10.6% | 0.5% |
| **Operational as generated** | **192,116** | **190,111** | **1.1%** | |

Figure 8 shows this graphically and highlights the residual variance, being the variance that is not explained by any of the measured components, is small, equating to -425 GWh (or 0.25% over-forecast). Any impact of COVID-19 not accounted for through variations in connections growth or rooftop PV installations, would be included in this residual. The variances for the disaggregated components explain the vast majority of the overall forecast error for the NEM combined.

**Figure 8 NEM operational energy consumption variance by component**




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 break-down of these components. In summary:

- The more significant sources of rooftop PV variance were in Queensland, New South Wales and South Australia.
- Network losses and generator auxiliary loads have been consistently overestimated across all mainland regions.

## 4.1 New South Wales

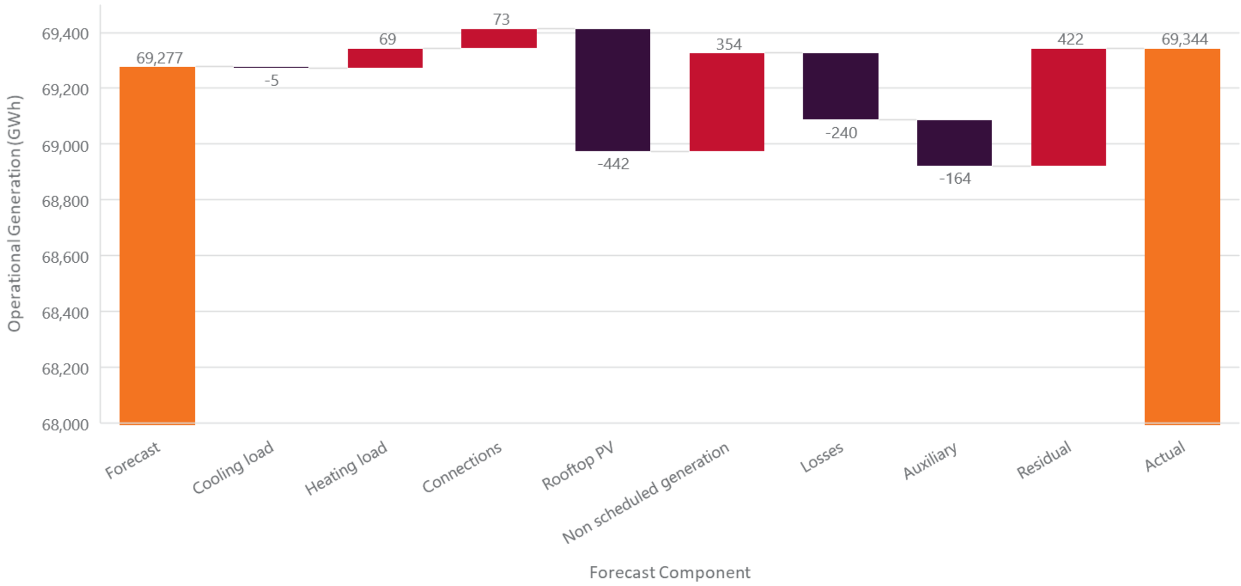
Operational as-generated energy consumption for New South Wales in 2019-20 was slightly above the Central forecast, leading to a percentage error of -0.1%. Table 9 and Figure 9 demonstrate the forecast accuracy by component. Summer cooling degree days and winter heating degree days were close to median. The largest inaccuracy driver was an under-forecast of rooftop PV mostly offset by an over forecast of small non-scheduled generation (which was lower due to drought affecting hydro generation). Overall, the model for New South Wales has performed well with the residual being 422 GWh as per Figure 9 (or -0.6%).

The positive residual is slightly surprising given COVID-19 impacts on economic activity, and may in fact indicate that other input variables, not easily assessable (such as an over-estimation of energy efficiency), may also be contributing to the differences between forecasts and actual consumption in New South Wales.

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

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | 1,294 | 1,289 | 0.4% | 0.0% |
| Heating Degree Days | 1,845 | 1,914 | -3.6% | -0.1% |
| Connections Growth | 258 | 332 | -22.1% | -0.1% |
| Rooftop PV | 3,027 | 3,470 | -12.7% | -0.6% |
| Small non-scheduled generation | 2,117 | 1,763 | 20.0% | 0.5% |
| Network losses | 4,106 | 3,865 | 6.2% | 0.3% |
| Operational sent out | **66,182** | **66,412** | **-0.3%** | **-0.3%** |
| Auxiliary load | 3,096 | 2,932 | 5.6% | 0.2% |
| Operational as generated | **69,277** | **69,344** | **-0.1%** | |

**Figure 9 New South Wales operational energy consumption variance by component**




## 4.2 Queensland

Operational as-generated energy consumption for Queensland in 2019-20 was below the Central forecast by 0.9%. Table 10 and Figure 10 demonstrate the forecast accuracy by component. Summer cooling degree days were slightly higher and winter heating degree days were slightly lower compared to the median forecast.

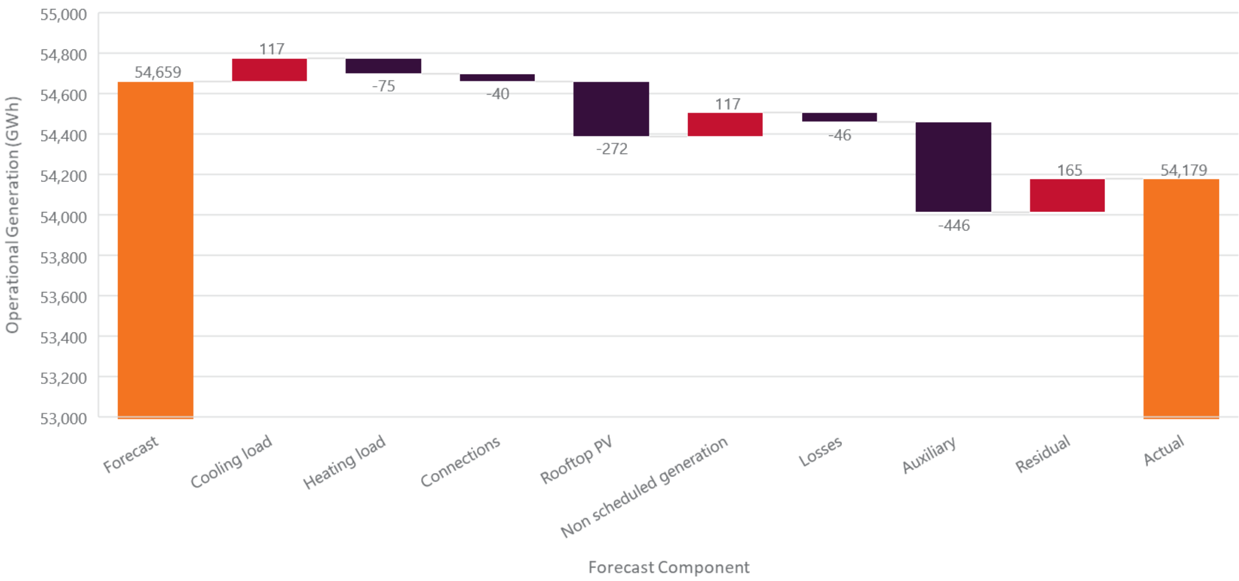
The largest inaccuracy driver was an under-forecast of rooftop PV, but this was somewhat offset by an over-forecast of small non-scheduled generation and lower auxiliary loads. The latter was driven by a change in data source for auxiliary load as explained in Section 3.4.

Subject to input variable correction, the model for Queensland has performed well with the residual being just 165 GWh as per Figure 10 (or -0.3%).

Table 10 Queensland operational energy consumption forecast accuracy by component

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | 1,486 | 1,603 | -7.3% | -0.1% |
| Heating Degree Days | 392 | 317 | 23.6% | 0.0% |
| Connections Growth | 199 | 158 | 25.4% | 0.0% |
| Rooftop PV | 4,006 | 4,278 | -6.4% | -0.1% |
| Small non-scheduled generation | 2,232 | 2,115 | 5.5% | 0.1% |
| Network losses | 2,935 | 2,889 | 1.6% | 0.0% |
| Operational sent out | **51,001** | **50,967** | **0.1%** | **0.0%** |
| Auxiliary load | 3,658 | 3,212 | 13.9% | 0.2% |
| Operational as generated | **54,659** | **54,179** | **0.9%** | |

Figure 10 Queensland operational energy consumption variance by component




## 4.3 South Australia

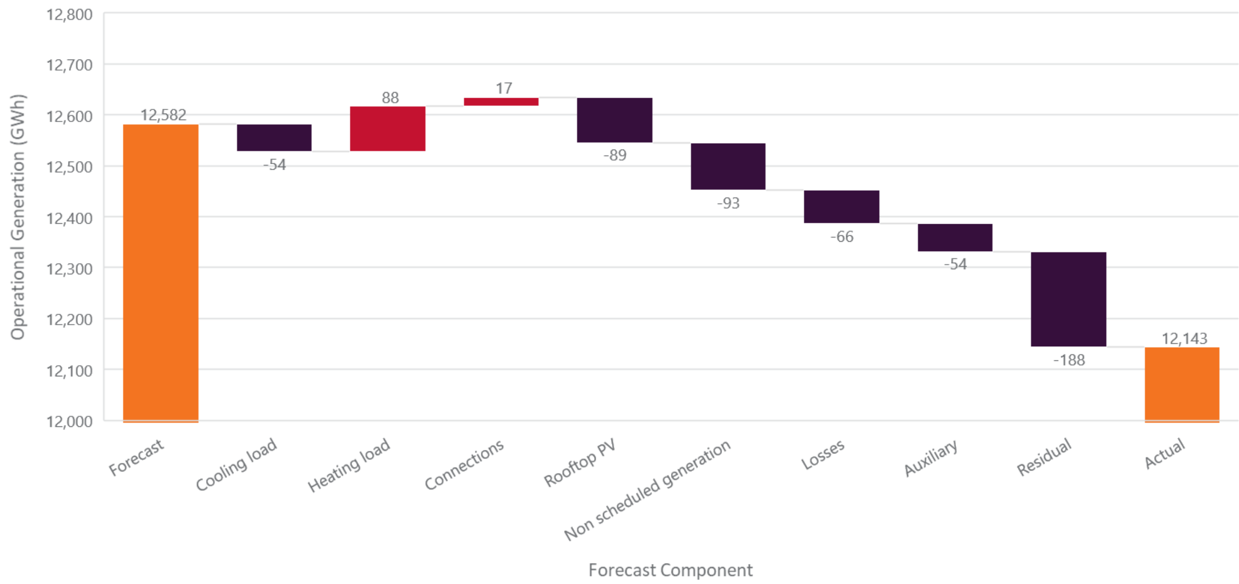
Operational as-generated energy consumption for South Australia in 2019-20 was below the Central forecast by 3.6%. Table 11 and Figure 11 demonstrate the forecast accuracy by component. Summer cooling degree days were slightly lower but winter heating degree days were higher compared to the median forecast.

The largest inaccuracy drivers were an under-forecast of rooftop PV and small non-scheduled generation (mainly driven by PV installations >100 kW). The residual variance shown in Figure 11 is moderate at about 1.5%. Analysis of meter data indicates demand was down due to COVID-19 restrictions, where residential demand in South Australia, unlike the other regions, did not to the same extent offset the reduction in business consumption.

**Table 11 South Australia operational energy consumption forecast accuracy by component**

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | 1,184 | 1,001 | 17.9% | 0.4% |
| Heating Degree Days | 1,771 | 2,057 | -14.2% | -0.7% |
| Connections Growth | 31 | 48 | -35.6% | -0.1% |
| Rooftop PV | 1,603 | 1,692 | -5.2% | -0.7% |
| Small non-scheduled generation | 218 | 311 | -30.0% | -0.8% |
| Network losses | 982 | 916 | 7.2% | 0.5% |
| Operational sent out | **12,276** | **11,891** | **3.2%** | **3.2%** |
| Auxiliary load | 307 | 252 | 21.6% | 0.4% |
| Operational as generated | **12,582** | **12,143** | **3.6%** | |

**Figure 11 South Australia operational energy consumption variance by component**




## 4.4 Tasmania

Operational as-generated energy consumption for Tasmania in 2019-20 was below the Central forecast by 2.3%. Table 12 and Figure 12 demonstrate the forecast accuracy by component. Winter heating degree days were lower than the median forecast.

The largest source of inaccuracy was an under-forecast of small non-scheduled generation, where upgrades to some of Hydro Tasmania's Lower Derwent power stations saw generation increase above historical levels.

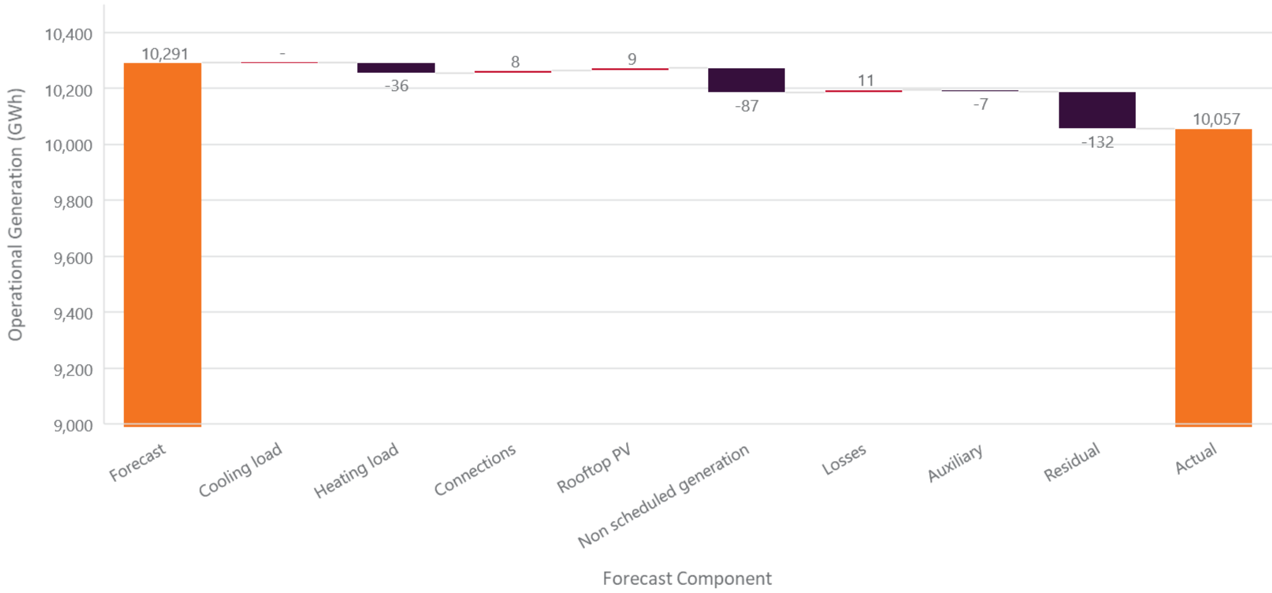
This leaves a residual of -132 GWh (1.3%) which is partly explained by lower consumption from large industrial loads than forecast, partly due to extended outages and partly reduced activity due to COVID-19.

Subject to input variable correction, the model for Tasmania has performed well.

**Table 12 Tasmania operational energy consumption forecast accuracy by component**

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | - | - | - | 0.0% |
| Heating Degree Days | 620 | 584 | 6.1% | 0.4% |
| Connections Growth | 23 | 31 | -26.4% | -0.1% |
| Rooftop PV | 191 | 182 | 5.1% | 0.1% |
| Small non-scheduled generation | 456 | 544 | -16.1% | -0.9% |
| Network losses | 480 | 490 | -2.2% | -0.1% |
| Operational sent out | **10,178** | **9,951** | **2.3%** | **2.3%** |
| Auxiliary load | 113 | 106 | 6.9% | 0.1% |
| Operational as generated | **10,291** | **10,057** | **2.3%** | |

**Figure 12 Tasmania operational energy consumption variance by component**




## 4.5 Victoria

Operational as-generated energy consumption for Victoria in 2019-20 was below the Central forecast by 2.1%. Table 13 and Figure 13 demonstrate the forecast accuracy by component. Winter heating degree days were higher than the median forecast and Summer cooling degree days were slightly lower.

The largest inaccuracy driver was an over-forecast of network losses and auxiliary load. The latter was driven by a change in data source for auxiliary load as explained in Section 3.4.

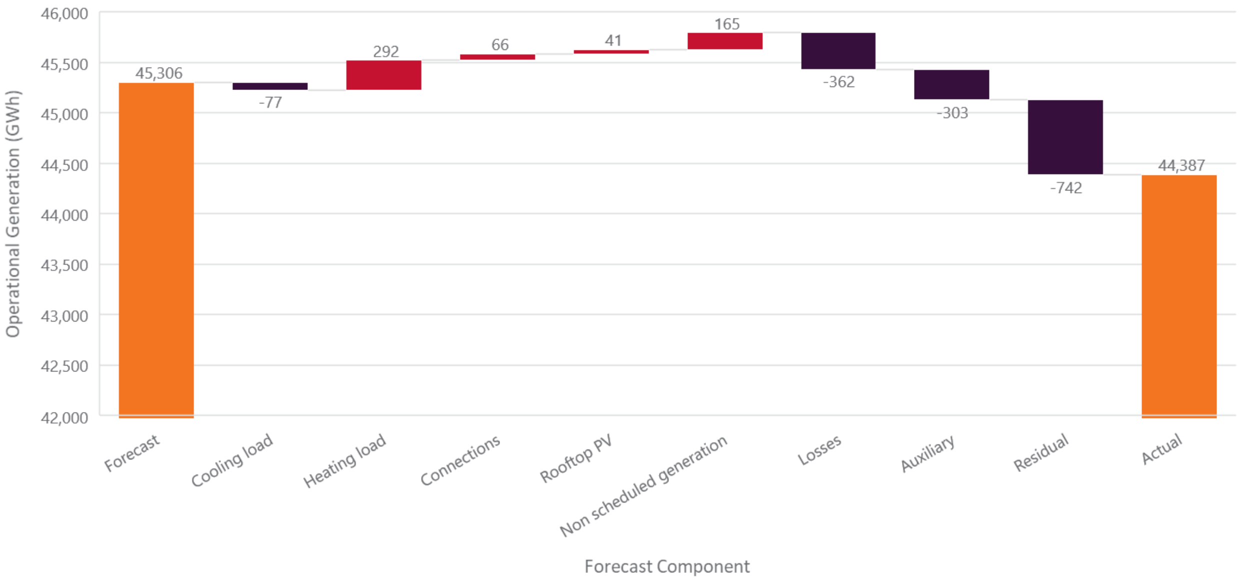
This leaves a moderate residual of -742 GWh (or 1.7%) which may, in part, be attributable to COVID-19 restrictions. Also, while the installed PV capacity was under-forecast for Victoria, forecast PV generation was slightly over the observed actual. Looking at solar insolation, it was a low solar year, but it may not sufficiently explain the outcome and AEMO will review the median PV generation used in the forecast to ensure it is fit for purpose. It could be another source of explanation for the residual.

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

**Table 13 Victoria operational energy consumption forecast accuracy by component**

| Category | 2019 forecast (GWh) | Actual (GWh) | Difference (%) | Indicative impact on total generation |
|---|---|---|---|---|
| Cooling Degree Days | 423 | 346 | 22.2% | 0.2% |
| Heating Degree Days | 1,938 | 2,230 | -13.1% | -0.7% |
| Connections Growth | 174 | 240 | -27.5% | -0.1% |
| Rooftop PV | 2,485 | 2,443 | 1.7% | 0.1% |
| Small non-scheduled generation | 1,288 | 1,122 | 14.7% | 0.4% |
| Network losses | 2,925 | 2,564 | 14.1% | 0.8% |
| **Operational sent out** | **42,327** | **41,711** | **1.5%** | **1.4%** |
| Auxiliary load | 2,979 | 2,676 | 11.3% | 0.7% |
| **Operational as generated** | **45,306** | **44,387** | **2.1%** | |

**Figure 13 Victoria operational 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, and sometimes 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[14].

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 (MW) 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[15].

## 5.1 Extreme demand events in 2019-20

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 6.7. A maximum demand day observed during summer may have occurred at a time of supply shortages, leading to load shedding, or very high prices which may have reduced demand. Comparing actual observed demand with forecast values can only be done if on the same basis, so some adjustments to actual demand are necessary. For the purposes of assessing forecast accuracy, adjustments have been grouped into two types:

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[14] 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.

[15] 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. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/ForecastMetricsAssessment_UoA-AEMO.pdf.

- 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 Victoria in 2019-20 occurred on 31 January 2020. Due to the heat and reduced generation availability, governments and utilities called for electricity conservation. Additionally, AEMO activated reserves through the Reliability and Emergency Reserve Trader (RERT) mechanism, including demand side participation. Due to extreme wind damaging transmission assets, there was also involuntary load shedding. The load shedding and RERT is considered firm, while an estimation of voluntary electricity conservation is considered potential.

### 5.1.1 Summer 2019-20 maximum demand events

Table 14 shows the summer maximum demand periods for the various regions in 2019-20, with Victoria being the only region where adjustments were required (see above).

**Table 14 Summer 2019-20 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, 1 Feb 2020 17:30 | 13,835 | 461 | 13,374 | - | - | 13,374 |
| QLD | Mon, 3 Feb 2020 17:30 | 9,853 | 473 | 9,380 | - | - | 9,380 |
| SA | Thu, 19 Dec 2019 19:00 | 3,218 | 71 | 3,147 | - | - | 3,147 |
| TAS | Tue, 3 Dec 2019 07:00 | 1,333 | 14 | 1,319 | - | - | 1,319 |
| VIC | Fri, 31 Jan 2020 17:00 | 9,667 | 423 | 9,244 | 500 | 109 | 9,853 |

### 5.1.2 Winter 2020 maximum demand events

Like summer maximum demand, AEMO has reviewed the winter maximum demand events to see if any firm or potential adjustments were necessary. AEMO found no adjustments were required to any of the winter maximum demand outcomes, despite South Australia's all-time high winter maximum demand event on Friday 7 August 2020 due to cold temperatures and high number of people home due to COVID-19. The winter maximum demand outcomes are shown in Table 15 below.

**Table 15 Winter 2020 maximum demand with adjustments per region (MW)**

| Region | Date/time of maximum demand | Operational as generated | Auxiliary load | Operational sent out | Adjustment (firm) | Adjustment (potential) | Adjusted sent out |
|---|---|---|---|---|---|---|---|
| NSW | Tue, 23 Jun 2020 18:30 | 12,166 | 502 | 11,664 | - | - | 11,664 |
| QLD | Tue, 14 Jul 2020 19:00 | 8,143 | 409 | 7,734 | - | - | 7,734 |
| SA | Fri, 7 Aug 2020 19:00 | 2,576 | 53 | 2,523 | - | - | 2,523 |
| TAS | Mon, 10 Aug 2020 08:30 | 1,661 | 16 | 1,645 | - | - | 1,645 |
| VIC | Tue, 4 Aug 2020 18:30 | 7,844 | 335 | 7,509 | - | - | 7,509 |

### 5.1.3 Annual 2019-20 minimum demand events

AEMO has reviewed the minimum demand events. In Tasmania, a large industrial load was taking an outage of approximately 50 MW of load on the day of minimum demand. Otherwise, it was typical minimum demand days either being Sundays or New Year's day. Both South Australia (10 November 2019) and Victoria (1 January 2020) reached their lowest minimum demand levels[16] 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)**

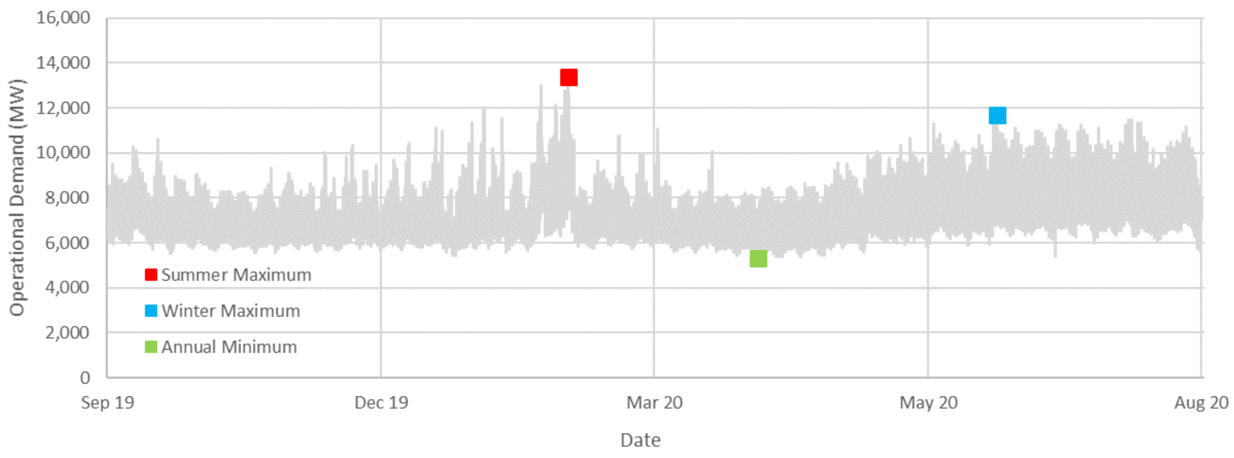
| Region | Date/time of maximum demand | Operational as generated | Auxiliary load | Operational sent out | Adjustment (firm) | Adjustment (potential) | Adjusted sent out |
|---|---|---|---|---|---|---|---|
| NSW | Sun, 5 Apr 2020 04:00 | 5,579 | 242 | 5,337 | - | - | 5,337 |
| QLD | Sun, 23 Aug 2020 12:30 | 3986 | 254 | 3732 | - | - | 3,732 |
| SA | Sun, 10 13:30 Nov 2019 | 458 | 11 | 447 | - | - | 447 |
| TAS | Mon, 16 Mar 2020 02:30 | 822 | 9 | 813 | - | - | 813 |
| VIC | Wed, 1 Jan 2020 12:30 | 3,300 | 292 | 3,008 | - | - | 3,008 |

[16] Records that have subsequently been broken in spring 2020.

## 5.2 New South Wales

The half hourly time-series for New South Wales operational sent-out (OPSO) demand is shown below in Figure 14. The extreme demand events for the last year until the end of winter 2020 are also shown in the graph. Further detail on the extreme demand events observed in 2019 is provided in Table 17.

**Figure 14 New South Wales demand with extreme events identified**




The maximum and minimum demand event forecasts are represented by a probability distribution of possible outcomes, as shown in Figure 15. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and customer behaviour. All minimum and maximum demand events fell well within their respective forecast distributions, either side of the 50% POE.

