Forecast Accuracy Report

December 2019

Review of the 2018 Demand, Supply and Reliability Forecasts

Important notice

PURPOSE

This Forecast Accuracy Report has been prepared consistent with AEMO Interim Reliability Forecast guidelines 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 2018 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 1 November 2019.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1	19/12/2019	First version for publication

Executive summary

AEMO has published an assessment of forecast accuracy since 2015 to help inform its continuous improvement plan and build confidence in the forecasts produced. This 2019 Forecast Accuracy Report primarily assesses the accuracy of AEMO's 2018 Electricity Statement of Opportunities (ESOO) [1], for each region in the National Electricity Market (NEM). The report has expanded to analyse and discuss a broader range of forecasts and components, now including customer demand, generator supply and system reliability. Specifically, it assesses the drivers of demand and supply that influenced the reliability assessments and planning for the 2018-19 summer, and the 2018-19 financial year more generally.

The expansion is in part driven by the introduction of the Retailer Reliability Obligation (RRO) requirements, which require AEMO to publish information related to the accuracy of its input, demand and supply forecasts, and information on improvements that will apply to the next ESOO.

The report validates AEMOs concerns about the deteriorating reliability of ageing coal fired power stations in the NEM, particularly in Victoria. Additionally, it highlights the impact that distributed photovoltaics (PV) can have on consumption, maximum and minimum demand and the resulting need for AEMO to have more visibility of uncontrollable rooftop PV and other distributed energy resources. Finally, it identifies areas of improvement in Victorian consumption forecasts which will be implemented prior to the 2020 ESOO.

The following table 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 intent:

🟢 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, 2018-19

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Drivers of demand	🟡	🟡	🟡	🟡	🟡	Growth in new household connections and distributed PV slower than projected in most regions.
Energy consumption	🟢	🟡	🟢	🟢	🔴	QLD above forecast due to LNG/CSG VIC below forecast due to differences not explained by variations in input assumptions
Summer maximum demand	🟢	🟡	🟢	🟢	🟢	QLD actual above forecast.
Winter maximum demand	🟢	🟡	🟢	🟢	🟡	QLD actual above forecast. VIC actual below forecast.
Annual minimum demand	🟡	🟢	🟡	🟡	🟡	Most actuals above forecast due to the overforecast of distributed PV.
Installed generation capacity	🟢	🟡	🟢	🟢	🟢	New variable renewable energy capacity installations were lower than predicted, particularly in QLD.
Summer supply availability of dominant fuel	🟢 Coal	🟢 Coal	🟢 Gas	🟢 Hydro	🟡 Coal	VIC Coal generation availability below expectation due to more forced outages than forecast.

[1] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO.

The accuracy of these forecasts are critical to ensure informed decision making by AEMO - for the RRO, Reliability and Emergency Reserve Trader (RERT) and Integrated System Plan (ISP) – and by industry and governments. In most cases, differences between forecasts and actual observations in 2018-19 can largely be explained by variations in the input assumptions. AEMO considers that the observed variations between forecast and actuals would have had minimal impact on key decisions made for 2018-19:

- In all regions except Queensland, the summer maximum demands observed were reasonably well explained by the prevailing conditions such as temperature and time of day. The impact on RRO, had it been in place before summer 2018-19, would have been negligible.
- In Queensland, summer maximum demand was higher than forecast, and supply availability was lower than expected. If the region did not currently have supply surpluses, this could have created supply scarcity risks.
- In Victoria, AEMO procured 40MW of long notice RERT over summer 2018-19. More RERT may have been procured if AEMO had predicted the higher than forecast incidence of brown coal forced outages.
- In longer term planning documents such as the ISP, uncertainties related to key inputs such as distributed PV uptake are captured through scenario analysis to understand risks and development needs.

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

- Customer connections and economic activity actuals were not well aligned with forecast, however this has not had a material impact on year ahead consumption or maximum demand forecast accuracy.
- Rooftop PV and PV non-scheduled generation (NSG) actuals were below the 2018-19 forecast, totalling 802 MW less capacity installed. This resulted in actual operational consumption and minimum demand being higher than forecast.
- Operational consumption models performed adequately considering inputs, except in Victoria, where there was an overforecast of operational consumption. All regions had a percentage error less than 4%, although in Victoria this percentage error is not well explained by variations in inputs.
- Maximum and minimum demand models performed as expected, except in Queensland, where an upward revision was required, and implemented in the 2019 ESOO. Minimum demand forecast accuracy was affected by rooftop PV and PVNSG forecasts.
- New generation installations were behind expectation, particularly in Queensland. At the end of summer there was 902 MW less variable renewable energy (VRE) installed capacity than expected in Queensland. However, this has not had a material impact on supply scarcity risk due to surplus generation supplies in the region.
- Generator forced outage rates were mostly aligned with assumptions, except for Victorian brown coal-fired generators where the recent trend of deteriorating reliability has continued, with material impacts on supply scarcity risk.
- Generator availability over the hottest periods in summer 2018-19 mostly aligned or exceeded forecast except for Victorian brown coal-fired generation.

Improvement plan

Numerous forecasting improvements and observations have been identified though this forecast performance assessment. Some of the observed differences between actuals and forecasts have affirmed changes already made to the forecast methodology for the 2019 ESOO and Draft 2020 ISP, and other relevant documents. Other differences have helped steer the direction for future improvements to be implemented for 2020 forecasts or beyond.

While a comprehensive register of proposed improvements is available in Chapter 9, the following two improvements were identified as the highest priority to be implemented for the 2020 ESOO to improve forecast accuracy in the first five years of the reliability forecast relied upon for the RRO.

Energy forecast methodology

In some regions, Victoria in particular, poor alignment was observed between the operational consumption history and forecast trends. While medium term trends were likely appropriate based on the structural drivers of the scenario being forecast, shorter term dynamics and a transition to the scenario conditions could be improved. The development of a multi-model ensemble for energy consumption forecasts is proposed per region, incorporating monthly time-series energy consumption forecasts for the next three years.

Development of multi-model ensembles was implemented within maximum and minimum demand forecasting processes in 2019, providing useful model output validation and increased confidence in the forecasts. Implementation of multi-model ensembles for energy forecasts is expected to improve year ahead forecast accuracy.

PV forecasts

Rooftop PV and PV NSG continues to be installed at a rapid rate, and discrepancies between forecast and actual uptake remains a material driver of energy and demand forecast inaccuracy. For 2019, AEMO acquired expert forecasts from multiple consultants, yet short term trends in installations and output are still problematic. AEMO intends to work closer with the Clean Energy Regulator and consultant forecasters to ensure insights and short-term trends from the DER register and cleaned historical installations are better captured.

Assessing forecast performance

Additionally, AEMO commissioned the University of Adelaide to undertake a review of its forecast accuracy metrics. This report suggested that "broadly, current AEMO practises are appropriate and well-supported"[2] and provided recommendations to improve the analysis, visualisation and communication of forecasting accuracy. Following consultation, almost all recommendations have been implemented in this report.

Early in 2020, AEMO will commence consultation on the current methodology used to assess forecast accuracy.

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 Friday 14 February 2020. Submissions should be sent by email to energy.forecasting@aemo.com.au.

In addition, AEMO will consult on the proposed methodology improvements in its January Forecasting Reference Group meeting to be held on Wednesday 29 January 2020.

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[2] 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.

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1. Stakeholder consultation process

The publication of this Forecast Accuracy Report commences consultation on the Australian Energy Market Operator's (AEMO)'s forecasting improvement plan to be implemented prior to developing its reliability forecasts to be published in AEMO's 2020 ESOO. This improvement plan has been guided by this Forecast Accuracy Report's assessment of the main contributors to forecast inaccuracies. This consultation focuses on the improvement of forecasts and forecast components only. AEMO will develop and consult on a Forecast Accuracy Report Methodology Paper during the first half of 2020.

AEMO is seeking feedback on the following questions:

- Is the forecasting improvement plan outlined in section 9 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 2020 ESOO or beyond?

AEMO values any feedback stakeholders are in a position to provide, and welcomes written submissions. Stakeholders are invited to submit written responses these questions. Submissions should be sent by email to energy.forecasting@aemo.com.au no later than Friday, 14th February 2020.

The table below outlines the steps AEMO will be undertaking to consult on the improvement plan summarised in this Forecast Accuracy Report. The level of consultation will be equivalent to the short-form written consultation with a single round of written submissions, as outlined in Appendix A of the Interim Reliability Forecasting Guidelines[3].

Table 2 Consultation timeline

Consultation steps	Dates
Forecast Accuracy Report and Improvement plan published	Thursday 19 December 2019
Forecasting Reference Group discussion	Wednesday 29 January 2020
Submissions due on Improvement plan	Friday, 14 February 2020
Final methodology improvements updated and published in existing methodology documents along with a Submission Response document	August 2020

AEMO is also currently consulting on inputs and assumptions for AEMO's 2020 forecasting and planning publications, including:

- Changes required to key inputs and assumptions used in AEMO's 2019 NEM planning and forecasting publications that affect AEMO's supply and demand forecasting models.
- CSIRO's latest 2019-20 GenCost draft which provides an annual update to generation technology costs.

For further details on that consultation, please visit AEMO's website[4].

[3] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Interim-reliability-forecast-guidelines/Draft-Interim-Reliability-Forecast-guidelines.pdf

[4] https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2020-Planning-and-Forecasting-Consultation-on-scenarios-inputs-and-assumptions

2. Introduction

Each year, AEMO assesses the accuracy of its electricity demand and consumption forecasts to help inform its continuous improvement plan and build confidence in the forecasts produced. As part of the Retailer Reliability Obligation (RRO) requirements, outlined in 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).

To meet this requirement, AEMO has prepared this forecast accuracy report over a broader set of demand, supply, and reliability forecast components. This assessment primarily reviews the accuracy of the 2018 ESOO for each region of the National Electricity Market (NEM).

Specifically, this 2019 Forecast Accuracy Report assesses the accuracy of:

- The demand and supply forecasts in AEMO's 2018 NEM ESOO[5] and related products, for each region in the NEM.
- Forecast components from earlier forecasts, where 2019 actuals are not yet available.
- Some demand and supply elements contributing to AEMO's Integrated System Plan (ISP)[6].

In preparation for this forecast accuracy report, AEMO commissioned the University of Adelaide to undertake a review of its forecast accuracy metrics. This report suggested that "broadly, current AEMO practises are appropriate and well-supported"[7] and provided 14 recommendations to improve the analysis, visualisation and communication of forecasting accuracy. Some of the recommendations relate to AEMO's internal accuracy assessment process. All recommendations that relate to the external presentation of forecast accuracy metrics were presented for discussion to the Forecast Reference Group (FRG). Subsequently, almost all recommendations have been implemented in this report.

Alongside the assessment of accuracy, AEMO has provided commentary on the adequacy of forecasting processes. Numerous improvements and observations have been identified. Some of the observed differences between actuals and forecasts have affirmed changes already made to the forecast methodology for the 2019 ESOO, 2020 ISP and other relevant documents. Other differences have helped steer the direction for future improvements to be implemented for 2020 forecasts or beyond.

2.1 Definitions

In this report, all forecasts are reported on a "sent out" basis unless otherwise noted. Terms used in this report are defined in the glossary. To assess demand forecasting performance, historical operational demand "as generated" (OPGEN) is converted to "sent-out" (OPSO) based on estimates of auxiliary load, or 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. Figure 1 shows the demand definitions used in this document.

For consistency, data and methodologies of actuals are the same as those used for the corresponding forecasts in the 2018 ESOO. This means:

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[5] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO.

[6] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[7] 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.

- All times mentioned are NEM time – Australian Eastern Standard Time (UTC+10) – not local times.
- 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.
- This report uses a definition of auxiliary load consistent with the 2018 NEM ESOO. This definition may result in variations from estimates published in 2017 and before.

Figure 1 Demand definitions used in this document

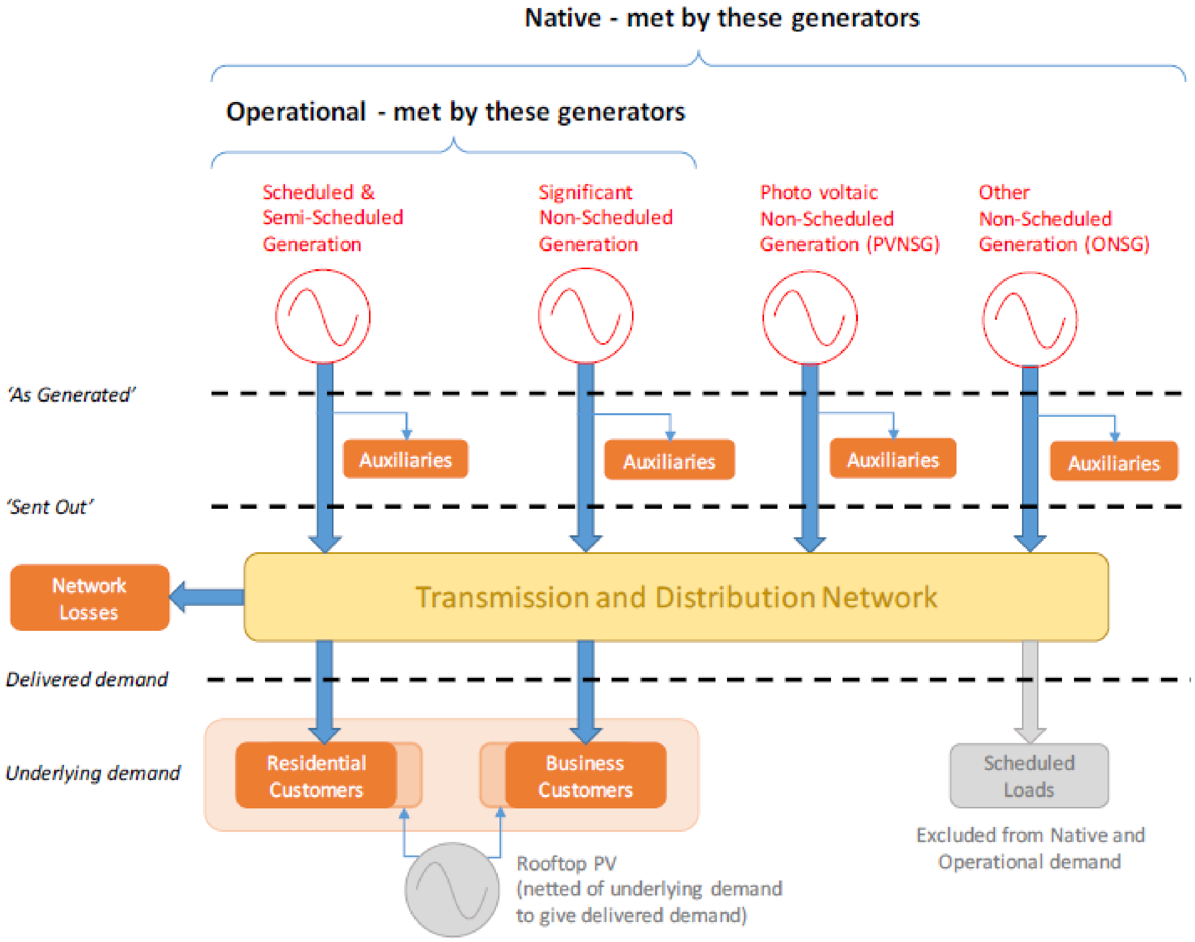
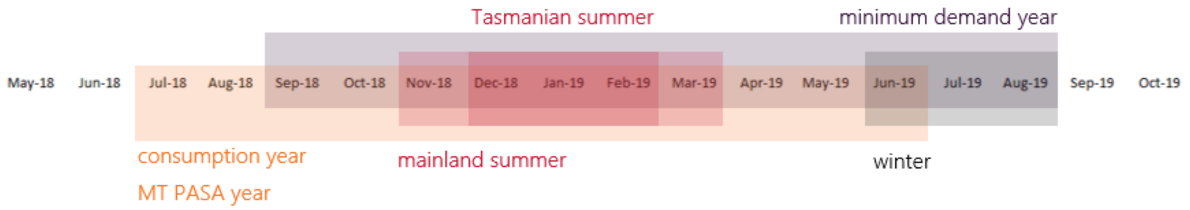


Figure 2 Seasonal definitions used in this document



3. Trends in demand drivers

Electricity forecasts are predicated on a wide selection of inputs, drivers, and assumptions. Demand models incorporate numerous forecast components, including:

- Economic growth and population.
- Rooftop photovoltaic (PV) and behind-the-meter batteries.
- Energy efficiency and appliance mix.
- Electric vehicles (EVs).

The 2018 NEM ESOO laid out 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. Three scenarios were therefore proposed to capture and test possible pathways: Slow Change, Neutral, and Fast Change. Not all input variables are measured regularly, or have material impacts on year ahead outcomes. For example, rooftop 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 chapter.

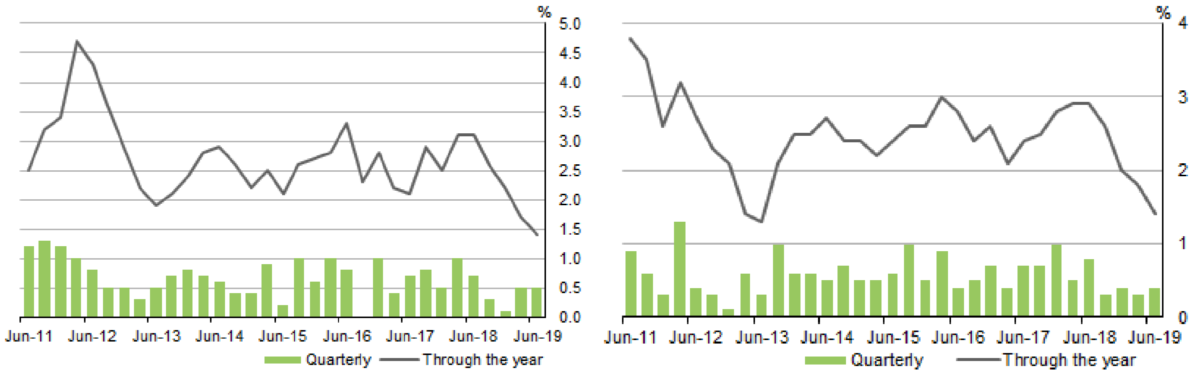
3.1 Macroeconomic conditions

There are numerous macroeconomic conditions that form the basis of the scenario forecasts. The 2018 NEM ESOO Neutral scenario incorporated consultant forecasts of 2.4% p.a. average real growth in Gross State Product (GSP) for the first five years, with Household Disposable Income (HDI) experiencing minimal growth as a result of stagnating wages and soft consumer confidence. Actual growth in economic activity fell below the assumption, as represented by the low growth in Gross Domestic Product (GDP) shown in Figure 3[8]. All things being equal, slower economic growth would lead to lower demand than forecast. The very low growth in household final consumption expenditure, was in line with the 2018 ESOO assumptions.

Figure 3 Macroeconomic growth rates

Gross domestic product

Household final consumption expenditure



[8] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2019, at https://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/5206.0Main%20Features2Jun%202019?opendocument&tabname=Summary&prodno=5206.0&issue=Jun%202019&num=&view=. Accessed 4 October 2019.

Population is another main driver of electricity demand, directly affecting the number of residential and non-residential connections. The 2018 NEM ESOO forecast residential connections as a function of population, taking dwelling and population forecasts from the Housing Industry Association (HIA) and the Australian Bureau of Statistics (ABS). Non-residential connections were forecast as a function of economic growth and population.

Table 3 shows the residential connection growth for 2018-19 sourced from AEMO Market Settlement and Transfer Solutions (MSATS) database via monthly snapshots, against the three 2018 ESOO scenarios.

Table 3 Forecast and actual residential connections growth rate comparison, 2018-19 (%)

	NSW	QLD	SA	TAS	VIC
Actual (Jun18-Jun19)	1.4%	1.4%	1.0%	1.2%	1.9%
Slow Change scenario	1.6%	1.5%	1.2%	0.7%	1.7%
Neutral scenario	1.8%	1.7%	1.3%	0.8%	1.9%
Fast Change scenario	2.0%	1.9%	1.5%	0.9%	2.1%

As the table shows, actual connections growth over 2018-19 was mostly lower than the range of scenario forecasts, except in the case of Victoria, which grew as expected and Tasmania which grew above forecast. The inaccuracy is driven by the assumptions applied in the HIA and ABS forecasts. The MSATS data available to AEMO now has five or more years of history for all regions, so a new connections model is now under development that incorporates greater visibility and consideration for the history and dwelling type characteristics. AEMO is also anticipating new information from the ABS that may inform more accurate short-term forecasts.

3.2 Rooftop PV and PV non-scheduled generation

The 2018 ESOO forecast rapid rates of PV system installation, a revision upwards from previous forecast trajectories. The forecast provided by CSIRO assumed a short term rise in installations, which would slow in the medium term as conditions for installation became less favourable. Both PV and PV non-scheduled generation (PVNSG) actuals are not known precisely and are subject to revision. In this case, both estimates of the history have been revised downwards due to the availability of better information.

Figure 4 shows the forecast for the 2018 ESOO and compares it with recently revised actuals.

Table 4 compares the forecast for June 2019 from the 2018 ESOO with recently revised estimates of actuals. These actuals are estimated from installation data provided by the Clean Energy Regulator, cleaned and de-rated by AEMO to reflect the average age of systems, and system replacements. Actuals have been further cleaned in 2019, removing systems that are located near, yet not connected to the NEM.

Figure 4 NEM rooftop PV and PVNSG installed capacity comparison, 2016-20

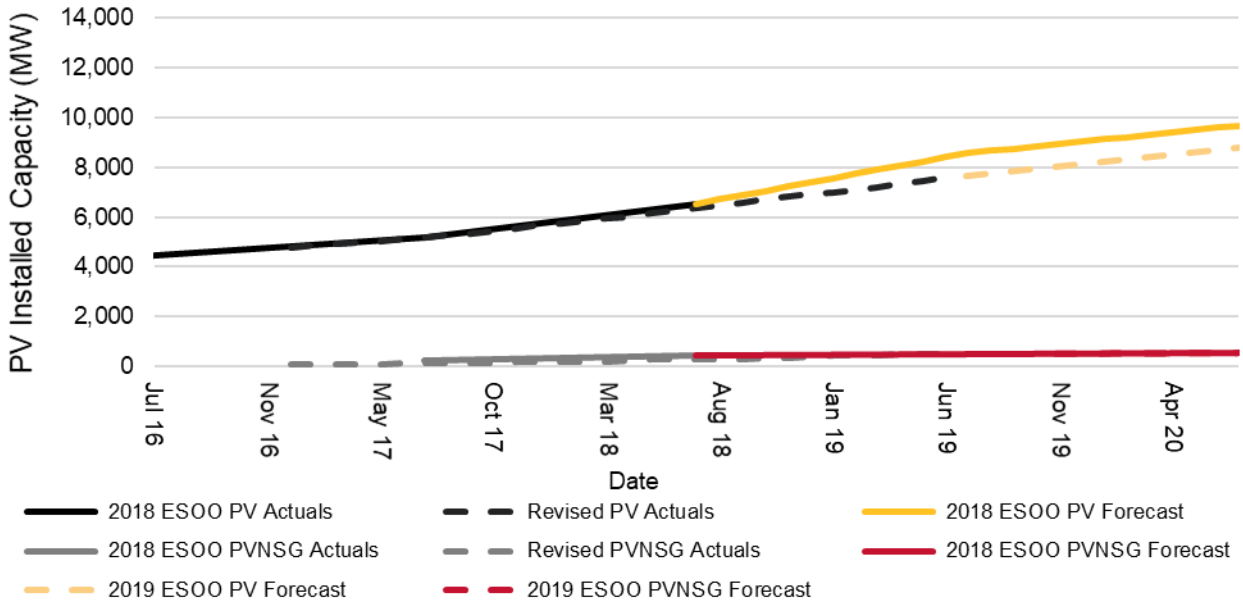


Table 4 Rooftop PV and PVNSG installed capacity comparison by region. June 2019. (MW)

June 2019	NSW	QLD	SA	TAS	VIC
PV Actual (MW)	2,112	2,560	1,071	141	1,684
PV Forecast (MW)	2,546	2,583	1,118	177	1,966
PV Difference (%)	-17%	-1%	-4%	-20%	-14%
PVNSG Actual (MW)	152	181	72	2	99
PVNSG Forecast (MW)	182	153	56	8	87
PVNSG Difference (%)	-17%	18%	27%	-76%	14%

While in aggregate PV installations were over forecast, there are regional differences, with the largest over forecast in New South Wales and Tasmania. PV NSG has greater differences between regions, where actuals exceed forecast in Queensland, South Australia and Victoria, while actuals in Tasmania and New South Wales do not.