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

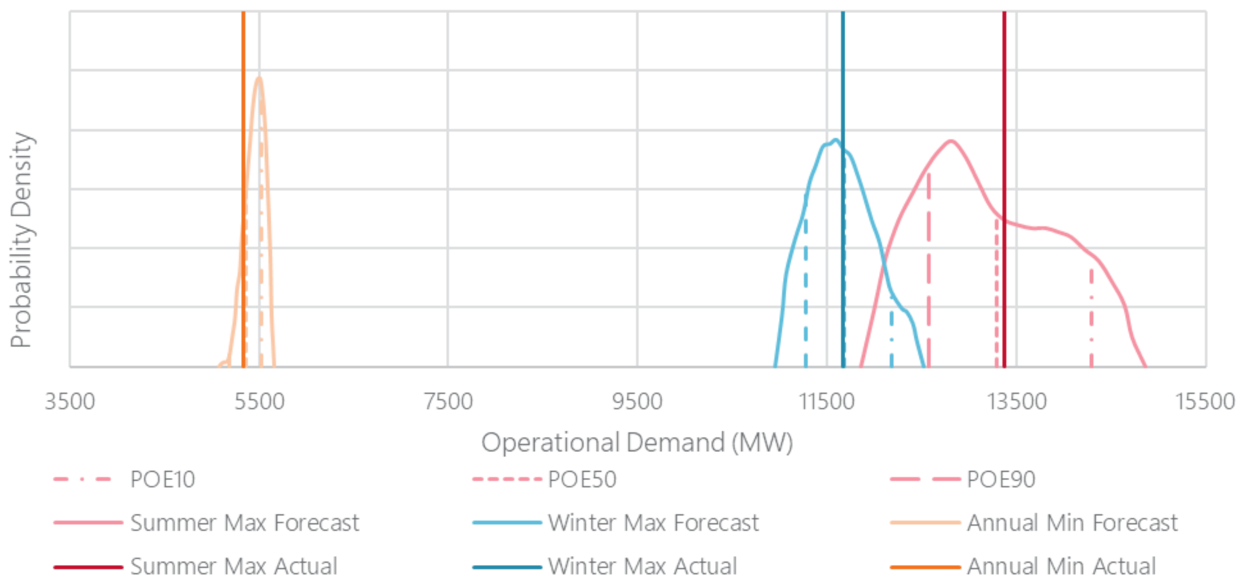


Table 17 New South Wales 2020 extreme demand events

| Event | Summer maximum | Winter maximum | Annual minimum |
|---|---|---|---|
| NEM Datetime | Sat, 1 Feb 2020 17:30 | Tue, 23 Jun 2020 18:30 | Sun, 5 Apr 2020 04:00 |
| Temperature* (°C) | 37.2 | 12.4 | 10.8 |
| Max temperature (°C) | 45.3 | 16.1 | 24.4 |
| Min temperature (°C) | 23.5 | 4.7 | 10 |
| Losses (MW) | 817 | 705 | 297 |
| NSG output (MW) | 212 | 182 | 126 |
| Rooftop PV output (MW) | 417 | 0 | 0 |
| Sent out (OPSO) | **13,374** | **11,664** | **5,337** |
| Auxiliary (MW) | 461 | 502 | 242 |
| As generated (OPGEN) | **13,835** | **12,166** | **5,579** |

*Bankstown Airport weather station. For more information please see Appendix A2 of the Electricity Demand Forecasting Methodology Information Paper (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf).

Figure 16 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum operational (sent out) demand occurred in summer on Saturday 1 February 2020 at 17:30 local time (16:30 NEM time). At the time of maximum demand, Bankstown recorded a temperature of 37.2°C with an earlier daily maximum of 45.3°C.

- Overall, maximum demand was within forecast expectations.
- New South Wales experienced a few days with particularly high maximum temperature last summer. The highest summer maximum temperature was not the maximum demand event. It was in January with a temperature of 47.0°C. The daily maximum temperature during the day of maximum demand was 45.3°C. Temperatures were particularly high throughout the maximum demand day, hitting 28.9°C at 9am, rising to the maximum of 45.3°C by midday then falling only four degrees to 41.7°C by 3pm. Humidity was low throughout the day at 29%, and with no cloud cover this resulted in much higher cooling load. Simulated temperature outcomes at time of maximum demand have a median of 37°C which, based on temperature alone, would indicate the actual maximum demand was close to the forecast 50% POE.
- Simulation outcomes were weighted towards occurring in late January/early February, which is consistent with the February occurrence. However, maximum demand falling on a Saturday is counter to forecast simulations, mainly due to the prevailing weather conditions on the day.
- PV generation at time of maximum demand sits around the median of the forecast distribution, which is high for a relatively late peak. However, PV capacity was under-forecast with 2,213 MW forecast but 2,672 MW installed capacity observed as at 1 February 2020. This 450 MW discrepancy, if included in the modelling, would have shifted the distribution of PV generation at time of peak to the right. This means that, after correcting for differences in installed PV capacity, the actual PV generation at time of peak would be at the lower end of the PV generation distribution, which is more consistent with timing when the peak occurred. Similarly, more PV capacity would have shifted the maximum demand forecast distribution down slightly, and the observed maximum demand would be between a 50% POE and 10% POE.

**Figure 16 New South Wales simulated extreme event probability distributions with actuals**

Winter maximum demand occurred on Tuesday 23 June 2020 at 18:30 local time, with a temperature of 12.4°C recorded at Bankstown.

- The observed maximum demand fell in the middle of the forecast distribution, while the temperature fell in the top end of the distribution. It suggests a change in consumption patterns following COVID-19 restrictions, for example an increase in people at home heating their houses.
- Maximum demand peaked at 18.30, an hour and a half 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.

Actual minimum demand occurred on Sunday 5 April 2020 at 04:00 local time, when the temperature was 10.8°C.

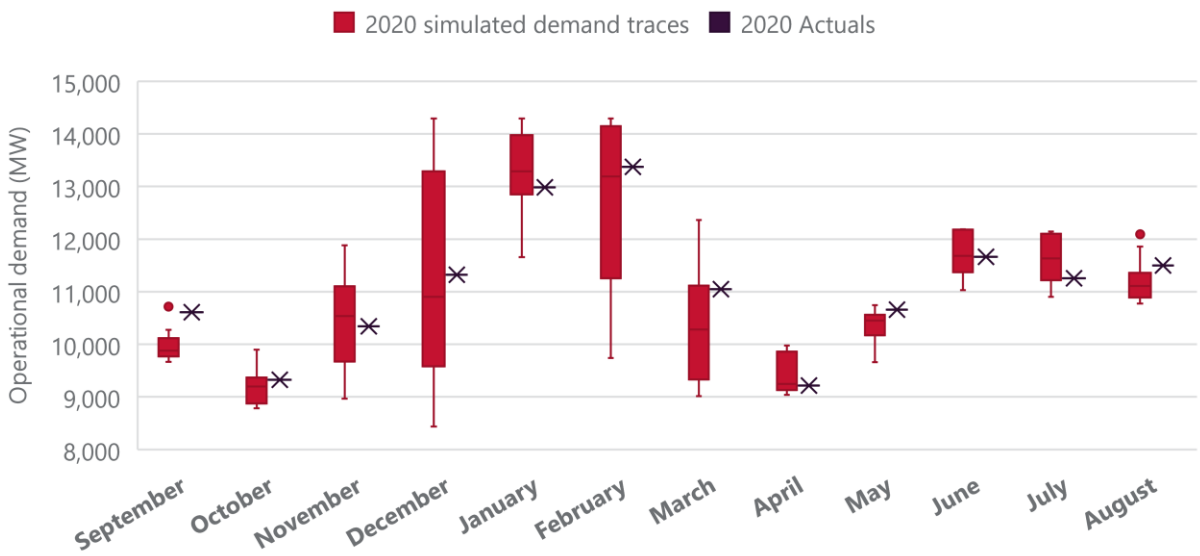
- Actual minimum demand is very close to the 50% POE, occurring overnight as expected.
- Simulation outcomes were weighted towards occurring in late November/early December, which is contrary to the Sunday 5 April 2020 occurrence. COVID-19 restrictions had just begun in New South Wales, which would have impacted electricity demand.
- Minimum demands have been growing in New South Wales as underlying demand in residential and business load have tended to grow by more than the rate of PV installations. In recent years summer minimum demand has been lower than those in the shoulder seasons. The ESOO 2019 predicted this to continue to be the case. However, the ESOO 2020 predicted that shoulder months would play an increasingly important role in NSW minimum going forward depending on the uptake of PV capacity and the balance with underlying demand growth.

### Monthly maxima

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 nine reference years (2011-19), 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 EAAP (Energy Adequacy Assessment Projection) and 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 impacts could also be another explanation for actuals falling outside the range.

The box plot in Figure 17 shows the range of monthly demand maximums for the 2020 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.

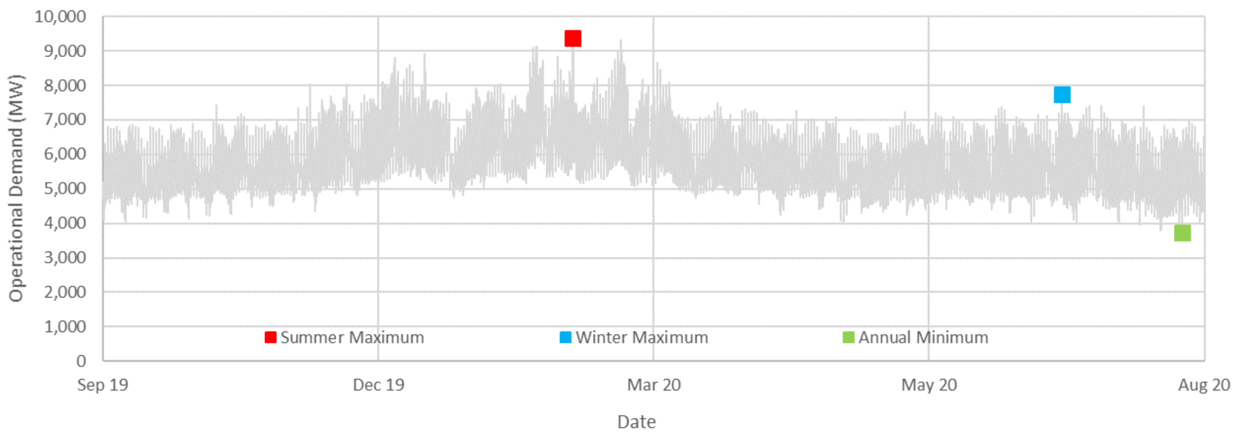
**Figure 17 New South Wales monthly maximum demand in demand traces compared with actuals**




## 5.3 Queensland

Queensland's half hourly OPSO demand time-series and extreme events are shown below in Figure 18, demonstrating Queensland's clear summer peak. Further detail on the extreme demand events for 2020 is provided in Table 18.

**Figure 18 Queensland demand with extreme events identified**




The maximum and minimum demand event forecasts are represented by a probability distribution of possible outcomes, as shown in Figure 19. Both maximum demand events fell in the middle of their respective forecast distributions, while the minimum event fell well below the forecast distribution.

**Figure 19 Queensland simulated extreme event probability distributions with actuals**

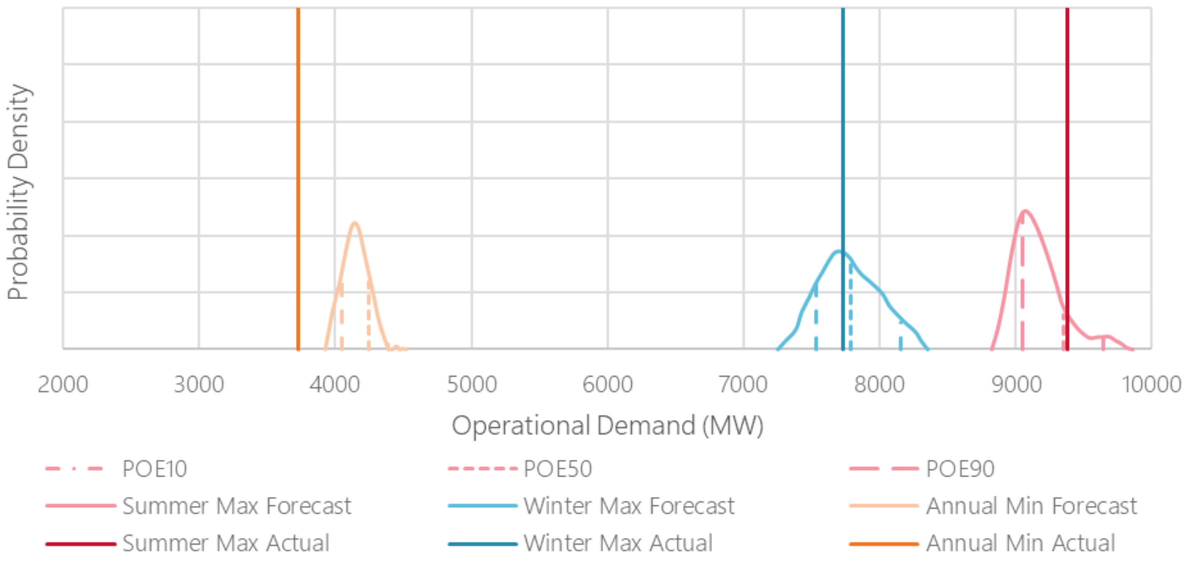



**Table 18 Queensland 2020 extreme demand events**

| Event | Summer maximum | Winter maximum | Annual minimum |
|---|---|---|---|
| NEM Datetime | Mon, 3 Feb 2020 17:30 | Tue, 14 Jul 2020 19:00 | Sun, 23 Aug 2020 12:30 |
| Temperature (°C) | 30.4 | 11.5 | 19.6 |
| Max temperature (°C) | 35.4 | 17.6 | 20.6 |
| Min temperature (°C) | 23.2 | 8.4 | 6.6 |
| Losses (MW) | 587 | 471 | 179 |
| NSG output (MW) | 255 | 205 | 333 |
| Rooftop PV output (MW) | 394 | 0 | 2,239 |
| **Sent out (OPSO MW)** | **9,380** | **7,734** | **3,732** |
| Auxiliary (MW) | 473 | 409 | 254 |
| **As generated (OPGEN MW)** | **9,853** | **8,143** | **3,986** |

*Archerfield Airport weather station. For more information please see Appendix A2 of the Electricity Demand Forecasting Methodology Information Paper (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf).

Figure 20 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

**Figure 20 Queensland simulated input variable probability distributions with actuals**

Actual maximum demand occurred in summer on Monday 3 February 2020 at 17:30 local time. At the time of maximum demand, Archerfield recorded a temperature of 30.4°C with an earlier daily maximum of 35.4°C.

- Maximum demand was within forecast expectations for the conditions on the day. However, Queensland had a seasonal maximum temperature of 41.2°C on Monday 16 December 2019 that did not result in the summer maximum demand event. 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 New South Wales, was driven by milder temperatures this year which was reflected in the peak demand event. The temperature at time of maximum demand was a full 10 degrees below the summer maximum temperature of 41.2°C. Simulated temperature outcomes ranged from 27°C to 42°C with a mode of 35°C which, based on temperature alone, would indicate a lower actual maximum demand between 50% and 90% POE would be expected.
- PV generation was at the lower end of simulated outcomes, with an actual of 394 MW at time of maximum demand, compared to a simulation mean of 700 MW and likely range of outcomes between 300 and 1,100 MW. Total PV capacity for Queensland was under-forecast, with an actual 3,389 MW of installed capacity as at 1 July 2020 compared to a forecast of 3,054 MW. Cloud cover on the day was minimal, while relative humidity was at a month-low of 49%, which are good conditions for high PV generation. However, in the afternoon showers and thunderstorms developed over the Greater Brisbane region, which decreased PV generation consistent with what was observed.
- Simulation outcomes were weighted towards occurring during the week and in late January/early February, which is consistent with the Monday 3 February 2020 occurrence.

Winter maximum demand occurred on Tuesday 14 July 2020 at 19:00 local time. Temperature at the time was 11.5°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 saw the coldest 9am temperature of the season (12.6°C) and one of the coldest winter days overall (daily maximum temperature of 18.1°C), further exacerbated by strong winds. 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 Tuesday 14 July 2020 .

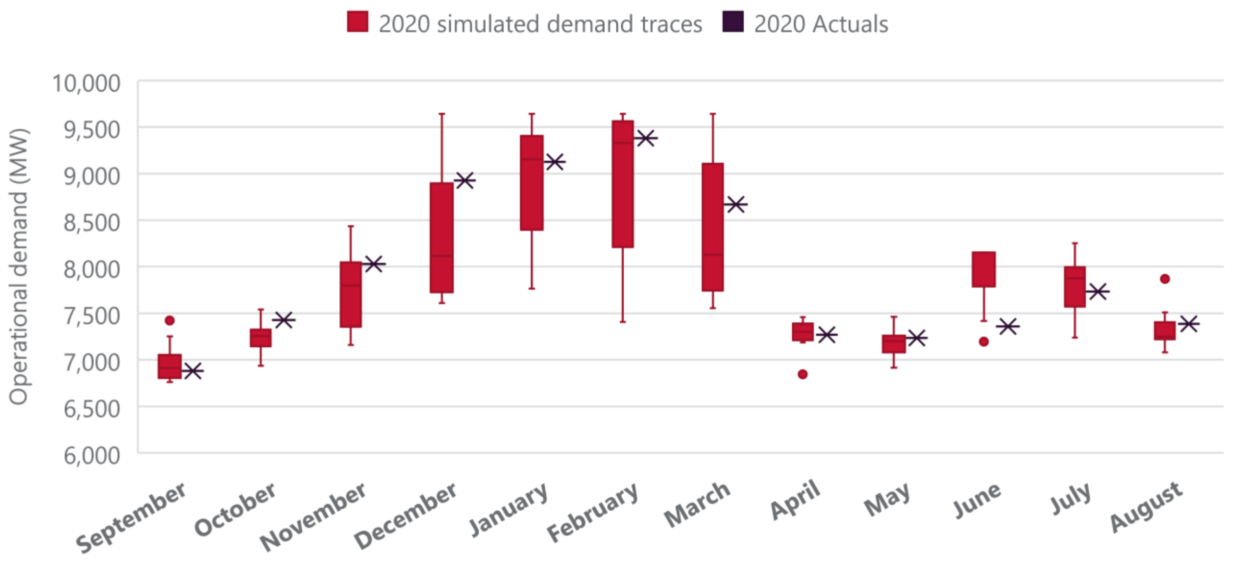
Actual minimum demand occurred in winter on Sunday 23 August 2020 at 12:30 local time, when the temperature was 19.6°C.

- Minimum demand was lower than forecast expectations due to the rate of PV installations being higher than forecast.
- Prevailing conditions on the day were very similar to when the annual minimum demand occurred last year on Sunday 18 August 2019 at 12:00 local time.
- 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 around 340 MW too low, and accounts for most of the error in the forecast.
- Simulation outcomes were weighted towards occurring on the weekend and in August, which is consistent with the Sunday 23 August 2020 occurrence.

### Monthly maxima

The box plot in Figure 21 shows the range of monthly demand maximums for the 2020 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums all fell within the simulated ranges. Some industrial loads reduced operation in response to COVID-19, which partly explains the low outcome in June.

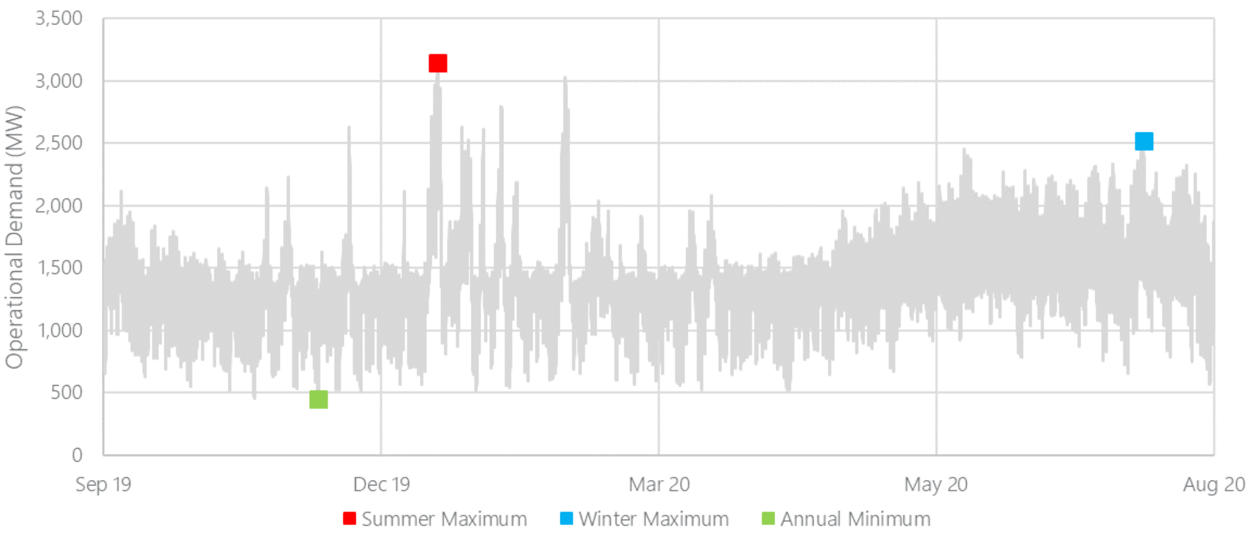
**Figure 21 Queensland monthly maximum demand in demand traces compared with actuals**




## 5.4 South Australia

South Australia's half hourly OPSO demand time-series and extreme events are shown below in Figure 22. Summer peakiness is clearly shown. Further detail on the extreme demand events for 2020 is provided in Table 19.

**Figure 22 South Australia demand with extreme events identified**



The maximum and minimum demand event forecasts are represented by a probability distribution of possible outcomes, as shown in Figure 23. Both actual maximum demand events fell well within the upper tail of the forecast distributions, while the annual minimum is lower than the probability distribution.

**Figure 23 South Australia simulated extreme event probability distributions with actuals**

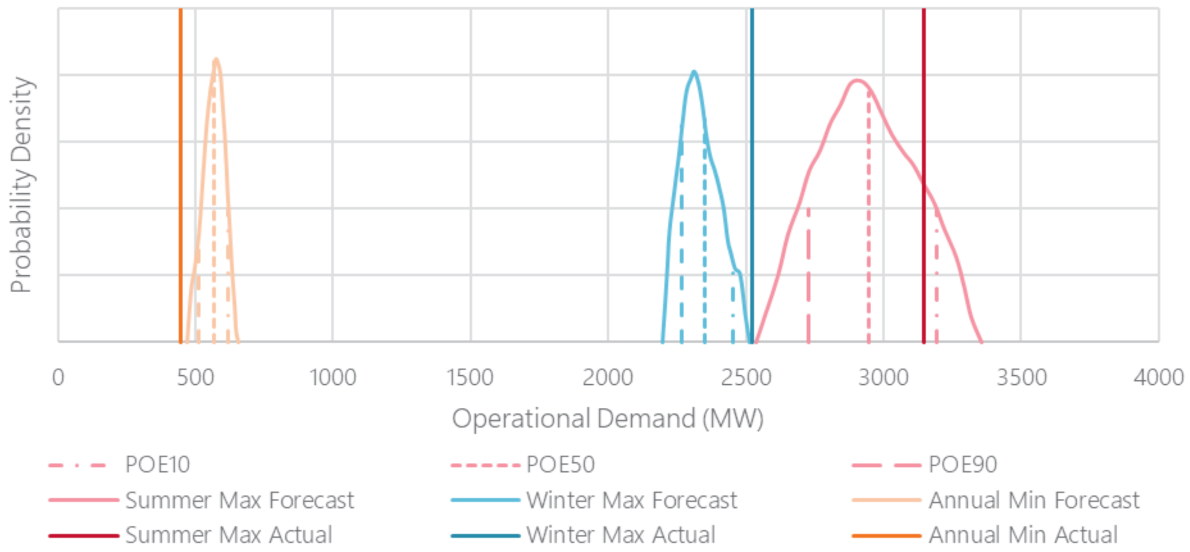



**Table 19 South Australia 2020 extreme demand events**

| Event | Summer maximum | Winter maximum | Annual minimum |
|---|---|---|---|
| **NEM Datetime** | Thu, 19 Dec 2019 19:00 | Fri, 7 Aug 2020 19:00 | Sun, 10 13:30 Nov 2019 |
| **Temperature (°C)** | 40.5 | 7.6 | 20.7 |
| **Max temperature (°C)** | 45.3 | 10.3 | 23.1 |
| **Min temperature (°C)** | 23.2 | 5.9 | 13 |
| **Losses (MW)** | 262 | 205 | 23 |
| **NSG output (MW)** | 54 | 6 | 100 |
| **Rooftop PV output (MW)** | 60 | 0 | 858 |
| **Sent out (OPSO MW)** | **3,147** | **2,523** | **447** |
| **Auxiliary (MW)** | 71 | 53 | 11 |
| **As generated (OPGEN MW)** | **3,218** | **2,576** | **458** |

*Adelaide (Kent Town), BOM weather station 023090, until 31 July 2020. From 1 August 2020 measurements use the Adelaide (West Terrace) weather station, BOM station 023000. For more information please see Appendix A2 of the Electricity Demand Forecasting Methodology Information Paper (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf).

Figure 24 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum demand occurred on Thursday 19 December 2019 at 19:00 local time with a temperature of 40.5°C recorded at Adelaide (Kent Town).

- The conditions on the day of the maximum demand event indicate that the event should be between a 50% POE and 10% POE. This is the second year in a row with summer maximum demand in the high end of the distribution.
- South Australia experienced a four-day heatwave in mid-December, with an annual (2019-20) maximum temperature recorded earlier on the Thursday of 45.3°C. The following day also saw the hottest minimum daily temperature of 33.6°C. The annual maximum temperature was 1.5°C cooler than the previous annual (2018-19) maximum demand set in 24-January-2019.
- High temperatures on the day would have impacted PV generation and, coupled with the time of maximum demand occurring an hour before sunset, it is reasonable that PV output was at the lower end of the distribution even with total PV installations having been under-forecast.
- Simulation outcomes were weighted toward a weekday maximum and in late January/early February, while annual maximum demand fell in December. This is mainly due to the extended heatwave experienced in mid-December, and moderate January temperatures.

Winter maximum demand occurred on Friday 7 August 2020 at 19:00 local time, with a temperature of 7.6°C recorded at Adelaide (West Terrace).

- South Australia saw its highest winter maximum demand in history, the previous record being 2,489 MW set last year on 24 June 2019.
- Friday 7 August 2020 was one of the coldest days in winter, with the lowest daily maximum of 10.3°C for the year.
- Simulation outcomes were weighted towards occurring on a weekday, which is consistent with the occurrence on Friday 7 August 2020. However, the August peak is contrary to expectations, and largely attributable to a mild winter in July.
- South Australia has had a very stable winter maximum demand historically, with values ranging between 2,240 MW and 2,489 MW with small increases seen in the trend year on year. The observed actual maximum demand in winter 2020 was the highest on record and above the winter 10% POE forecast. The timing and temperature drivers are pointing towards an outcome closer to the median. The higher than expected maximum demand may have been a consequence of more people staying home during COVID-19 and consuming more power for heating. It highlights the value of capability to assess consumption by individual sectors, such as residential, to explain outcomes and, if required, improve forecasting inputs and/or models.

Actual minimum demand occurred on Sunday 10 November 2019 at 13:30 local time, when the temperature was 20.7°C.

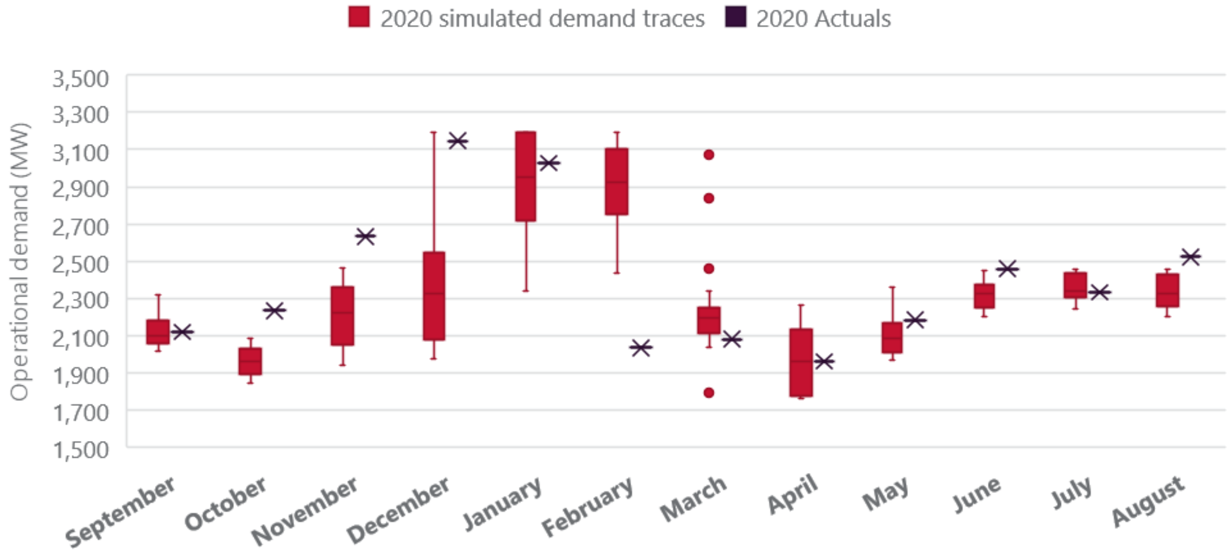
- Simulated temperature outcomes fell between 17°C and 23°C, with temperature at time of minimum demand being in the middle of the distribution.
- South Australian minimum demand has been occurring mid-day for a number of years, with minimum demand reducing year on year in response to growth in installed rooftop PV capacity. Last year's minimum demand for South Australia was 583 MW, compared to 447 MW this year.
- Total PV capacity for South Australia was quite close to forecast, with an actual 1,247 MW of installed capacity as at 1 December 2019, compared to a forecast of 1,147 MW. However, given the tightness of the minimum demand distribution, a 100 MW under-forecast of PV capacity can shift the observed minimum demand completely outside the forecast distribution. As such, the over-forecast of minimum demand is almost entirely attributable to the under-forecast of installed PV capacity.
- 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 70.3%, 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 10 November 2019 occurrence.

**Figure 24 South Australia simulated input variable probability distributions with actuals**

### Monthly maxima

The box plot in Figure 25 shows the range of monthly demand maximums for the 2020 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums during two winter months fell above the ranges formed by the traces, due to the reference years being scaled to a 10% and 50% POE demands, which were lower than the actuals observed. There are three additional observations outside the monthly ranges formed by the traces, as 2019-20 was rather exceptional weather-wise, with spring being exceptionally hot and dry due to the El Nino conditions and late summer being abnormally mild. Inclusion of the 2019-20 weather year in future simulations will widened the range of monthly maxima considered for South Australia.

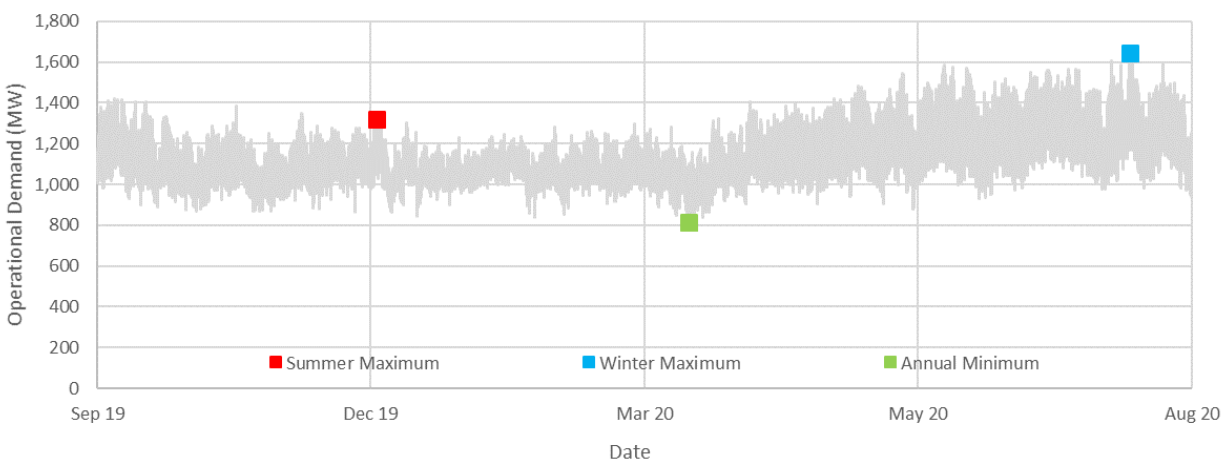
**Figure 25 South Australia monthly maximum demand in demand traces compared with actuals**




## 5.5 Tasmania

Tasmania's half hourly OPSO demand time-series and extreme events are shown below in Figure 26. Tasmania is winter peaking, with summer maximums substantially below the winter maximums. Further detail for the extreme demand events in 2020 is provided in Table 20.

**Figure 26 Tasmania demand with extreme events identified**



The maximum and minimum demand event forecasts are represented by a probability distribution of possible outcomes, as shown in Figure 27. 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 27 Tasmania simulated extreme event probability distributions with actuals**

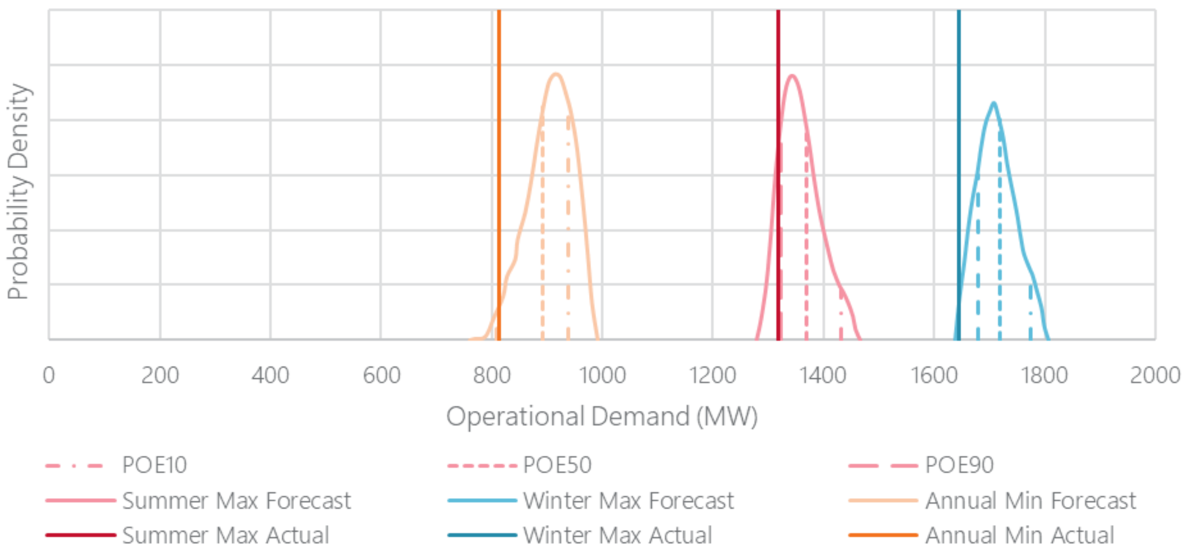



**Table 20 Tasmania 2020 extreme demand events**

| Event | Summer maximum | Winter maximum | Annual minimum |
|---|---|---|---|
| **NEM Datetime** | Tue, 3 Dec 2019 07:00 | Mon, 10 Aug 2020 08:30 | Mon, 16 Mar 2020 02:30 |
| **Temperature* (°C)** | 10.8 | 1.0 | 11.6 |
| **Max temperature (°C)** | 15.3 | 12.7 | 18.5 |
| **Min temperature (°C)** | 6 | 0.5 | 11.5 |
| **Losses (MW)** | 68 | 90 | 38 |
| **NSG output (MW)** | 58 | 72 | 58 |
| **Rooftop PV output (MW)** | 29 | 28 | 0 |
| **Sent out (OPSO)** | **1,319** | **1,645** | **813** |
| **Auxiliary (MW)** | 14 | 16 | 9 |
| **As generated (OPGEN)** | **1,333** | **1,661** | **822** |

*Hobart (Ellerslie Road) weather station. For more information please see Appendix A2 of the Electricity Demand Forecasting Methodology Information Paper (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf).

Figure 28 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Demand in Tasmania in 2019-20 was in many ways atypical, as affected by a partial load reduction of a large industrial load that spanned most of the year and another large industrial load reduction, this one being a result of COVID-19, during winter. As large industrial loads represent a large proportion of total demand in Tasmania compared to other NEM regions, this impacted the observed operational demand under all three extreme demand events.

Actual maximum demand occurred in winter on Monday 10 August 2020 at 08:30 local time, with a temperature of 1.0°C recorded at Hobart (Ellerslie Road).

- Overall, these factors suggest the forecast distribution to be accurate, allowing for the lower than expected large industrial load demand (which mainly can be attributed to COVID-19).
- Tasmania experienced another Monday morning maximum demand event this year, driven largely by heating load, industrial activity and businesses returning from the weekend.
- Weather conditions on the day were particularly good for PV generation, and sunrise had occurred just over an hour before the peak (07:11 local time), which explains why PV generation was at the right of the forecast distribution.
- Simulation outcomes were weighted towards occurring during the week and in the June-August period, which is consistent with the Monday 10 August 2020 occurrence.
- Large industrial loads at time of peak were 625 MW, whereas the forecast had a 50% POE value of 682 MW (10% POE was 695 MW, and the 90% POE was 669 MW). This large discrepancy between forecast and actual (57 MW) accounts for most of the forecast inaccuracy of operational demand for the Tasmanian winter maximum.

Summer maximum demand occurred on Tuesday 3 December 2019 at 07:00 local time, with a temperature of 10.8°C recorded at Hobart (Ellerslie Road).

- The observed demand corresponds to a 90% POE outcome. Conditions on the day suggest an event closer to a 50% POE, which is consistent with the outcome if accounting for the lower than forecast large industrial load (see below for details).
- This year Tasmania returned to having a morning peak during a cold snap in summer, following last year's relatively mild afternoon peak.
- Simulated temperature outcomes were consistent with the actual observed temperature of 10.8°C. Similarly, PV generation at time of maximum was within expectation.
- Simulation outcomes were weighted towards occurring mid-week and in late December/early January, which is consistent with the Tuesday 3 December 2019 occurrence.
- Large industrial loads at time of summer maximum was 599 MW, well below 666 MW, which is the median for a 50% POE outcome. It was mainly driven by partial outage of a large load that started in spring 2019 and lasted most of the financial year.
- Day of week and month of year were well within expectation.

Actual minimum demand occurred on Monday 16 March 2020 at 02:30 local time, when the temperature was 11.6°C. Tasmania is particularly affected by industrial activity, and as such minimum demand is inherently volatile.

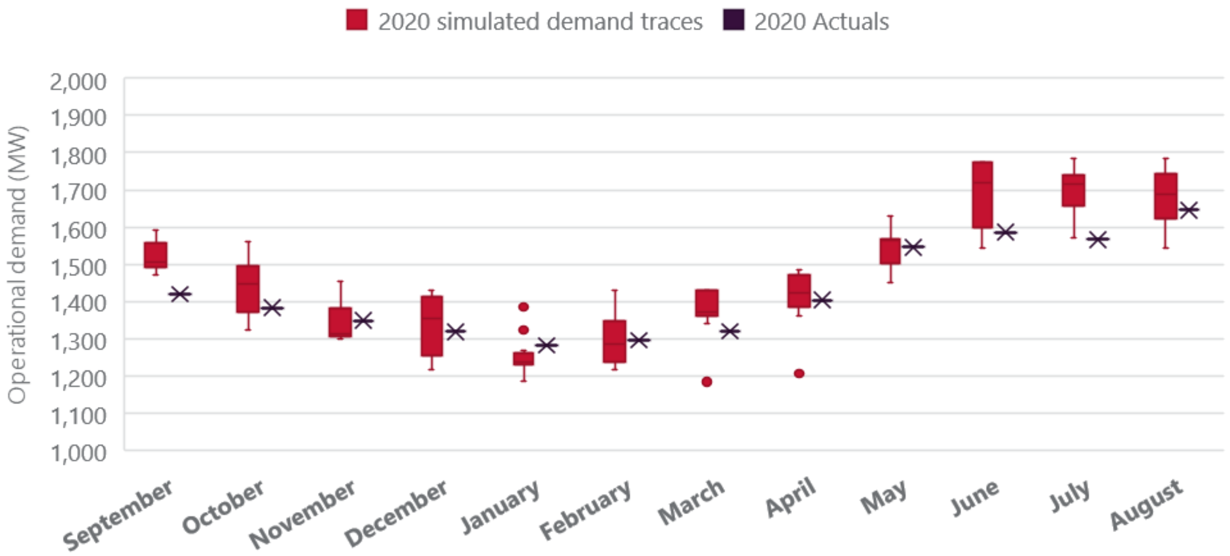
- Conditions on the day suggest a moderate annual minimum demand event close to a 50% POE, whereas the forecast distribution is around 100 MW above the annual minimum. This is mostly explained by large industrial loads at the time being roughly 73 MW over-forecast (499 MW actual versus 573 MW as the forecast median for 50% POE demand). While a significant part of this can be explained by a partial outage of a large load at the time, AEMO will review the variability of Tasmanian large industrial loads in its simulations to ensure it reflects the variability that can reasonably be expected.
- 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, which is consistent with the Monday 16 March 2020 occurrence.

**Figure 28 Tasmania simulated input variable probability distributions with actuals**

### Monthly maxima

The box plot in Figure 29 shows the range of monthly demand maximums for the 2020 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums mostly fell within the simulated ranges, though in the lower end due to the reduced large industrial load for most of the year.

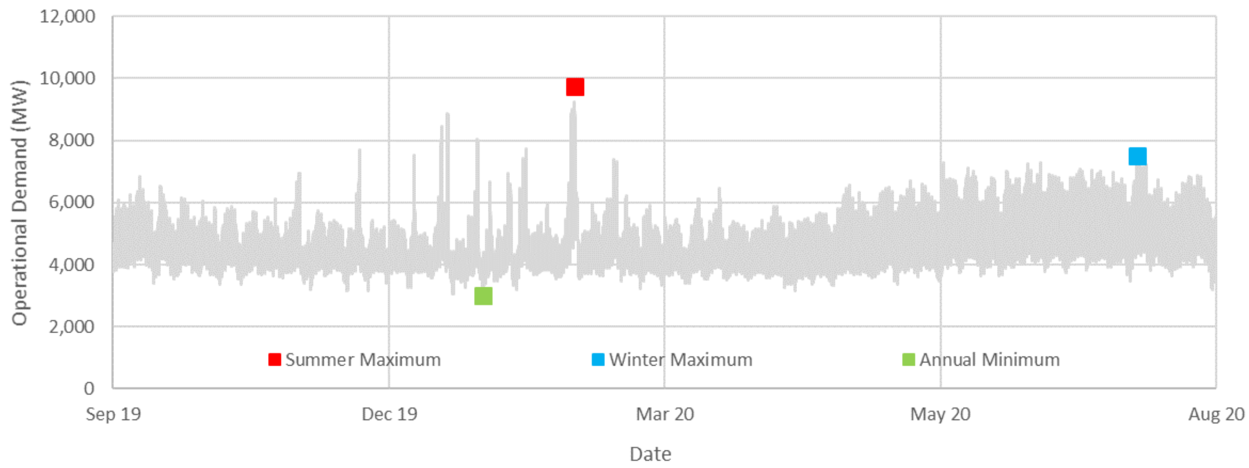
**Figure 29 Tasmania monthly maximum demand in demand traces compared with actuals**




## 5.6 Victoria

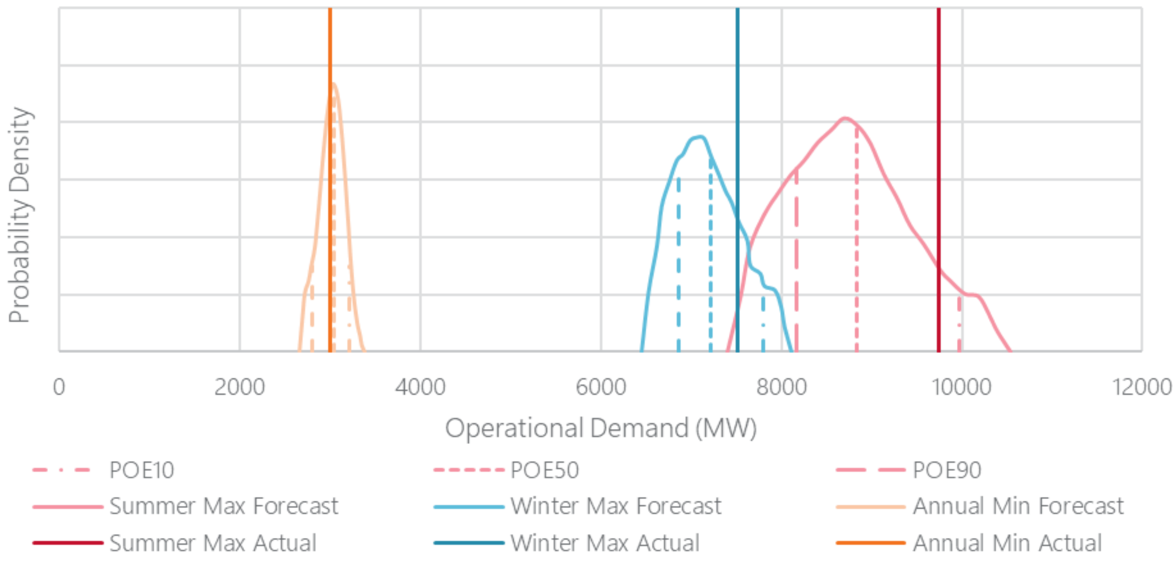
Victoria's half hourly OPSO demand time-series and extreme events are shown below in Figure 30. Further detail on the extreme demand events observed in 2020 is provided in Table 21.

**Figure 30 Victoria demand with extreme events identified**




The demand events are forecast separately, each represented by a probability distribution, as shown in Figure 31. All demand events fell well within their respective forecast distributions, with the annual minimum close to a 50% POE and the summer and winter maximums between a 50% POE and 10% POE.

#### Figure 31 Victoria simulated extreme event probability distributions with actuals




#### Table 21 Victoria 2020 extreme demand events

| Event | Summer maximum | Winter maximum | Annual minimum |
|---|---|---|---|
| **NEM Datetime** | Fri, 31 Jan 2020 17:00 | Tue, 4 Aug 2020 18:30 | Wed, 1 Jan 2020 12:30 |
| **Temperature* (°C)** | 36.3 | 6.5 | 24.6 |
| **Max temperature (°C)** | 42.9 | 10.3 | 28.3 |
| **Min temperature (°C)** | 22.5 | 4.9 | 10.9 |
| **Losses (MW)** | 609 | 481 | 174 |
| **NSG output (MW)** | 162 | 108 | 231 |
| **Rooftop PV output (MW)** | 451 | 0 | 1,436 |
| **Sent out (OPSO)** | **9,244 adjusted to 9,744 (firm only) and 9,853 (firm and potential)^** | **7,509** | **3,008** |
| **Auxiliary (MW)** | 423 | 335 | 292 |
| **As generated (OPGEN)** | **9,667 adjusted to 10,167 (firm only) and 10,276 (firm and potential)^** | **7,844** | **3,300** |

*Melbourne (Olympic Park) weather station. For more information please see Appendix A2 of the Electricity Demand Forecasting Methodology Information Paper (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf).
^Summer maximum demand is adjusted to include a firm adjustment of 500 MW, and 109 MW potential adjustment.

Figure 32 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum demand occurred on Friday 31 January 2020 at 17:00 local time. At the time of maximum demand, Melbourne (Olympic park) recorded a temperature of 36.3°C, with an earlier daily (and monthly) maximum temperature of 42.9°C. On the day there was 500 MW of firm adjustments from RERT, DSP and network outages and 109 MW of potential adjustment (see Table 14).

- The actual demand event was around a 10% POE after adjusting for RERT, DSP and network outages.
- The daily maximum temperature on the day was high at around 14:00 (42.9°C). It then cooled off by the time of maximum demand at 17:00 (36.3°C).
- 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 0.21 MW per MW of installed capacity, consistent with the observed time of the peak and good weather conditions for PV generation. As for most other regions, installed PV capacity was under-forecast, with the actual installed capacity 30 June 2020 being 269 MW above forecast.
- Simulation outcomes were weighted towards occurring during the week and in late January/early February, which is consistent with the Friday 30 January 2020 occurrence.
- This is the second year in a row with summer maximum demand in the high end of the distribution. The consecutive number of hot days support a high demand outcome. Furthermore, maximum demand occurred the day before the Australia Day long weekend, and the week before schools returned, which would have impacted demand.

Winter maximum demand occurred on Tuesday 4 August 2020 at 18:30 local time, with a temperature of 6.5°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 10.3°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. COVID-19 does not appear to have impacted winter maximum in Victoria to the same extent as South Australia, presumably due to the more widespread use of residential gas heating in Victoria.
- Overall, these factors suggest the forecast distribution to be accurate.
- Simulation outcomes were weighted towards occurring during the week and in the late June/early July period, which is consistent with the Thursday occurrence. An August peak, while less frequent, was within expectation.

Actual minimum demand occurred on Wednesday 1 January 2020 (New Year's Day) at 12:30 local time, when the temperature was 24.6°C.

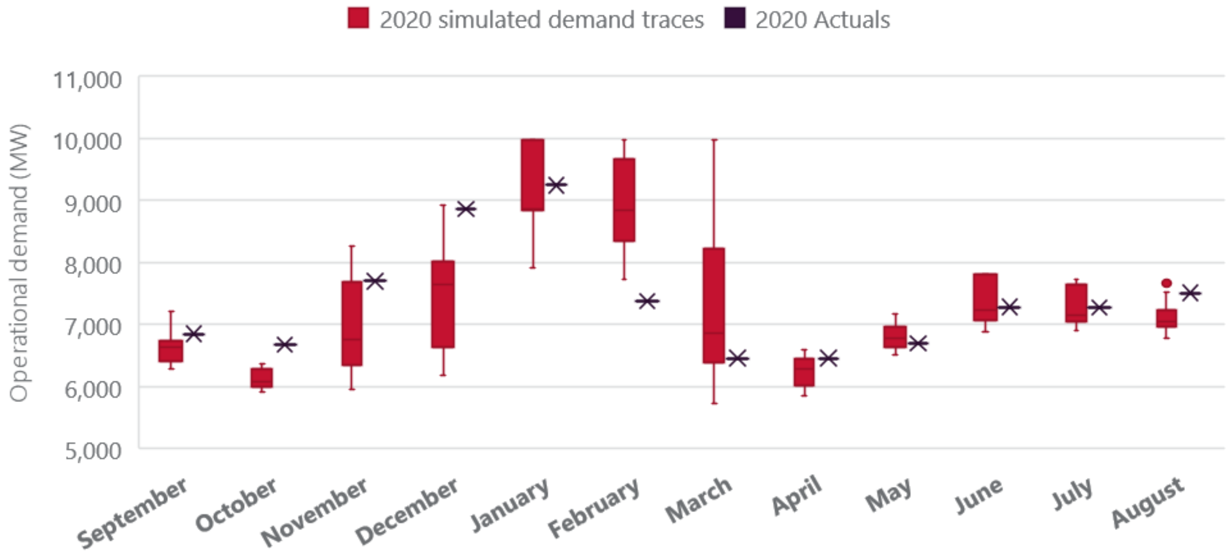
- Overall, these factors suggest the forecast distribution to be accurate, and correctly places the observation around the 50% POE level.
- This year saw the first New Year's Day minimum for Victoria in the middle of the day when temperatures were mild, and demand was low due to the public holiday.
- Simulation outcomes were weighted towards occurring on the weekend or public holiday and in late-December/early-January, which is consistent with the Wednesday 1 January 2020 (New Year's Day) occurrence. This is partially due to the PV capacity forecast prematurely pushing simulated minimums into the afternoon, coinciding with lower afternoon demand on public/school holidays.
- 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.

**Figure 32 Victoria simulated input variable probability distributions with actuals**

### Monthly maxima

The box plot in Figure 33 shows the range of monthly demand maximums for the 2020 simulated demand traces for 10% POE and 50% POE annual forecasts. Actual monthly maximums mostly fell within the simulated ranges.