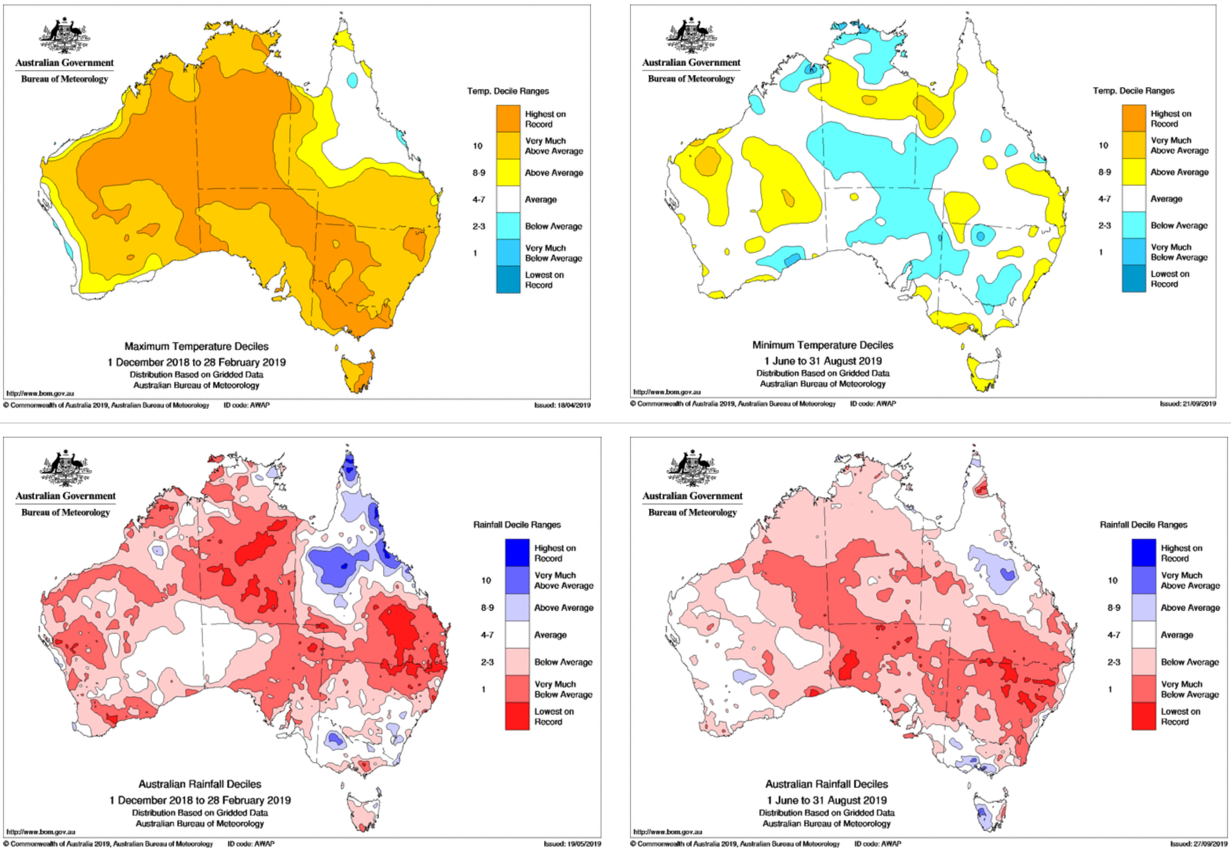
As installed PV capacity is negatively correlated with operational consumption, maximum and minimum demand, lower PV uptake may produce higher operational consumption and demand than otherwise forecast. The PV forecasts in the 2019 ESOO were revised downward as shown in Figure 4.

3.3 Weather and climate

Both customer demand and system supply are highly responsive to weather, which will change over time given expected changes in climate. The 2018 ESOO considered the effect of future climate change in forecasting electricity consumption and demand, while impacts on supply will be considered in future ESOO and ISP publications. The Bureau of Meteorology's summary reports about weather in 2018-19 summer[9] and 2019 winter[10] include the following comments and charts:

Figure 5 Bureau of Meteorology seasonal summaries

Summer 2018-19	Winter 2019
Australia's warmest summer on record, breaking records by almost one degree. Exceptional heatwaves occurred across much of Australia during December and January Significant fires affected eastern Queensland, large parts of Tasmania, eastern Victoria, north-eastern New South Wales, and south west Western Australia Rainfall was below to very much below average across most of Australia	Warmer than average winter for Australia Mean maximum temperatures were warmer than average for winter over most of Australia; with the sixth-warmest winter days on record nationally. Minimum temperatures were mixed across the country A cold night in June saw some of the lowest winter temperatures on record in South Australia Rainfall below average for most of Australia



Demand forecasting processes are not fitted to a specific weather prediction, but instead simulate many weather years around a long-term climate trend. Simulated weather years include short, medium and long term trends: such as seasonal variability, El Nino/La Nina, and climate change. Temperature and heat waves are not the only factors that contribute to maximum demand. However, given high temperatures are positively correlated with summer electricity demand, the hot summer in 2018-19 produced higher average demand than expectation for numerous regions. Additionally, low temperatures are negatively correlated with

[9] Bureau of Meteorology, Australia in summer 2018-19, at www.bom.gov.au/climate/current/season/aus/archive/201902.summary.shtml.

[10] Bureau of Meteorology, Australia in winter 2019, at www.bom.gov.au/climate/current/season/aus/archive/201908.summary.shtml.

high winter electricity demand, so the mixed winter resulted in mixed winter maximum demand outcomes (see section 5 for more details).

3.4 Network losses

Estimates of distribution and transmission network losses are taken from Regulatory Information Notices (RIN) submitted to the Australian Energy Regulator (AER) from relevant network service providers. Numerous RINs were published subsequent to the 2018 ESOO. As such, updated estimates of network losses vary from those forecast. The list of assumed and updated loss factors is shown in Table 5.

Table 5 Estimated network loss factors

	Transmission Loss Factor		Distribution Loss Factor	
	Applied to 2018 forecast	Estimated actual for 2018-19	Applied to 2018 forecast	Estimated actual for 2018-19
New South Wales	2.21%	2.29%	4.49%	4.63%
Queensland	2.52%	2.58%	4.50%	4.80%
South Australia	3.26%	2.62%	7.53%	6.57%
Tasmania	2.97%	2.43%	3.98%	5.31%
Victoria	2.62%	2.62%	4.81%	5.12%

Among the regions, the loss factor revision was largest for South Australia, where both transmission and distribution loss factors were revised downward. The impact of this revision is evident in South Australian energy consumption and demand results. Queensland, Victoria and New South Wales factors were revised upwards marginally, while Tasmanian revisions were downward for transmission and upward for distribution, somewhat cancelling each other out. Network losses directly contribute to operational demand, meaning higher rates should result in higher demand, all other things being equal.

3.5 Residential business split

The residential and business (distribution connected) consumption split is informed by the Australian Energy Regulator (AER) reported actuals from each jurisdiction's Distribution Network Service Providers (DNSPs). The split is used to identify the portions of the historical data series attributable to each customer type for independent forecasting. As such, revisions over time adjust the historical series, and may result in forecast inaccuracy.

The data is usually provided to AEMO in the first quarter of the calendar year for publishing in the subsequent year's ESOO. The timing of receipt of this historical information prohibits up-to-date forecast accuracy assessments. For example, the latest historical residential and business consumption split available to AEMO is for the 2016-17 financial year, so accuracy of AEMO's forecasts for these components need to be assessed by comparing against the ESOO 2017, as this was the last ESOO to forecast the 2016-17 year.

Presented below is the residential and business distribution consumption split from data provided by the AER in 2017 (to inform the first year of the ESOO 2017) would be based on the complete 2015-16 data for all regions except Victoria which is instead based on the 2016 calendar year. In 2018, the AER provided an update to the business and residential split that contained the full 2016-17 data which shows a slight variation from what was assumed. Some of the variation is likely due to weather variations (which the residential sector consumption is more sensitive to), and some of the variation will also be due to usage changes in the relativity in each sector. However, there is a general stability in the year-to-year variation, with values differing only by 1% to 2%.

Table 6 Calculations for the business and residential split

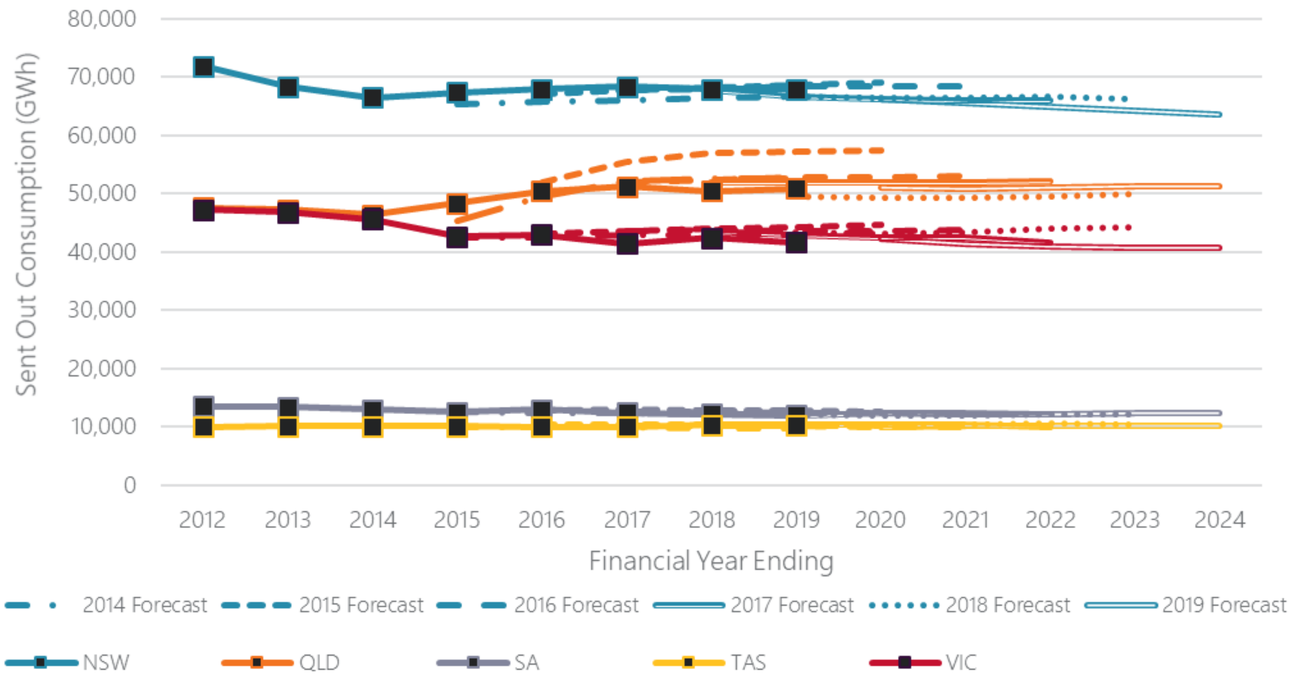
	Values used in ESOO 2017 for 2016-17		Actual Values for 2016-17	
	Residential %	Non-residential %	Residential %	Non-residential %
New South Wales	42%	58%	44%	56%
Queensland	48%	52%	48%	52%
South Australia	46%	54%	47%	53%
Tasmania	55%	45%	57%	43%
Victoria	40%	60%	41%	59%

Given the relatively gradual change in energy consumption composition over time, residential business split modelling is unlikely to result in radically different energy forecasts. The variations observed for 2016-17 are not expected to result in material impacts on energy consumption forecast accuracy.

4. Operational energy consumption forecasts

AEMO forecasts annual operational energy consumption by region, on a financial year basis, each for three scenarios. Figure 6 shows the 2014-19 central forecasts for each region relative to history. Most recent forecasts have been somewhat similar; however, the 2018 and 2019 forecast show lower trends compared to earlier years.

Figure 6 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:

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

This calculation of percentage error varies from previous forecast accuracy reports (which used '*actual*' as the denominator) however provides a clearer interpretation of the difference. For example, a percentage error of -20% implies the actual is 20% lower than forecast.

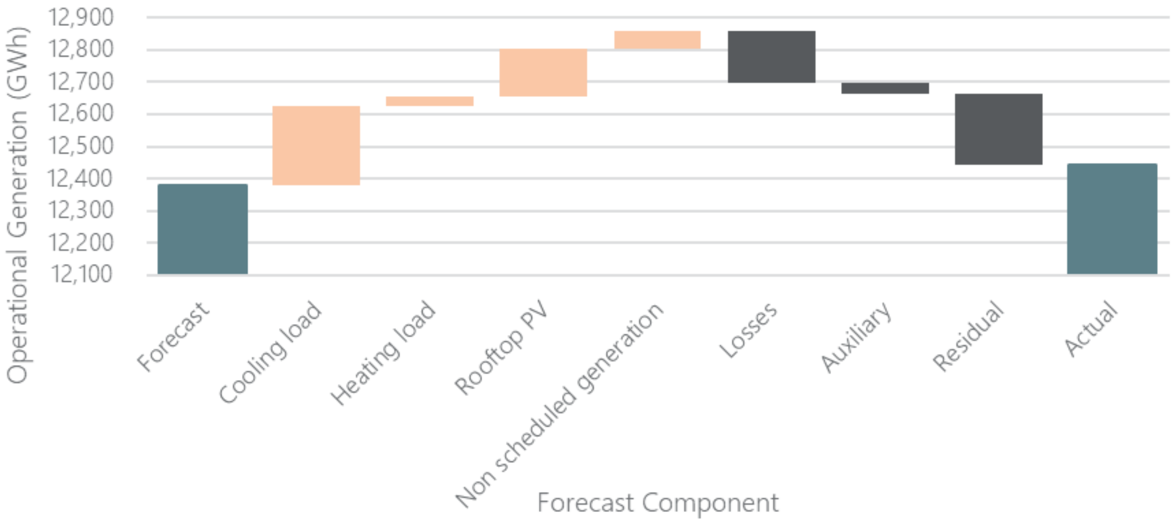
Table 7 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using this new percentage error calculation. In the last four years, all regions have a percentage error less than 5%. For some regions, the one year ahead forecasting performance has improved over time, while in others the error has increased.

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

One-year ahead annual operational consumption accuracy (%)	2014 NEFR forecast in 2014-15	2015 NEFR forecast in 2015-16	2016 NEFR forecast in 2016-17	2017 ESOO forecast in 2017-18	2018 ESOO forecast in 2018-19
New South Wales	3.2%	1.2%	0.8%	0.1%	1.8%
South Australia	-0.2%	1.6%	-1.6%	0.8%	0.8%
Tasmania	2.3%	-3.5%	-2.4%	0.1%	-1.3%
Queensland	6.7%	-2.6%	-1.6%	-2.8%	3.1%
Victoria	0.3%	-0.5%	-5.0%	-2.5%	-3.7%

To better decompose the drivers of variance, AEMO is reporting the contribution of each input driver to the difference between forecast and actual energy consumption. This analysis assumes that all inputs are independent and have an additive relationship with consumption. Figure 7 shows the South Australia energy consumption component variance chart with commentary to demonstrate interpretation.

Figure 7 Example operational energy consumption component variance chart, South Australia



The annual energy consumption forecast (12,379 gigawatt hours [GWh]) is shown as the first bar in the waterfall chart, while the actual energy consumption for 2018-19 (12,441 GWh) is shown as the last bar, a value that is 0.5% higher than forecast. The bars in between indicate the component contribution to the difference between forecast and actual values, where light orange represents a positive impact, and charcoal represents a negative impact. The residual captures all difference not explainable by the identified input components.

In this example, there are positive contributions from cooling load, heating load, rooftop PV and non-scheduled generation, and a negative contribution from losses and auxiliary. Any difference between forecast and actual bars that is attributable to these variables is best resolved through examination of the input forecasts. Forecast differences that can not be explained by the components and fall in to the residual may be caused by input variables that can not be measured, or by the energy consumption model itself. In this example, the small positive residual implies that, given observed inputs, the forecast model would have expected an actual that was slightly higher (closer to 12,650 GWh) and a small downward revision in forecast may be considered alongside input forecast updates for future ESOOs.

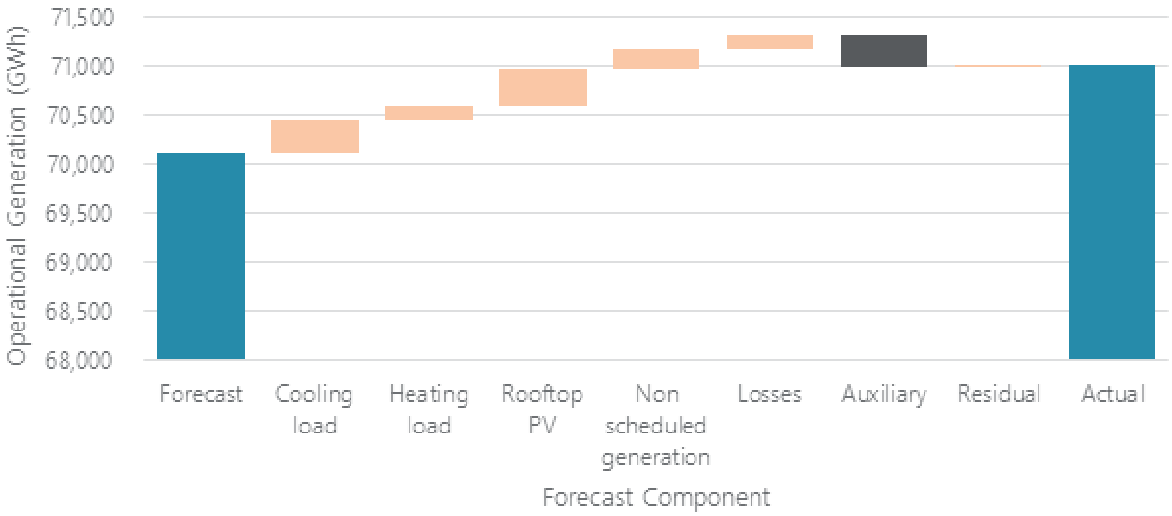
4.1 New South Wales

Operational energy consumption for New South Wales in 2018-19 was slightly above the neutral forecast by 1.8%. Table 8 and Figure 8 demonstrate the forecast accuracy by component. Both summer cooling degree days and winter heating degree days exceeded expectation which contributed to the higher than forecast consumption. The remainder of the difference is explained by an under-forecast of network losses and over-forecast of PV and NSG. Subject to input variable correction, the model for New South Wales has performed well.

Table 8 New South Wales operational energy consumption forecast accuracy by component

Category	2018 neutral forecast	Actual	Difference (%)	Indicative impact on operational consumption
Cooling degree days	442	522	+18.3%	+0.5%
Heating degree days	625	652	+4.4%	+0.2%
Rooftop PV (GWh)	3,006	2,621	-12.8%	+0.5%
Small non-scheduled generation (GWh)	2,097	1,888	-10.0%	+0.3%
Network losses (GWh)	4,083	4,215	+3.2%	+0.2%
Operational sent out (GWh)	66,705	67,938	+1.8%	+1.8%
Auxiliary load (GWh)	3,418	3,105	-9.2%	-0.4%
Operational as generated (GWh)	70,123	71,004	+1.3%	

Figure 8 New South Wales operational energy consumption variance by component



4.2 Queensland

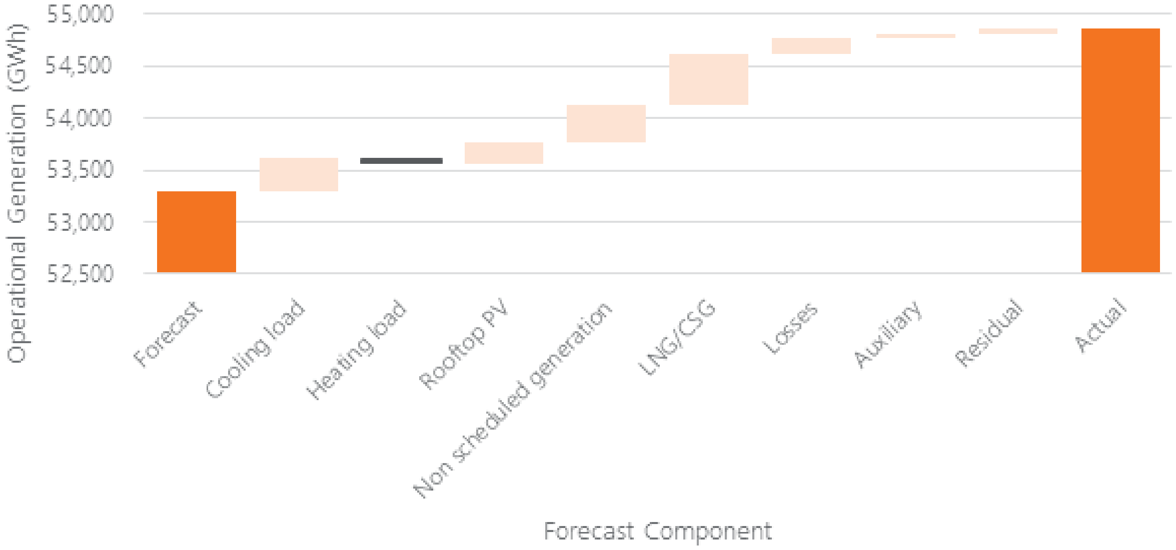
Operational energy consumption for Queensland in 2018-19 was above the neutral forecast by 3.1%. Table 9 and Figure 9 demonstrate the forecast accuracy by component. Both summer cooling degree days and winter heating degree days exceeded expectation which contributed to higher observed consumption. Consumption from the Liquified Natural Gas and Coal Seam Gas sector (LNG/CSG), which was forecast separately in

Queensland substantially exceeded expectation. Observed weather variations and over forecast of PV and NSG, explain about half of the difference between forecast and actual operational consumption, with LNG/CSG explaining the other half. Subject to input variable correction, the model for Queensland has performed well.

Table 9 Queensland operational energy consumption forecast accuracy by component

Category	2018 neutral forecast	Actual	Difference (%)	Indicative impact on operational consumption
Cooling degree days	724	793	+9.5%	0.6%
Heating degree days	219	195	-11.1%	-0.1%
Rooftop PV (GWh)	3,571	3,373	-5.6%	+0.4%
Small non-scheduled generation (GWh)	2,451	2,083	-15.0%	+0.7%
Network losses (GWh)	2,784	2,933	+5.4%	+0.3%
LNG/CSG consumption (GWh)	5,739	6,217	+8.3%	+0.9%
Operational sent out (GWh)	49,422	50,935	+3.1%	+2.8%
Auxiliary load (GWh)	3,880	3,929	+1.3%	+0.1%
Operational as generated (GWh)	53,302	54,863	+2.9%	

Figure 9 Queensland operational energy consumption variance by component



4.3 South Australia

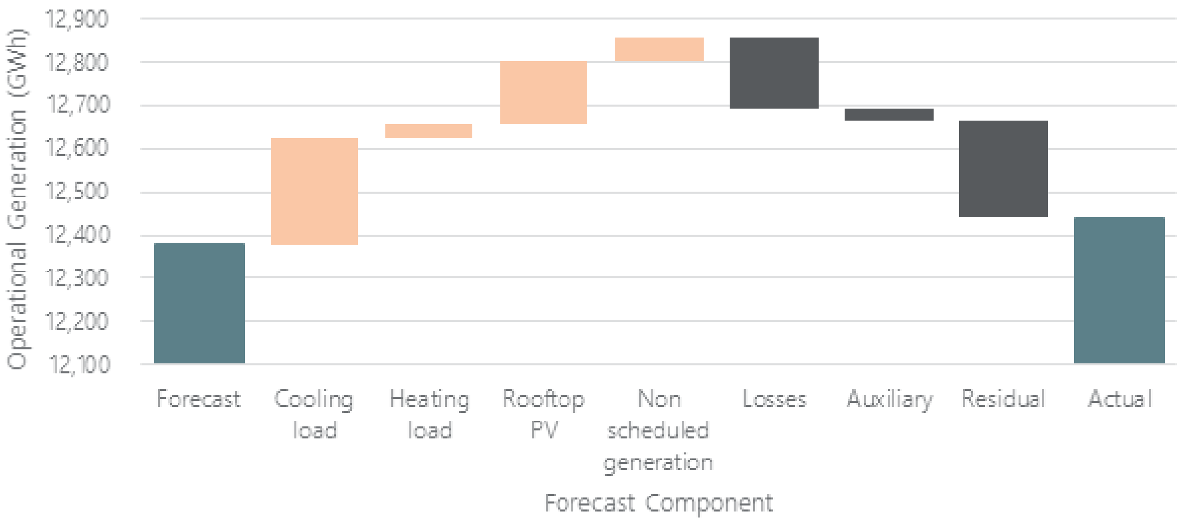
Operational energy consumption for South Australia in 2018-19 was above the neutral forecast by 0.8%. Table 10 and Figure 10 demonstrate the forecast accuracy by component. Summer cooling degree days significantly exceeded expectation, while winter heating degree days did not reach forecast. Combined, the observed weather should result in higher consumption. The observed weather and over forecast of PV and NSG, contributed to higher than forecast operational consumption, while the adjustment of the loss rate (discussed in 3.4), has the opposite effect of lowering actual operational consumption compared to forecast.

Actual operational energy consumption was 0.8% above forecast, however, due to the various input components serving to impact consumption in opposing directions, the net result masks the full impact of any model error. The size of the negative residual in Figure 10 indicates that, if all inputs were known with certainty ahead of time, the model would have slightly over-forecast operational consumption by 1.8%.

Table 10 South Australia operational energy consumption forecast accuracy by component

Category	2018 neutral forecast	Actual	Difference (%)	Indicative impact on operational consumption
Cooling degree days	436	685	+57.0%	+2.0%
Heating degree days	725	659	-9.0%	+0.2%[11]
Rooftop PV (GWh)	1,523	1,374	-9.8%	+1.2%
Small non-scheduled generation (GWh)	228	173	-24.1%	+0.4%
Network losses (GWh)	1,131	967	-14.5%	-1.3%
Operational sent out (GWh)	12,053	12,147	+0.8%	+0.8%
Auxiliary load (GWh)	326	294	-9.6%	-0.3%
Operational as generated (GWh)	12,379	12,441	+0.5%	

Figure 10 South Australia operational energy consumption variance by component



4.4 Tasmania

Operational energy consumption for Tasmania was quite close to forecast in 2018-19, with actual consumption 1.3% below the neutral forecast. Table 11 and Figure 11 demonstrate the forecast accuracy by

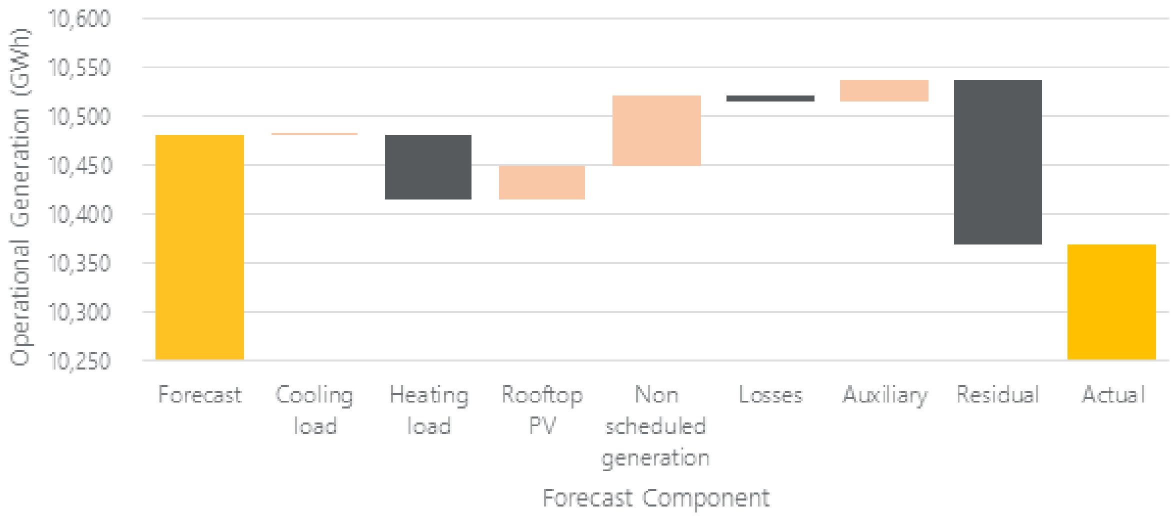
[11] Despite reduced heating load for residential customers, heating related business variance was positive and greater.

component. Summer cooling degree days slightly exceeded expectation, while winter heating degree days fell slightly below forecast. Actual operational consumption was 1.3% below the neutral forecast. This difference is minimal, but is masked by the impact of the over forecast of rooftop PV and NSG. The size of the negative residual in Figure 11 indicates that, if all inputs were known with certainty ahead of time, the model would have slightly over-forecast operational consumption by 1.4%.

Table 11 Tasmania operational energy consumption forecast accuracy by component

Category	2018 neutral forecast	Actual	Difference (%)	Indicative impact on operational consumption
Cooling degree days	38	45	+18.9%	0.0%
Heating degree days	1,287	1,225	-4.8%	-0.6%
Rooftop PV (GWh)	196	161	-18.1%	+0.3%
Small non-scheduled generation (GWh)	458	388	-15.4%	+0.7%
Network losses (GWh)	495	490	-1.0%	-0.0%
Operational sent out (GWh)	10,388	10,254	-1.3%	-1.3%
Auxiliary load (GWh)	93	116	+24.2%	+0.2%
Operational as generated (GWh)	10,481	10,363	-1.1%	

Figure 11 Tasmania energy consumption variance by component



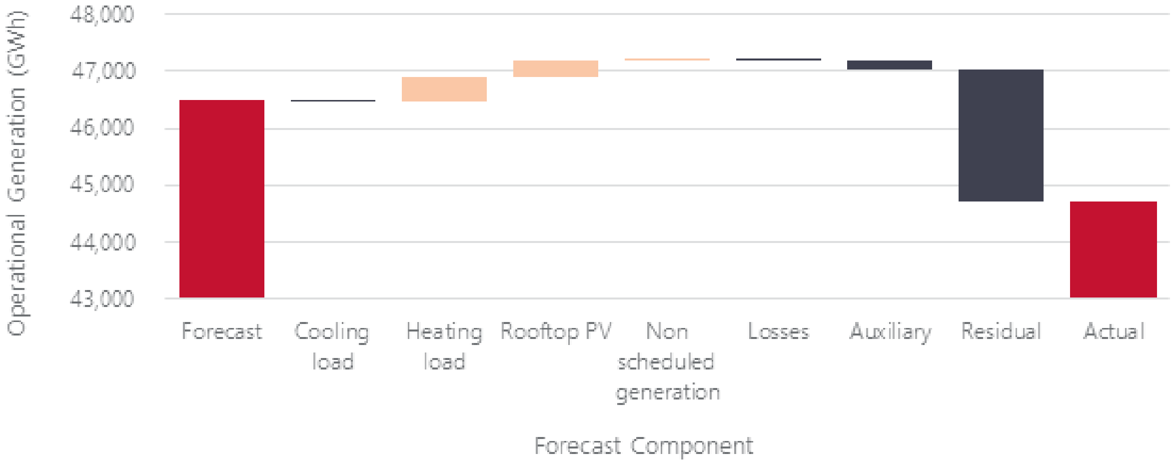
4.5 Victoria

Operational energy consumption for Victoria in 2018-19 was below the neutral forecast by 3.7%. Table 12 and Figure 12 demonstrate the forecast accuracy by component. While summer cooling degree days were slightly below expectation, heating degree days were above expectation, which should result in higher consumption overall. Despite the weather driven factors, the actual was below forecast. The negative residual shown in Figure 12 is equivalent to a 5.0% forecast error which cannot be attributed to any currently measurable input variable. Forecast process improvements are proposed to improve accuracy based on this result. See section 9 for more details.

Table 12 Victoria operational energy consumption forecast accuracy by component

Category	2018 neutral forecast	Actual	Difference (%)	Indicative impact on operational consumption
Cooling degree days	441	423	-4.0%	-0.0%
Heating degree days	646	844	+30.6%	+0.9%
Rooftop PV (GWh)	2,234	1,944	-13.0%	+0.6%
Small non-scheduled generation (GWh)	1,136	1,109	-2.4%	+0.1%
Network losses (GWh)	2,967	2,944	-0.8%	-0.1%
Operational sent out (GWh)	43,303	41,689	-3.7%	-3.5%
Auxiliary load (GWh)	3,192	3,020	-5.4%	-0.4%
Operational as generated (GWh)	46,495	44,709	-3.8%	

Figure 12 Victoria operational energy consumption forecast 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.

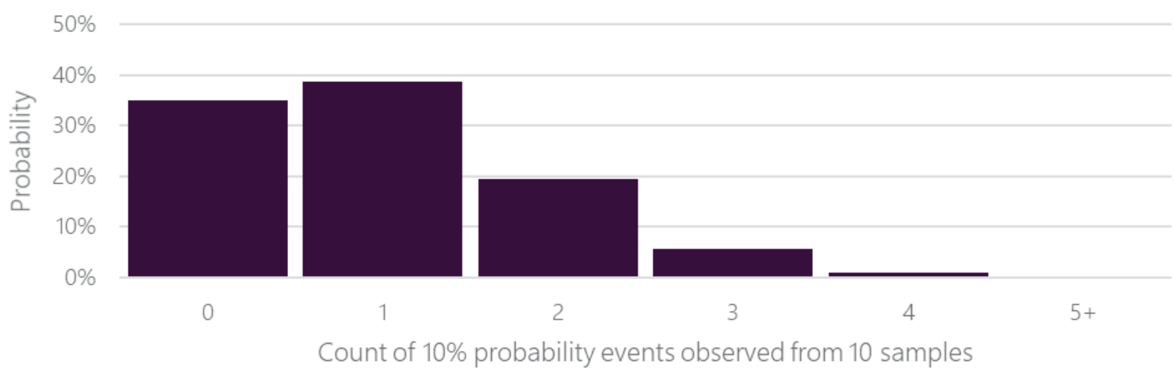
Maximum demand events are driven by coincident appliance use, typically in response to extreme heat or cold. Minimum demand events typically occur with extremely mild weather, sometimes overnight when customer demand is low, and sometimes during the day when rooftop PV is offsetting consumption.

Unlike the consumption forecast, which is a point forecast (single value), the minimum or maximum demand forecast is represented by a distribution of possible outcomes and probabilities. The distribution of possible minimum or maximum demand outcomes is represented by the published 10%, 50%, and 90% probability of exceedance (POE) forecasts.

These POE forecasts can be challenging to evaluate, due to the very low sampling, that is, only one event per year. A 10% POE forecast should be exceeded one in every 10 years; however, hundreds of years would need to pass before this could be proven reliably. This is no different from a coin toss – the coin should land on heads one in every two tosses, but it takes many tosses of a coin to reliably observe this.

Assuming 10 years of available history (10 samples), Figure 13 shows the number of 10% probability observations that should be expected. It implies that with 10 years of history, there is less than 40% probability that exactly one year will be a 10% POE or greater outcome.

Figure 13 Number of 10% probability events expected from 10 samples

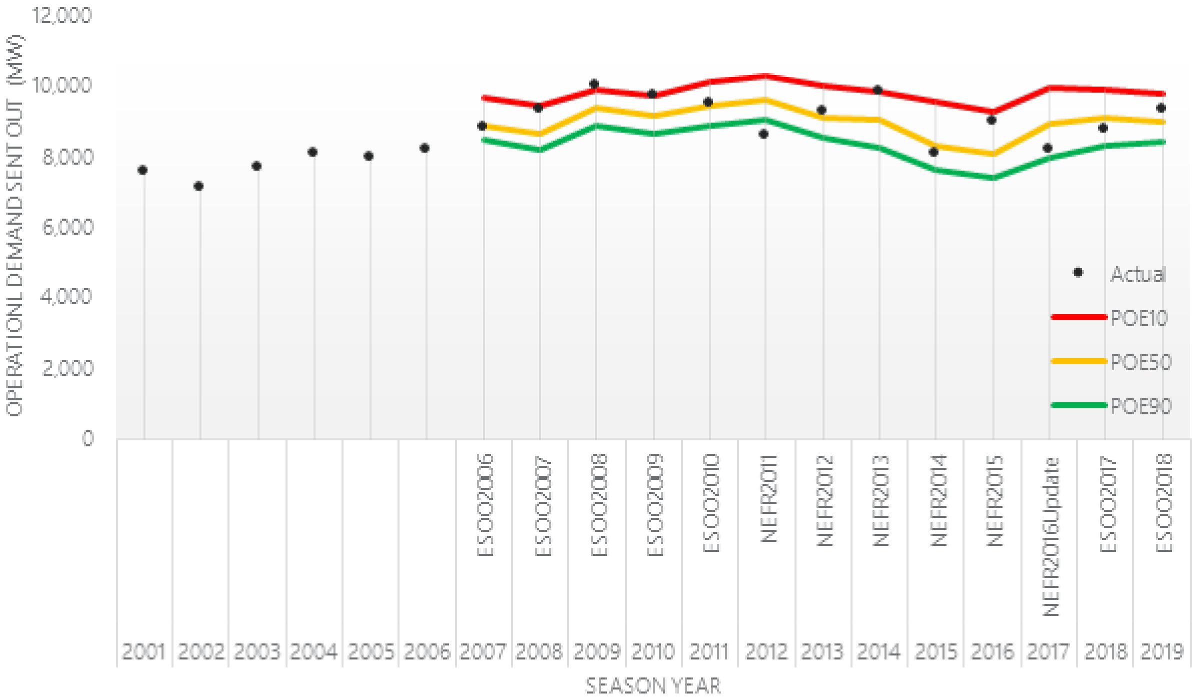


Based on expert advice from academia, AEMO has discontinued the backcast metric which was presented in the 2018 Forecasting Accuracy Report. The University of Adelaide advised AEMO that backcasting was an inappropriate metric for assessing an interval forecast and an extreme value forecast where minimums and maximums are inherently at the extreme end of the distribution. They instead recommended assessing the forecasts across a longer-term horizon by simulating history and comparing the actuals within the simulation of history (a visualisation similar to Figure 14 below). They also cautioned that assessing the simulation of history on a limited number of data points is difficult due to the reasons stated above.

Figure 14 provides an example of comparing a forecast distribution against a longer timeseries of data to sense check the forecast accuracy. It shows Victoria's one-step-ahead maximum demand forecast from each publication back to 2006 compared against unadjusted historical actuals (actuals adjusted for RERT, DSP and load shedding will be higher than actuals reported below). AEMO took on the role of forecasting maximum demand for NEM regions from 2010 onwards, and the sophistication of its model has improved since then as access to input data has improved. This analysis is therefore not truly a re-simulation of history using the current maximum demand model, but still provides a useful insights into the reasonableness of the maximum demand distributions forecast in previous ESOOs.

The figure shows that roughly 60% of actuals exceed the 50% POE out of the 13 observations, and roughly three observations or 20% of actuals are equal to or greater than the 10% POE. As stated above, it is difficult to draw a conclusion based on the limited number of observed actuals however the distribution and one-step-ahead forecasts appears to be performing well.

Figure 14 Victoria's historical one-step-ahead demand forecasts against unadjusted historical actuals

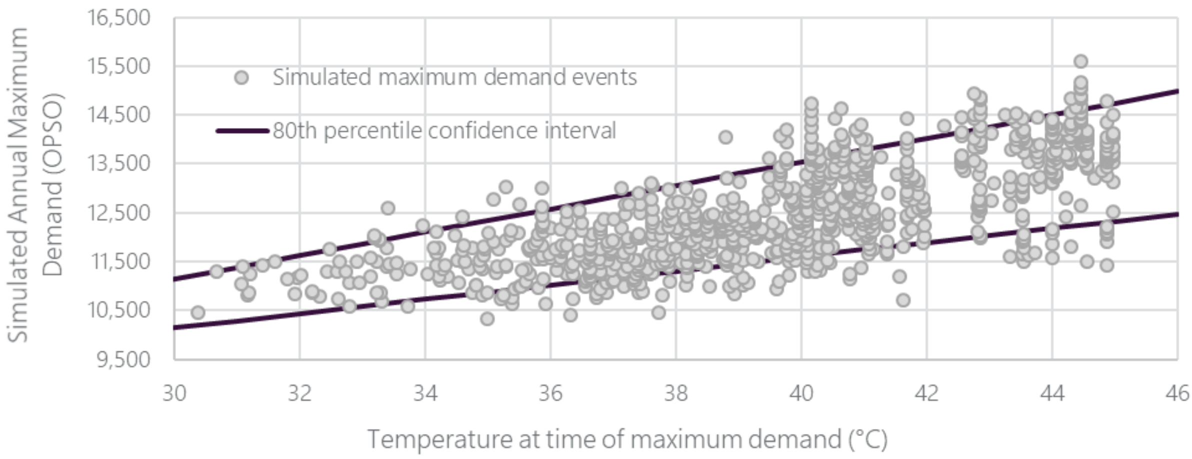


Probability distributions of demand extremes aim to capture a variety of random drivers including weather driven coincident customer behaviour and non-weather driven coincident behaviour. Non-weather driven coincident customer behaviour is driven by a wide variety of random factors including:

- Work and school schedules, traffic and social norms around meal times.
- 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. Figure 15 shows the simulated relationship between temperature and maximum demand for New South Wales from the 2018 ESOO.

Figure 15 2018 ESOO simulated relationship between temperature and maximum demand for New South Wales in 2019

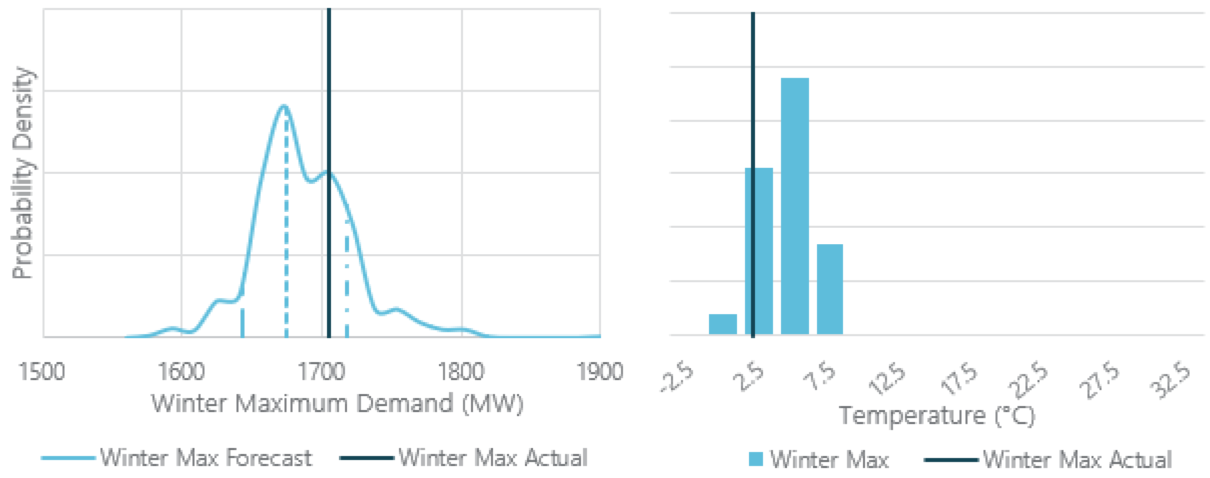


The figure indicates that, even in the presence of a 45 degrees Celsius (°C) temperature, maximum demand was forecast between 11,500 MW and 15,500 MW. This phenomenon of demand having a wide variation for given temperature values can also be seen in the below sections for each of the regions. Figure 20 in Section 5.2 shows a weekday maximum temperature event of 37°C with 13 GW of demand recorded in New South Wales while at the same temperature there is another maximum demand event of 11 GW.

To better elucidate model performance in the presence of this variance, AEMO is now reporting 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[12]. Simulation output was not retained in the development of the 2018 ESOO once POE estimates were identified. AEMO has subsequently run 1,000 new simulations using the same models for the purposes of this report. Small variations will occur between the original and new simulation outputs.

Figure 16 shows the Tasmanian 2019 winter maximum demand forecast, with commentary below to aid interpretation.

Figure 16 Example extreme event and probabilistic driver



[12] 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.

The probability density for winter maximum demand is shown on the left, indicating that winter maximum demand events are forecast to occur anywhere between 1,560 MW and 1,820 MW with varying probability. Relevant probabilities of exceedance thresholds are identified with dotted lines [90% POE: 1,642 MW, 50% POE: 1,675 MW, 10% POE: 1,717 MW]. The actual winter maximum was 1,704 MW, a result towards the upper end of the distribution.

The expected temperature at time of simulated winter maximum is shown on the right, ranging from -1.25 to 11.25 °C. It indicates that winter maximum demand is most likely to occur at a temperature of approximately 5°C. The observed temperature at time of actual winter maximum was 2.2°C, a temperature that would involve greater use of electricity for heating.

This information may be used to conclude that the higher than expected winter maximum demand was, in part, driven by the particularly cold temperatures observed. All input drivers should be considered in combination. Where actual input drivers diverge from the expectation of the model or simulation, it may imply inaccuracy of the forecast distribution.

Seasonal forecasts and simulated intra-day demand time-series are developed for each region. Forecasts are also developed for the many connection points within each region. This section assesses the accuracy of the seasonal forecasts, the demand time-series and the connection point forecasts.

5.1 Summer 2018-19 maximum demand events

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 chapter 6.10. 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:

- 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 2018-19 occurred on 25 January 2019. Due to the heat and reduced generation availability, governments and utilities called for electricity conservation. Additionally, AEMO procured demand side participation through the Reliability and Emergency Reserve Trader (RERT) mechanism and there was involuntary load shedding. The load shedding and RERT is considered firm, while an estimation of voluntary electricity conservation is considered potential. Table 13 shows the summer maximum demand periods for the various regions in 2019 with calculated adjustments.

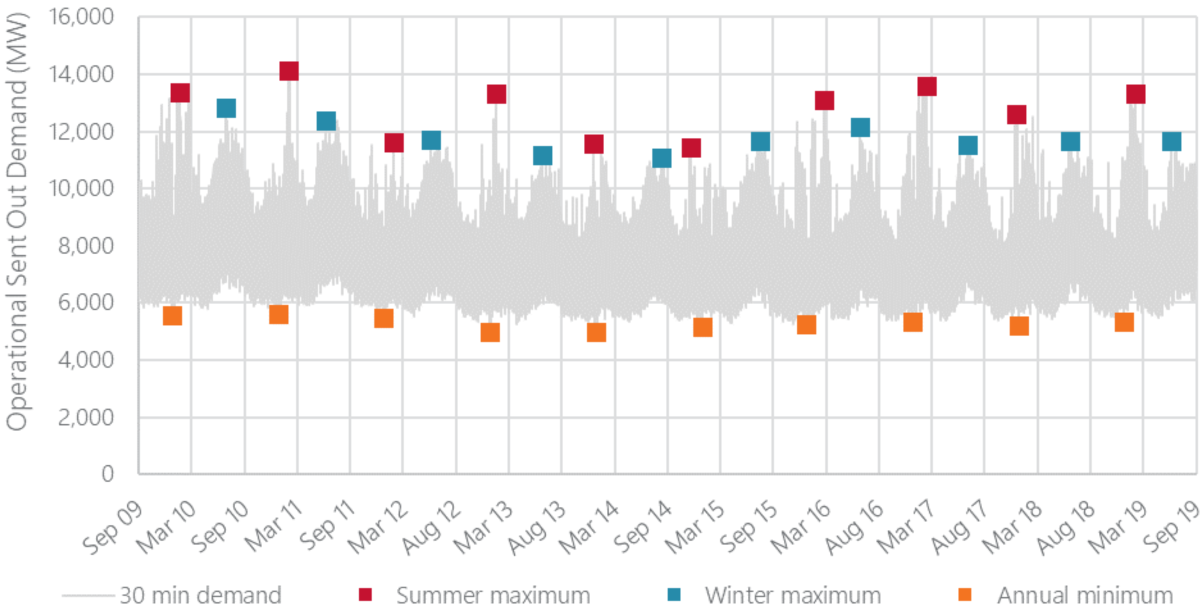
Table 13 Summer 2019 maximum demand with adjustments per region (MW).

Region	Time of maximum	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	31 Jan 19 16:30	13,821	500	13,320	0	0	13,320
QLD	13 Feb 19 17:30	10,044	552	9,492	20	0	9,512
SA	24 Jan 19 19:30	3,240	100	3,140	82	55	3,277
TAS	15 Jan 19 15:30	1,330	18	1,312	0	0	1,312
VIC	25 Jan 19 13:00	9,110	335	8,775	510	120	9,405

5.2 New South Wales

The half hourly time-series for New South Wales operational sent-out (OPSO) demand is shown below in Figure 17. The extreme demand events are also shown in the graph, which indicate that New South Wales is summer peaking, with no clear trend in any of the extreme demand events. Further detail on the extreme demand events observed in 2019 is provided in Table 14.

Figure 17 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 18. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and customer behaviour. Both actual summer and winter maximum demand events fell well within the forecast distributions, while the annual minimum is higher than most of the probability distribution.