**Figure 33 Victoria monthly maximum demand in demand traces compared with actuals**



# 6. Supply forecasts

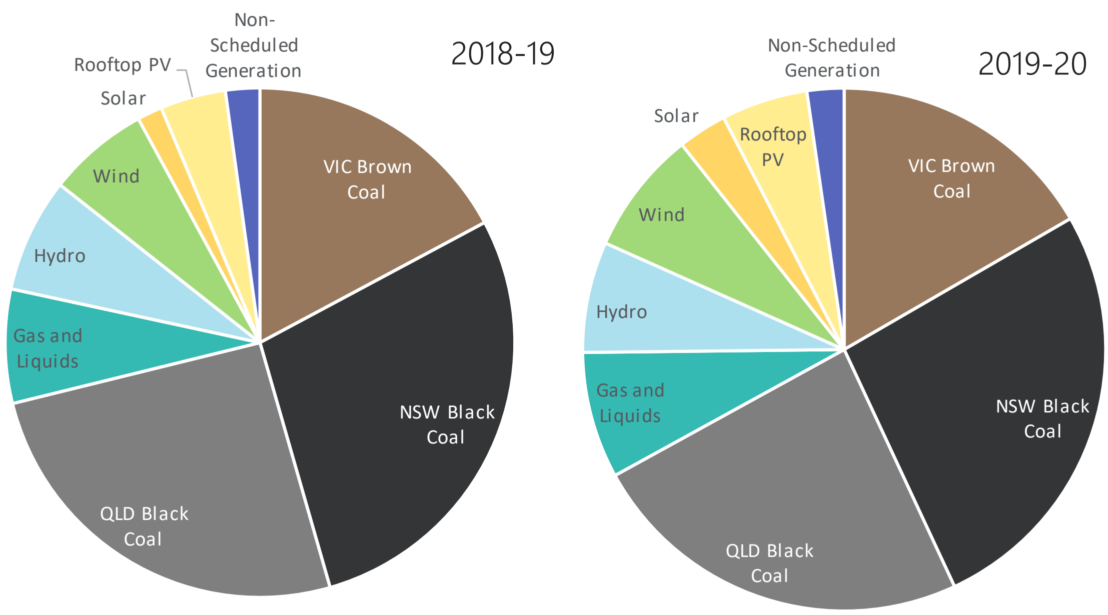
Generator supply of the NEM comes from a variety of locations and fuel sources, as shown below in Figure 34. Black and brown coal remain the largest source, while solar, wind, and rooftop PV have shown the largest increase in supply proportion between 2018-19 and 2019-20.

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

- Forecasts of new generator connections.
- Forced outage rates for major generation sources and inter-regional transmission elements.
- 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. The category 'gas and liquids' includes open and closed cycle gas turbines, diesel generators and other similar peaking plant.

**Figure 34 NEM generation mix by energy, including demand side components, 2018-19 and 2019-20**




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 2019 ESOO matched actual generation availability.

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

- Commissioning or decommissioning of generators may not match schedules provided by generator participants.
- Generator ratings during peak temperatures may not match ratings provided by generator participants.
- Unplanned outages may vary from forecast outage rates (full, partial, or high impact outages).

- Planned outages 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.

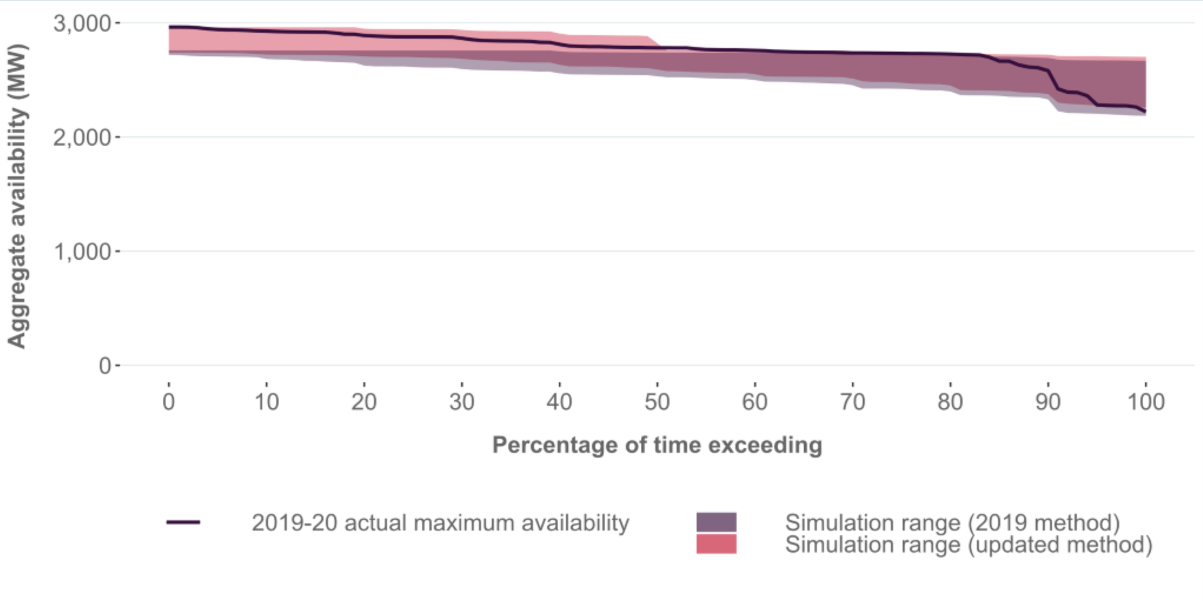
Consistent with the Forecast Accuracy Report Methodology[17], AEMO implements and publishes a variety of metrics to assess supply forecast accuracy. For each region, the accuracy of generator commissioning and decommissioning schedules is assessed. Supply availability is then assessed, comparing actual availability with simulated availability, including additional exploration of forced outage rates and other relevant considerations where relevant.

Section 6.6 assesses the accuracy of inter-regional transmission element forced outage rates. These transmission elements are increasingly relevant to system reliability as they support inter-regional capacity and energy sharing. Finally, Section 6.7 assesses the accuracy of the demand side participation forecasts, which are considered a component of AEMO's supply forecasts.

### Example supply availability interpretation

Figure 35 shows an example graph of supply availability, using South Australian gas and liquid generators as an example. The graph compares simulated availability to actual availability from 40 hours sampled from the top 10 hottest days of each simulated, or actual year, ordered from highest to lowest availability. The purple range shows the 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 2020 ESOO, AEMO updated the methodology to better capture generator performance at a variety of summer temperatures. The pink range shows the range should this method have been applied in the 2019 ESOO.

**Figure 35 Example simulated and actual supply availability (South Australian gas and liquid generators)**




In this example, actual supply availability remains within or above simulated availability, indicating that the capacity and outage rates of the generator fleet were within forecast expectations. The updated method better captures generator performance over the periods of interest.

[17] 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

The key insights from these results are as follows:

- The commissioning of new generation was aligned with forecast for most regions, however Victoria observed delays against provided timing. For summer 2019-20, there was 1,241 MW less installed VRE capacity than expected in Victoria. These delays had the potential to impact reliability, however, were accommodated due to high availability from brown coal-fired generators during hot periods.
- Generator forced outage rates for coal-fired generators continued to worsen but were mostly aligned with assumptions, except for New South Wales black coal-fired generators, which performed worse than expected. An updated methodology used in the 2020 ESOO now uses participant and consultant forecasts of forced outage rates to better capture trends in performance and maintenance.
- Outage rates on inter-regional transmission elements were higher than forecast, primarily due to bushfire impacts on Victoria to New South Wales transmission elements, and destructive wind gusts and asset failure impacts on Victoria to South Australian transmission elements.
- The supply availability of Queensland coal-fired and gas generation was below the simulated range, however this was accommodated due to surplus amounts of dispatchable capacity. Notably, as a major provider of capacity through export to New South Wales, Queensland coal-fired and gas generators maintained expected levels of availability during high temperature periods in New South Wales.
- Wind generation output was over-forecast in Victoria during some high temperature periods, as the forecasts did not capture temperature derating and delayed connections. Wind generation was also under-forecast in South Australia as the simultaneous occurrence of high wind speeds and high temperatures was inconsistent with weather patterns during summer periods from 2011 to 2019 repeated in the forecast simulations.

## 6.1 New South Wales

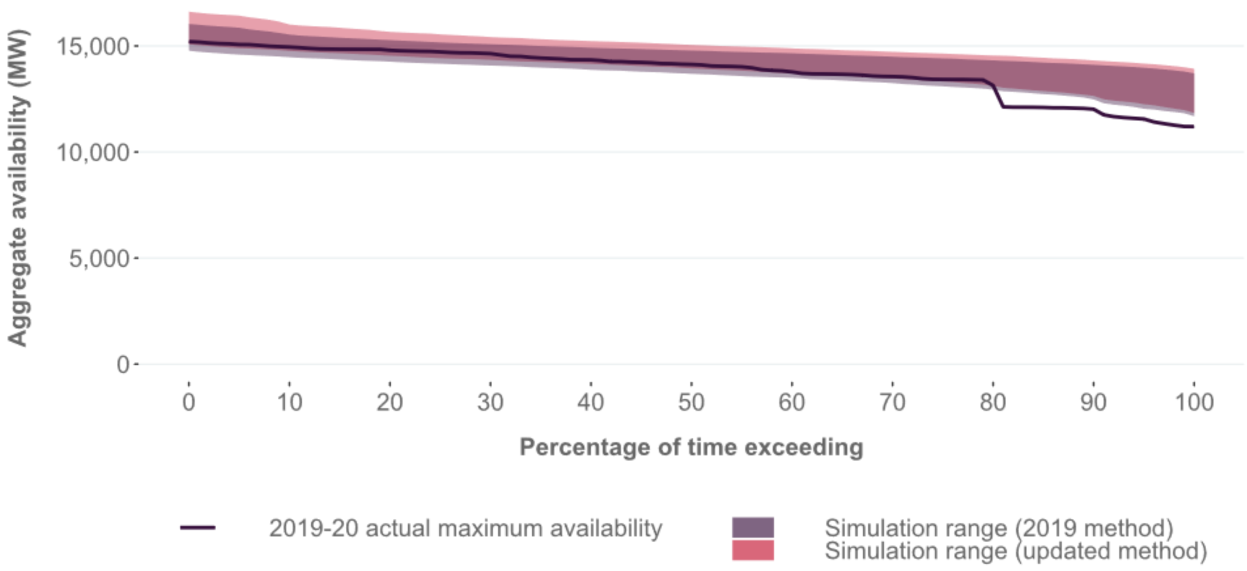
AEMO collects generation information reported from generation industry participants on the commissioning, decommissioning, and capacity of individual generators. Table 22 shows how the information was implemented in the 2019 ESOO, compared to actual generator characteristics for February 2020. Only one generator was behind commissioning schedule, however full completion of commissioning took additional time, meaning that full availability of new capacity was not accessible throughout summer 2019-20.

**Table 22 Forecast and actual generation count and capacity, February 2020**

| New South Wales generation | Facilities actually operating | | Facilities forecast to operate | | Difference in Capacity (actual - forecast) | |
|---|---|---|---|---|---|---|
| | Count | MW | Count | MW | MW | % |
| VRE generation | 25 | 2,223 | 26 | 2,498 | -275 | -12.4% |
| Non-VRE generation | 53 | 14,748 | 53 | 14,748 | 0 | 0% |
| **All generation** | **78** | **16,971** | **79** | **17,246** | **-275** | **-1.6%** |

Figure 36 shows total summer availability for New South Wales for the high temperature periods of interest. Actual availability remains within or below the simulation range. The lower than forecast availability was primarily due to outages on the black coal fleet, and lower availability of other technologies, as explored in the technology aggregate sections below.

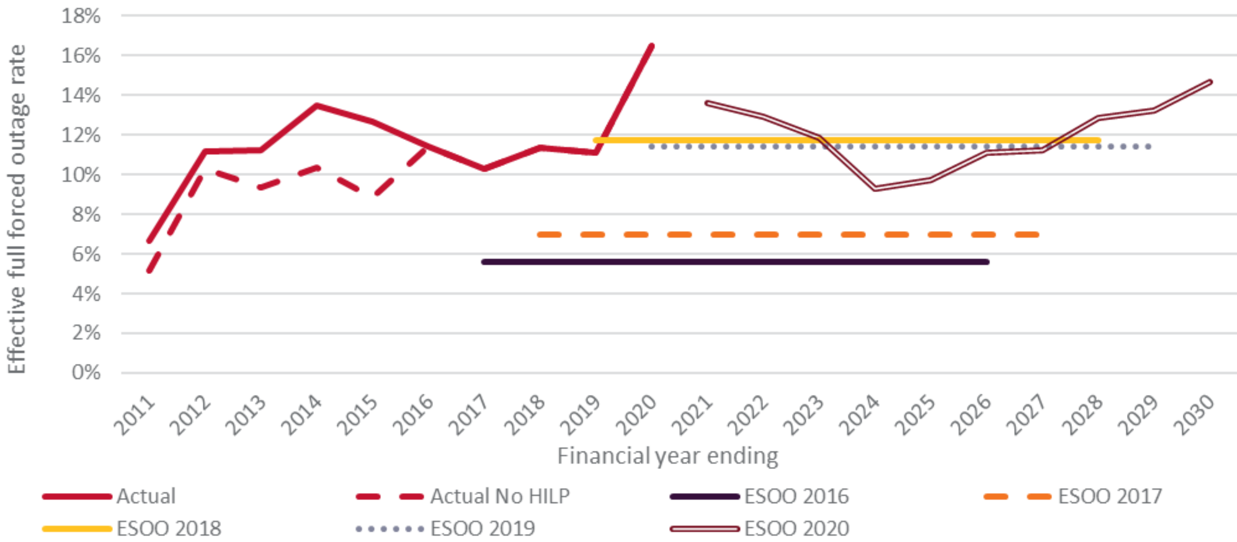
**Figure 36 New South Wales supply availability for the top 10 hottest days**




## Black coal

Recent history of unplanned outage rates of black coal-fired generation in New South Wales has shown an upward trend. Figure 37 shows the effective rates of unplanned outages, considering partial, full and high impact outages. In the 2019 ESOO and before, outage rates were developed by averaging history, while in the 2020 ESOO, outage rates were developed from participant and consultant provided projections. The outage rate in 2019-20 was higher than any previously observed, and the 2019 forecast outage rate under-estimated this outcome.

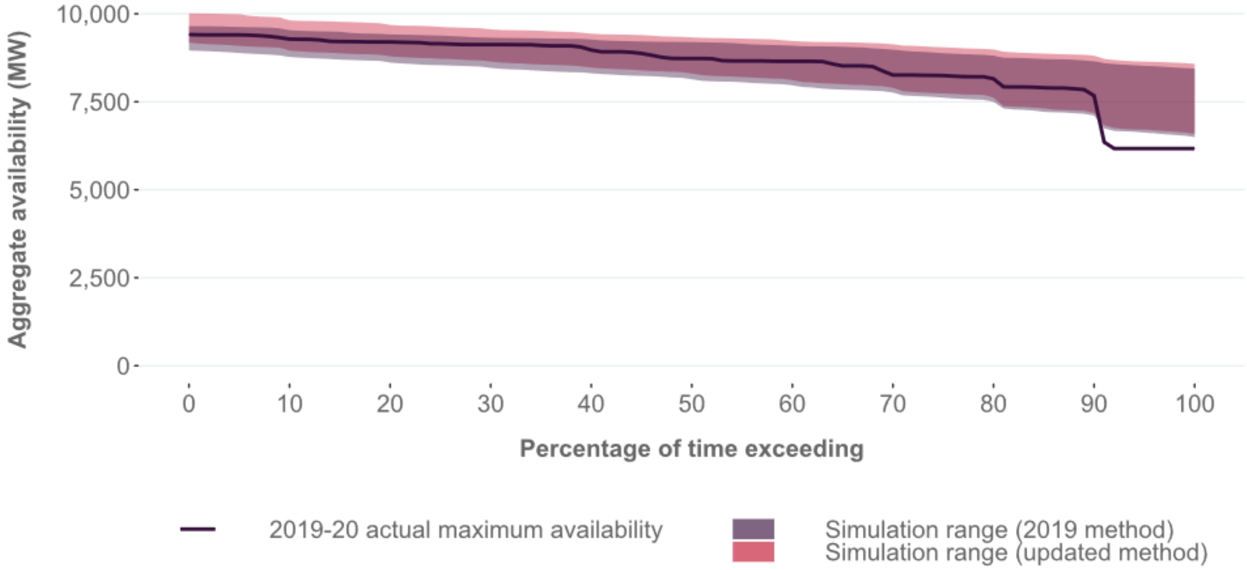
**Figure 37 New South Wales black coal effective unplanned outage rates, including HILP outages**




HILP refers to high impact, low probability events.

Figure 38 shows that actual availability over the top 10 hottest days was within or below simulated availability. The observed availability was lower than the 2019 ESOO simulated range on one of the top 10 hottest days, where higher than expected multiple outages were coincident with high temperature.

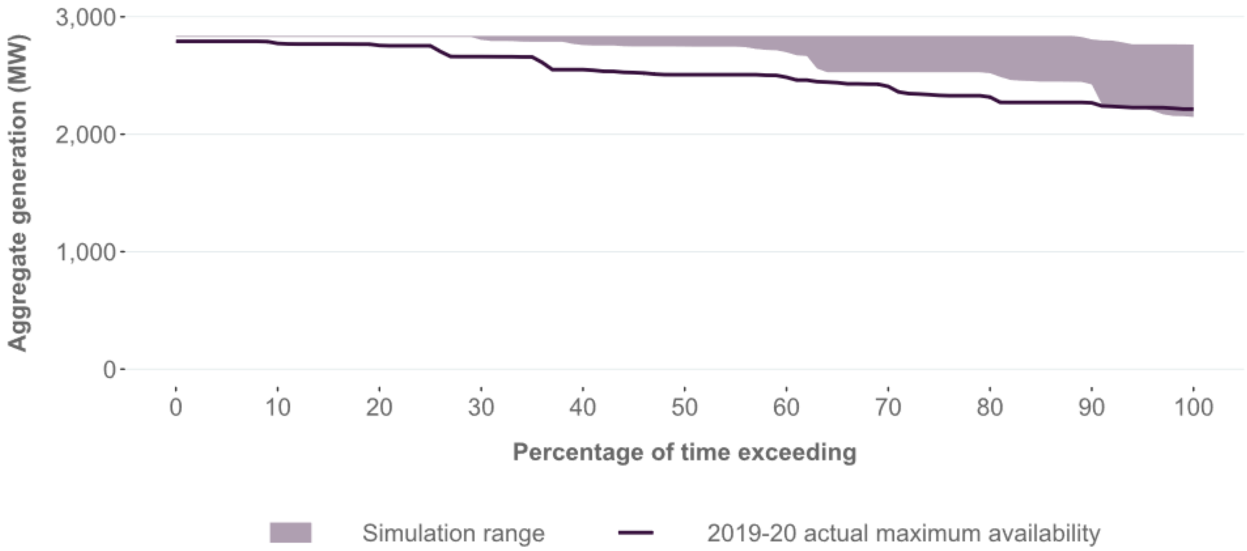
Figure 38 New South Wales black coal supply availability for the top 10 hottest days




## 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 2019-20, the observed availability was, in majority, lower than the 2019 ESOO simulated range. This indicates that capacity derating and outages were higher than average during actual periods of high temperature.

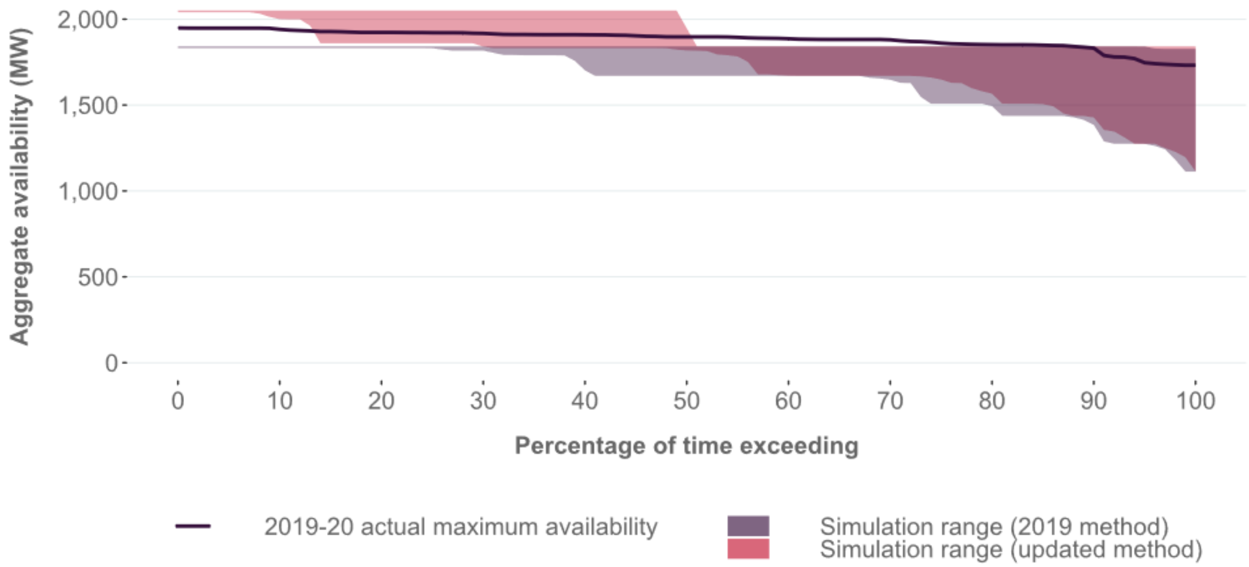
Figure 39 New South Wales hydrogeneration supply availability for the top 10 hottest days




## Gas and liquids

Figure 40 shows the supply availability for New South Wales gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was above the 2019 forecast availability, indicating that the generator fleet performed as forecast, or better. The updated methodology better captures observed availability.

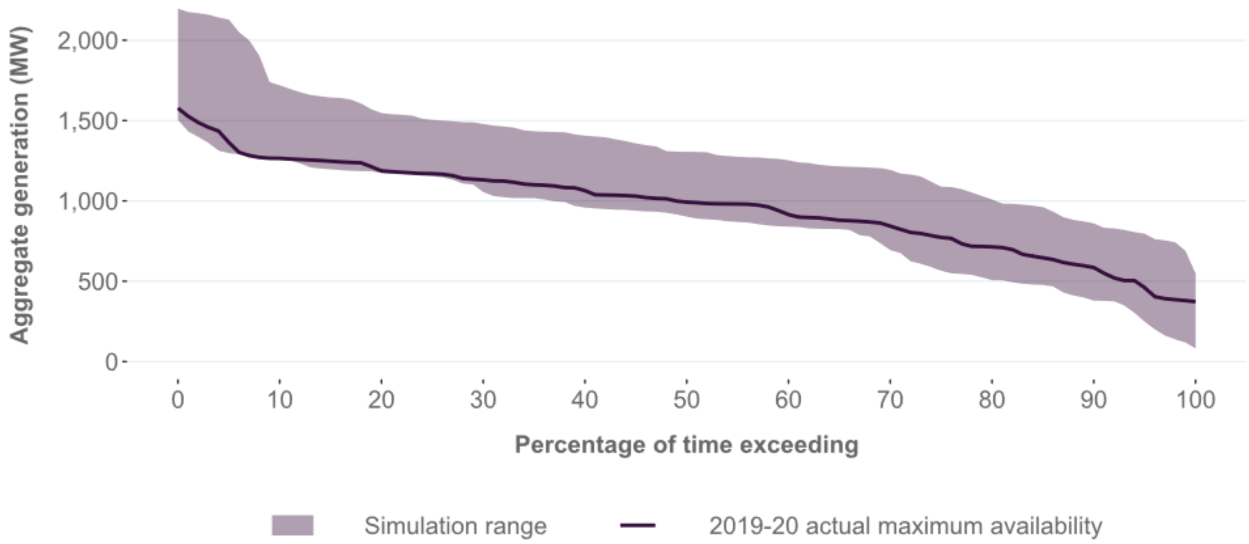
**Figure 40 New South Wales gas and liquid supply availability for the top 10 hottest days**




### Variable renewable energy

Figure 41 shows the supply availability for New South Wales VRE generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was within, but towards the lower end of the 2019 ESOO simulated range. The lower than anticipated output was due to the delays in generator commissioning prior to summer 2019-20.

**Figure 41 New South Wales variable renewable energy supply availability for the top 10 hottest days**




## 6.2 Queensland

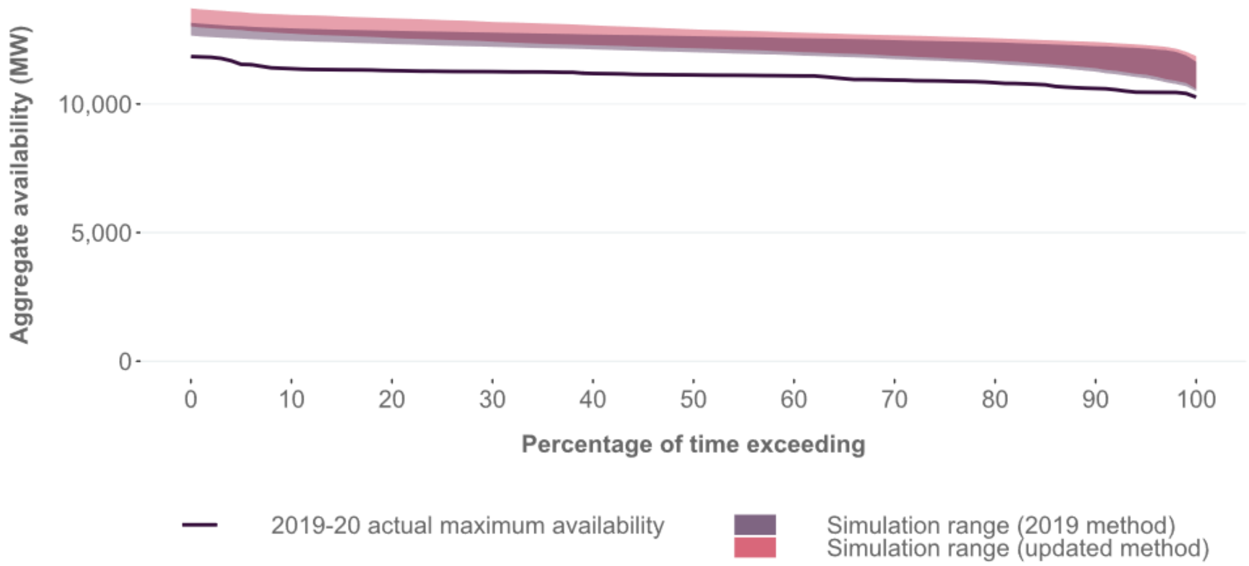
Table 23 shows how the Queensland generation information was implemented in the 2019 ESOO, compared to actual generator characteristics for February 2020. In aggregate, generators connected as projected, with one commissioned ahead of schedule, although at a limited capacity.