Figure 18 New South Wales simulated extreme event probability distributions with actuals

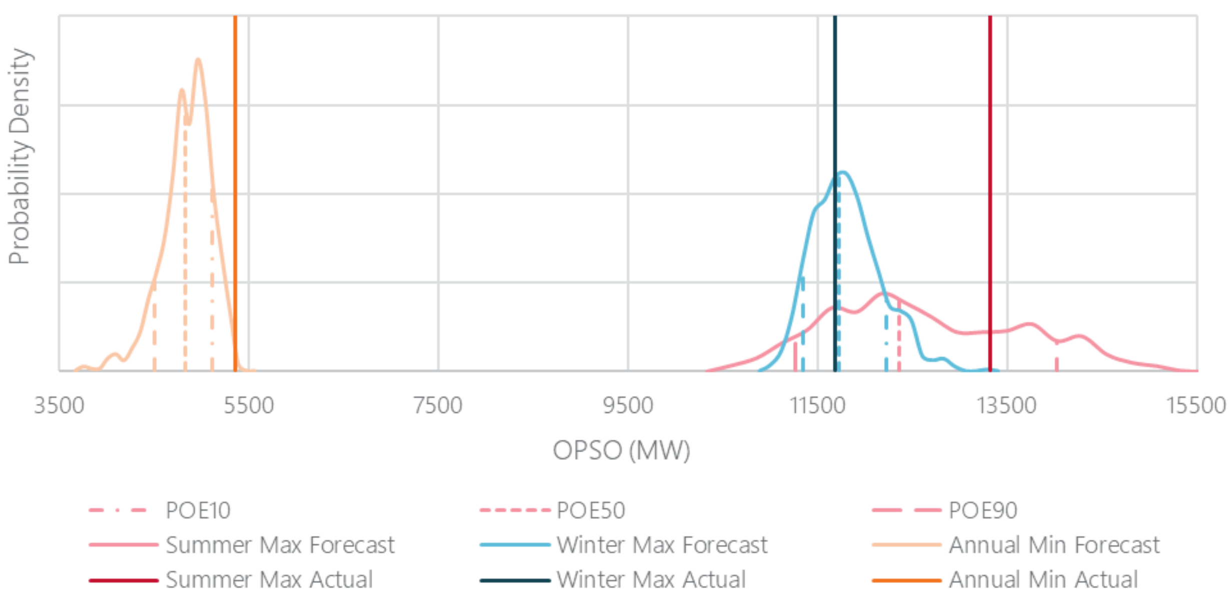
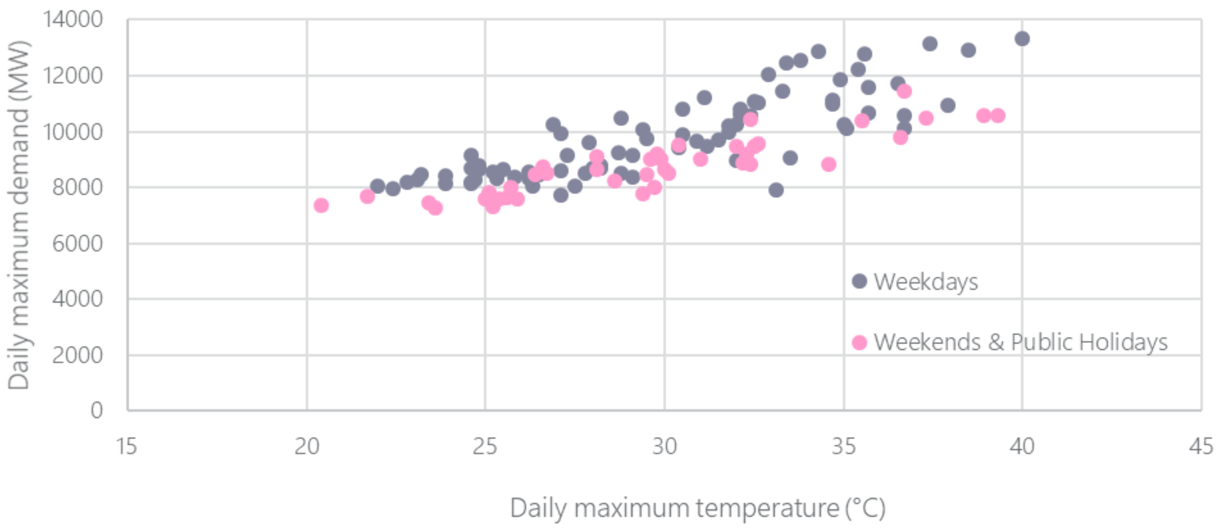


Table 14 New South Wales 2019 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	31 Jan 19 16:30	4 Jun 19 18:30	25 Dec 18 4:00
Temperature (°C)	38.1	11.1	16.4
Rolling Heat Index (°C) [13]	7.2	0	0.9
Rolling Cold Index (°C) [14]	0	8.1	2.0
Losses (MW)	864	752	316
NSG Output (MW)	293	148	180
Rooftop PV Output (MW)	561	0	0
Sent Out (OPSO)	**13,320**	**11,687**	**5,356**
Auxiliary (MW)	500	443	261
As Generated (OPGEN)	**13,821**	**12,130**	**5,617**

Figure 19 shows the relationship between daily maximum demand and daily maximum temperature observed at the Bankstown Airport weather station. The correlation between weekday maximum demand and maximum temperature is 83% indicating that on a linear basis, 83% of the variation in daily maximum demand (MW) can be explained by variations in daily maximum temperature. In 2019, the day of maximum demand coincided with the day of maximum temperature, however there were several near contenders at marginally lower temperatures. Similarly, the third hottest weekday only lead to demand of approximately 11,000MW, highlighting that temperature and type of weekday are not the only determinants of maximum demand.

Figure 19 New South Wales demand and daily maximum temperature scatterplot, summer 2019



[13] Rolling 144 interval average of cooling degrees over threshold; designed to capture the effect of heat accumulation.

[14] Rolling 144 interval average of heating degrees over threshold; designed to capture the effect of cold accumulation.

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

Actual maximum demand occurred in summer on Thursday 31 January 2019 at 17:30 local time (16:30 NEM datetime). At the time of maximum demand, Bankstown recorded a temperature of 38.1°C with an earlier daily (and annual) maximum of 40.0°C.

- New South Wales did not experience a particularly high maximum temperature, with the summer maximum temperature being only 40.0°C. Simulated temperature outcomes ranged from 35°C to 45°C with a mode of 40°C which, based on temperature alone, would indicate a lower actual maximum demand closer to 50% POE.
- Simulation outcomes were weighted towards occurring during the week and in late January/early February, which is consistent with the Thursday 31 January 2019 occurrence.
- Large industrial loads at time of maximum demand consumed 75 MW less than expected (1,250 MW forecast, 1,175 MW actual). While not forecast, the variation of the large loads observed is considered to be within standard operating ranges for these loads and does not constitute a reduction for Demand Side Participation (DSP) purposes.
- PV generation at time of maximum demand is slightly over-estimated largely due to the high PV capacity forecast, as actual PV normalised generation was consistent with the 2018 ESOO forecast, sitting at roughly 29%.
- Overall, these impacts suggest the forecast would have been higher and the forecast distribution shifted slightly to the right, had the PV capacity forecast been lower. A downward revision to the PV capacity forecast was implemented in 2019, capturing these observations.

Winter maximum demand occurred on Tuesday 4 June 2019 at 18:30 local time, with a temperature of 11.1°C recorded at Bankstown.

- Maximum demand occurred on a particularly rainy day with cloud cover continuing from the previous day. Due to the cloud cover and late peak, PV generation was zero at time of maximum demand.
- The forecast expected a later winter peak sometime in July, when heating loads are significantly higher.
- The observed maximum demand fell squarely in the middle of the forecast distribution, which is supported by the time of day, day of week, and month of year all landing on values within the simulated outcomes.
- Overall, the input variables support the accuracy of the forecast distribution.

Actual minimum demand also occurred in summer, on Tuesday 25 December 2018 at 5:00 local time, when the temperature was 16.4°C.

- Actual minimum demand is roughly 230 MW above the 10% POE and, considering the moderate maximum summer temperatures experienced by New South Wales, the 2018 ESOO forecast was likely too low.
- This is largely due to the effect of a higher than actual PV capacity forecast. Had PV capacity increased as expected in the 2018 ESOO, New South Wales' minimum demand would have shifted from an overnight minimum to early afternoon, reflecting the large impact PV generation has on minimum demand. However, PV capacity was roughly 275 MW lower than expected.
- Simulation outcomes were weighted towards occurring in late November/early December, which is consistent with the Tuesday 25 December 2018 (Christmas Day) occurrence. The forecast expected an annual minimum on a weekend or public holiday, where high PV generation combined with relatively low grid demand would eventuate in a seasonal minimum. This difference is again largely due to the overestimate of PV capacity.

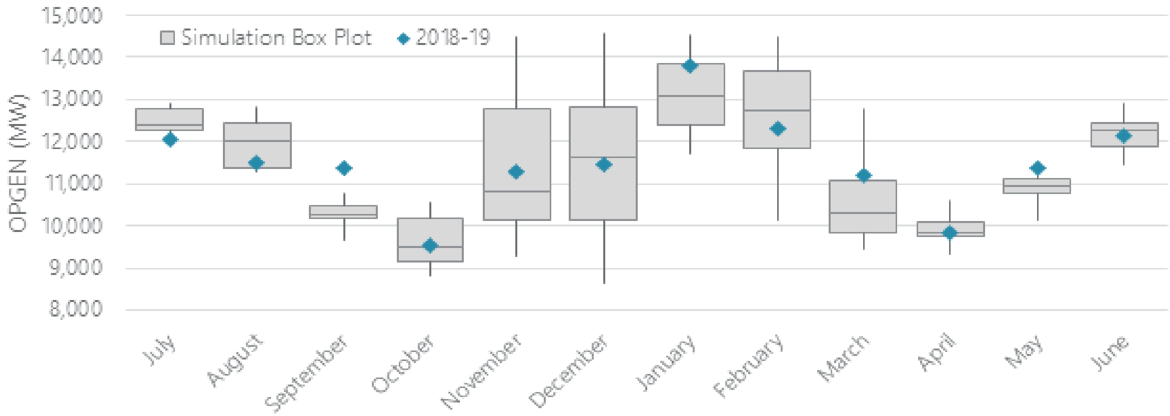
The overestimate of PV installations was identified early by AEMO and considerable work was undertaken with consultations around industry, and expert bodies, to ensure the 2019 ESOO improved on this input.

Figure 20 New South Wales simulated input variable probability distributions with actuals

Monthly maximums

The operational energy consumption and extreme demand forecasts are used to develop demand profiles of 30-minute customer demand in time-series consistent with the 10% POE and 50% POE annual maximum demand forecasts, referred to as demand 'traces'. These traces are used in assessing reliability in both the ESOO and Medium Term Assessment of System Adequacy (MT PASA). Figure 21 uses a box plot to demonstrate the range of monthly demand maximums from these simulated traces for a 10% POE and 50% POE annual forecast. Each trace is independently scaled to achieve the summer maximum demand forecast at least once throughout the year, hence November, December, January, and February all share similar upper ends depending on the month in the year when maximum demand occurred in history. The monthly maximums fall out of the scaling process, and are broadly consistent with the relativity of monthly maximum demand to annual maximum observed in the historical reference trace. Observed monthly maximums mostly fell within the simulated ranges, including summer maximums. September exceeded the simulation range, due to unexpected cold temperatures observed early in the month.

Figure 21 New South Wales monthly maximum demand in demand traces compared with actuals

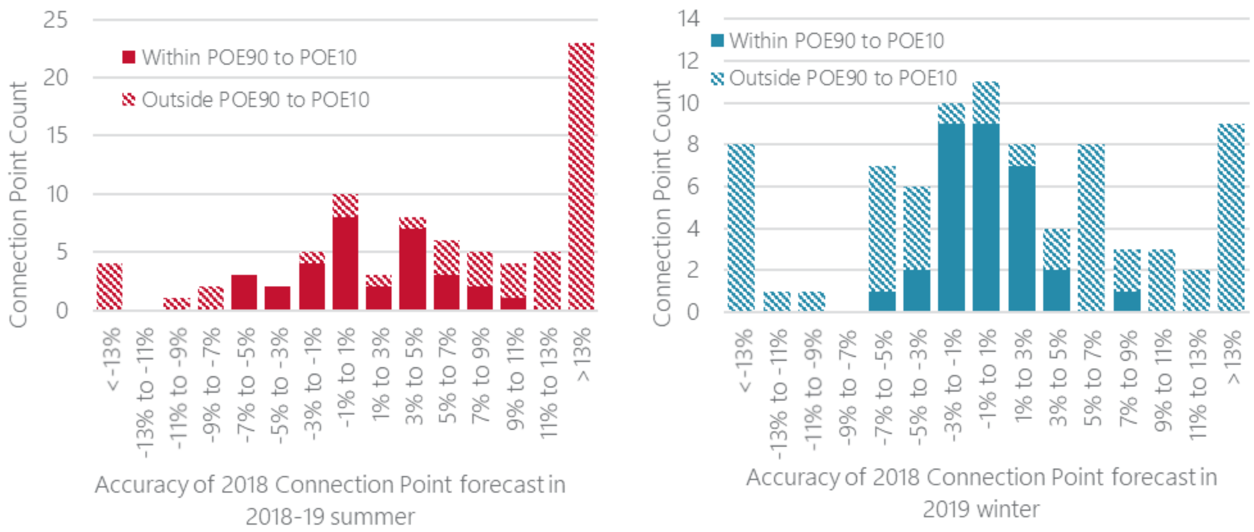


Connection points

AEMO develops forecasts for 96 connection points within the New South Wales region. As with the regional forecasts, probability distributions are developed to predict where the summer and winter maximums could fall. Figure 22 shows the percentage difference between the actual maximum demand event and the median of the probability distribution (the 50% POE forecast). The accuracy is further categorised as to whether the actual is within the forecast range that covers 80% of all events: "Within POE90 to POE10", or not: "Outside POE90 to POE10".

For example, Figure 22 indicates that actual maximum demand for 10 summer connection points fell within 1% of the 50% POE forecast. Of that 10, two actuals fell outside the 90%/10% POE bands (potentially indicating the POE bands are too narrow), and eight actuals fell within the range. AEMO's expectation is that the performance results exhibit a bell-curve shape with most connection points near the middle (the +/- 1% range) and fewer connection points showing larger percentage differences. A positive percentage difference indicates the actual was higher than the 50% POE forecast.

Figure 22 New South Wales connection point accuracy, summer and winter maximums

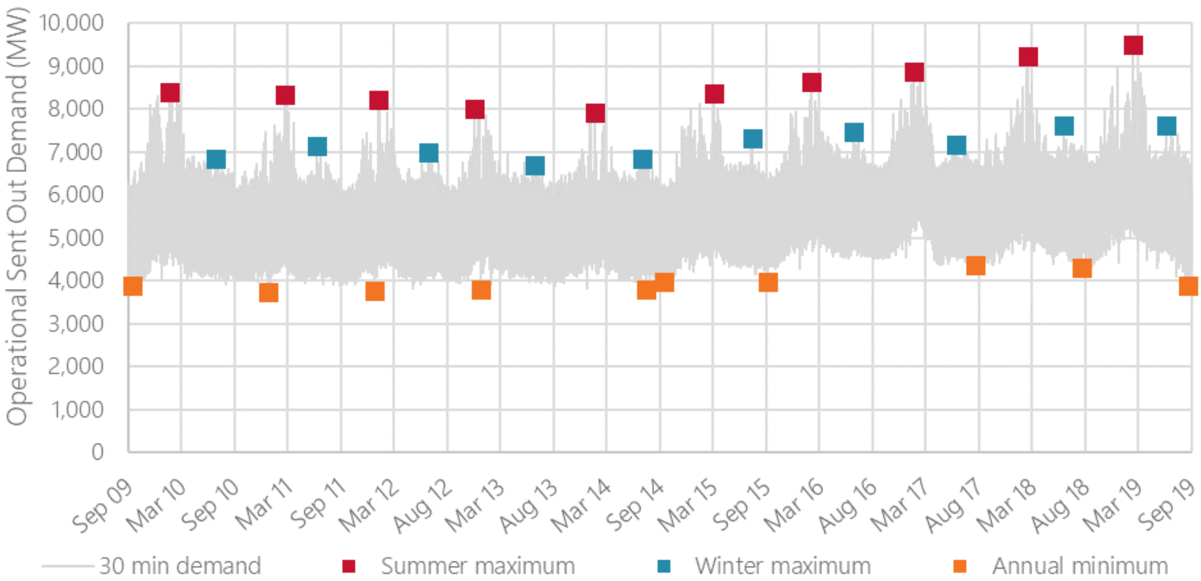


Forecasts that are different by more than 13% are likely affected by load switching and network reconfiguration and should therefore be excluded from consideration of forecasting performance. Once removed, winter accuracy is somewhat normally distributed with a mean of 0.8% indicating a tendency for actuals to be higher than the forecast 50% POE. On the same basis, summer saw a stronger tendency towards actuals being higher than forecast with a mean of 2.8%. This is not-altogether inconsistent with the regional maximum demand actual that fell above the 50% POE yet below the 10%POE (as discussed earlier in this chapter).

5.3 Queensland

The half hourly time-series for Queensland OPSO demand is shown below in Figure 23. The extreme demand events are also shown in the graph, which indicate that Queensland is summer peaking, with an apparent upward trend in summer. Further detail on the extreme demand events for 2019 is provided in Table 15.

Figure 23 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 24. Both maximum demand events fell in the upper tail of their respective forecast distributions, while the minimum event fell closer to the centre of the forecast distribution.

Figure 24 Queensland simulated extreme event probability distributions with actuals

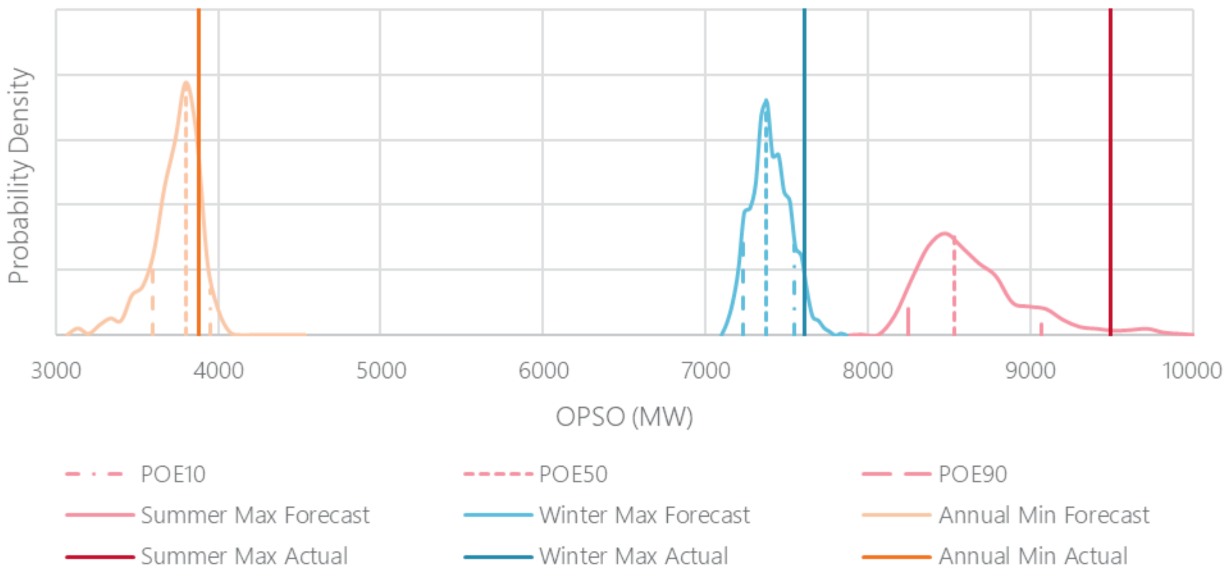


Table 15 Queensland 2019 extreme demand events

Event	Summer Maximum	Winter maximum	Annual minimum[15]
NEM Datetime	13 Feb 19 17:30	4 Jun 19 19:00	18 Aug 19 12:00
Temperature (°C)	30.3	11.8	22.1
Rolling Heat Index (°C)	5.1	0	0.4
Rolling Cold Index (°C)	0	6.8	6.5
Losses (MW)	602	467	
NSG Output (MW)	230	230	
Rooftop PV Output (MW)	377	0	1,550
Sent Out (OPSO)	**9,492**	**7,606**	**3,883**
Auxiliary (MW)	552	463	328
As Generated (OPGEN)	**10,044**	**8,069**	**4,211**

Figure 25 shows the relationship between daily maximum demand and daily maximum temperature observed at the Archerfield Airport weather station. The correlation between weekday maximum demand and maximum temperature is 77% indicating that on a linear basis, 77% of the variation in daily maximum demand (MW) can be explained by variations in daily maximum temperature. In summer 2019, the day of

[15] Due to the late timing of the annual minimum, some input variables are not yet available or are early estimates.

maximum demand did not coincide with the day of maximum temperature, due to a combination of weather and non-weather driven coincident behaviours.

Figure 25 Queensland demand and daily maximum temperature scatterplot, summer 2018-19

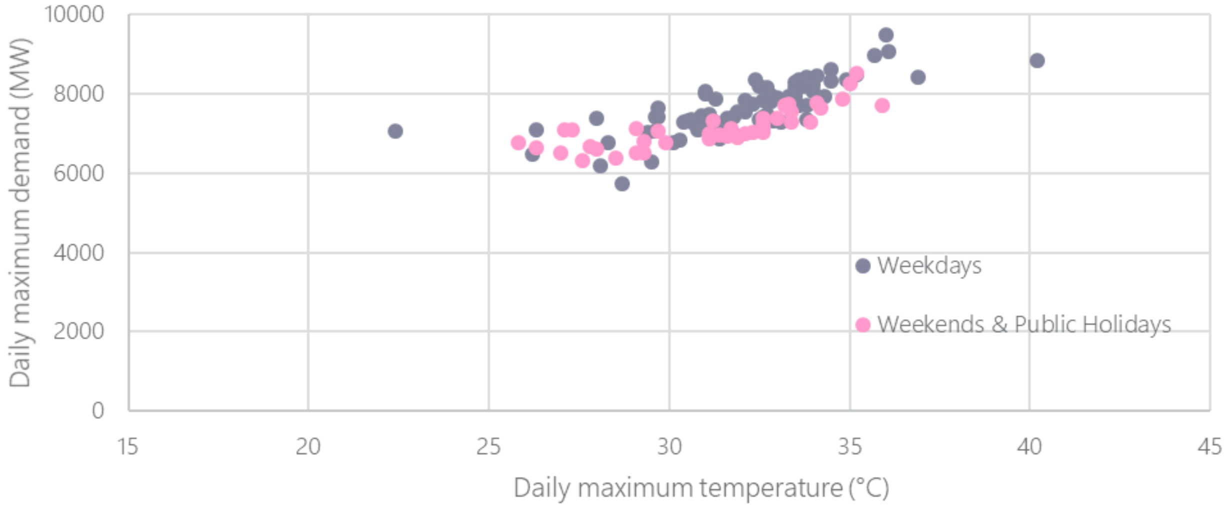


Figure 26 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum demand occurred in summer on Wednesday 13 February 2019 at 17:30 local time. At the time of maximum demand, Archerfield recorded a temperature of 30.3°C with an earlier daily maximum of 36.0°C.

- Queensland, similar to New South Wales, had a fairly mild peak event with the temperature at time of maximum demand a full 10 degrees below the summer maximum temperature of 40.2°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 low end of simulated outcomes, with an actual of around 350 MW at time of maximum demand, compared to a distributional mode of 1,200 MW and likely range of outcomes between 500 and 1,600 MW. Total PV capacity for Queensland was quite close to forecast, with an actual 2,560 MW of installed capacity as at 1 July 2019 compared to a forecast of 2,583 MW. Cloud cover on the day was only partial, while relative humidity was at a month-high of 57%, which would have reduced the efficacy of PV units. As such, low PV generation seems reasonable given the weather conditions.
- Simulation outcomes were weighted towards occurring during the week and in late January/early February, which is consistent with the Wednesday 13 February 2019 occurrence.
- The observed maximum demand came after three consecutive hot days state-wide, on a weekday, and outside the school holiday season. The combination of these factors rarely happens and generally leads to outcomes in the high end of the forecast distribution. Therefore, while temperature was well below the indicative 10% POE temperature, the combination of factors resulted in maximum demand that AEMO considers to be close to a one-in-10-year expectation. Given the forecast suggests an event 400 MW *above* the 10% POE level, the forecast distribution is likely too low. The 2019 ESOO has revised the summer forecast upwards.

Winter maximum demand occurred on Tuesday 4 June 2019 at 19:00 local time, just 30 minutes after the winter maximum demand occurred in New South Wales. Temperature at the time was 11.8°C at Archerfield.

- Maximum demand fell on one of the coldest days of winter, with the maximum temperature on the day only 17.6°C, further exacerbated by strong winds throughout the day. The late timing of the peak meant

PV generation had long since ceased. 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, which is consistent with the Tuesday 4 June 2019 occurrence. However, as with the New South Wales winter maximum, the forecast expected a later winter peak sometime in July when heating loads are significantly higher.
- Overall, conditions on the day suggest an outcome much closer to a 50% POE, rather than above a 10% POE as the forecast distribution asserts. As such, the forecast is likely in need of an upward revision, consistent with energy consumption and summer maximum demand. This revision to the forecast distribution was implemented in 2019, capturing these observations.

Actual minimum demand occurred in winter on Sunday 18 August 2019 at 12:00 local time, when the temperature was 22.1°C.

- This is the second time minimum demand has occurred mid-day in Queensland. With the growth in rooftop PV capacity following the trajectories of the 2018 ESOO, future years are most likely to see mid-day annual minimum demand occurrences, with an associated rapid decline in minimum demand.
- Actual minimum demand fell between the 50% and 10% POE levels, with simulated temperature outcomes at time of minimum demand ranging between 15°C and 30°C. PV generation at time of minimum demand was 1,550 MW, sitting just below the distributional mode of 1,600 MW.
- Simulation outcomes were weighted towards occurring on the weekend, which is consistent with the Sunday 18 August 2019 occurrence. Some August events were captured in the forecast; however, it was expected that the annual minimum would occur sometime in June or September when weather conditions were significantly more mild than the winter or summer extremes.
- These factors suggest the forecast to be reasonable given the strong uptake in PV capacity, continuing trend of mid-day minimums, and moderate temperature.

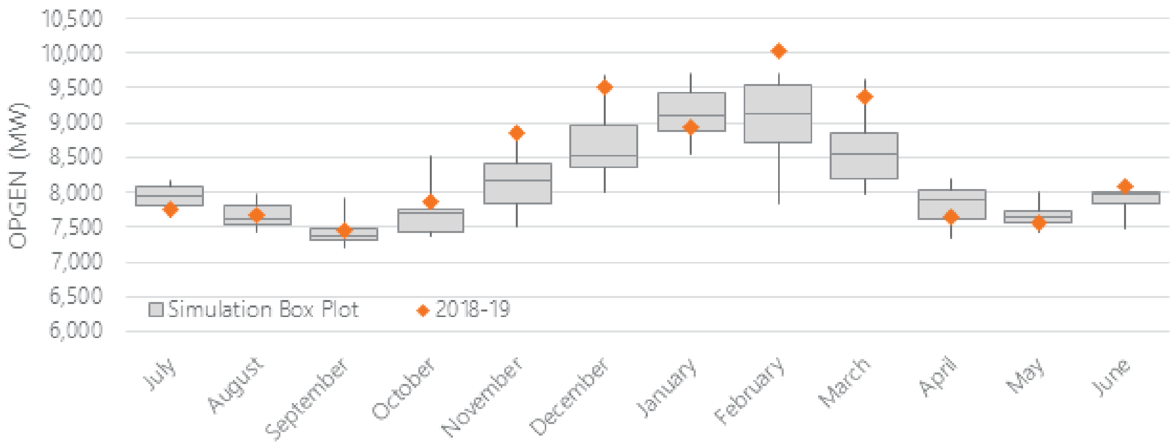
Figure 26 Queensland simulated input variable probability distributions with actuals

Due to the late timing of the annual minimum, some input variables are not yet available or are early estimates. For example, losses have not yet been calculated.

Monthly maximums

Figure 27 uses a box plot to demonstrate the range of monthly maximums from simulated traces for 10% POE and 50% POE annual forecasts used in MT PASA. Each simulation is independently scaled to achieve the 10% POE and 50% POE summer forecasts at least once throughout the year, hence December, January, February and March share similar maximums. Observed monthly maximums mostly fell in the upper end of simulated ranges, which aligns well with the higher than forecast energy consumption and summer maximum demand.

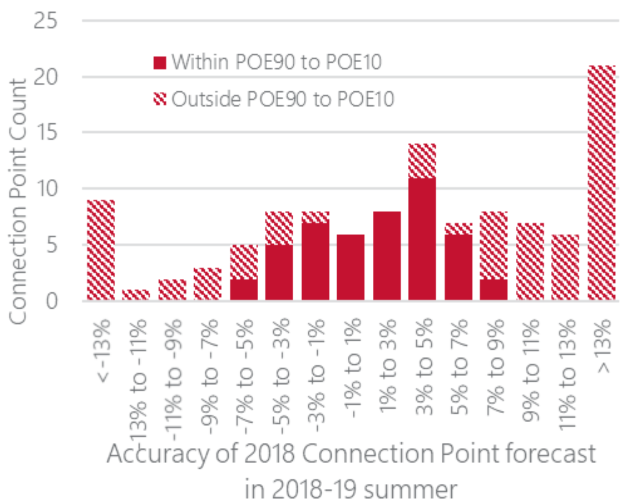
Figure 27 Queensland monthly maximum demand in demand traces compared with actuals

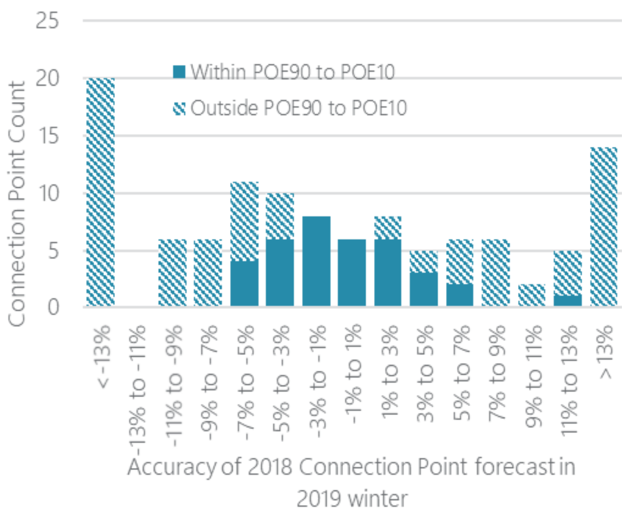


Connection points

AEMO develops forecasts for 113 connection points within the Queensland region. As with the regional forecasts, probability distributions are developed to predict where the summer and winter maximums will fall. Figure 28 shows the percentage difference between the actual maximum demand event and the mean of the probability distribution. The accuracy is further categorised as to whether the actual is within the forecast range that covers 80% of all events: "Within POE90 to POE10" or not: "Outside POE90 to POE10".

Figure 28 Queensland connection point accuracy, Summer and Winter maximums



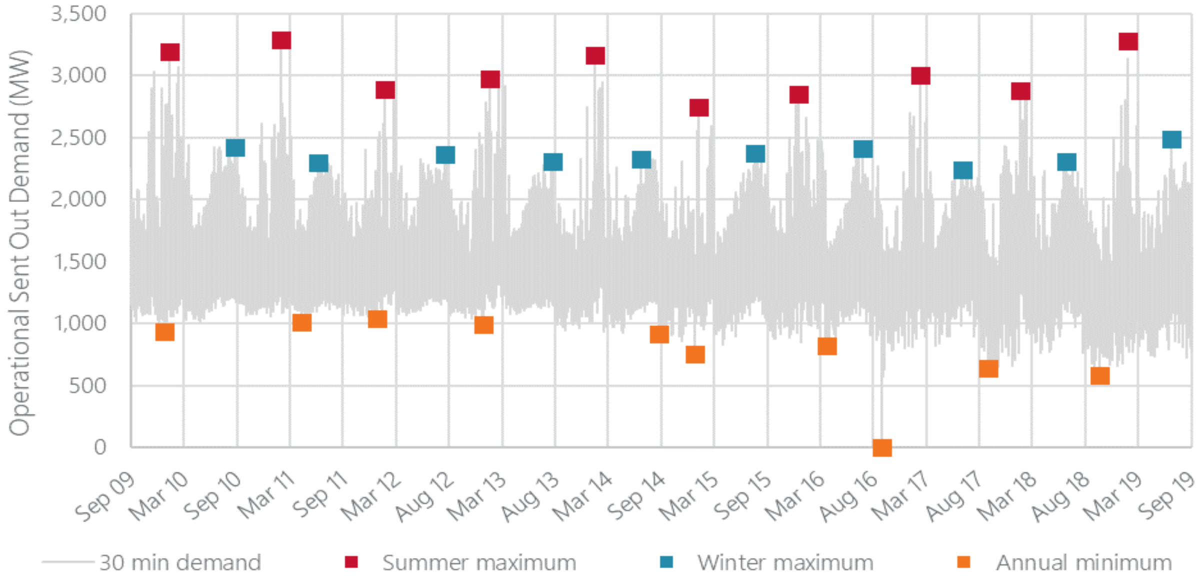


Actuals that are more than 13% inaccurate are likely affected by load switching and network reconfiguration, and should therefore be excluded from consideration of forecasting performance. Once removed, winter accuracy is somewhat normally distributed with a mean difference close to zero (-0.3%). On the same basis, summer saw a larger mean difference of 2.2% indicating actuals tended to be higher than 50% POE forecasts. This is generally consistent with the heatwave conditions that drove regional demand to near 10%POE levels.

5.4 South Australia

The half hourly time-series for South Australia OPSO demand is shown below in Figure 29. The extreme demand events are also shown in the graph, which indicate that South Australia is summer peaking, with a clear downward trend in annual minimums. Further detail on the extreme demand events for 2019 is provided in Table 16. Figure 29 also highlights the atypical minimum that occurred during the South Australia blackout on 28 September, 2016.

Figure 29 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 30. Both actual maximum demand events fell well within the upper tail of the forecast distributions, while the annual minimum is higher than the probability distribution.

Figure 30 South Australia simulated extreme event probability distributions with actuals

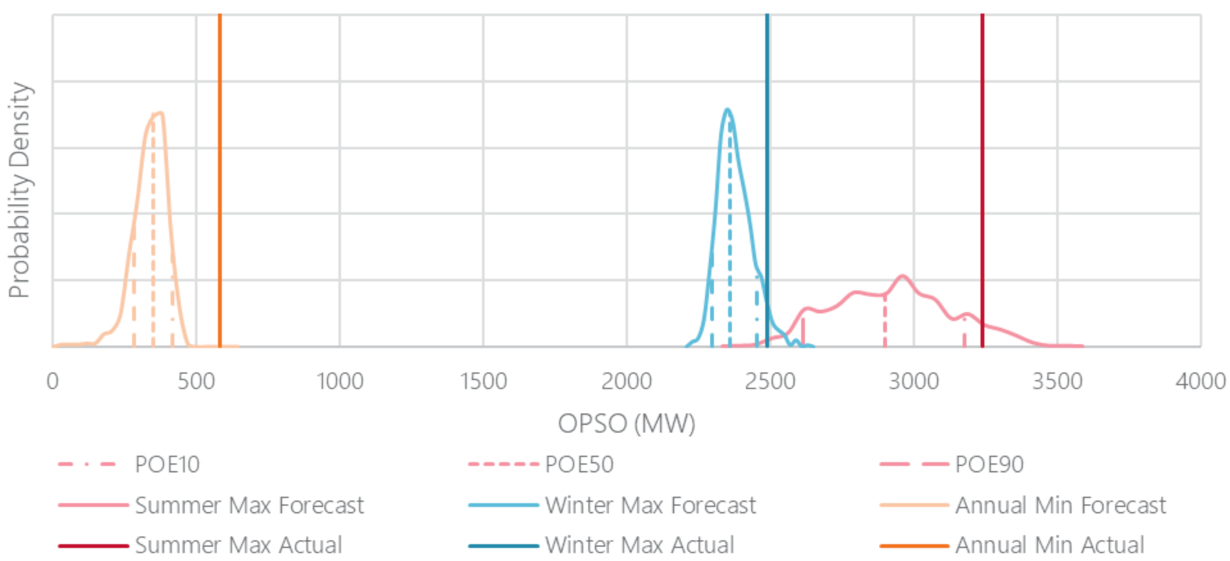


Table 16 South Australia 2019 extreme demand events

Event	Summer maximum[16]	Winter maximum	Annual minimum
NEM Datetime	24 Jan 19 19:30	24 Jun 19 19:00	21 Oct 18 13:00
Temperature (°C)	44.3	10.6	21.9
Rolling Heat Index (°C)	13.2	0	0.4
Rolling Cold Index (°C)	0	12.8	4.8
Losses (MW)	271	209	39
NSG Output (MW)	18	12	39
Rooftop PV Output (MW)	25	0	663
Sent Out (OPSO)	**3,277**	**2,489**	**583**
Auxiliary (MW)	100	72	16
As Generated (OPGEN)	**3,377**	**2,561**	**599**

Figure 31 shows the relationship between daily maximum demand and daily maximum temperature observed at the Adelaide (Kent Town) weather station. The correlation between weekday maximum demand and maximum temperature is 72% indicating that on a linear basis, 72% of the variation in daily maximum demand (MW) can be explained by variations in daily maximum temperature. In 2019, the day of maximum demand coincided with the day of maximum temperature by a significant margin. The second hottest weekday only lead to demand of approximately 2,300MW, highlighting that temperature and type of weekday are not the only determinants of maximum demand.

Figure 31 South Australia demand and daily maximum temperature scatterplot, summer 2018-19

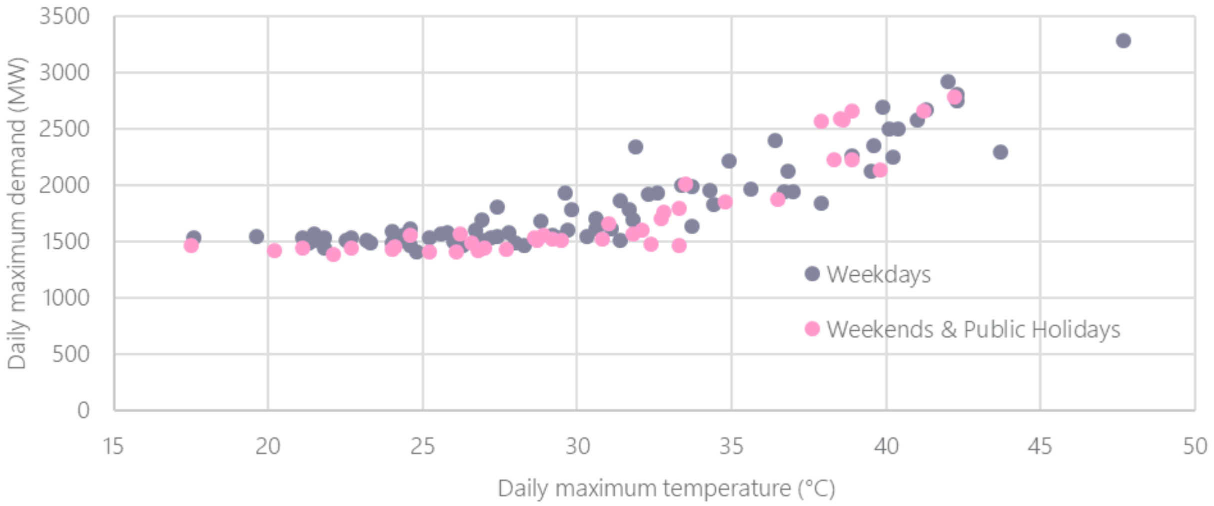


Figure 32 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

[16] Includes adjustments.

Actual maximum demand occurred on Thursday 24 January 2019 at 20:00 local time with a temperature of 44.3°C recorded at Adelaide (Kent Town).

- South Australia experienced a hot period in late January, with an annual maximum temperature recorded earlier in the day of 46.6°C. The day also saw the hottest minimum daily temperature of 30.7°C.
- Total PV capacity for South Australia was quite close to forecast, with an actual 1,070 MW of installed capacity as at 1 July 2019, compared to a forecast of 1,120 MW. High temperatures on the day would have impacted PV generation and, coupled with the time of maximum demand occurring just 28 minutes before sunset, it is reasonable that PV output was at the lower end of the distribution.
- Simulation outcomes were weighted toward a weekday maximum and in late January/early February, which is consistent with the Thursday 24 January 2019 occurrence.
- Coming off the back of a strong three-day mid-week heatwave with PV generation close to zero, the combination of factors resulted in maximum demand that AEMO considers to have exceeded a one-in-10-year expectation.

Winter maximum demand occurred on Monday 24 June 2019 at 18:30 local time, with a temperature of 10.6°C recorded at Adelaide (Kent Town).

- South Australia saw its highest winter maximum demand in history, the previous record being 2,408 MW set on 26 July 2016. Furthermore, South Australia continues its trend of 18:30 local time of peak since 2012.
- Monday 24 June 2019 was the coldest day in winter, with the lowest daily minimum of 1.3°C and lowest daily maximum of 12.0°C for the season, consistent with expectation.
- Simulation outcomes were weighted towards occurring early in the week and around July, which is consistent with the Monday 24 June 2019 occurrence.
- As South Australia has had a very stable winter maximum demand historically, with values ranging between 2,240 MW and 2,490 MW. This, combined with the other inputs, suggests that a small upward revision was required, as implemented in the 2019 ESOO.

Actual minimum demand occurred on Sunday 21 October 2018 at 13:30 local time, when the temperature was 21.9°C.

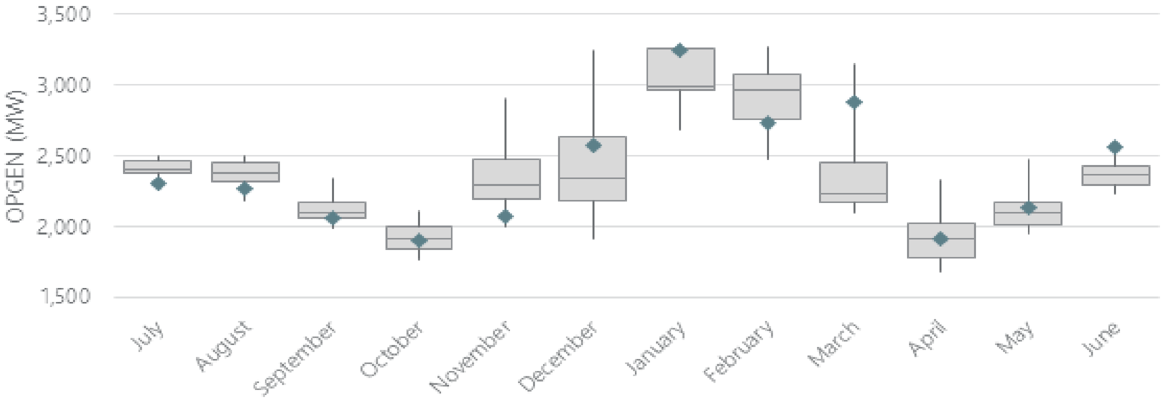
- Simulated temperature outcomes fell between 17°C and 27°C, with temperature at time of minimum demand being in the middle of the distribution.
- South Australian minimum demand has been occurring mid-day for a number of years, with minimum demand reducing year on year in response to growth in installed rooftop PV capacity.
- Despite total PV capacity for South Australia being close to forecast, PV generation was at the far lower end of the forecast distribution at time of minimum demand. Weather conditions on the day were conducive to high PV generation, with low temperatures, low humidity, and no cloud cover. Actual normalised generation at time of minimum demand was 67.4%, consistent with other high PV generation days, implying that the forecast overstated the ability for each PV unit to generate power. The PV generation model was subsequently changed prior to inclusion in the 2019 ESOO.
- Simulation outcomes were weighted towards occurring on the weekend and during the October-December period, which is consistent with the Sunday 21 October 2019 occurrence.
- These factors together suggest the minimum demand forecast overestimated the rate of decline in minimum demand due to the PV generation model. An upward revision has been implemented in the 2019 ESOO based on both revised PV uptake forecasts and improved PV generation modelling.

Figure 32 South Australia simulated input variable probability distributions with actuals

Monthly maximums

Figure 33 uses a box plot to demonstrate the range of monthly maximums from simulated traces for 10% POE and 50% POE annual forecasts used in MT PASA and ESOO. Each simulation is independently scaled to achieve the 10% POE and 50% POE summer forecasts at least once throughout the year, in this case affecting only January. Observed monthly maximums entirely fell within the simulated ranges. While the OPSO summer 10% POE forecast was exceeded slightly, due to lower auxiliaries than forecast, the OPGEN January actual is right on the 10% POE simulation.

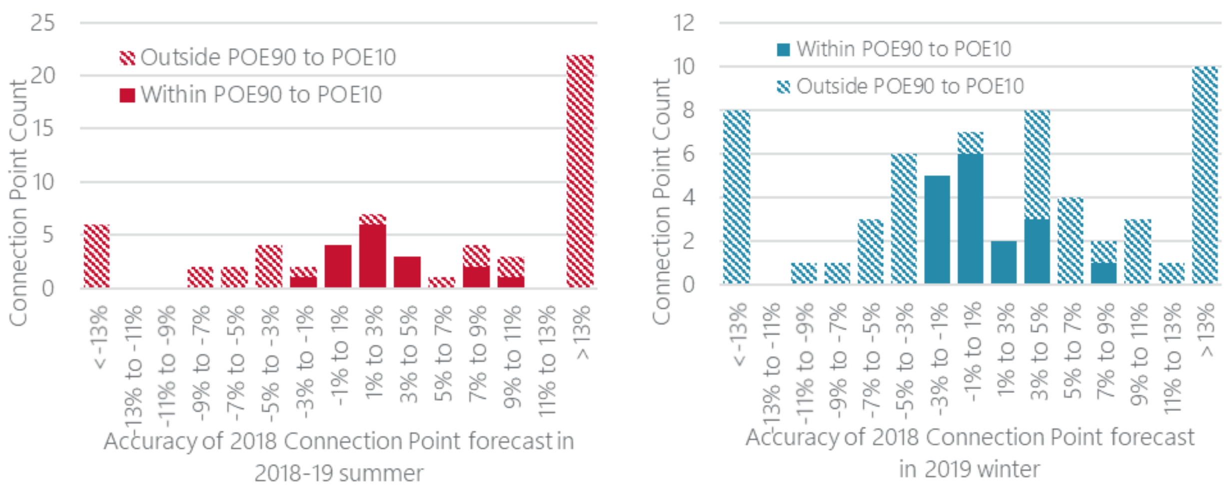
Figure 33 South Australia monthly maximum demand in demand traces compared with actuals



Connection points

AEMO develops forecasts for 61 connection points within the South Australia region. As with the regional forecasts, probability distributions are developed to predict the range where the summer and winter maximums are likely to fall, after taking into account uncertainties in weather conditions. Figure 34 shows the percentage difference between the actual maximum demand event and the mean of the probability distribution. "Within POE90 to POE10" or not: "Outside POE90 to POE10".

Figure 34 South Australia connection point accuracy. Summer and Winter maximums

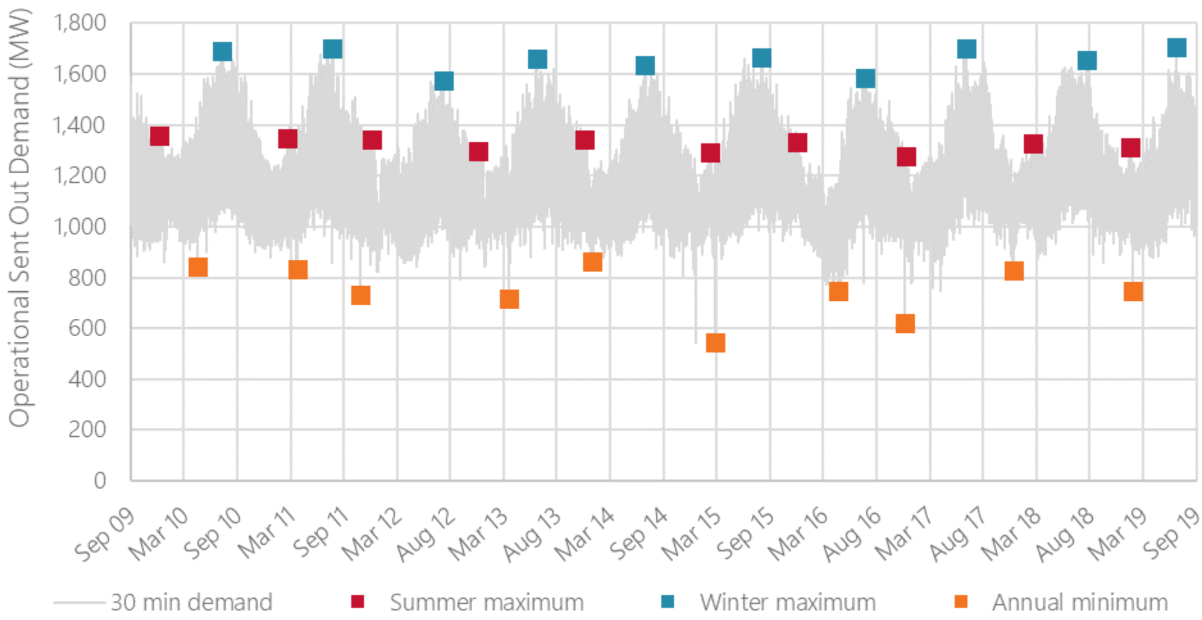


Actuals that are more than 13% inaccurate are likely affected by load switching and network reconfiguration, and should therefore be excluded from consideration of forecasting performance. Once removed, winter accuracy is somewhat normally distributed with a tendency for actuals to be higher than the 50% POE forecast (a mean difference of 1.1%). A normal distribution indicates a lack of bias in the forecasts. While somewhat normal, fewer connection points fell within the ideal prediction interval than is desirable. On the same basis, summer has a similar mean difference of 1.4% indicating a stronger tendency for actuals to be higher than forecast. In both cases, the connection point result is consistent with the regional result, in that actuals exceeded forecast, and aligns with the extreme weather that occurred in January and June leading to regional demands that sit at the higher end of the regional forecast distribution.

5.5 Tasmania

The half hourly time-series for Tasmania OPSO demand is shown below in Figure 35. The extreme demand events are also shown in the graph, which indicate that Tasmania is winter peaking, with summer maximums substantially below the winter maximums. Further detail for the extreme demand events in 2019 is provided in Table 17.