Table 23 Forecast and actual generation count and capacity, February 2020

| Queensland generation | Facilities actually operating | | Facilities forecast to operate | | Difference in Capacity (actual - forecast) | |
|---|---|---|---|---|---|---|
| | Count | MW | Count | MW | MW | % |
| VRE generation | 24 | 2,249 | 23 | 1,919 | 330 | 14.7% |
| Non-VRE generation | 56 | 12,536 | 56 | 12,536 | 0 | 0% |
| **All generation** | **80** | **14,785** | **79** | **14,455** | **330** | **2.2%** |

Figure 42 shows total summer availability for Queensland high temperature periods of interest. Actual availability remains below the simulation range over the entire period. While this would be problematic in most regions, the surplus amount of dispatchable capacity in Queensland means that planned and unplanned outages can be accommodated throughout summer without a material risk of USE. Further, in 2020, the annual maximum demand event did not occur during the maximum temperature days of the year. The lower than forecast availability was primarily due to gas and black coal generator outages, as explored in the technology aggregate sections below.

Figure 42 Queensland supply availability for the top 10 hottest days




## Black coal

The outage rate of black coal-fired generation in Queensland in 2019-20 was the second highest since previously observed from 2011. The 2019 forecast outage rate under-estimated this outcome, as shown in Figure 43.

**Figure 43 Queensland black coal effective unplanned outage rates, including HILP outages**

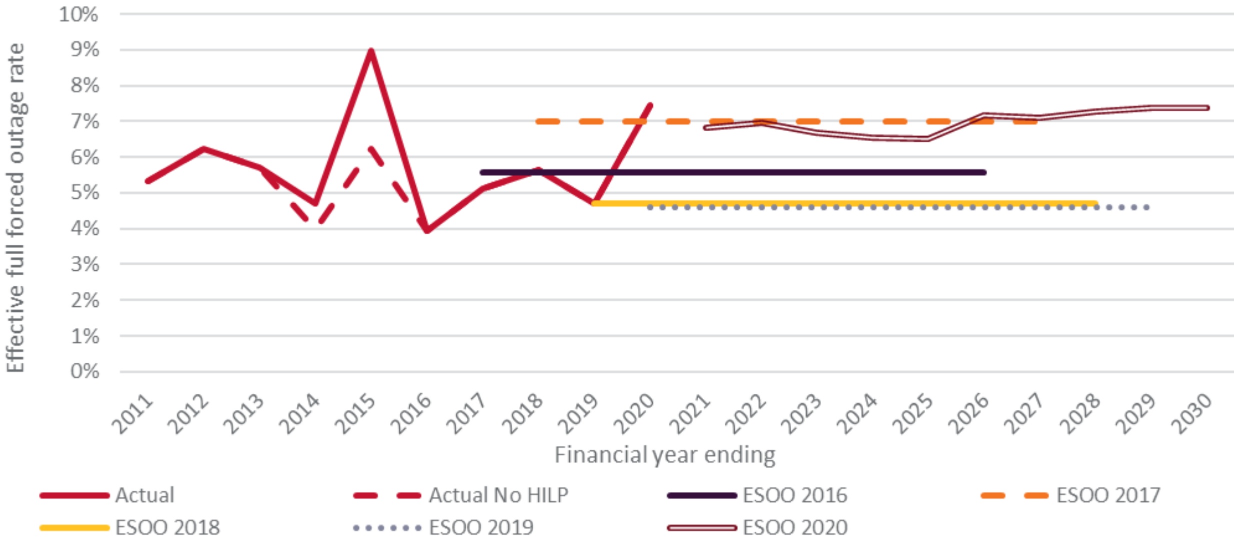
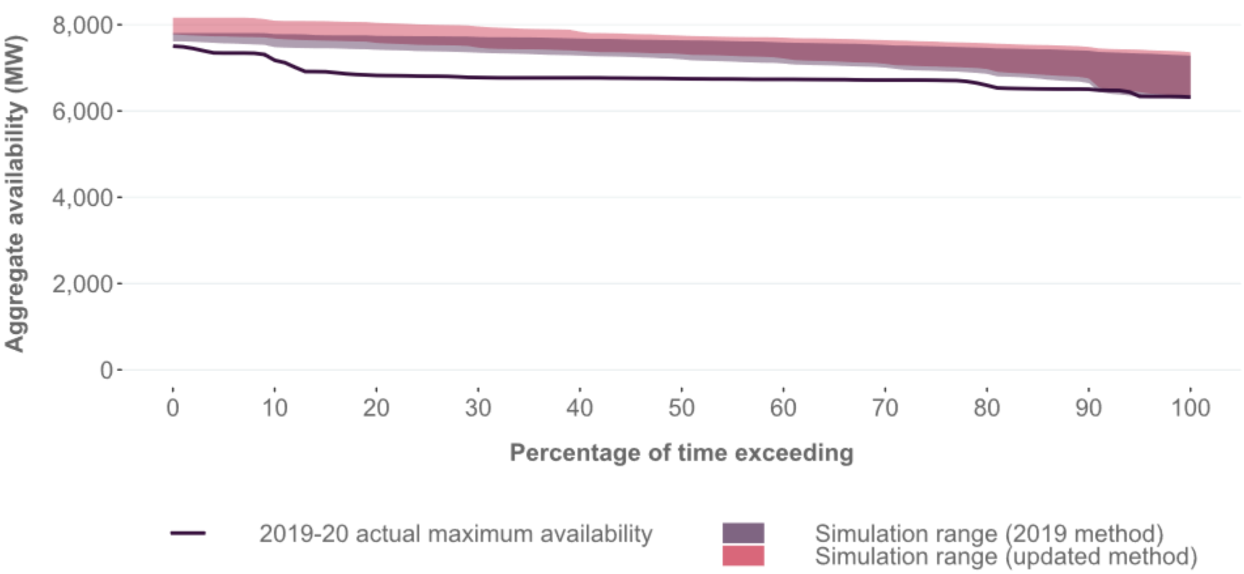


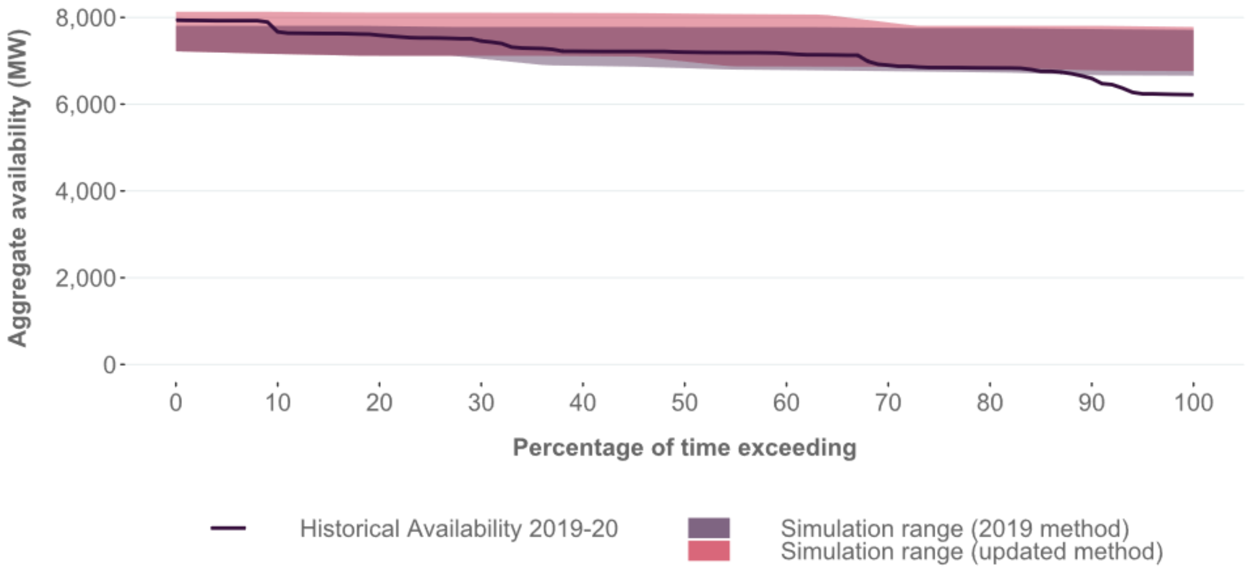

Figure 44 shows the supply availability for Queensland black coal generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was always lower than the 2019 ESOO simulated range, however this was accommodated due to the surplus of available capacity.

**Figure 44 Queensland black coal supply availability for the top 10 hottest days**




Queensland is a net exporter of energy to New South Wales and southern NEM regions, and may provide peak capacity support during non-coincident peak demand events. While availability during periods of interest in Queensland was lower than expectation, Figure 45 shows that availability in Queensland was high during the hot periods in New South Wales. During these periods, Queensland black coal-fired generators have mostly maintained expected levels of availability.

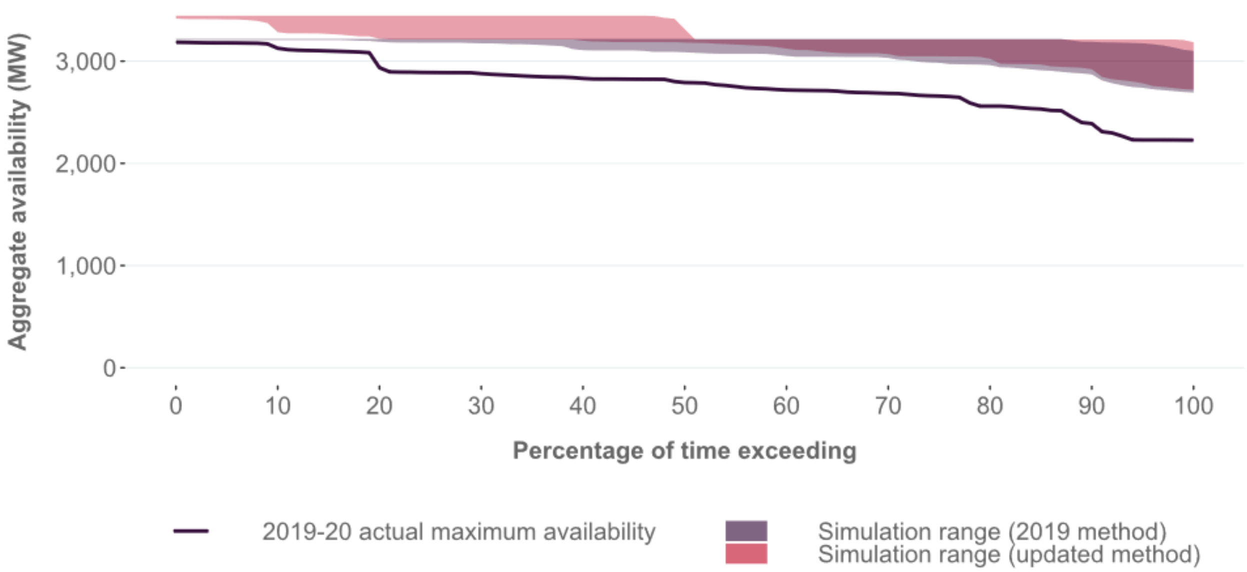
Figure 45 Queensland black coal supply availability for the New South Wales top 10 hottest days




## Gas and liquids

Figure 46 shows the supply availability for Queensland gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was always lower than the 2019 ESOO simulated range. This lower availability was due to planned outages during high temperature periods, and some unplanned outages.

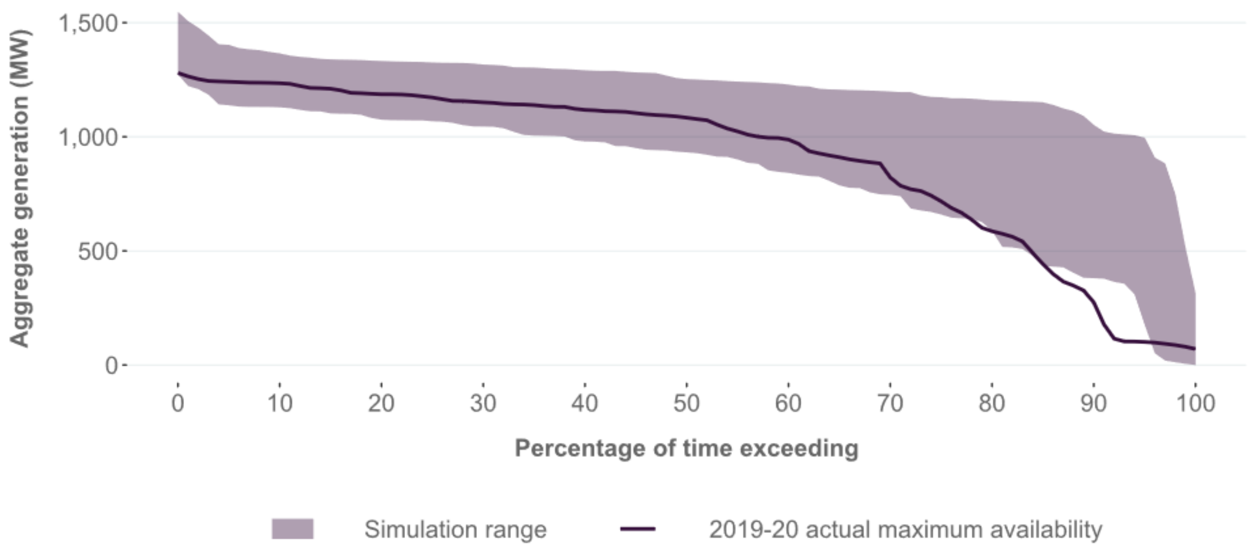
Figure 46 Queensland gas and liquids supply availability for the top 10 hottest days




## Variable renewable energy

Figure 47 shows the supply availability for Queensland VRE generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was, in majority, within the 2019 ESOO simulated range. While generator commissioning was generally ahead of schedule in Queensland, some were not operating in the periods of interest, resulting in excursions from the forecast range.

Figure 47 Queensland variable renewable energy supply availability for the top 10 hottest days




## 6.3 South Australia

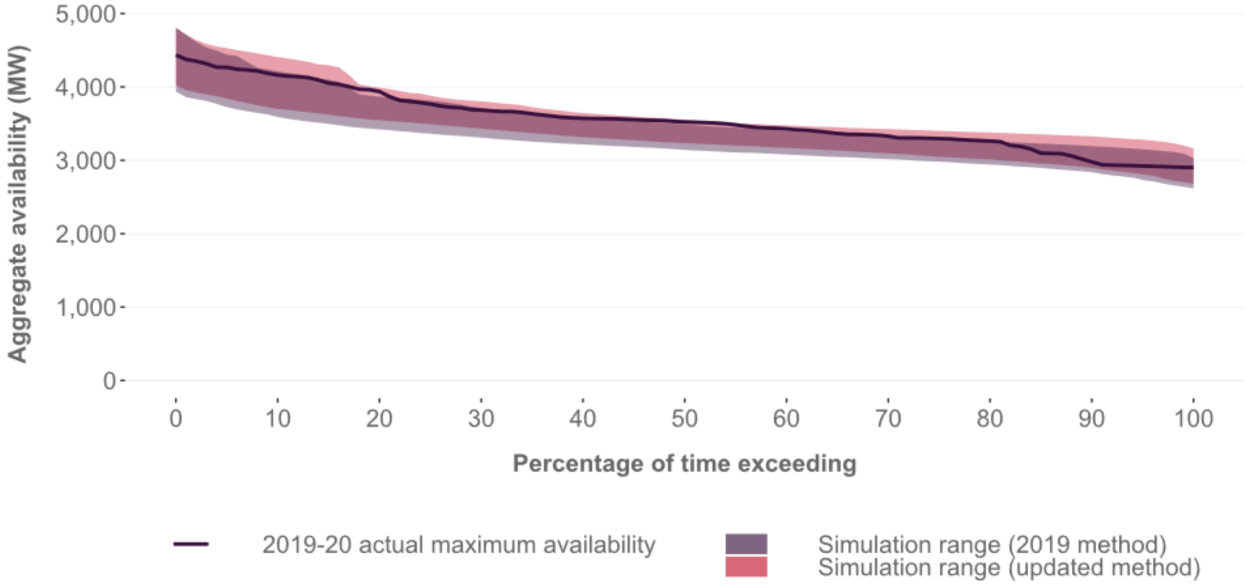
Table 24 shows how the South Australia generation information was implemented in the 2019 ESOO, compared to actual generator characteristics for February 2020. In aggregate, generators connected as projected, however one battery project was ahead of schedule, and one battery project was delayed.

**Table 24 Forecast and actual generation count and capacity, February 2020**

| South Australia generation | Facilities actually operating | | Facilities forecast to operate | | Difference in Capacity (actual - forecast) | |
|---|---|---|---|---|---|---|
| | Count | MW | Count | MW | MW | % |
| VRE generation | 25 | 2,387 | 25 | 2,387 | 0 | 0.0% |
| Non-VRE generation | 62 | 3,408 | 62 | 3,393 | 15 | 0.4% |
| **All generation** | **87** | **5,795** | **87** | **5,780** | **15** | **0.3%** |

Figure 48 shows total summer availability for South Australia for the high temperature periods of interest. Actual availability is within or above the 2019 ESOO simulation range and entirely within the simulation range for the updated method.

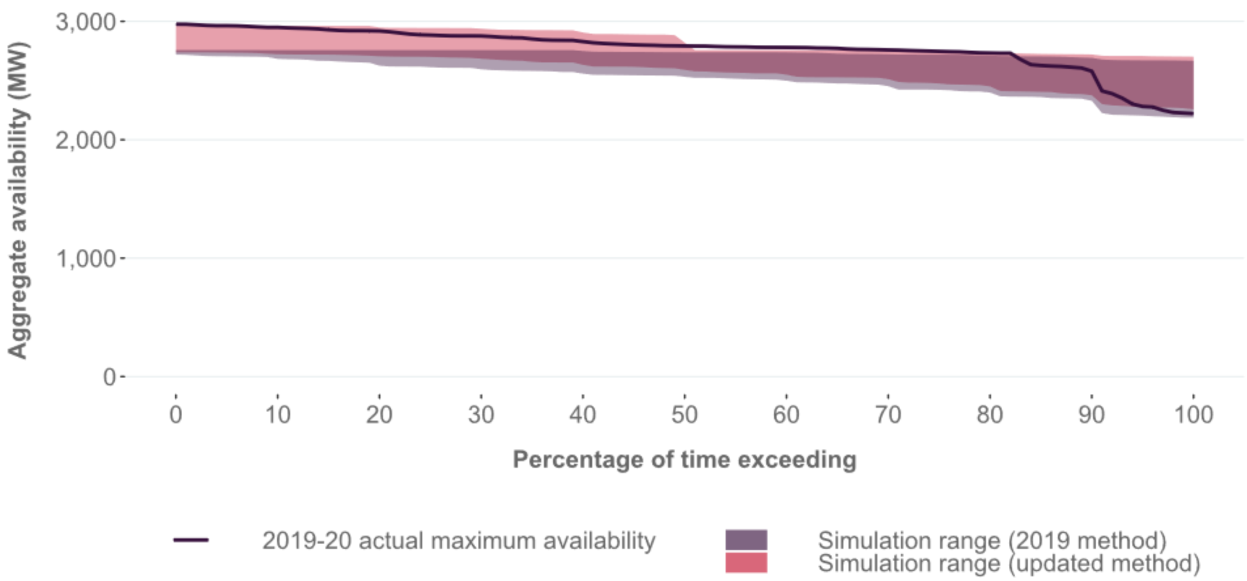
Figure 48 South Australia supply availability for the top 10 hottest days




## Gas and liquids

Figure 49 shows that availability over the top 10 hottest days was above or within simulated availability. In 2019-20, the observed availability was at times higher than the 2019 ESOO simulated range. The updated methodology better captures generator performance over these periods.

Figure 49 South Australia gas and liquids supply availability for the top 10 hottest days




## Variable renewable energy

Figure 50 shows the supply availability for South Australia VRE generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was, in majority, within or above the forecasting range in the 2019 ESOO. The excursion from simulated range is due to the simultaneous occurrence of high wind speeds and high temperatures, a relationship which is typically not observed in South Australia.

Figure 51 shows the relationship between daily maximum temperature, and wind speed at time of maximum temperature. Given the simulation is derived from the last 10 years of history, the three days of high wind-speed outcomes observed in 2019-20 explain the deviation from simulation range.

**Figure 50 South Australia variable renewable energy supply availability for the top 10 hottest days**

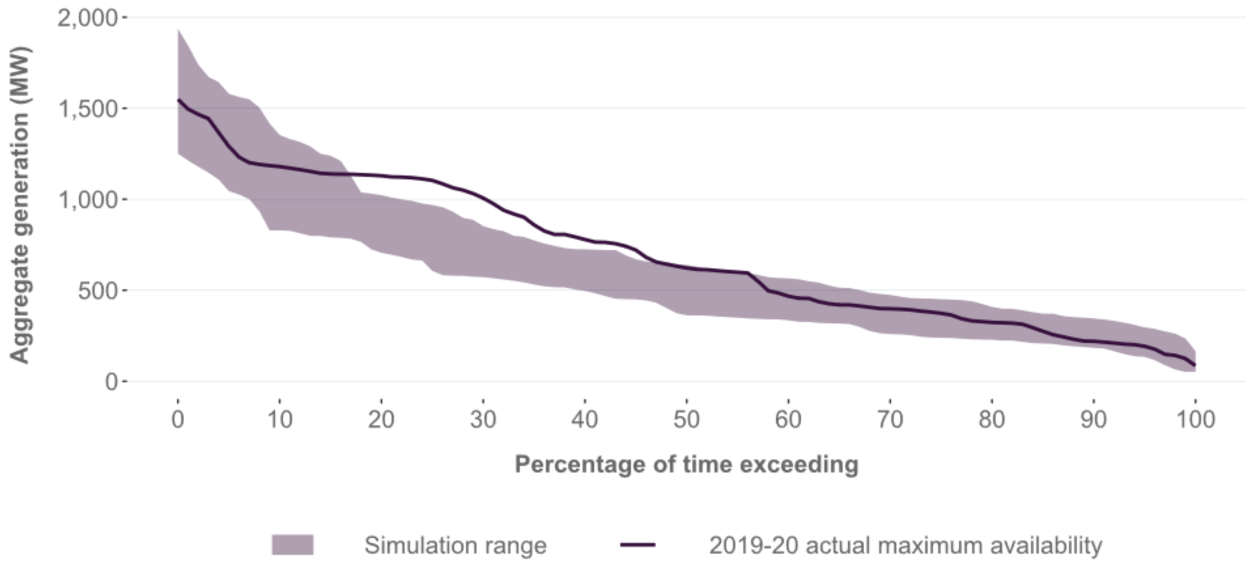
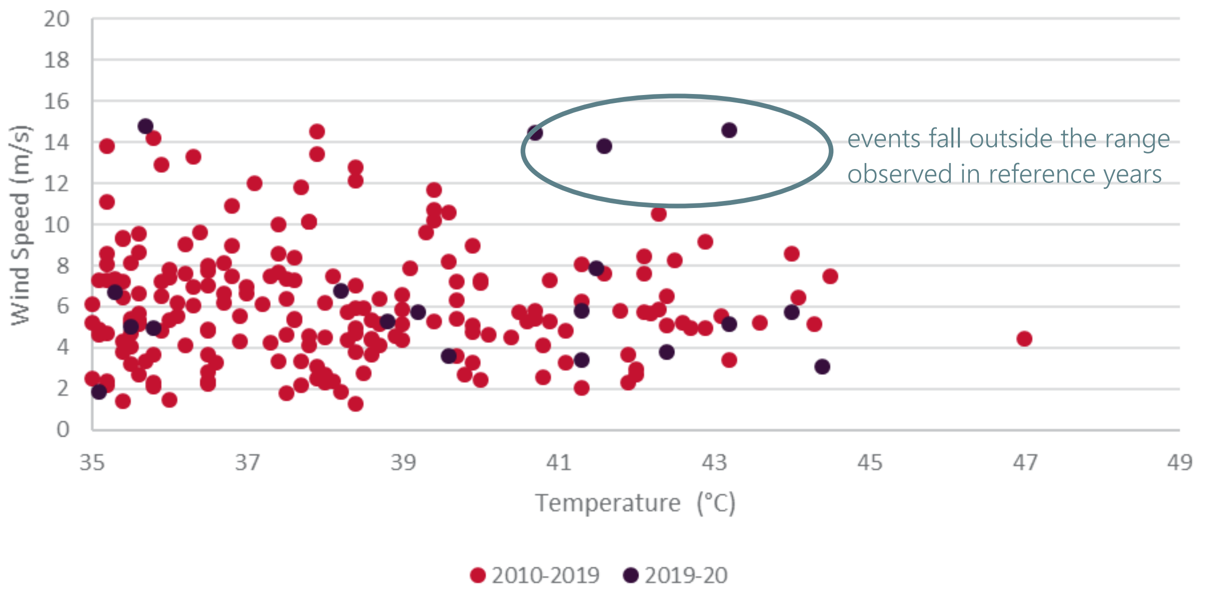



**Figure 51 Scatter plot of daily maximum temperature over 35°C and wind speeds for South Australia**




## 6.4 Tasmania

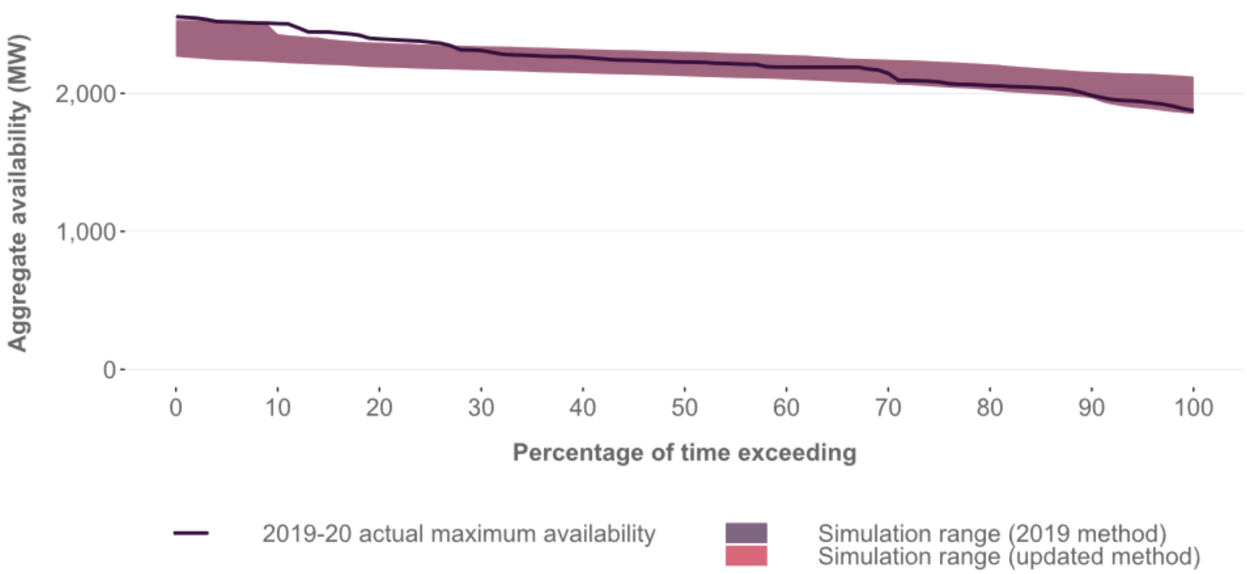
Table 25 shows how Tasmanian generation information was implemented in the 2019 ESOO, compared to actual generator characteristics for February 2020. In Tasmania, some generators that had indicated they would not be available during summer 2019-20 were actually available. While Tasmania is a winter-peaking 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, where Tasmanian capacity may be valuable to support Victorian peak demand events.