Figure 35 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 36. The winter maximum demand event fell towards the upper end of the forecast probability distribution, while the minimum and summer maximum fell towards the lower end, or below the forecast distribution.

Figure 36 Tasmania simulated extreme event probability distributions with actuals

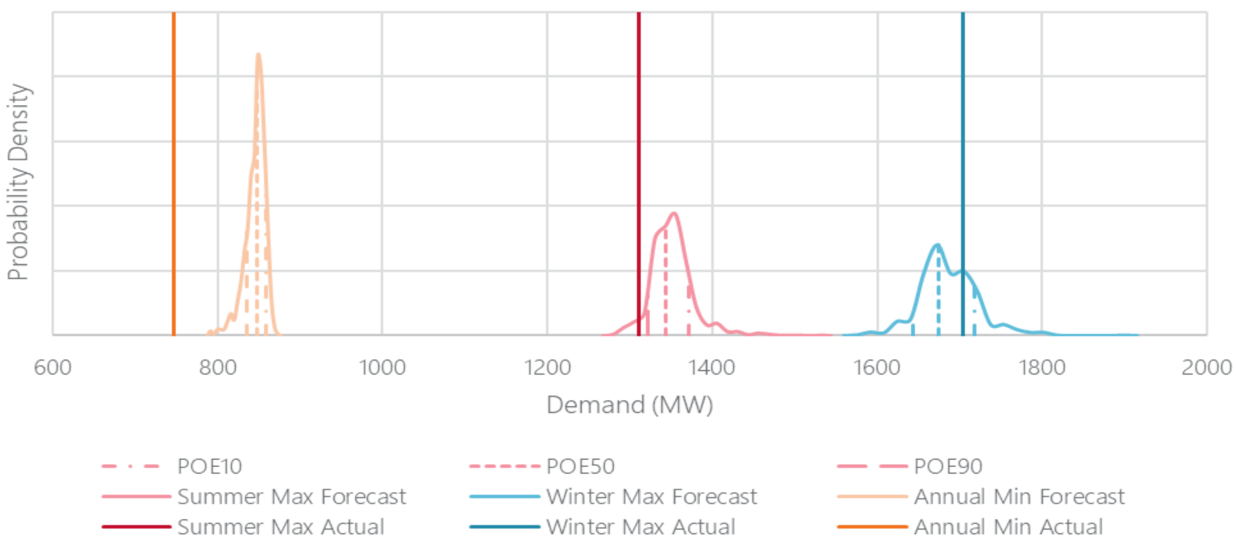


Table 17 Tasmania 2019 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	15 Jan 19 17:30	24 Jun 19 8:30	27 Jan 19 16:30
Temperature (°C)	22.5	2.2	21.8
Rolling Heat Index (°C)	3.42	0	5.6
Rolling Cold Index (°C)	0.7	10.3	0.1
Losses (MW)	65	94	41
NSG Output (MW)	33	23	26
Rooftop PV Output (MW)	32	42	15
Sent Out (OPSO)	**1,311**	**1,705**	**747**
Auxiliary (MW)	19	19	9
As Generated (OPGEN)	**1,330**	**1,724**	**756**

Figure 37 shows the relationship between daily maximum demand and daily maximum temperature observed at the Hobart (Ellerslie Road) weather station. The correlation between weekday maximum demand and maximum temperature is 23%, indicating that on a linear basis, 23% of the variation in daily maximum demand (MW) can be explained by variations in daily maximum temperature. As demand is not driven substantially by high temperatures, the relationship is weak, and summer maximum demand did not occur on the hottest day.

Figure 37 Tasmania demand and daily maximum temperature scatterplot, summer 2018-19

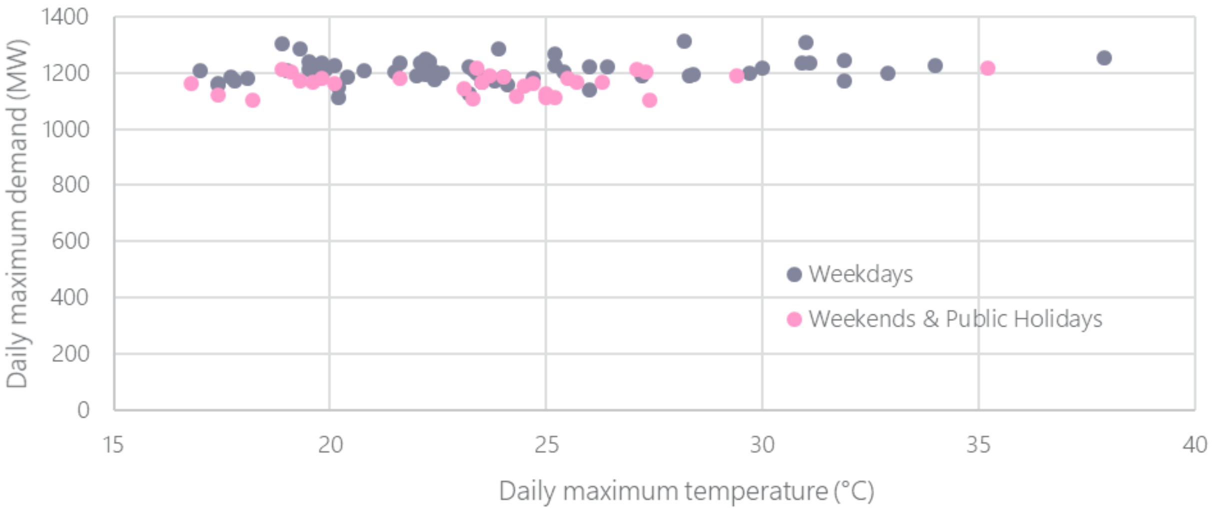


Figure 38 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum demand occurred in winter on Monday 24 June 2019 at 08:30 local time, with a temperature of 2.2°C recorded at Hobart (Ellerslie Road).

- 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, but the early morning peak occurred just after sunrise (07:42 local time), which explains why PV generation was at the left 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 24 June 2019 occurrence.
- Overall, these factors suggest the forecast distribution to be accurate, with observed maximum between 50% and 10% POE.

Summer maximum demand occurred on Tuesday 15 January 2019 at 18:30 local time, with a temperature of 22.5°C recorded at Hobart (Ellerslie Road).

- This is the first year Tasmania has seen an afternoon summer maximum event during a hot summer day, with all previous years having a morning peak during a cold snap during summer. This indicates that the 2019 peak was the first true summer cooling peak observed in Tasmania. While unusual, the absence of a summer cold snap is unlikely to occur frequently.
- Simulated temperature outcomes were different to the actual observed temperature of 22.5°C, mainly due to this unexpected afternoon event. Similarly, PV generation at time of maximum was higher than forecast.
- Simulation outcomes were weighted towards occurring mid-week and in late January/early February, which is consistent with the Tuesday 15 January 2019 occurrence.
- Besides the difference in temperature and time of day, day of week and month of year were well within expectation. As such, these factors together suggest an event closer to a 50% POE, implying the forecast distribution may need to be slightly shifted down, particularly if this afternoon trend continues and forecast PV uptake eventuates.

Actual minimum demand occurred on Sunday 27 January 2019 at 17:30 local time, when the temperature was 21.8°C.

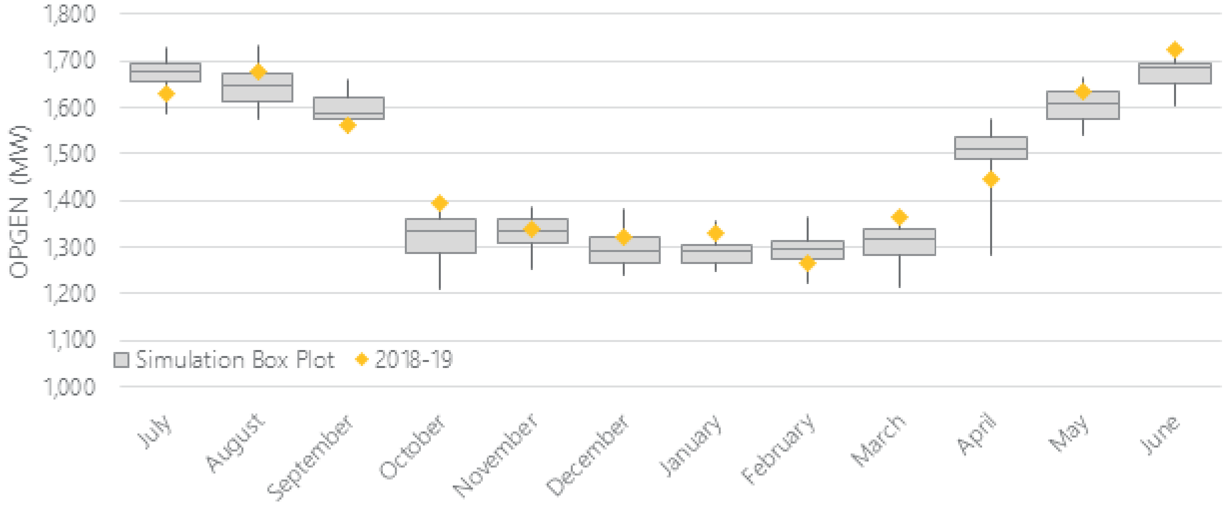
- This is the first year Tasmania has seen an afternoon minimum demand event, with 2018 seeing a morning minimum and previous years all being overnight. Tasmania is particularly affected by industrial activity, and as such minimum demand is inherently volatile.
- Weather conditions on the day were not particularly good for PV generation with a decent amount of cloud cover throughout the day. Heating and cooling loads were low due to the sustained moderate temperatures, only dropping to 15.6°C overnight.
- Simulation outcomes were weighted towards occurring on the weekend and around January, which is consistent with the Sunday 27 January 2019 occurrence.
- These factors combined would suggest a fairly moderate annual minimum demand event close to a 50% POE, whereas the forecast distribution is clearly around 100 MW above the annual minimum. This suggests the forecast distribution has not correctly captured the inherent volatility in Tasmanian minimum demand, largely due to prevailing weather on the day and industrial activity. Additionally, the forecast distribution is likely too high given the moderate minimum demand observed this year.

Figure 38 Tasmania simulated input variable probability distributions with actuals

Monthly maximums

Figure 39 uses a box plot to demonstrate the range of monthly maximums from simulated traces for a 10% POE annual forecast used in MT PASA and ESOO. Each simulation is independently scaled to achieve the 10% POE and 50% POE winter forecast at least once throughout the year, hence June, July, and August all share a similar upper end. Observed monthly maximums all fell within the simulated ranges, including winter maximums.

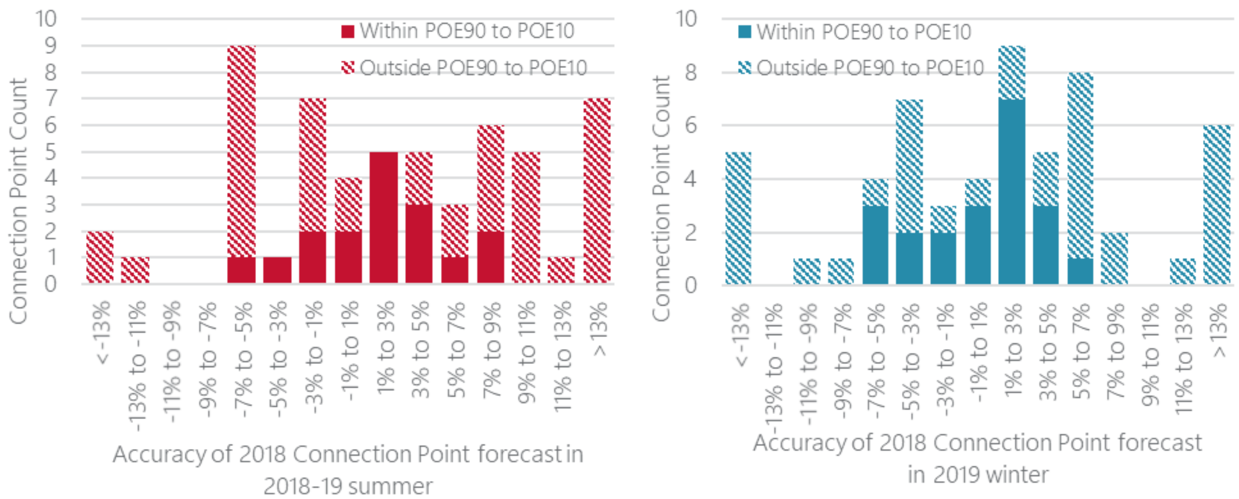
Figure 39 Tasmania monthly maximum demand in demand traces compared with actuals



Connection points

AEMO develops forecasts for 56 connection points within the Tasmania region. As with the regional forecasts, probability distributions are developed to predict where the summer and winter maximums will fall. Figure 40 shows the percentage difference between the actual maximum demand event and the mean of the probability distribution. The accuracy is further categorised as to whether the actual is within the forecast range that covers 80% of all events: "Within POE90 to POE10" or not: "Outside POE90 to POE10".

Figure 40 Tasmania connection point accuracy, summer and winter maximums

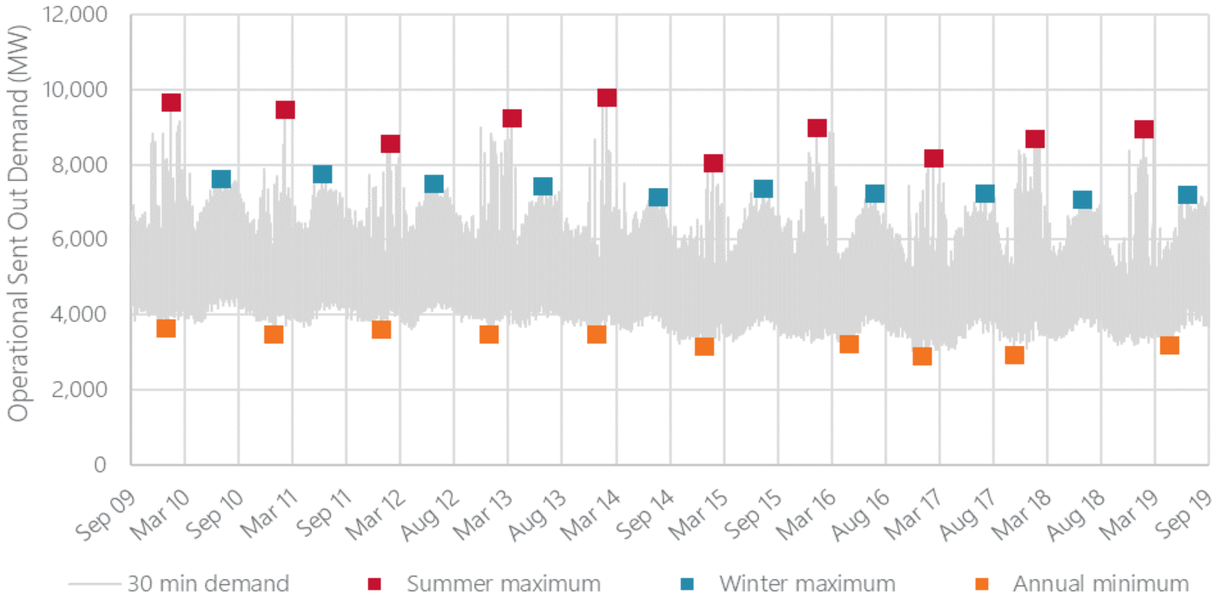


Actuals that are more than 13% inaccurate are likely affected by load switching and network reconfiguration, and should therefore be excluded for consideration of forecasting performance. Once removed, winter accuracy is fairly normally distributed with a weak tendency for actuals to be higher than forecast (mean difference of 0.8%). On the same basis, summer has a stronger difference (tendency for actuals to be higher than the forecast with a mean of 1.6%), despite the regional actual falling in the lower end of the forecast distribution. This suggests the summer connection point forecasts were too low in light of the outcomes at the regional level.

5.6 Victoria

The half hourly time-series for Victoria OPSO demand is shown below in Figure 41. The extreme demand events are also shown in the graph, which indicate that Victoria is summer peaking, with a volatile downward trend in all extreme demand events. Further detail on the extreme demand events observed in 2019 is provided in Error! Reference source not found.Table 18.

Figure 41 Victoria demand with extreme events identified



The demand events are forecast separately, each represented by a probability distribution, as shown in Figure 42. Summer actual maximum demand fell well within the forecast distributions, while the winter maximum was below and the annual minimum was above the probability distribution.

Figure 42 Victoria simulated extreme event probability distributions with actuals

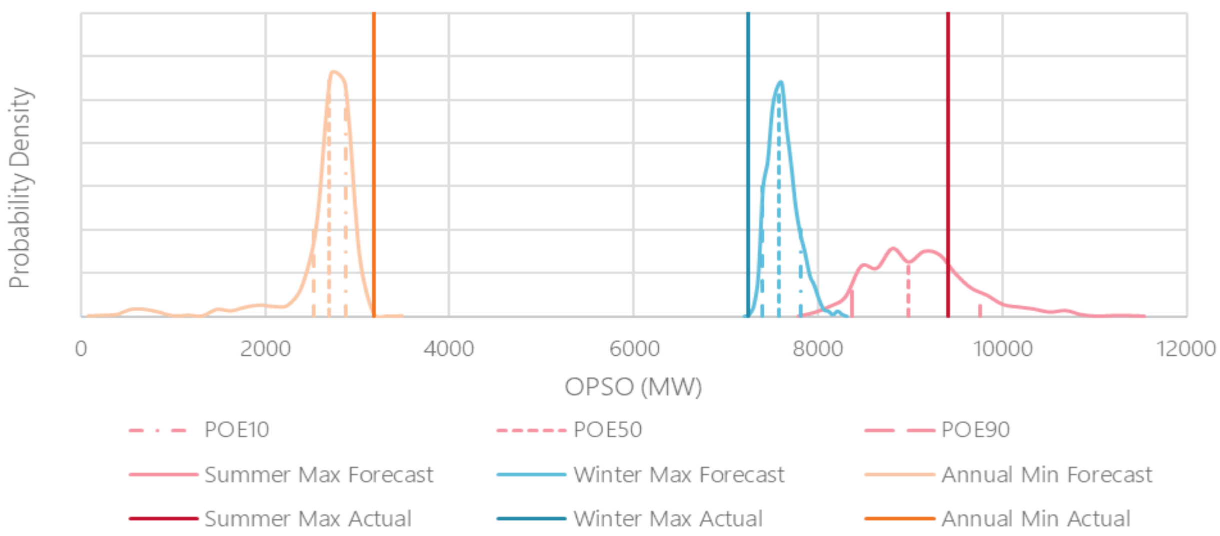
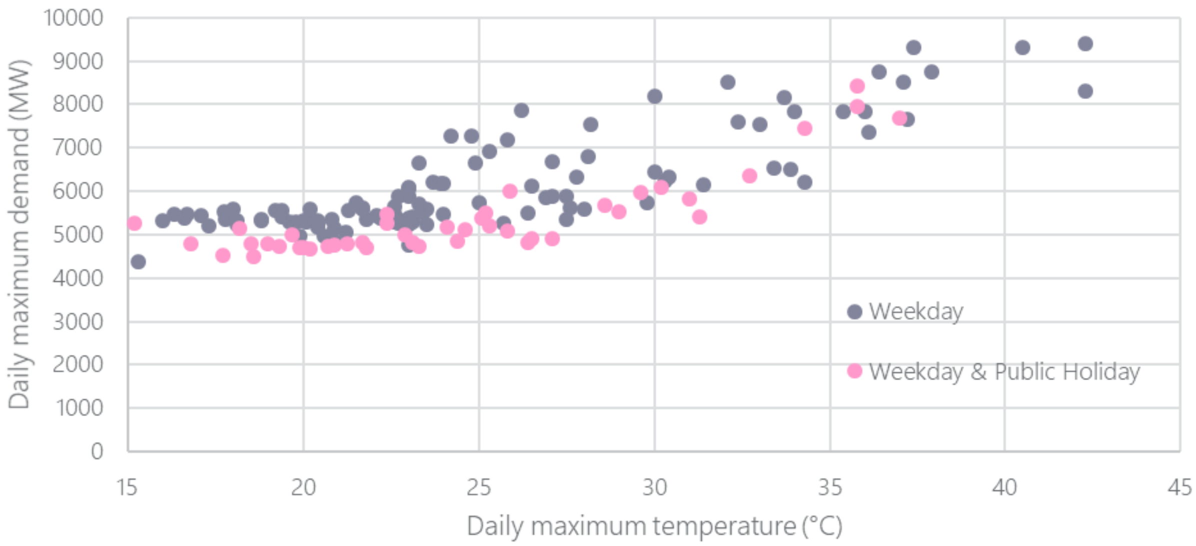


Table 18 Victoria 2019 extreme demand events

Event	Summer maximum[17]	Winter maximum	Annual minimum
NEM Datetime	25 Jan 19 13:00	20 June 19 18:30	22 Apr 19 4:30
Temperature (°C)	40.2	9.0	14.1
Rolling Heat Index (°C)	7.7	0	2.3
Rolling Cold Index (°C)	0	7.9	2.6
Losses (MW)	657	523	217
NSG Output (MW)	209	79	83
Rooftop PV Output (MW)	849	0	0
Sent Out (OPSO)	**9,405**	**7,203**	**3,187**
Auxiliary (MW)	335	386	313
As Generated (OPGEN)	**9,740**	**7589**	**3,500**

Figure 43 shows the relationship between daily maximum demand and daily maximum temperature observed at the Melbourne (Olympic Park) weather station. The correlation between weekday maximum demand and maximum temperature is 84% indicating that on a linear basis, 84% of the variation in daily maximum demand (MW) can be explained by variations in daily maximum temperature. In summer 2019, the day of maximum demand coincided with the day of maximum temperature, however there were several other contenders at lower temperatures. In this case, numerous weekdays were observed with similar maximum temperatures, while observed maximum demand varied more substantially, highlighting the numerous factors driving customer demand beyond temperature.

Figure 43 Victoria demand and daily maximum temperature scatterplot, summer 2019



[17] Includes adjustments.

Figure 44 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Actual maximum demand occurred on Friday 25 January 2019 at 14:00 local time. At the time of maximum demand, Melbourne (Olympic park) recorded a temperature of 40.2°C, with an earlier daily (and annual) maximum temperature of 42.8°C.

- Victoria had two consecutive extreme weather days, with temperatures only dropping to 21.1°C overnight. While the heatwave would suggest a very high maximum demand outcome, there was a cool change on Friday afternoon that granted the state relief and reduced the severity of the event.
- Simulation outcomes were weighed towards occurring during the week and in late January/early February, which is consistent with the Friday 25 January 2019 occurrence.
- Given the high temperatures, relative humidity of 50%, and early afternoon time of event, it is reasonable that PV generation was 53% of installed capacity at the time of maximum demand. This is further corroborated by the PV generation forecast distribution, with actual generation lying just higher than the distributional mode. Had the cool change not occurred, it is likely grid demand would have continued to increase into the afternoon with PV generation falling off.
- Furthermore, maximum demand occurred the day before the Australia Day long weekend, and the week before schools returned, thus it is reasonable to assume some workers would have taken the Friday off to avoid the heat and gain a four-day weekend. This, combined with the above factors, suggests that maximum demand could have been much higher than observed, and hence the forecast distribution seems fairly accurate placing the event between 50% and 10% POE.

Winter maximum demand occurred on Thursday 20 June 2019 at 18:30 local time, with a temperature of 9.0°C recorded at Melbourne (Olympic Park). Victoria had another cold winter evening peak in 2019 coming off the back of a few colder-than-average days, with maximum daily temperatures below 14°C. Simulated temperature outcomes ranged from 5°C to 15°C which, on the basis of temperature alone, would suggest a peak demand just below 50% POE.

- Simulation outcomes were weighted towards occurring during the week and in the late June/early July period, which is consistent with the Thursday 20 June 2019 occurrence.
- As such, these factors together suggest a winter maximum event much closer to a 50% POE, rather than a few hundred MW beneath the 90% POE as implied by the forecast distribution.

Actual minimum demand occurred on Monday 22 April 2019 (Easter Monday) at 04:30 local time, when the temperature was 14.1°C. Victoria experienced a very mild day, with temperatures only varying four degrees across the entire day between 13.7°C and 17.6°C. With heating load overnight minimal, the region continues its trend of overnight minimums.