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

| Tasmania generation | Facilities actually operating | | Facilities forecast to operate | | Difference in Capacity (actual - forecast) | |
|---|---|---|---|---|---|---|
| | Count | MW | Count | MW | MW | % |
| VRE generation | 3 | 462 | 3 | 462 | 0 | 0.0% |
| Non-VRE generation | 49 | 2,348 | 47 | 2,225 | 123 | 5.2% |
| **All generation** | **52** | **2,810** | **50** | **2,687** | **123** | **4.4%** |

Figure 52 shows total summer availability for Tasmania for the high temperature periods of interest. Actual availability was above the simulation range during some of the high temperature periods, which was driven by higher than expected Hydro availability as shown in the technology aggregate section as below.

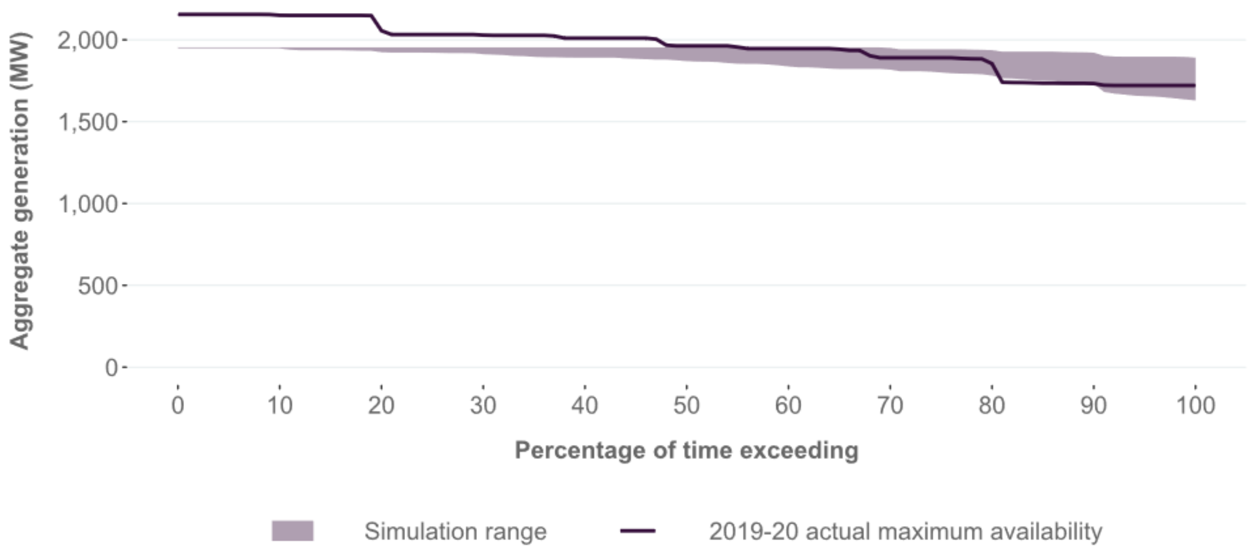
Figure 52 Tasmania supply availability for the top 10 hottest days




## Hydro

Figure 53 shows the supply availability for Tasmania hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was above the 2019 ESOO simulated range in some high temperature periods, due to the higher than expected available capacity for some hydro generators.

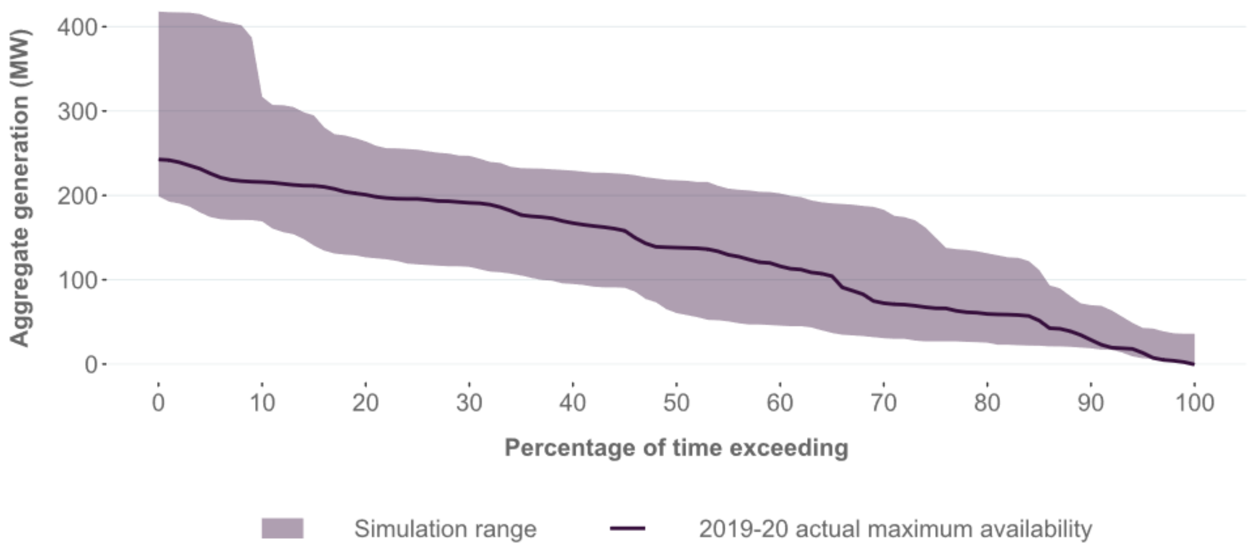
Figure 53 Tasmania hydrogeneration supply availability for the top 10 hottest days




### Variable renewable energy

Figure 54 shows the supply availability for Tasmania VRE generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was within the forecasting range in the 2019 ESOO.

Figure 54 Tasmania variable renewable energy supply availability for the top 10 hottest days




## 6.5 Victoria

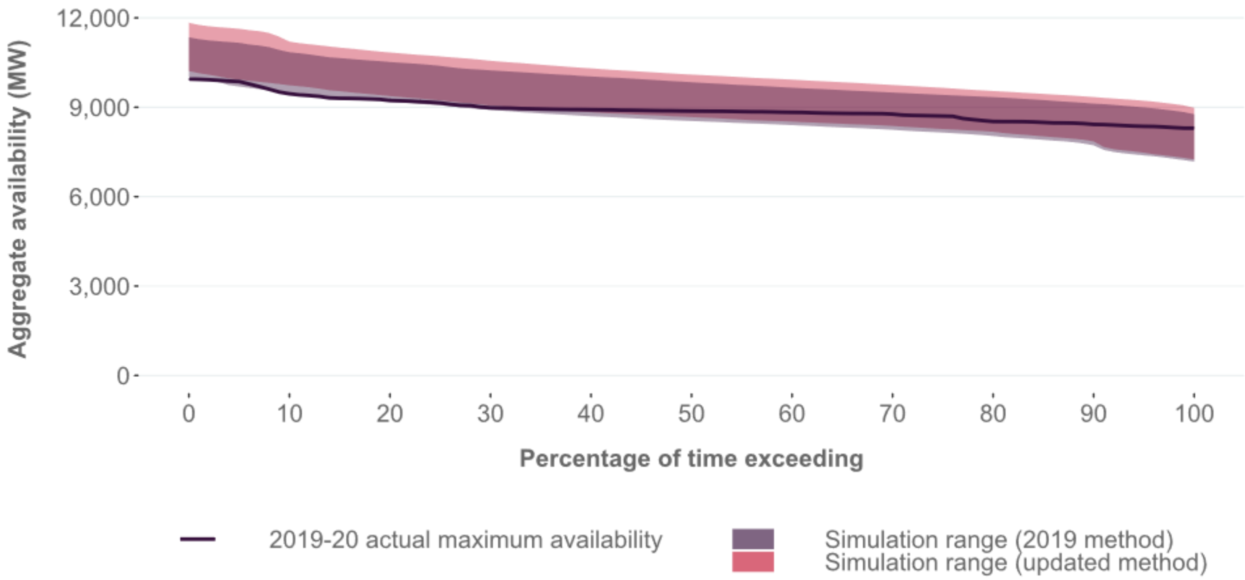
Table 26 shows how the Victoria generation information was implemented in the 2019 ESOO, compared to actual generator characteristics for February 2020. In Victoria, the connection of some VRE projects was delayed and the full availability of new capacity was not accessible throughout summer 2019-20.

Table 26 Forecast and actual generation count and capacity, February 2020

| Victoria generation | Facilities actually operating | | Facilities forecast to operate | | Difference in Capacity (actual - forecast) | |
|---|---|---|---|---|---|---|
| | Count | MW | Count | MW | MW | % |
| VRE generation | 22 | 2,494 | 27 | 3,715 | -1221 | -49.0% |
| Non-VRE generation | 66 | 9,301 | 67 | 9,321 | -20 | -0.2% |
| **All generation** | **88** | **11,795** | **94** | **13,036** | **-1241** | **-10.5%** |

Figure 55 shows total summer availability for Victoria for the high temperature periods of interest. Actual availability was within, but towards the lower end of the ESOO 2019 simulation range. This was mainly due to the delayed commission of some VRE projects, and reduced wind output due to high temperatures, as explored in the technology aggregate sections below.

Figure 55 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 56. The outage rate in 2019-20 continued the recent trend and was amplified by a high impact low probability (HILP) outage as shown in Figure 56. The 2019 forecast outage rate was developed as an average of the last four years performance, resulting in a slight under-forecast. The 2020 forecast outage rate was developed using participant and consultant provided forecasts, capturing the longer-term upward trend.

**Figure 56 Victorian brown coal effective unplanned outage rates, forecasts including HILP outages**

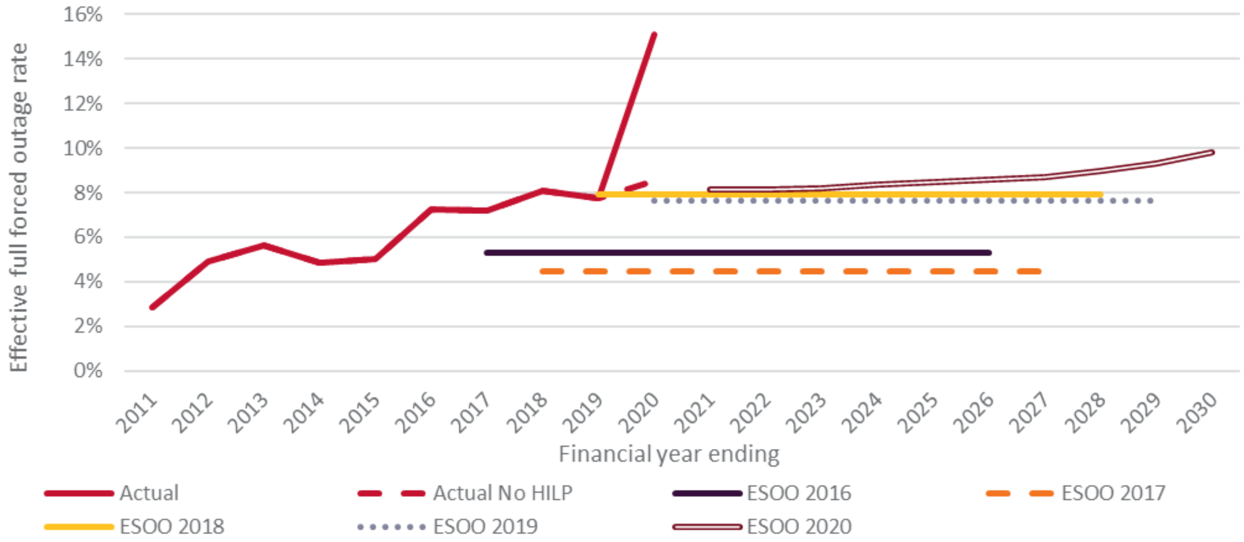
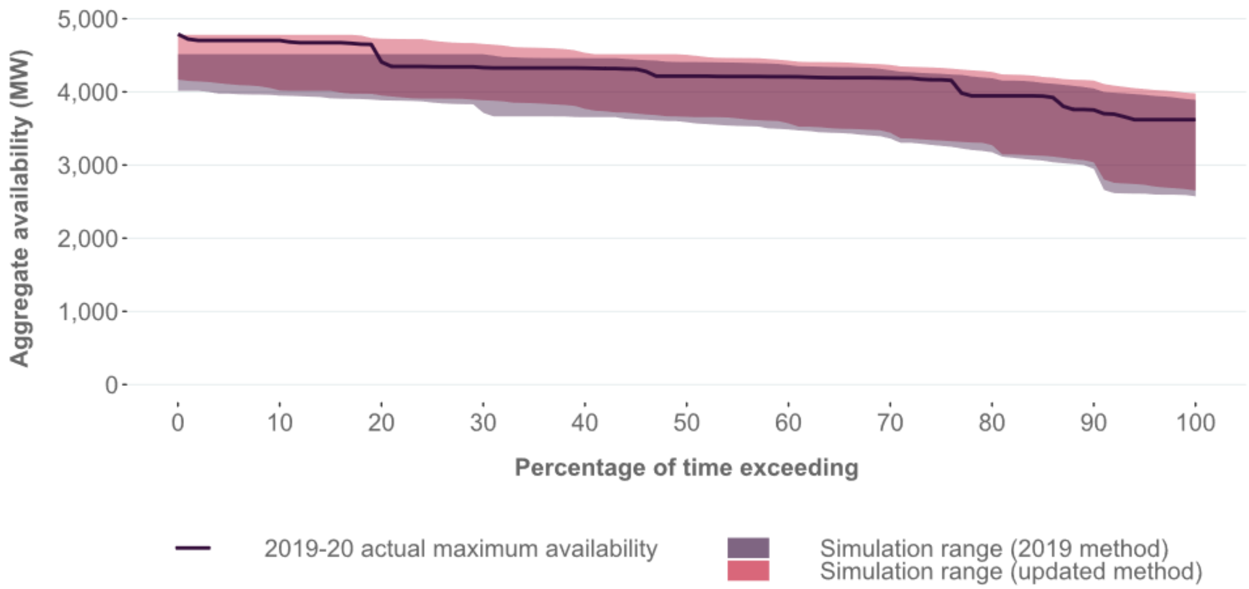



Figure 57 shows that availability over the top 10 hottest days was above or within simulated availability. In 2019-20, the observed availability was at times higher than the 2019 ESOO simulated range. The updated methodology better captures generator performance over these periods.

**Figure 57 Victoria brown coal supply availability for the top 10 hottest days**




## Variable renewable energy

Figure 58 shows the supply availability for Victoria VRE generators over the top 10 hottest days, comparing actual with simulated availability. In 2019-20, the observed availability was below or towards the lower end of the 2019 ESOO simulation range. This was due to delays in the connection of new generator capacity, intra-regional transmission constraints and higher than expected temperature de-rating.

**Figure 58 Victoria variable renewable energy supply availability for the top 10 hottest days**

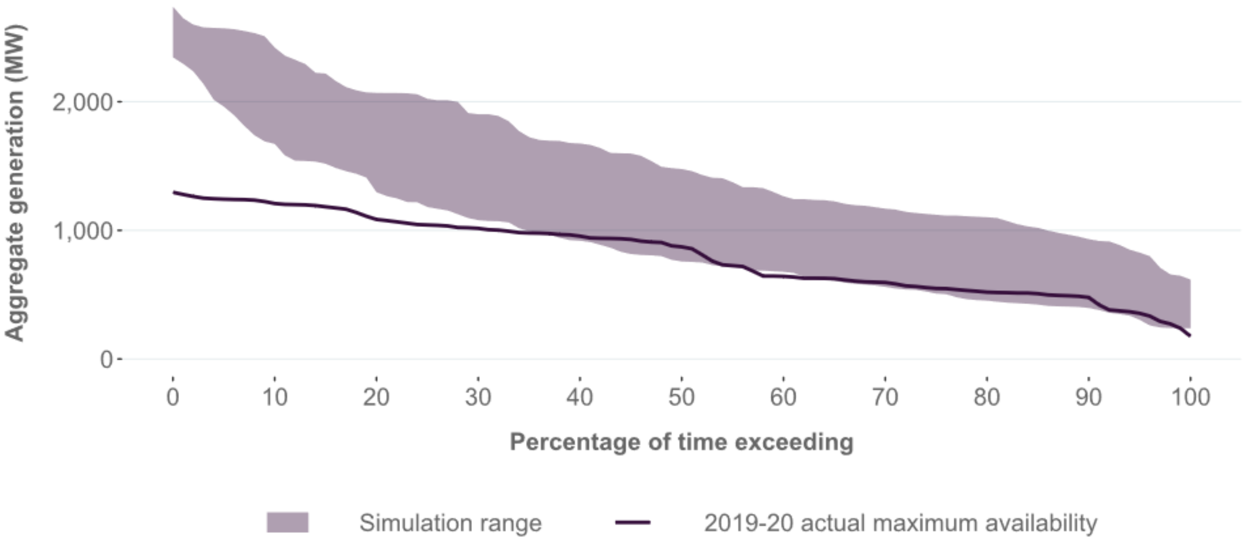
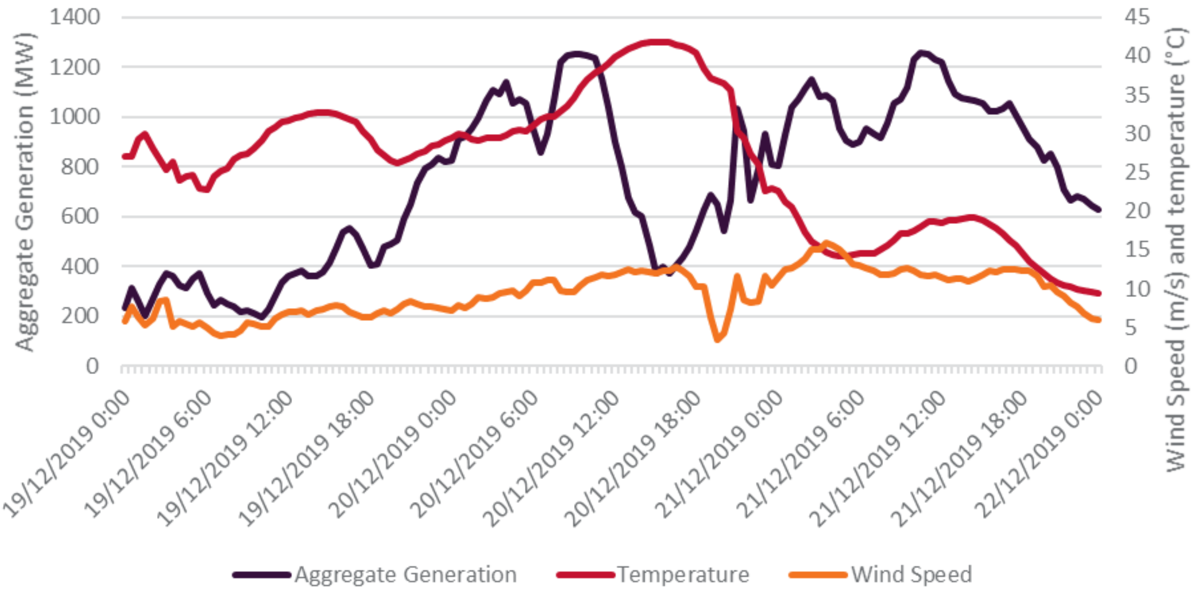



Figure 59 shows an example of temperature de-rating on Victorian wind generators. On 20 December 2019, temperatures in Victoria rose above 40°C, while wind speeds remained high. Due to the high temperatures observed, many of the wind generators reduced output during the heat of the day. Forecast wind traces used in the 2019 ESOO did not have explicit consideration for this effect, and over-estimated wind farm output during high temperature events as a result. Interim measures were deployed to correct these issues in the 2020 ESOO and a more comprehensive improvement is proposed in Chapter 8.

**Figure 59 Victoria aggregate wind generation output on a high temperature day**




## 6.6 Inter-regional transmission elements

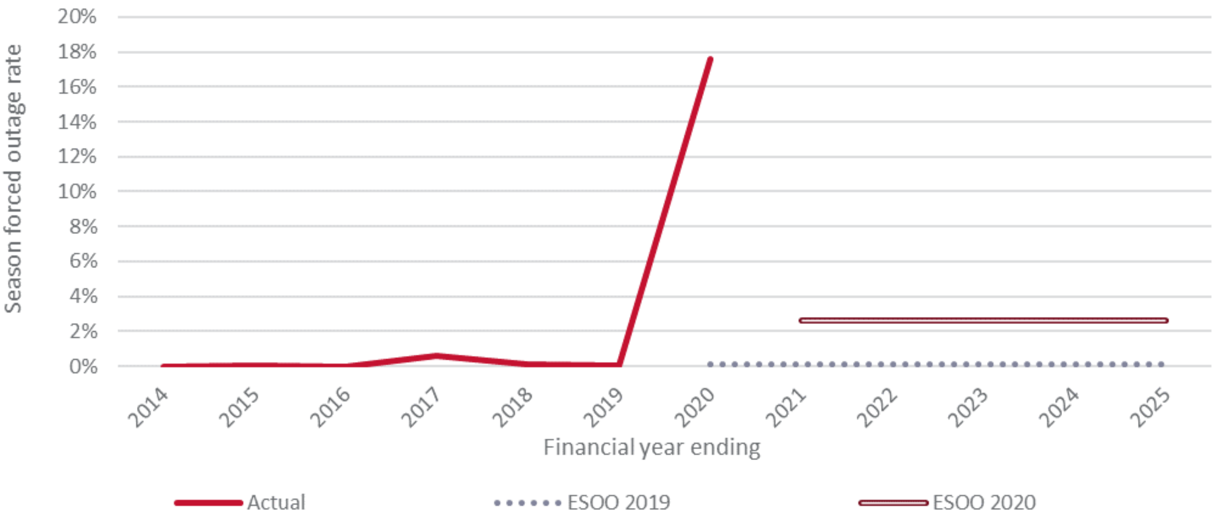
Since the 2019 ESOO, AEMO has included consideration for unplanned outages that result in single credible contingencies on key inter-regional transmission elements. Transmission lines are subject to numerous environmental and electrical hazards that may result in a forced outage. Unplanned outages on these transmission elements have the potential to exacerbate the risk of loss of load for connected regions, particularly if the outage coincides with high demand, and supply scarcity. Outage rates apply between October and April in each forecast year.

The Victoria to New South Wales inter-regional transmission elements are subject to infrequent high impact events as shown in Figure 60. In history, two major impacts from bushfires stand out, namely the 2009 Victorian Black Saturday bushfires, and the 2019-20 Black Summer bushfires. The 2020 ESOO outage rate has been revised upwards in response. Further consideration for seasonal and climate change trends may improve the accuracy of these forecasts.

**Figure 60 Victoria – New South Wales transmission forced outage rates**

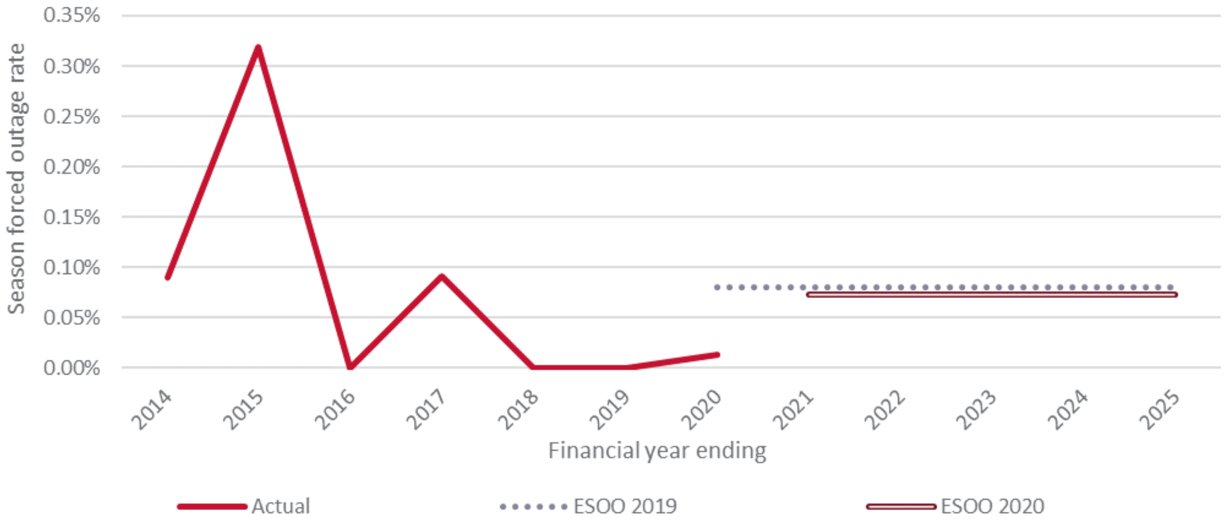

The Victoria to South Australia inter-regional transmission elements are subject to infrequent high impact events, as shown in Figure 61. The largest event, which was observed in 2019-20, was due to destructive high winds. The 2020 ESOO outage rate has been revised upwards to better reflect the increased risk of single credible contingency events. Further consideration for seasonal and climate change trends may improve the accuracy of these forecasts.

**Figure 61 Victoria – South Australia transmission forced outage rates**



The Tasmania to Victoria (Basslink) inter-regional transmission element is subject to infrequent low impact events, as shown in Figure 62. Recent outages rates have been lower than the longer-term mean.

**Figure 62 Tasmania – Victoria interconnector (Basslink) forced outage rates**




## 6.7 Demand side participation

AEMO forecast DSP for use in its medium to long term reliability assessments (ESOO, EAAP and MT PASA) as well as the ISP. It represents 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[18] used for the 2019 ESOO was published in August 2019 and is the one assessed in the following section.