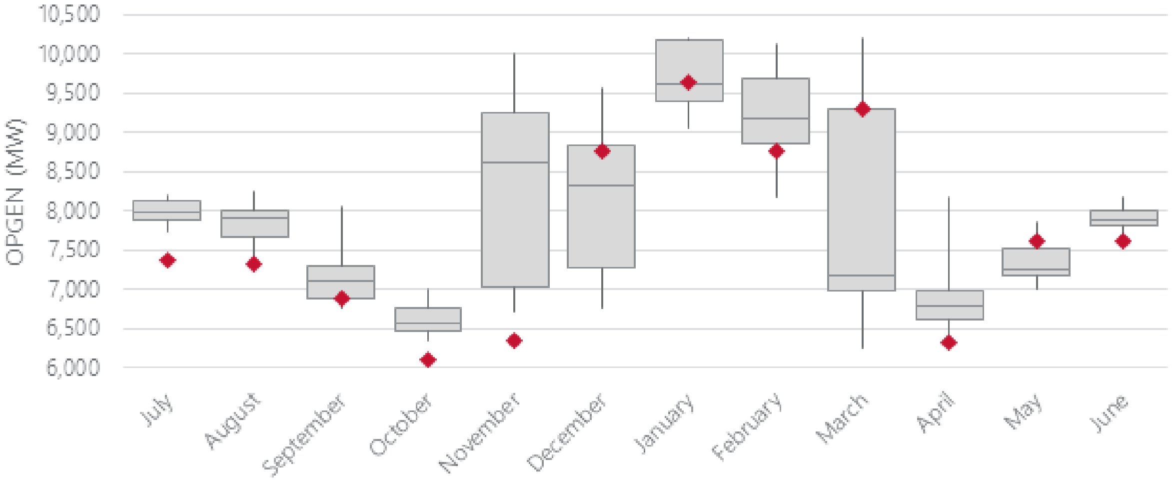
- Simulation outcomes were weighted towards occurring on Sunday or mid-week and around the December holiday period, which is inconsistent with the Monday 22 April 2019 occurrence. This is partially due to the PV capacity forecast prematurely pushing simulated minimums into the afternoon, coinciding with lower afternoon demand on public/school holidays.
- Due to the higher than actual PV capacity forecast, the forecast distribution is significantly below the observed minimum demand, largely due to the assumption that minimum demand would transition to an afternoon event with excess PV generation in the grid. Victoria ended up almost 15% under forecast for PV installed capacity by April 2019, which is roughly 140 MW of PV generation absent at time of minimum demand that was expected from the forecast. The PV capacity forecast has been corrected for the 2019 ESOO, and subsequently the minimum demand forecast distribution has been shifted up in response. See the previous discussion on PV forecast changes (Section 2.2: Rooftop PV and PV non-scheduled generation).

Figure 44 Victoria simulated input variable probability distributions with actuals

Monthly maximums

Figure 45 uses a box plot to demonstrate the range of monthly maximums from simulated traces for a 10% POE annual forecast used in MT PASA. Each simulation is independently scaled to achieve the 10% POE and 50% POE summer forecasts at least once throughout the year, hence January, February, and March all share a similar upper bound. The simulated maximum ranges for November and March were particularly large, due to a combination of poor demand trace scaling and highly variable maximum temperatures for these months. Depending on observed weather, high maximums are possible in Victoria on the fringes of summer. Observed monthly maximums mostly fell within the simulated ranges for summer, and sometimes below the range for winter, consistent with the lower than forecast annual consumption. The maximum for January was right at the median of the box plot, which implies the actual was approximately half way between a 10% and 50% POE summer event.

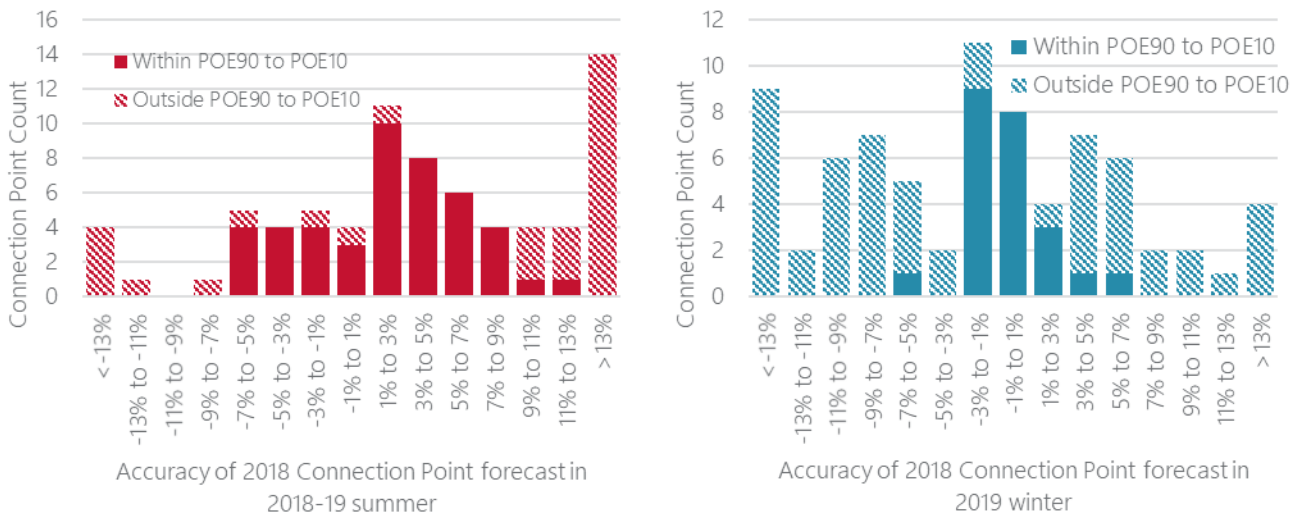
Figure 45 Victoria monthly maximum demand based on demand traces with actuals



Connection points

AEMO develops forecasts for 78 connection points within the Victoria region. As with the regional forecasts, probability distributions are developed to predict where the summer and winter maximums will fall. Figure 46 shows the percentage difference between the actual maximum demand event and the mean of the probability distribution. The accuracy is further categorised as to whether the actual is within the forecast range that covers 80% of all events: "Within POE90 to POE10" or not: "Outside POE90 to POE10".

Figure 46 Victoria connection point accuracy, summer and winter maximums



Actuals that are more than 13% inaccurate are likely affected by load switching and network reconfiguration, and should therefore be excluded from consideration of forecasting performance. Once removed, winter accuracy is broadly distributed with a mean difference of -1.3% (actuals lower than forecast), consistent with the low regional winter outcome. On the same basis, summer has a mean difference of 2.4% (actuals tending to be higher than the 50% POE forecasts), consistent with a regional actual that fell in the upper end of the forecast distribution but below the 10% POE level. In summer, a higher number of connection points fell within the POE90 to POE10 bands, while fewer were within this band for winter. This may imply the prediction intervals for winter are too narrow.

6. Trends in supply drivers

Generator supply availability forecasts are predicated on a wide selection of inputs and assumptions. In some cases, these inputs are provided from registered generator participants directly through a portal and subsequent report. In other cases, assumptions like future input pricing for capacity and market modelling are assumed though analysis of history and global supply chain trends.

6.1 Generation information

AEMO collects generation information reported from generation industry participants, via a web-based online system, and regularly publishes updates of information collected[18]. The information collected from current and future participants is used to develop the reliability assessments published in MT PASA and ESOO and system capacity planning published in the Integrated System Plan (ISP).

The 2018 NEM ESOO used this information to develop an understanding of the generation that would be operating over summer 2018-19. Table 19 shows the forecast and actual scheduled, semi-scheduled, and significant non-scheduled generation operating in the NEM by the end of February 2019. The table excludes smaller scale generation like rooftop PV and small non-schedulable generation. The majority of committed new entrant generators are variable renewable energy (VRE) projects, that is wind and solar generation facilities. As such, VRE has been identified separately.

Table 19 Forecast and actual generation count and capacity, February 2019

	Facilities forecast to operate		Facilities actually operating[A]		Difference in Capacity (forecast – actual)	
	Count	MW	Count	MW	MW	%
New South Wales VRE	19	1,870	20	1,767	103	-5.5%
New South Wales all generation	70	16,134	72	16,065	69	-0.4%
Queensland VRE	24	1,860	15	958	902	-48.5%
Queensland all generation	78	13,547	69	12,645	902	-6.7%
South Australia VRE	23	2,012	23	1,856	156	-7.8%
South Australia all generation	69	4,770	69	4,614	156	-3.3%
Tasmanian VRE	2	308	2	308	0	0.0%
Tasmania all generation	49	2,601	50	2,809	-208	8.0%
Victoria VRE	19	1,977	19	1,900	77	-3.9%
Victoria all generation	81	10,879	81	10,802	77	-0.7%

A. Total summer capacity is estimated based on available data. Actual capacity may be lower due to hold points imposed during commissioning.

In Table 19, the forecast MW quantity represents the capacity applied during summer in the 2018 ESOO. This is compared with actual data which is based on the same summer rating, unless the maximum generation

[18] AEMO Generation Information. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

achieved during the summer period was well below this value, in which case the maximum generation achieved during summer is applied. The count of the number of facilities shows the number of generators with a summer rating above zero (for forecast) or that generated during the summer (for actual).

The table shows that in Queensland there were a number of projects that were expected to be operational that were not operating at all during the key summer months. As a result, there was a noticeable difference between the total renewable capacity forecast to be operational and what was realised. Of the nine projects which were not operational in Queensland, eight were 'Committed' projects and one was 'Committed*'. A number of new projects which were operating had reduced capacities below their expected rating, which is reflected in the difference between the actual and forecast MW quantities.

Fewer delays in operational commencement were experienced in other regions, with Victoria having one 'Committed*' unit expected to be in operation over summer unavailable. However, all regions other than Tasmania had less new capacity available than forecast.

Note that if a project was delayed but still became operational by end of February 2019 this delay is not reflected in either the facility count or the capacity.

6.2 Generation Cost

The GenCost project is the result of a collaboration between CSIRO and AEMO, together with stakeholder input, to deliver an annual process of updating electricity generation development costs. Regularly updated information on current and projected electricity generation and storage technology costs remains a necessary and highly impactful input to electricity market modelling studies like the ISP.

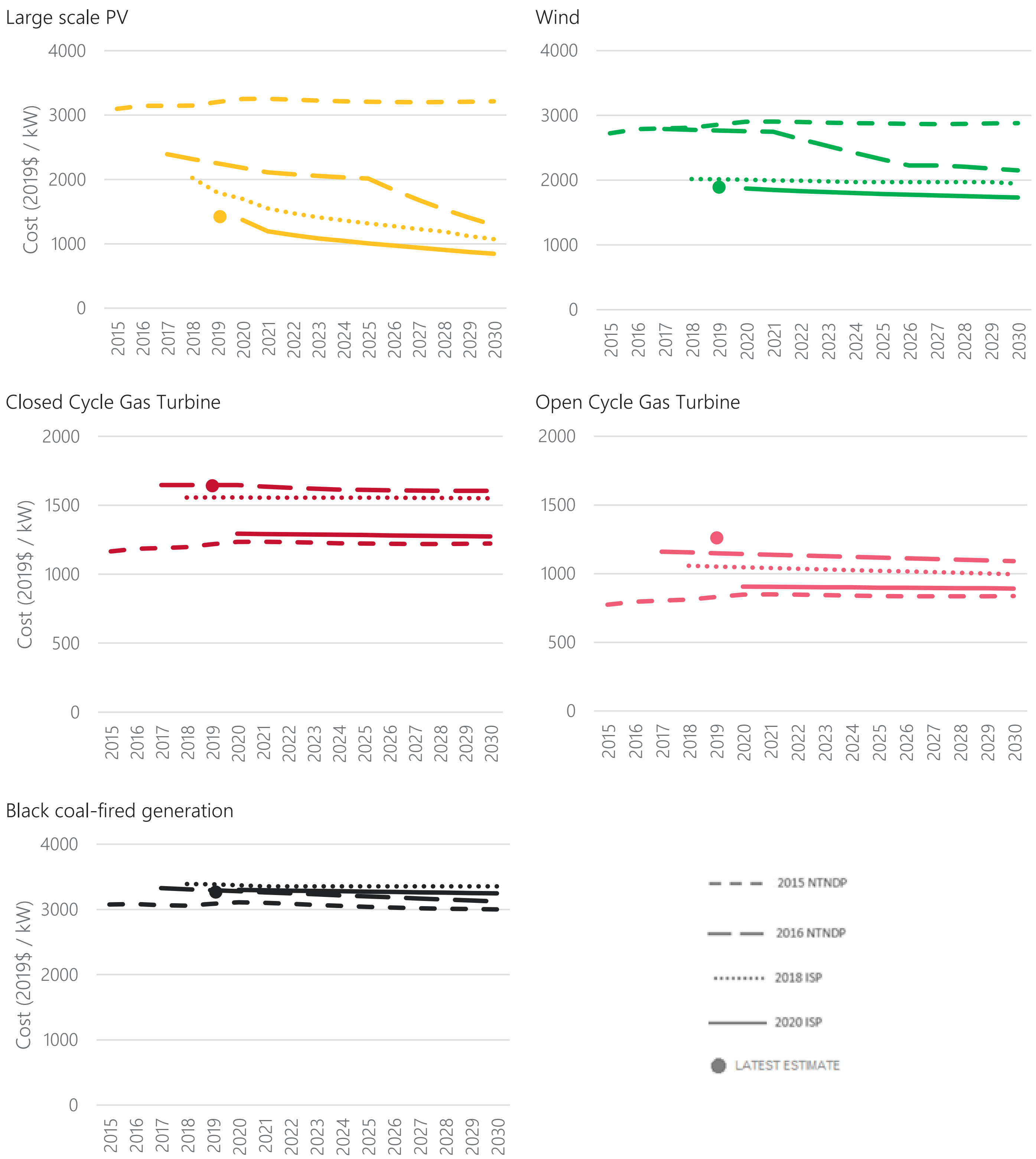
Measuring generation costs remains challenging, given the commercial sensitivity and infrequency of new builds in some technologies. The 2020 ISP uses generation capital costs derived from the 2018 GenCost report[19]. Figure 47 compares this latest cost trajectory with its predecessors used in previous ISPs and National Transmission Network Development Plans (NTNDPs). The latest estimate is based on an Aurecon study prepared for the Draft GenCost 2019-20 publication currently under consultation[20]. Consistency in estimated cost can be used as an estimate of accuracy, and an indicator of any long term bias, as frequently changing values or persistent under or over forecasting indicate that some market trends may have not been considered.

The figure indicates relative stability across established technologies like coal and gas generation, while solar and wind generation capital costs have fallen more than anticipated in the 2015 study, due to greater than expected learning rates for these VRE technologies. The latest estimates vary most for CCGT and OCGTs, for which the study reveals a higher than previously estimated cost.

[19] Graham, Paul; Hayward, Jenny; Foster, James; Story, Oliver; Havas, Lisa. GenCost 2018: Updated projections of electricity generation technology costs. Newcastle, N.S.W.: CSIRO; 2018. https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1. Accessed 8 October 2019.

[20] For more information on the Draft GenCost 2019-20, please see AEMO's Inputs and Assumptions consultation page, at https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2020-Planning-and-Forecasting-Consultation-on-scenarios-inputs-and-assumptions

Figure 47 Comparison of recent studies on capital costs of generation technologies

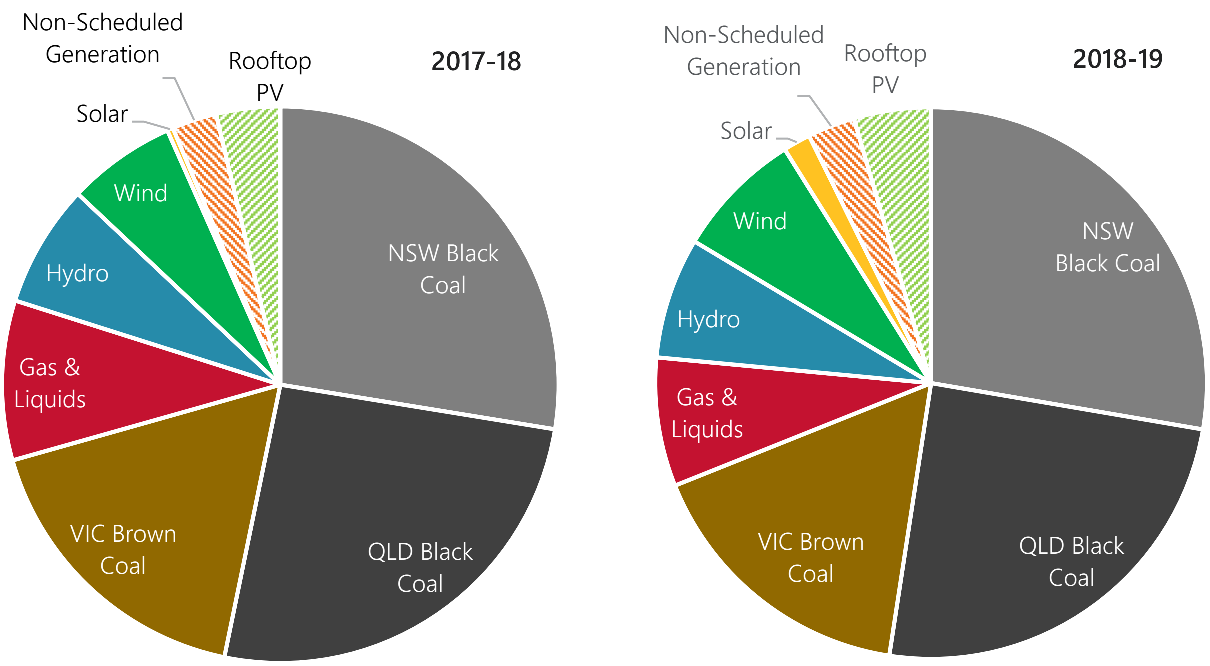


7. Supply forecasts

Generator supply of the NEM comes from a variety of locations and fuel sources, as shown below in Figure 48. While black and brown coal remain the largest source, solar, wind, and rooftop PV have shown the largest increase in supply proportion between 2017-18 and 2018-19.

Supply availability has been assessed for the majority of generation sources, with a particular focus on those with the largest contribution. For example, availability of coal generation is currently a larger contributor to the risk of unserved energy (USE) than solar generation.

Figure 48 NEM generation mix by energy, including demand side components, 2017-18 and 2018-19



Generator supply availability is an important input in reliability studies, given it is commonly a key driver of USE estimates. Supply forecasts are therefore assessed by the degree to which capacity availability estimated in the 2018 ESOO matched actual generation availability. To achieve this goal, AEMO developed a method to compare 2018 ESOO simulations with historical observations (based on PASA availability) during 80 of the most heat-affected trading periods over the ten days with the highest maximum temperatures from summer 2019[21]. Extreme temperature periods are likely to align closely with periods of very high demand, possible derating and possible supply shortfalls. These periods allow exploration of forecast versus actual supply availability, considering:

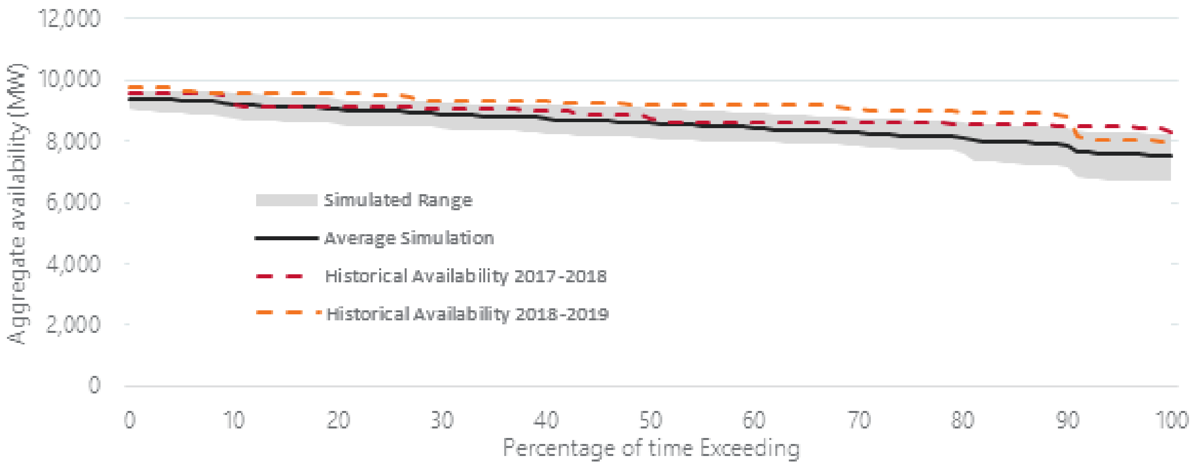
- Generator de-ratings due to the impact of ambient temperature.
- Full unplanned outages.
- Partial unplanned outages.
- Fuel availability (for VRE).

[21] For more information on the supply availability evaluation method, please see the 2019 Summer Forecast Accuracy Update, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting

AEMO collects information from all generators on the timing, duration, and severity of unplanned outages via an annual survey process. This data is used to calculate the probability of full and partial unplanned outages, which are then applied randomly to each unit in the ESOO modelling[22].

To protect the confidentiality of this data, AEMO only publishes calculated outage parameters for a number of technology aggregations. The performance of the forecast unplanned outage rates and availabilities is shown in the following sections. The regions and fuel types that contribute most substantially to supply availability are shown, excluding some minor contributors. Figure 49 shows the simulated and actual availability for New South Wales black coal, with commentary below to demonstrate interpretation.

Figure 49 Example simulated and actual supply availability



The grey range on the chart demonstrates the simulated aggregate availability of generators over the 10 hottest days in the evaluation period, ordered from highest to lowest. It shows that simulated availability ranges from approximately 9,500 MW to 8,000 MW. Actual availability for 2018-19 is shown in the dotted orange line. In this example, the actual availability in almost all intervals was higher than simulated availability. The additional availability is associated with a reduced risk of load shedding. The difference could be attributable to the assumed derating, or full or partial forced outage rates.

The key insights from these results are as follows:

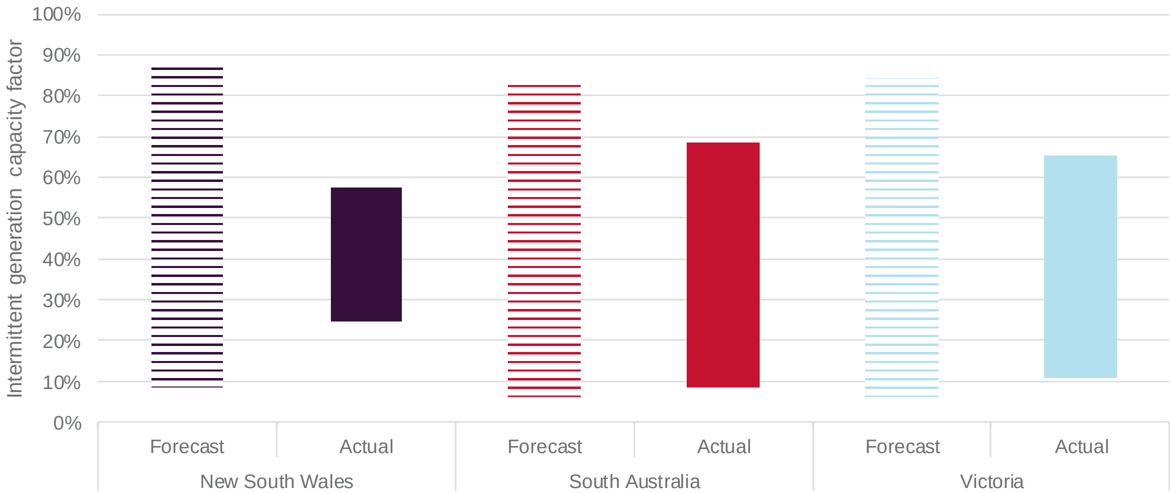
- The aggregate reliability of New South Wales coal-fired generation has been relatively consistent in the last two years. The forecast reliability in 2018-19 was well aligned with actual reliability. Despite this, the actual performance of the New South Wales coal-fired generation fleet during the hottest period of the summer was frequently above the simulated range due to the lack of extreme temperatures.
- The reliability of Queensland coal-fired generation was well matched with the simulated performance in the 2018 ESOO.
- Victorian brown coal-fired generation showed continued reliability deterioration, with the aggregated forced outage rate over five times the rate observed between 2011-12 and 2014-15. The outage rates used in the 2018 ESOO were well below the rates observed in 2018-19. Furthermore, an analysis of high temperature periods also showed that the reliability of the brown coal was frequently below the simulated range of brown coal reliability, at these critical times.
- The reliability of other technologies (hydro and gas) was generally within the simulated range during high temperature periods. The forecasts were similar to observed reliability, except for closed-cycle gas turbines (CCGTs) and large open-cycle gas turbines (OCGTs) where the outage rates were underforecast and overforecast respectively.

[22] Further details on the methodology used to calculate forced outages and how they are applied in the market modelling can be found at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/ESOO-Methodology-Document.pdf.

7.1 Variable renewable energy ranges

Figure 50 below shows the forecast and actual range of capacity factors that variable renewable energy (VRE) operated at during the identified 10 hottest days for Victoria, New South Wales and South Australia. The figure shows that the actual operating range of generation was within forecast range, as expected.

Figure 50 VRE capacity factor range during hot temperature days



7.2 New South Wales black coal generation availability

Black coal-fired generation in New South Wales has no strong trend in the rate of unplanned outages. Figure 51 shows how the rates of unplanned outages have changed over time, relative to recent forecasts.