### Background

AEMO's DSP forecast methodology 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 50$^{th}$ 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[19]. 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 2019 DSP forecast excluded:

- Regular (such as daily) DSP including responses to TOU tariffs and hot water load control.
- Load reductions driven by embedded generators modelled as part of AEMO's other non-scheduled generation (ONSG) forecast.
- Load reductions driven by embedded battery storage installations.
- Any response currently contracted under the Reliability and Emergency Reserve Trader (RERT) framework[20].

[18] At: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.

[19] 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.

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

The first three 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 RERT and these RERT resources cannot therefore be included in the DSP forecasts.

It should be noted that the methodology for the 2020 forecast has seen a number of changes to the components that are excluded or included[21], but the assessment here has been made using the 2019 approach for consistency.

### Assessment of DSP forecast accuracy

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

- Median (50th percentile) observed DSP response for various wholesale price triggers during the 2019-20 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 summer 2019-20 consumption data for the same list of DSP resources as the 2019 forecast. This is compared to the forecast DSP responses that were based on consumption data from the three previous years (June 2016 to end of May 2019). The comparisons highlight the difference between forecast DSP and median observed response.

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 63 through to Figure 67 and highlight that Victoria and South Australia experienced the highest number of high price events, providing the greatest number of observations to contribute to the evaluation. Prices greater than $5,000/MWh were not seen over summer in New South Wales, Queensland or Tasmania.

In conclusion:

- Median observed actual responses in New South Wales were lower than forecast, for example 16 MW lower for the >$5,000/MWh price trigger. This suggests the forecast is slightly too high. Note the estimates of actuals excluded a site that in the last year was on a RERT contract and responded significantly above previous voluntary responses and therefore not a like-for-like comparison. If the site was included the median observed responses were 7-18 MW above forecast for the >$2,500/MWh and >$5,000/MWh price triggers respectively. There were too few observations to reliably estimate the response for >$7,500/MWh.
- In Queensland, there was good alignment for price triggers up to >$500/MWh. There were too few observations to reliably assess responses for higher price levels.
- For South Australia, the median of observed responses agreed reasonably well with the forecast up to the >$1,000/MWh price trigger. Above this level, there were generally too few observations to reliably estimate the responses.
- Median observed responses in Tasmania agreed well with the forecast for the higher price levels, which is what is important for reliability assessments.. For prices below $1,000/MWh, responses were higher than forecast. There were too few observations to reliably estimate the response for >$5,000/MWh.

[21] See updated DSP methodology, following consultation with stakeholders in 2020: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

- Median observed responses in Victoria are lower than forecast, up to ~20 MW below forecast for the price triggers >$2,500/MWh or above, suggesting the 2019 forecast was too high. Note actuals excluded two sites that in the last year were on a RERT contract and responded significantly above previous voluntary responses and therefore not a like-for-like comparison. If the sites had been included, the median observed responses would instead be ~20 MW above forecast for all price triggers above >$2,500/MWh.

**Figure 63 Evaluation of actual compared to forecast price-driven DSP in New South Wales**

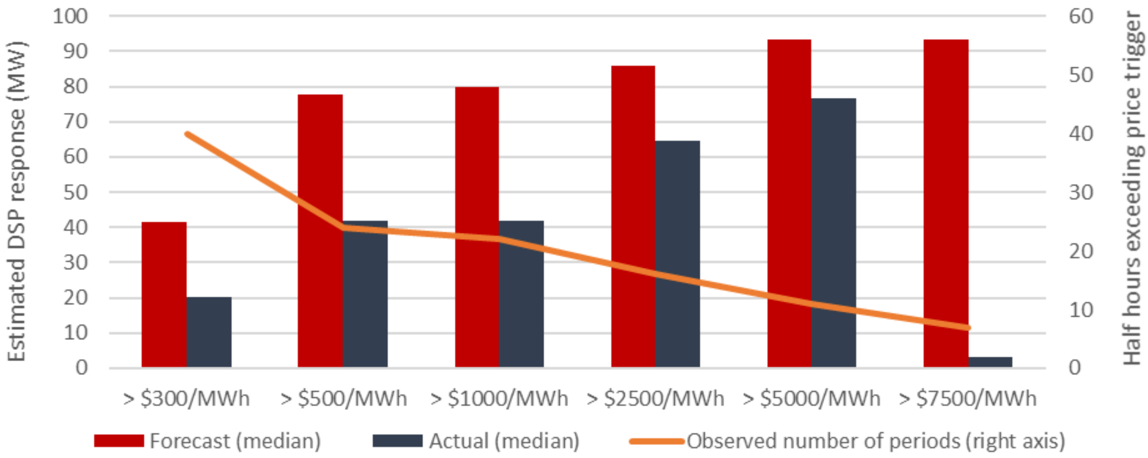



**Figure 64 Evaluation of actual compared to forecast price-driven DSP in Queensland**

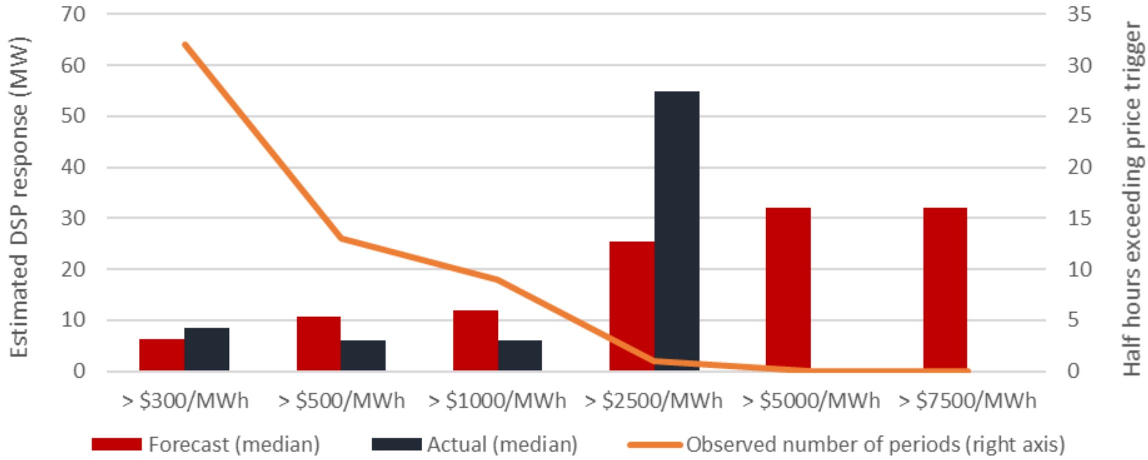



**Figure 65 Evaluation of actual compared to forecast price-driven DSP in South Australia**

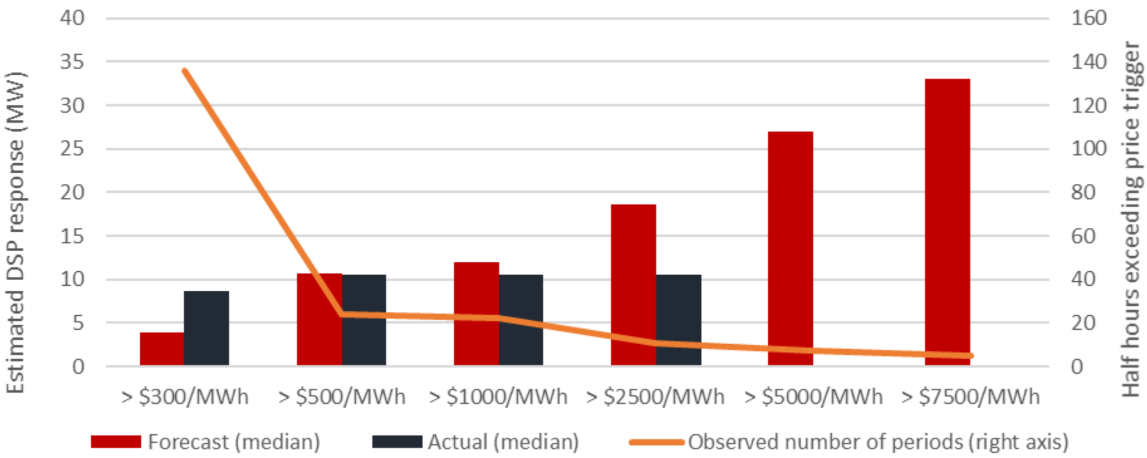


**Figure 66 Evaluation of actual compared to forecast price-driven DSP in Tasmania**

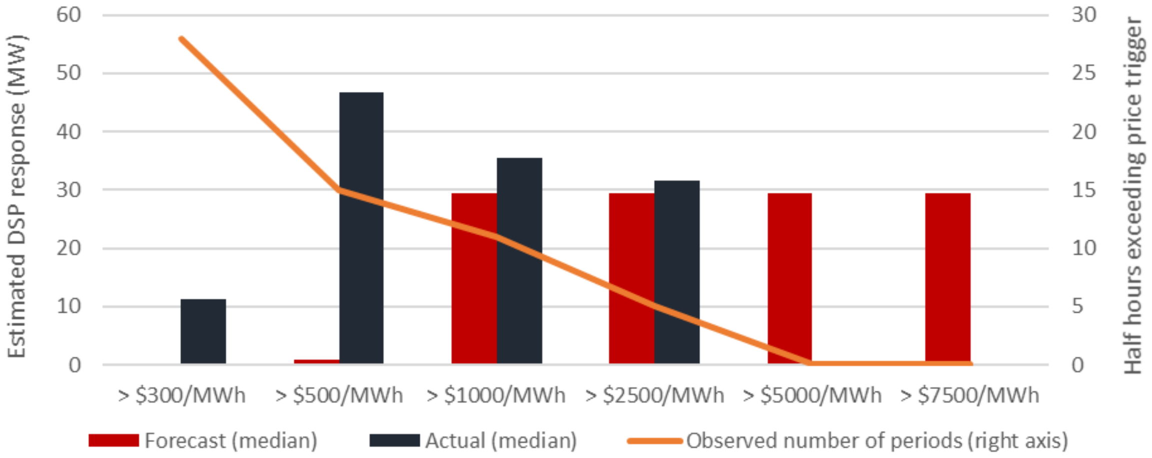
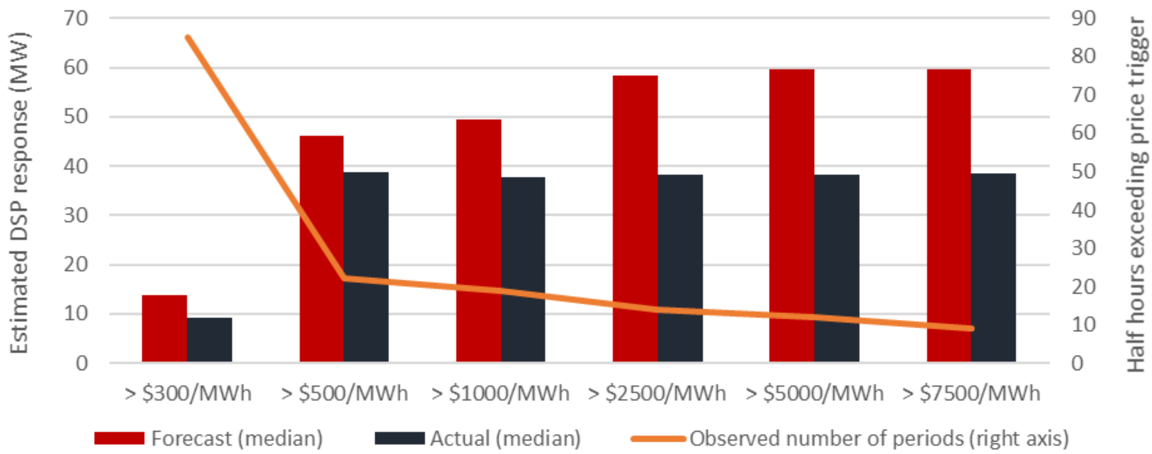



**Figure 67 Evaluation of actual compared to forecast price-driven DSP in Victoria**




## DSP response during reliability events

The reliability response from the 2019 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 | 93 | 52 | 33 | 30 | 185 |
| Winter | 93 | 32 | 33 | 30 | 160 |

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

- **New South Wales** – this region had its maximum demand on 1 February 2020 and did enter LOR2 on that day, but also on 4, 23 and 31 January 2020. A major customer which had not been price responsive in previous years did lower consumption in response to high prices on three of the four days, with an average across the four days of 243 MW. The DSP response from other sources were generally lower than the 93 MW forecast (on 31 January, it did just exceed 100 MW, but the average across the four days was only 40 MW).

- **Queensland** – the thresholds for LOR2 or LOR3 were not met during the year and prices remained well below $300/MWh across the top five maximum demand days, so no price driven DSP was recorded. Energy Queensland did operate its controlled air-conditioner program on a number of high demand days but not on 3 February, which was the maximum demand day.
- **South Australia** – this region had its 2019-20 maximum demand in the evening of 19 December 2020. Prices reached the market price cap ($14,700/MWh) but the region had sufficient supply to avoid declaring an LOR2. A few customers reduced consumption, but not beyond what they often do during that time of day. On the second highest demand day, 30 January 2020, the region entered an actual LOR2 state and prices reached the market price cap. On that day, AEMO estimated 50-60 MW of DSP response from various customers.
- **Tasmania** – being winter peaking, Tasmania had its annual maximum demand on 10 August. There were no LOR2 or LOR3 conditions and prices were moderate and did not trigger any observable price driven DSP response.
- **Victoria** – the region experienced three days with actual LOR2, including the maximum demand day 31 January 2020, and one day with an actual LOR1 but forecast LOR2, which could have triggered DSP responses from sites with some lead time. A major customer, which had been excluded since on a RERT contract (based on the methodology used in 2019), did adjust down consumption in response to high prices on three occasions. AEMO's updated DSP methodology, consulted on in 2020, acknowledges this response as something that should be accounted for as DSP. The average response from this customer was 122 MW across the three days, which wasn't reflected in the forecast. Other observed DSP response averaged 90 MW across the four days, with a peak of 130 MW.

### DSP forecast conclusions

Of the five NEM regions, New South Wales, South Australia and Victoria all reached conditions similar to what the forecast DSP reliability response represents. It is observed that:

- In **New South Wales**, actual DSP response was significantly above forecast, with an average of 283 MW observed against 93 MW forecast. This 190 MW shortfall has been addressed in the 2020 DSP forecast based on recent observable major customer behaviour.
- In **South Australia**, there was only a single observation with the LOR2 condition met. Here, DSP response of 60 MW was about double the forecast value of 33 MW, but it was noted that on an even higher demand day with similar price outcomes, no statistically significant level of DSP response could be measured. It is impossible to conclude anything from the single day that met the criterion, but it should be noted that AEMO's DSP forecast published with the 2020 ESOO using updated data, estimates 61 MW of DSP response for South Australia for the coming summer.
- **Victoria** saw an average DSP response on the four days analysed of 212 MW, which is slightly above the forecast value of 185 MW.

# 7. Reliability forecasts

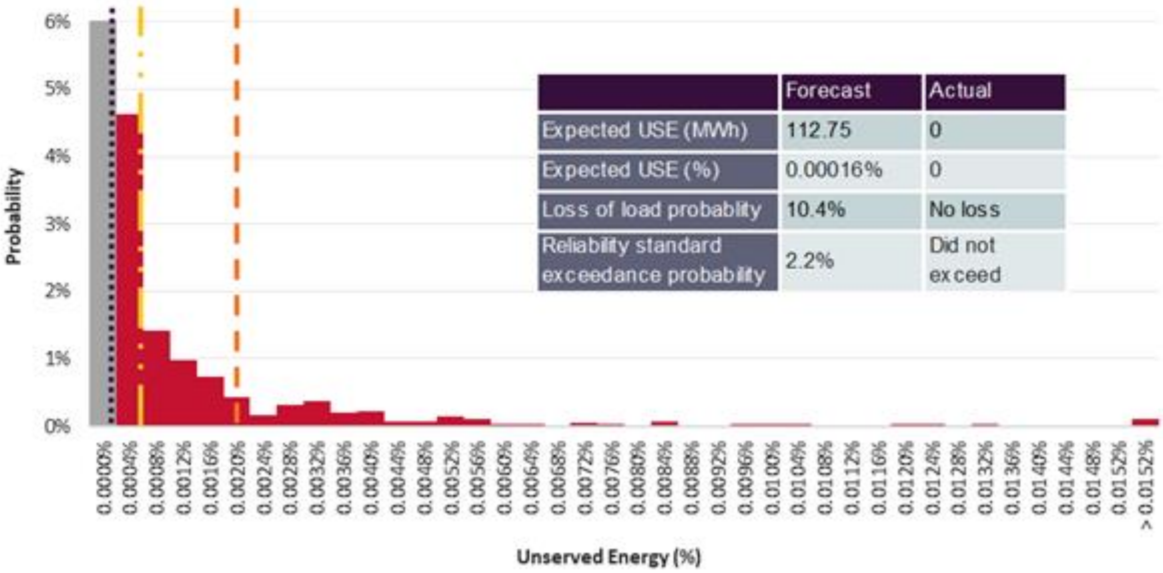
AEMO forecasts and reports on scarcity risk of generation supply availability, demand side participation, and inter-regional transmission capability relative to demand. Reliability in this context does not include outages arising from network capacity shortfall or failure impacting demand within a region. This forecast of reliability risk is an implementation of the reliability standard[22] and Interim Reliability Measure (IRM)[23], with the expectation that the market will respond to avoid USE occurring. Further, in operational and planning timeframes, AEMO uses long and short notice RERT and other operational mechanisms to avoid USE events where possible. No USE events occurred in 2019-20.

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 expectations should not eventuate.

## 7.1 New South Wales

Figure 68 shows the forecast distribution of USE in New South Wales in the 2019 ESOO. The distribution shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 10.3%. In 2019-20 no load was lost, an outcome predicted by 89.7% of simulations.

**Figure 68 New South Wales USE forecast distribution for 2019-20 summer**




| | Forecast | Actual |
|---|---|---|
| Expected USE (MWh) | 112.75 | 0 |
| Expected USE (%) | 0.00016% | 0 |
| Loss of load probablity | 10.4% | No loss |
| Reliabilty standard exceedance probabilty | 2.2% | Did not exceed |

Average USE   Reliability Standard   Interim Reliability Measure

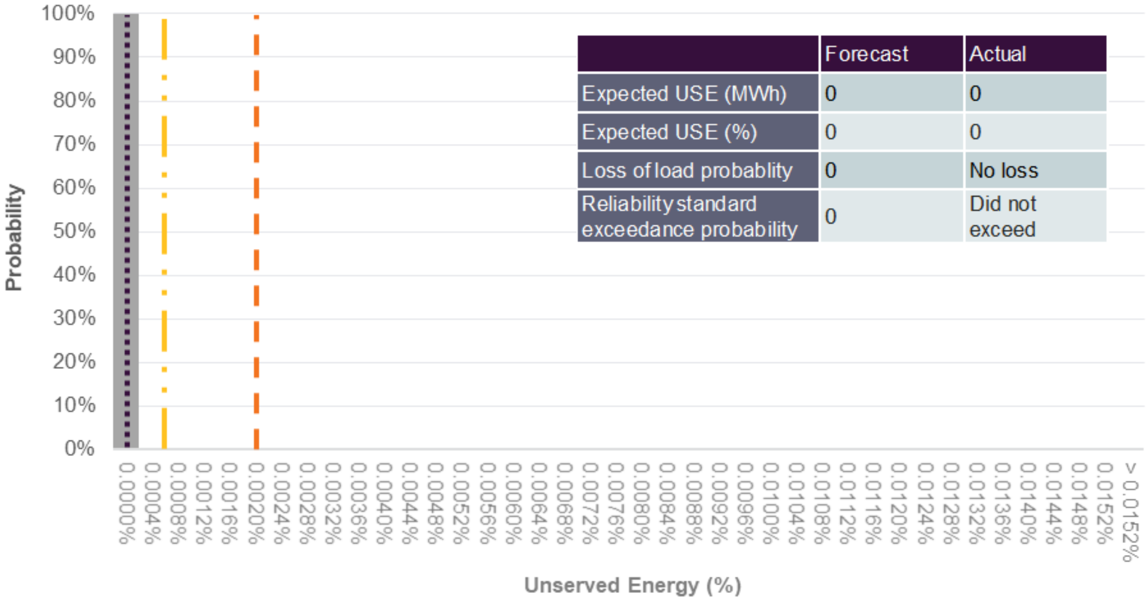
[22] The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

[23] 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 69 shows the forecast distribution of USE in Queensland in the 2019 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2019-20, no load was lost, consistent with expectation.

**Figure 69 Queensland USE forecast distribution for 2019-20 summer**

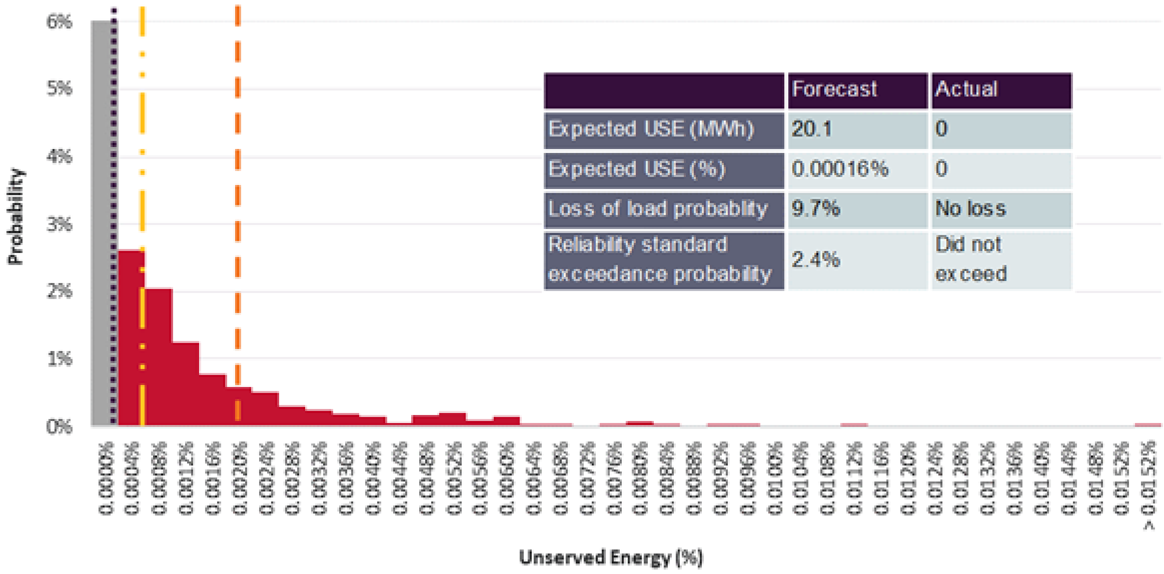



Average USE — Reliability Standard — Interim Reliability Measure

## 7.3 South Australia

Figure 70 shows the forecast distribution of USE in South Australia in the 2019 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 8.3%. In 2019-20 no load was lost, an outcome predicted by 91.7% of the simulations.

**Figure 70 South Australia USE forecast distribution for 2019-20 summer**

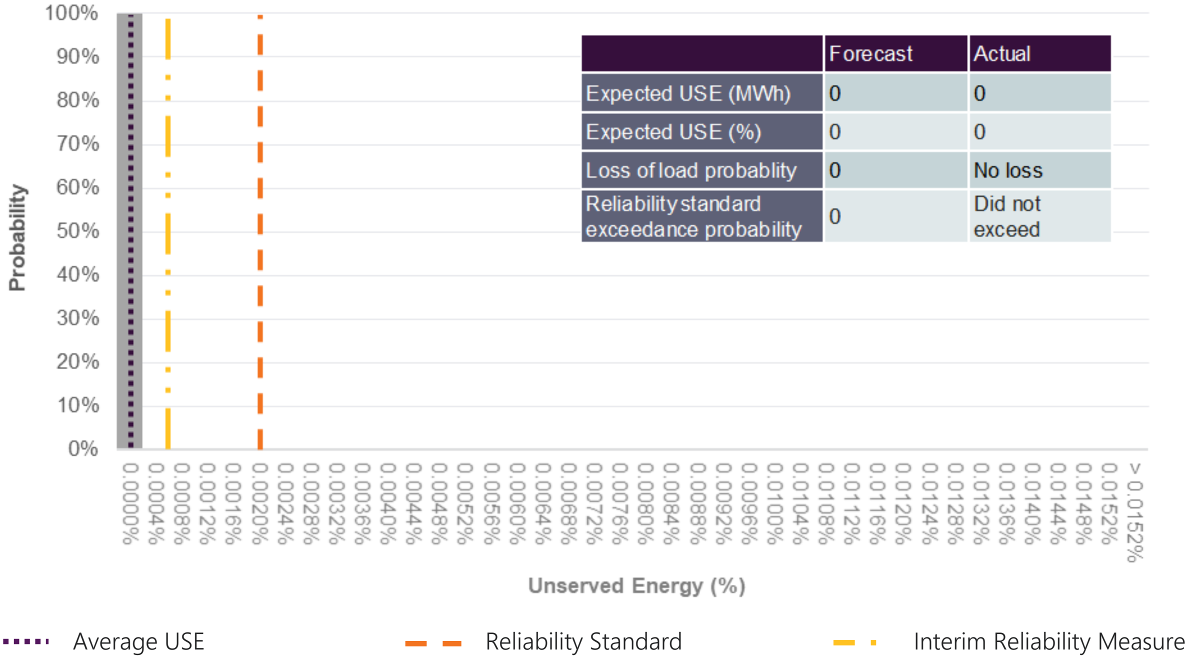



Average USE — Reliability Standard — Interim Reliability Measure

## 7.4 Tasmania

Figure 71 shows the forecast distribution of USE in Tasmania in the 2019 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2019-20, no load was lost, consistent with the expectation.

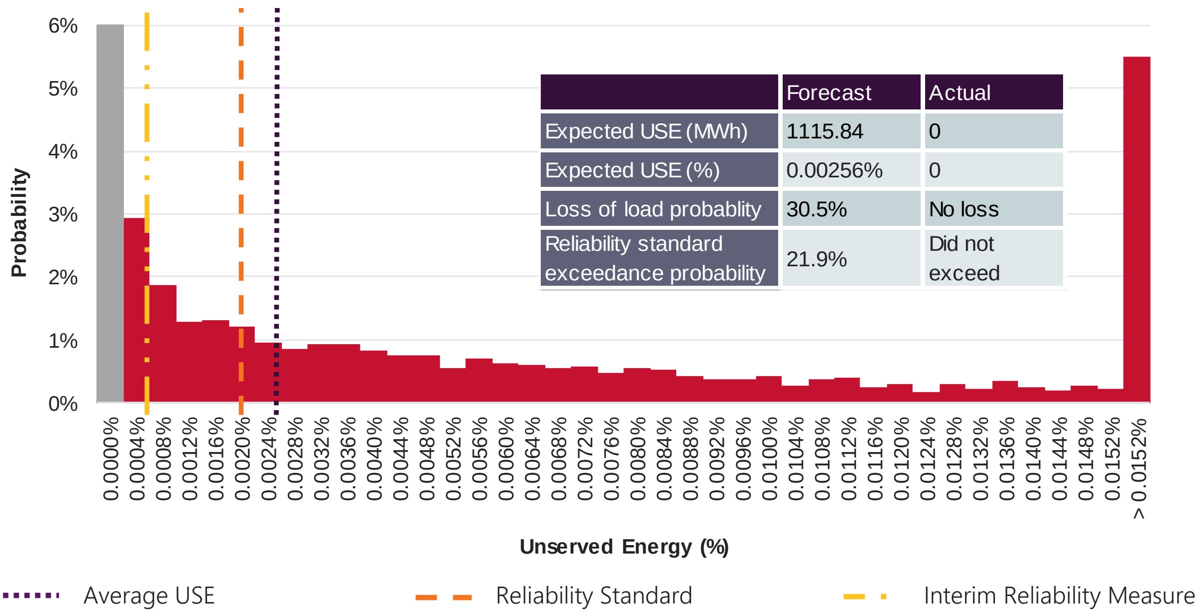
**Figure 71 Tasmania USE forecast distribution for 2019-20 summer**




## 7.5 Victoria

Figure 72 shows the forecast distribution of USE in Victoria in the 2019 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 24.8%. While there were some customers without power in 2019-20, the USE did not meet the definition of a system reliability incident. No load was lost as a reliability incident, an outcome predicted by 75.2% of simulations.

**Figure 72 Victoria USE forecast distribution for 2019-20 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 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 Liquified Natural Gas (LNG) export facilities supported by electrical loads associated with coal seam gas (CSG) operations), or consumer technological changes (such as electric vehicles 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 Retailer Reliability Obligation (RRO) required a number of changes to AEMO's forecasting process. Similarly, the Actionable ISP will increase the focus on intra-regional transmission requirements over previous AEMO planning publications, causing 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 2019 forecasts summarised in Section 8.1. Section 8.2 summarises the priority initiatives included in AEMO's 2020 Forecast Improvement Plan.

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. AEMO will accordingly consult on improvements required for the ISP separately during 2021.

## 8.1 2019 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:

- Distributed PV installations were above the 2019-20 forecast in all regions, resulting in over-forecasting of operational consumption and in particular minimum demand in most cases.
- Actual economic activity was significantly lower than forecast, due to the impacts of domestic and international measures to minimise the spread of COVID-19 from late March 2020 onwards, which significantly reduced economic activity.
  - The impact on consumption is relatively smaller. While some business electricity consumption was reduced, residential consumption typically increased, and the net impact for the last quarter of the financial year was minor.
  - AEMO has limited ability to see impacts from COVID-19 separately from other potential drivers.
- On the supply side:
  - Outage rates on inter-regional transmission elements were higher than assumed, primarily due to the reclassification of credible contingencies due to bushfires near Victoria to New South Wales transmission elements, and other asset failure events.
  - Wind generation in Victoria saw higher than expected de-rating during hot summer days, where wind generation dropped while wind remained strong. The forecast wind traces used in the 2019 ESOO did not have explicit consideration for this effect, and over-estimated wind farm output during high temperature events as a result.

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 2020 ESOO, such as those identified in the 2019 Forecast improvement Plan initiatives. These observations include:

- DSP aligned well with forecast in most regions, but in both New South Wales and Victoria the DSP responses were under-estimated. The DSP methodology has subsequently been revised and implemented for the 2020 ESOO forecast following consultation on DSP methodology in the first half of 2020.
- New generation installations were aligned with forecast for most regions, however Victoria observed delays against provided timing. For summer 2019-20, there was 1,241 MW less installed capacity than expected in Victoria. While further delays have been observed in 2020-21, no further changes to this forecasting process are proposed at this time. Instead, AEMO is working with industry to reduce likelihood of future generator connection delays.
- Generator forced outage rates for coal-fired generators continued to deteriorate but were mostly aligned with assumptions, except for New South Wales black coal-fired generators, which performed worse than expected. An updated methodology used in the 2020 ESOO now uses participant and consultant forecasts of forced outage rates to better capture trends in performance and maintenance.

For reference, Appendix A1 lists the improvements presented in the 2019 Forecast Improvement Plan along with a summary of implementation status of each of these initiative, and any other improvements implemented for the 2020 ESOO.

## 8.2 Forecast improvement priorities for 2021

AEMO proposes the following priority initiatives, guided by the observations in the FAR listed above, for its 2020 Forecast Improvement Plan:

1. Improve PV forecasts to minimize adverse impacts on consumption, demand, reliability and system security outcomes.

2. Gain increased visibility and understanding of consumption drivers and trends through data analytics to improve forecast accuracy and improve the ability to explain forecast variance, for example due to COVID-19, from the insights.
3. Better representation of the forecast distribution of monthly maximum demand outcomes.
4. Develop improved wind generation traces accounting for temperature cut-offs.
5. Improve modelling of inter-regional transmission element outage risk.

These are explained in the following sections.

### 8.2.1 PV forecast improvements

For the 2020 ESOO, AEMO has already implemented a number of changes to the PV forecasting process. This forecast attempted to better capture the range of rooftop PV and PVNSG uptake uncertainty by selecting a broader spread of uptake projections from the two DER consultants. However, post model adjustments for COVID-19 made in April 2020 may have been too broadly applied across the scenarios, with early indications being that the actual impact of COVID-19 on rooftop PV uptake is significantly less than suggested by the initial fall in rooftop PV sales lead data, used to support the consultant's post model adjustments to the rooftop PV forecasts. Another of the 2020 improvements was the use of a trend-based forecast in the short term by one of the consultants, although this may have missed an acceleration in PV installations by applying a trend over too long a time period, and without up-to-date installation data to capture most recent trends.

Preliminary investigation into the 2020 PV forecast performance (to be covered in detail in the 2021 Forecast Accuracy Report) shows more work is needed, in particular:

- Improved visibility of installed capacity by using the newly developed DER Register as a primary data source, reducing the potential lag time that exists with the current CER data stream. From 1 March 2020, network service providers[24] are required to supply data to AEMO on every relevant generator or battery device connected to its network within 20 business days of the DER device being connected to the grid and capable of generating.
- Increased analysis and consideration of short-term installation trends, particularly if the trend has exhibited non-linear features.
- Review of the normalised PV generation profiles used to ensure the forecast generation per MW of installed PV capacity is within expectation when used to offset the consumption forecast as well as at time of maximum and minimum demand.

These refinements are scheduled for the 2021 ESOO forecast.

### 8.2.2 Improved visibility and understanding of consumption drivers and trends

To improve its understanding of consumption and demand drivers and trends, AEMO plans to analyse smart meter data to improve the split of residential and business consumption consumers. Overall, this will:

- Help verify the models for residential and business consumption and have them based on the last year of estimated actuals rather than AER data that is currently used, and may be 18 months old. This should improve model performance and validation.
- Improve the ability to explain forecast differences by increasing the understanding of sectoral or spatial trends, such as COVID-19 impacts that may differ across NEM regions.
- Improve understanding of variability of large industrial loads at time of minimum demand events.

### 8.2.3 Improved visibility of forecast maximum demand within a year

The comparison of observed monthly maximum demand and the maximum demand of the traces used in the ESOO and MT PASA modelling shows examples (see for example Figure 25), where the actual value fell

[24] In some regions this is done directly by the installers, but with data entries being validated by the network service providers.

outside the range spanned by the reference years used, typically during shoulder seasons[25]. This is because the shoulder months in the traces reflect the last nine years of *actual* outcomes rather than the *forecast* range of outcomes. If in the last nine years, there has not been a very hot period in October in a particular region, but longer term climate series show it is possible, the forecast maximum demand for October for that region would be higher than any of the maximum demand values in the traces.

The traces based on historical reference years are scaled to meet summer and winter maximum demand forecast values, which are most relevant when assessing supply scarcity risks. Monthly maximums in shoulder months are not targeted in the same way as they generally do not drive unserved energy outcomes. This limits the distortion to the daily demand profiles, which otherwise could have unrealistic ramping events. Further, if monthly demand in every trace was scaled to a 50% POE or 10% POE maximum demand outcome, this could lead to overestimation of annual consumption.

However, for other purposes, such as generator outage scheduling based on MT PASA outcomes, the traces may not fully capture the distribution of maximum demand outcomes during the shoulder months when plant maintenance often occurs. AEMO will explore ways to better capture the range of maximum monthly demand outcomes across the sample of traces used, while still preserving annual consumption forecasts and minimising demand profile shape distortion. As part of this improvement initiative, the approach used to develop the 10% POE daily peak load, and the most probable daily peak load forecasts published as a stand-alone component of the MT PASA process will be reviewed.

### 8.2.4 Wind generation trace development

AEMO's current process for wind generation traces is to use historical weather readings, filling gaps and missing values, and applying an empirical wind turbine power curve to convert wind speed and other weather variables into energy generated.

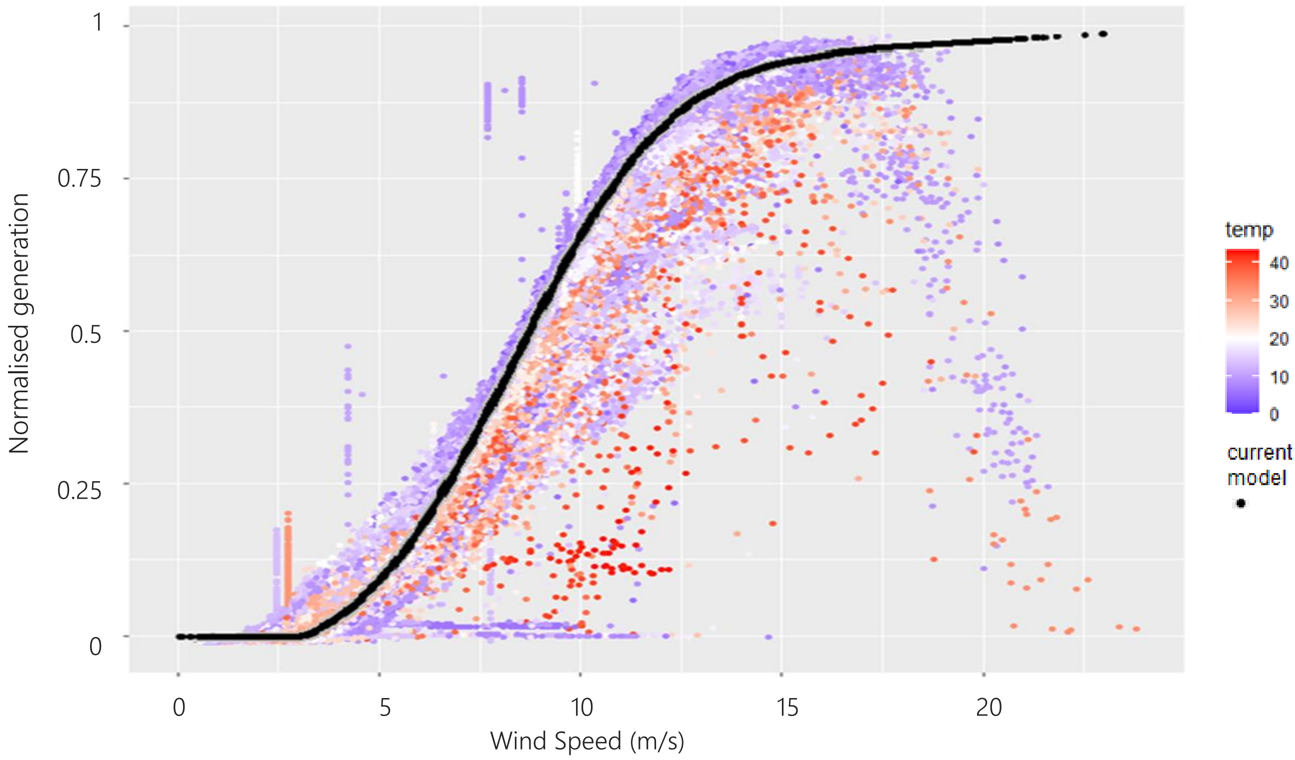
An example empirical power curve shown in relation to observed wind farm output is available in Figure 73. This empirical power curve is increasingly used rather than historical wind generation measurements, as wind farms connect to regions physically distant from existing wind farms. The empirical power curves do not currently capture the effects of high wind and high temperature cut-outs. In the example case shown below, wind speeds over 19 metres a second are associated with reduced output, and a similar effect can be seen with temperatures over 35°C.

High temperature cut-outs were observed in the 2020 summer and resulted in an unexpected reduction in supply availability. Recent analysis suggests that wind generation output during annual high temperature events may reduce more often due to climate change[26]. As installed wind capacity increases across the NEM, improved consideration of the relationship between wind generation and high temperature is important.

[25] This refers to months that do not fall within the defined summer or winter periods.

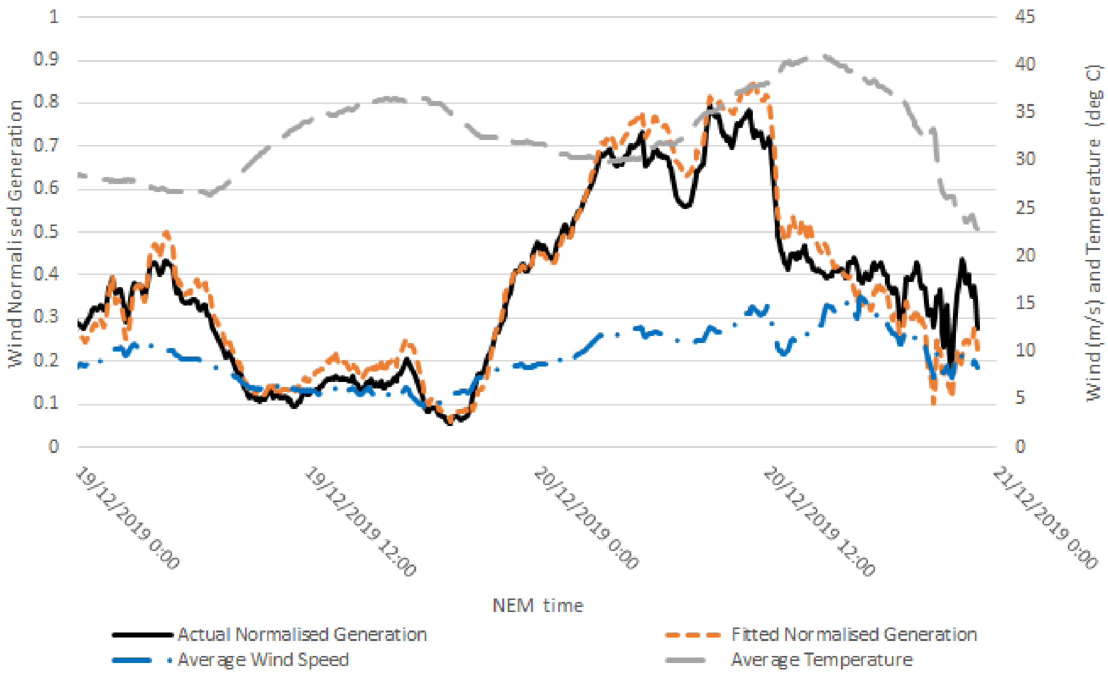
[26] CSIRO, BOM, AEMO. 2020. Electricity Sector Climate Information Project Case Study - Heat Impacts on VRE Generation Output. https://www.climatechangeinaustralia.gov.au/en/climate-projections/future-climate/esci/, based on Huang J, Jones B, Thatcher M, and Landsberg J. 2020. Temperature impacts on utility-scale solar photovoltaic and wind power generation output over Australia under RCP8.5. https://aip.scitation.org/doi/10.1063/5.0012711

**Figure 73 Current wind generation model with scatter plot of wind speed and temperature**




AEMO intends to develop and implement a new wind generation model that will produce more realistic traces in the presence of high temperatures or wind speeds. Figure 74 shows a potential trace from a prototype model, demonstrating realistic wind farm output driven entirely by meteorological inputs.

**Figure 74 Prototype wind generation model on high temperature day**



This improvement will result in better wind traces in current application and will build increased capability to explore weather and power system outcomes beyond those observed in the history. Such capability is required to comprehensively model the impacts of climate change.

### 8.2.5 Inter-regional transmission elements forced outage rate model

The AEMO current process for forced outage rates on inter-regional transmission elements uses available outage history for the months November to March, as per the following formula.

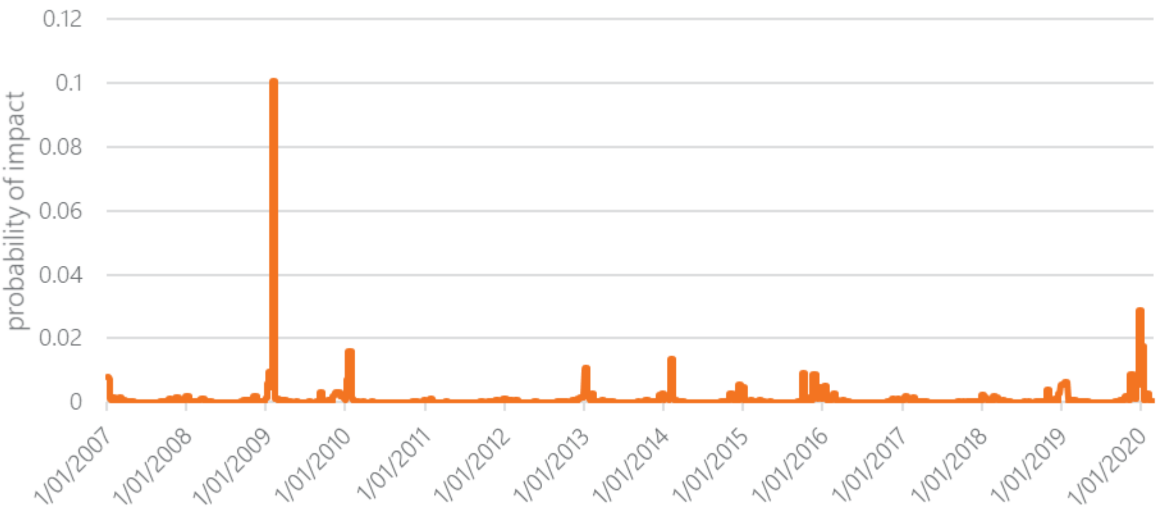
$$forced\ outage\ rate = \frac{\text{outage hours in sampled history}}{\text{total hours in sampled history}}$$

The current method is appropriate for random outages but may not adequately capture trends in frequency or timing/coincidence when the outages are driven by weather. Weather conducive for bushfires and high wind gust events is identifiable and can be used to develop forced outage simulations that better capture trends in frequency and timing. For example, bushfires are more likely to occur during periods of high temperatures that follow periods of low rainfall. Given that weather is increasingly the cause of transmission outages, as observed in 2019-20, improving the simulation of single credible contingencies is important for accurate forecasts.

AEMO intends to develop and implement new transmission failure models, that predict failure as a function of weather, where relevant. For example, as the Victoria to New South Wales inter-regional transmission elements can be impacted by bushfire, predicting bushfire impact probability as a function of daily bushfire weather, expressed as Forest Fire Danger Index (FFDI) may improve outage rate assumptions.

Figure 75 shows the output of a prototype model that shows that the daily probability of impact attributable to bushfire is centred on high temperature periods of summer with variation in conditions year to year. The 2009 bushfire year has the highest instantaneous probability, while the 2019-20 bushfire year has reduced probabilities that are distributed over a longer time. These probabilities align with observed impacts, but also recognise that bushfire risk exists in every year, to varying degrees. In implementation, the projected outage rates will consider the increasing frequency of bushfires projected by climate change models.

**Figure 75 Prototype daily transmission bushfire impact model output for Victoria – New South Wales inter-regional transmission elements**




While this improvement will result in better modelling of single credible contingencies on inter-regional transmission elements in current application, it also builds capability that allows for exploration of weather and power system outcomes beyond those observed in the history. Such capability is required to comprehensively model the impacts of climate change, and will be subject to further consultation over time.

# A1. Status of 2020 ESOO improvements

The 2019 Forecast Improvement Plan was published in the 2019 Forecast Accuracy Report[27]. It proposed a number of improvements planned for the 2020 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 2020 ESOO**

| Improvement | Stakeholder feedback | Status |
|---|---|---|
| **Operational energy consumption forecast methodology**<br>Develop multi-model ensembles of energy consumption per region considering both the existing component based model and shorter-term monthly time-series models. | This proposed improvement was discussed at the January 2020 Forecasting Reference Group (FRG) meeting. Written feedback suggested broad support but requested clarity as to how time-series models would be incorporated or merged alongside component-based models to reflect customer segments or total energy consumption trends. | **Implemented**. Improvements have been implemented and demand methodology documents have been updated to provide requested clarity. |
| **PV forecasts**<br>Use the DER Register and work more closely with the Clean Energy Regulator (CER) to ensure insights from historical installations are captured in short-term trends, possibly at more detailed spatial granularity. | This proposed improvement was discussed at the January 2020 FRG. | **Partially implemented**. The timing of the DER Register data availability precluded its use in underpinning these forecasts, however AEMO's DER forecasts considered the most up-to-date information on historical uptake from the CER, and CSIRO's forecast methodology improved to incorporate this trend. Green Energy Markets (GEM) was engaged as a second consultant to complement the forecasts provided by CSIRO. |
| **Generator derating in response to summer heat**<br>AEMO will apply two summer capacity ratings to better capture available capacity at different temperatures. | This proposed improvement was discussed at the November 2019 and January 2020 FRG. | **Implemented.** The 2020 ESOO and Reliability Forecasting Methodology document has been updated. |
| **Customer connection forecast methodology**<br>AEMO now has over five years of connections history for all regions, so a new connections model is being developed that incorporates greater visibility and consideration of the history and dwelling type characteristics. | This proposed improvement was discussed at the January 2020 FRG. | **Implemented**. Demand forecasting methodology document has been updated to reflect the changes to the connection model that better capture short-term trends. |

[27] AEMO. 2019. Forecast Accuracy Report 2019, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast_accuracy_report_2019.pdf

| Improvement | Stakeholder feedback | Status |
|---|---|---|
| **Forecasting portal*** Publish shoulder seasonal minimums in addition to summer/winter | This proposed improvement was discussed at the January 2020 FRG. | **Implemented**. Shoulder demand forecasts are now available on the portal. |
| **Demand side participation** Include responses from peaking type non-scheduled generators in DSP forecast rather than offsets in the demand forecast. | This proposed improvement was discussed at the January 2020 FRG and reflected in the DSP methodology consultation Feb-Aug 2020. | **Implemented**. DSP methodology documents have been updated. |
| **Auxiliary load** Estimations of auxiliary load will be requested from generators directly through the Generation Information data collection process. | This proposed improvement was discussed at the January 2020 FRG. | **Implemented**. Market modelling has been updated with generator provided auxiliary rates. |

* The AEMO forecasting portal can be found at http://forecasting.aemo.com.au.

In addition to the above improvements, AEMO conducted several investigations, and completed numerous minor methodological improvements including:

- Monitoring the performance of generator new entrant connections to ensure actual rates of connection match forecast.
- Implementing forward-looking forced outage rate projections (discussed in the June 2020 FRG).
- Changing how current RERT participation affects inclusion in DSP forecast, with voluntary responses now being reflected in the DSP forecast even for RERT participants (consulted on with industry as part of the DSP forecast methodology consultation in 2020).
- Developing a dynamic EV charge profile to reflect controlled EV charging that is optimised around minimum demand (only relevant beyond the 10-year ESOO planning horizon).
- Assessing the likely impacts of COVID-19 on consumption, maximum/minimum demand and DER investments to adjust 2020 ESOO forecast accordingly.

# Measures and abbreviations

## Units of measure

| Abbreviation | Full name |
| --- | --- |
| **GW** | Gigawatt |
| **GWh** | Gigawatt hour/s |
| **kW** | Kilowatt |
| **kWh** | Kilowatt hour/s |
| **MW** | Megawatt |
| **MWh** | Megawatt hour/s |
| **TWh** | Terawatt hour/s |

## Abbreviations

| Abbreviation | Full name |
| --- | --- |
| **ABS** | Australian Bureau of Statistics |
| **BoM** | Bureau of Meteorology |
| **CBD** | Central Business District |
| **CCGT** | Closed-cycle gas turbine |
| **Com*** | As per AEMO's generation information page, committed* or Com* are projects that are classified as advanced and have commenced construction or installation. |
| **CSG** | Coal seam gas |
| **CSIRO** | Commonwealth Scientific and Industrial Research Organisation |
| **DER** | Distributed Energy Resources |
| **DSP** | Demand Side Participation |
| **E3** | Equipment Energy Efficiency |
| **EAAP** | Energy Adequacy Assessment Projection |
| **EEGO** | Energy Efficiency in Government Operations |
| **EFI** | Electricity Forecasting Insights |
| **ESS** | Electricity Storage System |

| Abbreviation | Full name |
|---|---|
| **ESOO** | Electricity Statement of Opportunities |
| **FRG** | Forecasting Reference Group |
| **GSP** | Gross State Product |
| **HDI** | Household Disposable Income |
| **HIA** | Housing Industry Association |
| **ISP** | Integrated System Plan |
| **LOLP** | Loss of Load Probability |
| **LOR** | Lack of Reserve |
| **LRET** | Large-scale Renewable Energy Target |
| **MT PASA** | Medium Term Projected Assessment of System Adequacy |
| **MTTR** | Mean time to repair |
| **NEFR** | National Electricity Forecasting Report |
| **NEM** | National Electricity Market |
| **NER** | National Electricity Rules |
| **OPGEN** | Operational demand 'As Generated' |
| **OPSO** | Operational demand 'As Sent Out' |
| **PD PASA** | Pre-dispatch Projected Assessment of System Adequacy |
| **POE** | Probability of exceedance |
| **PV** | Photovoltaic |
| **PVNSG** | PV non-scheduled generation |
| **QRET** | Queensland Renewable Energy Target |
| **RCP** | Representative Concentration Pathway |
| **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 |
| **VRET** | Victorian Renewable Energy Target |