Figure 51 New South Wales black coal full unplanned outage rates

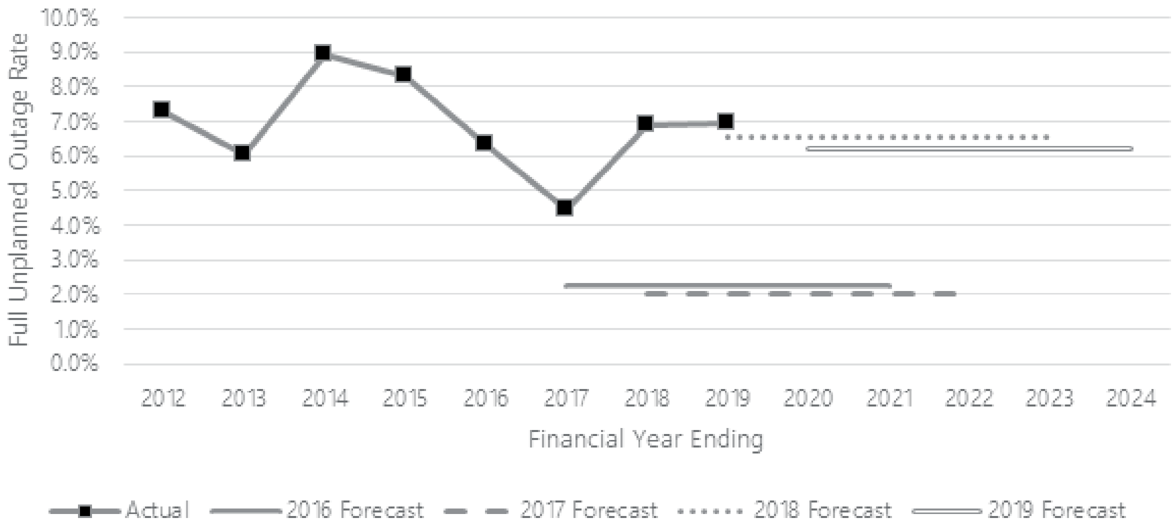
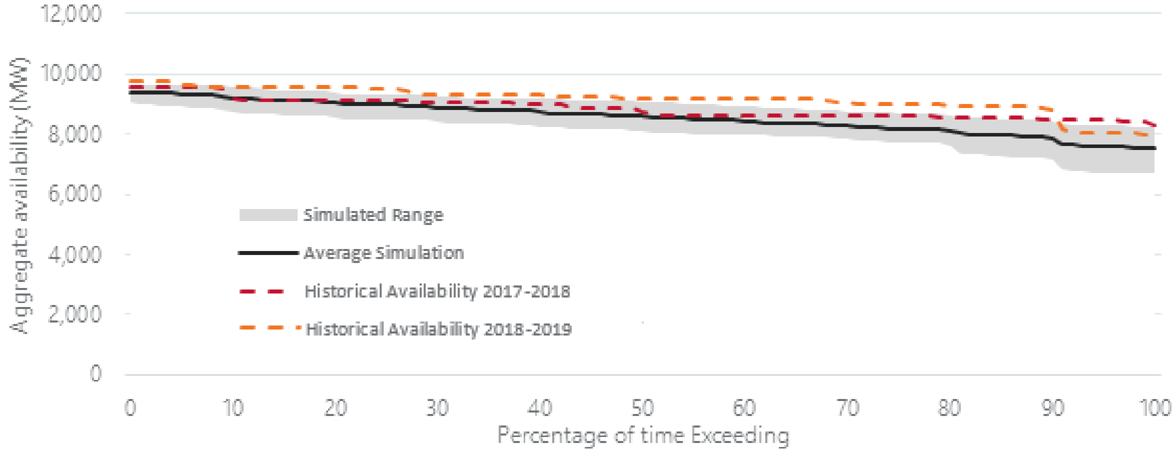


Figure 52 shows that availability over the identified top 10 hottest days slightly exceeded the simulated availability.

Figure 52 New South Wales black coal supply availability – top 10 hottest days



Despite the forecast of forced outages being closely aligned to actual forced outage rates in 2018-19, the observed availability during the hottest days was above the simulated range. One reason for this is that, for all trading intervals across summer the capacity assumed when a generator is not on a planned outage is based on the plant availability at the time the reference node is experiencing a 10% POE demand peak; these are provided as reference temperatures for each region. The summer rating provided by generators should represent the capacity expected from units given the ambient conditions at the generator location that occur when the reference node is experiencing the reference temperature specified.

In New South Wales, the reference temperature is 42°C; the maximum temperature over the top 10 days in 2018-19 was between 36.0°C and 39.6°C. As a result, a number of generators did not derate to their modelled summer rating, therefore increasing aggregate availability compared to the simulated range.

Further, the effective outage rate during the high temperature periods was lower than average outage rates throughout the year.

7.3 Queensland black coal generation availability

Black coal generation in Queensland has no clear trend in unplanned outage rates. Figure 53 shows how the rates of unplanned outages have changed over time relative to recent forecasts.

Figure 53 Queensland black coal full unplanned outage rates

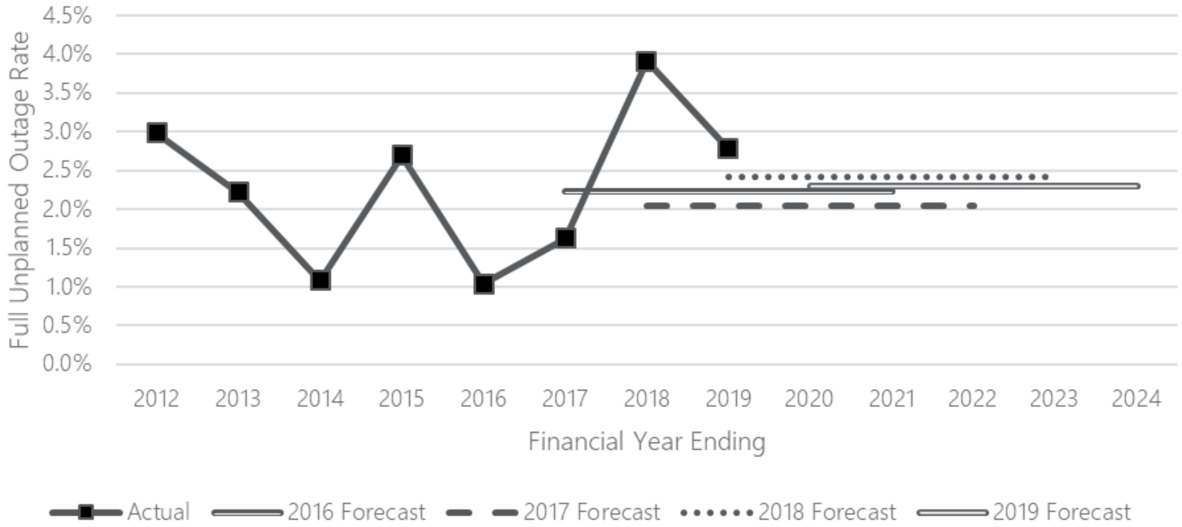
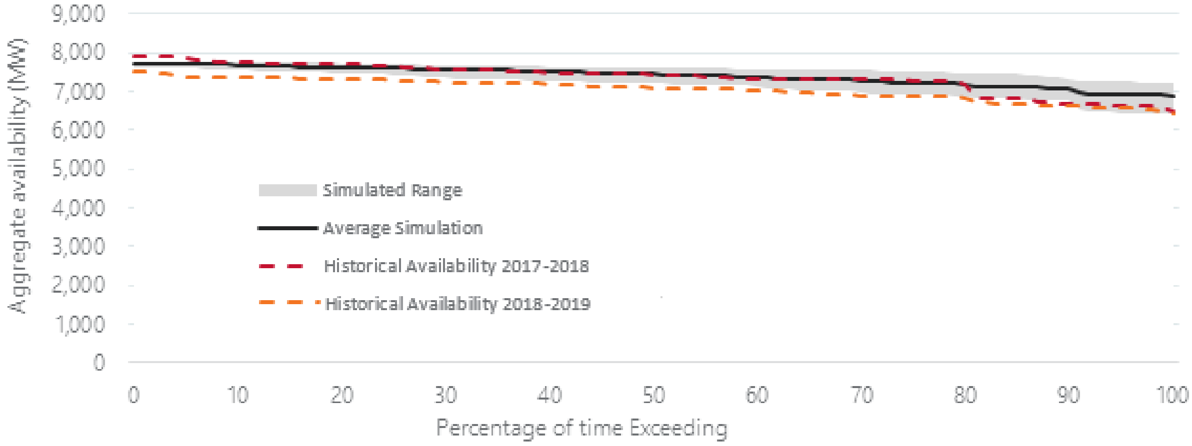


Figure 54 shows that availability over the top 10 hottest days was less than the simulated availability.

Figure 54 Queensland black coal supply availability – top 10 hottest days



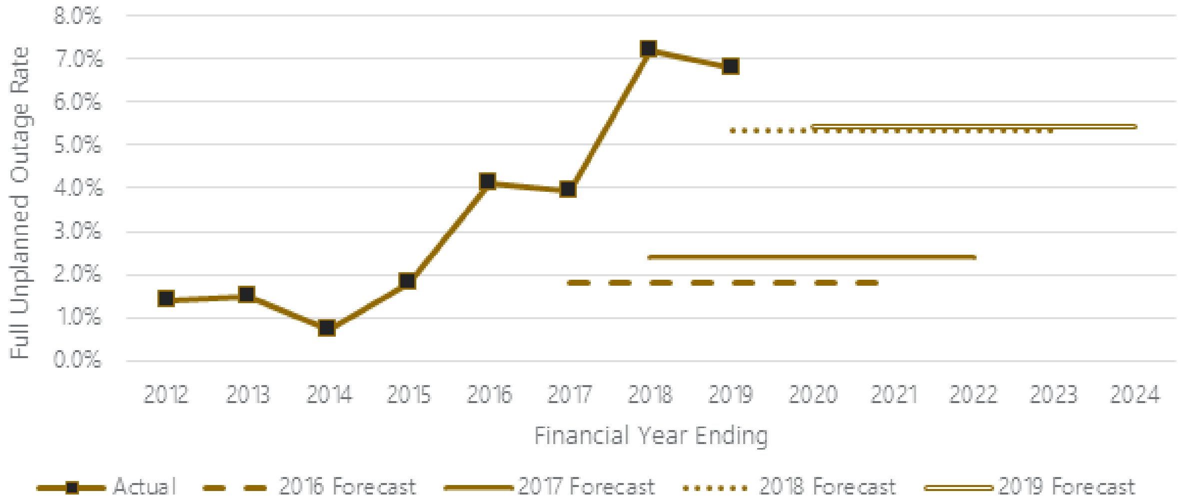
The observed availability in 2018-19 is lower than the simulated range, due to outages and/or unavailable capacity at several units. Queensland has a surplus of available capacity relative to maximum demand, so there are periods where capacity may not be offered as available, as it was not required despite the extreme temperature.

7.4 Victorian brown coal generation availability

Brown coal generation in Victoria has a significant upward trend in full unplanned outages, as shown in Figure 55. The outage rate of brown coal in aggregate in 2018-19 continued the recent trend of deteriorating reliability.

Because the forecasts are based on an average of historical observed outage rates, the forecast rate has been consistently lower than the observed rate. The rates for the 2016 and 2017 forecasts were well below realised performance, because these forecasts were based on longer-term averages, whereas more recent forecasts have focused on recent performance given its increased relevance for forecasting reliability in the future.

Figure 55 Victorian brown coal full unplanned outage rates

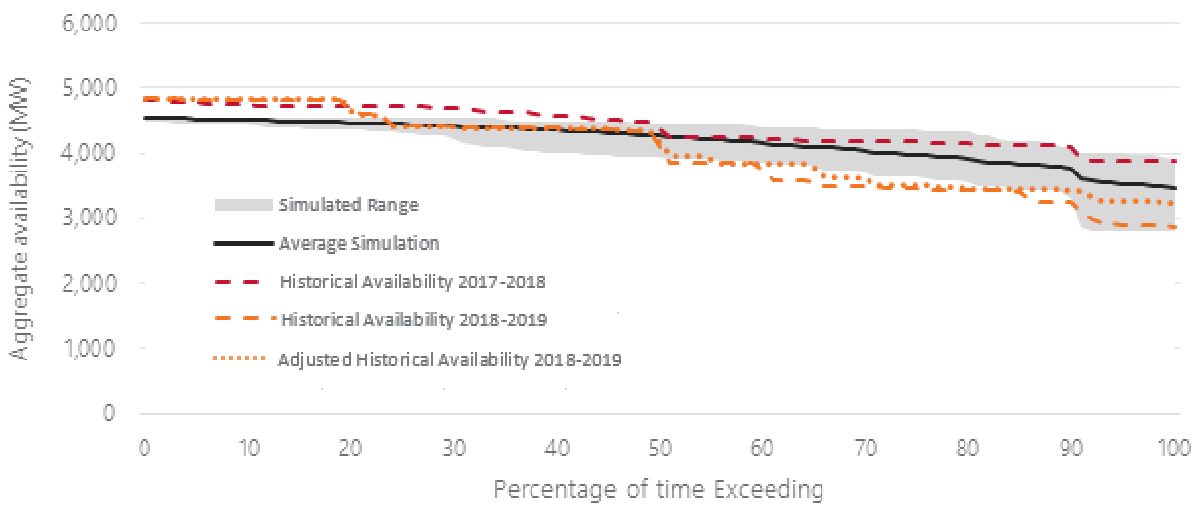


Note: The historical data and forecast outage rates in the 2016 and 2017 ESOO forecasts has been revised to account for the removal of Hazelwood Power Station.

Figure 56 shows the availability over the top 10 hottest days was frequently less than the simulated availability. In 2018-19, the observed availability was at times lower than the simulated range, and was generally at the lower end of the simulated range for the poorest performing days. This was due to multiple, coincident outages during these high temperature days.

One of the outages occurring on two of the high temperature days was a planned outage. It was assumed in the 2018 ESOO that this outage would have been conducted in a lower risk period, typically before the start of summer. However, in this case, overdue and urgent maintenance was planned for 19-26 January where, at the time, no lack of reserves (LORs) were forecast. As planned outages are not included in the calculation of the unplanned outage rate, a second line has been added (the dotted orange line) to show the effect, should the unit have been fully available. Victorian brown coal outages are considered to be one of the primary causes of the 25 January 2019 Victorian load shedding event.

Figure 56 Victorian brown coal supply availability – top 10 hottest days



7.5 Hydro generation availability

Hydro generation has obvious trends in the rate of full unplanned outages. Figure 57 shows how the rates of unplanned outages have changed over time relative to recent forecasts.

Figure 57 NEM hydro full unplanned outage rates

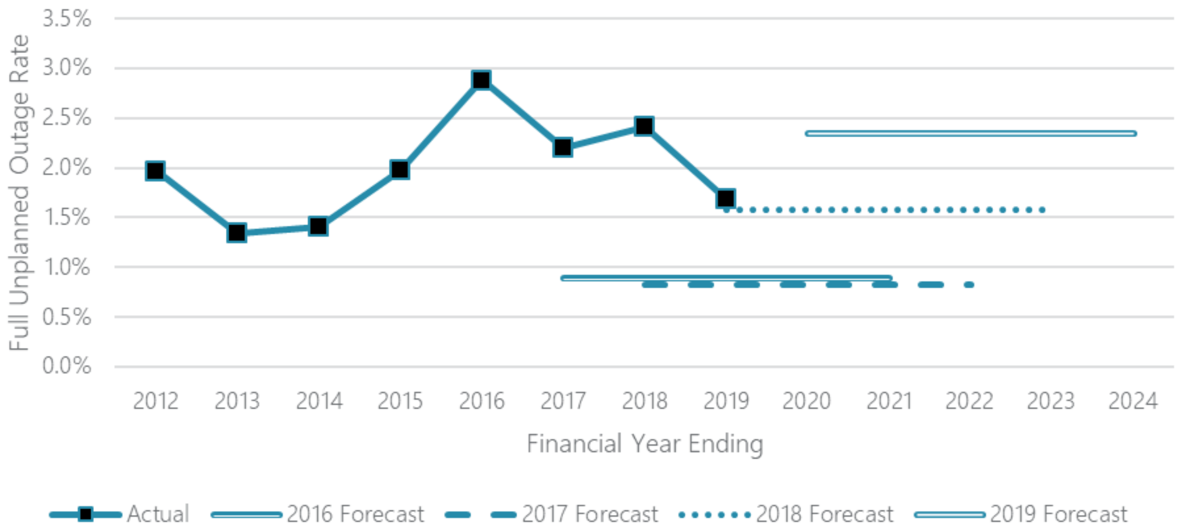
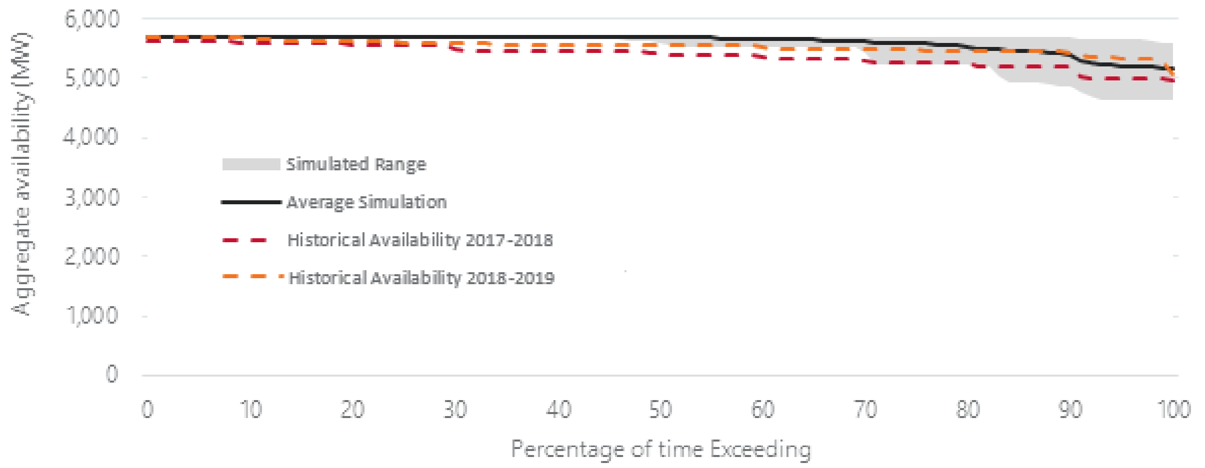


Figure 58 shows that availability over the top 10 hottest days was broadly consistent with the 2018 ESOO simulation for mainland NEM hydro generation.

Figure 58 Mainland hydro supply availability – top 10 hottest days



7.6 Gas and liquid fuel generation availability

The category of gas-fired and liquid-fired generators include OCGTs, CCGTs, gas-fired steam turbines, and small peaking plant. Full unplanned outage rates have been trending above recent forecasts for both CCGT and small peaking plant. The full unplanned outage rates are shown for each below, while availability is assessed in aggregate.

Figure 59 NEM CCGT full unplanned outage rates

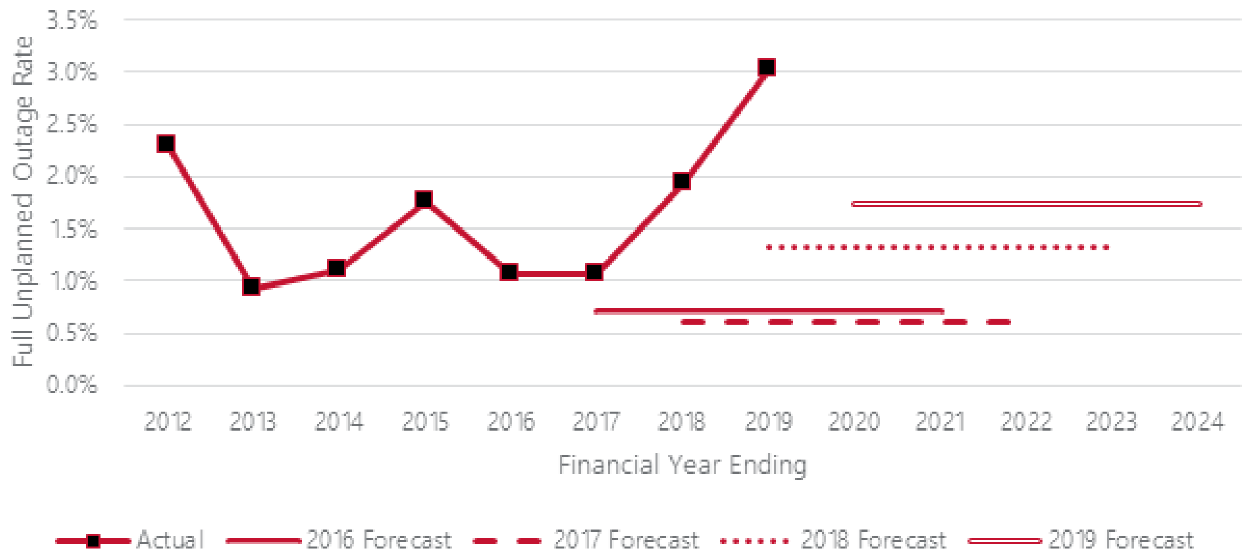


Figure 60 NEM OCGT full unplanned outage rates

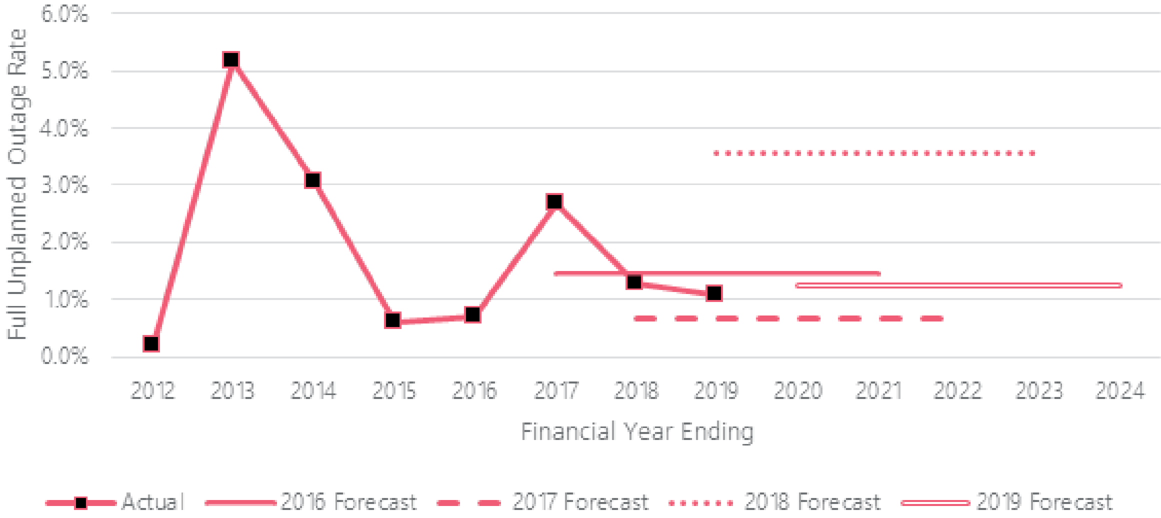


Figure 61 NEM steam turbine full unplanned outage rates

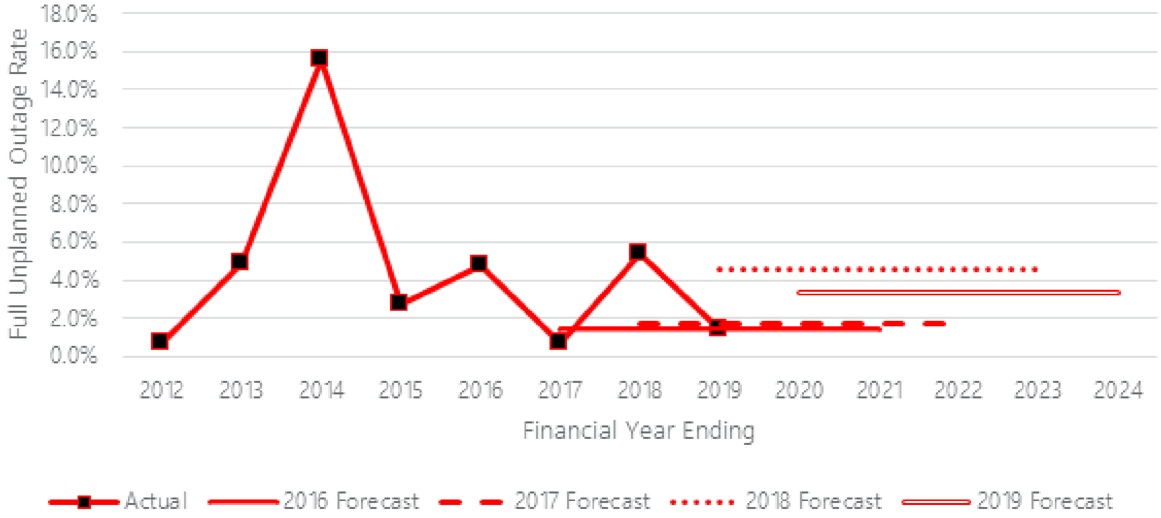


Figure 62 NEM small peaking plant full unplanned outage rates

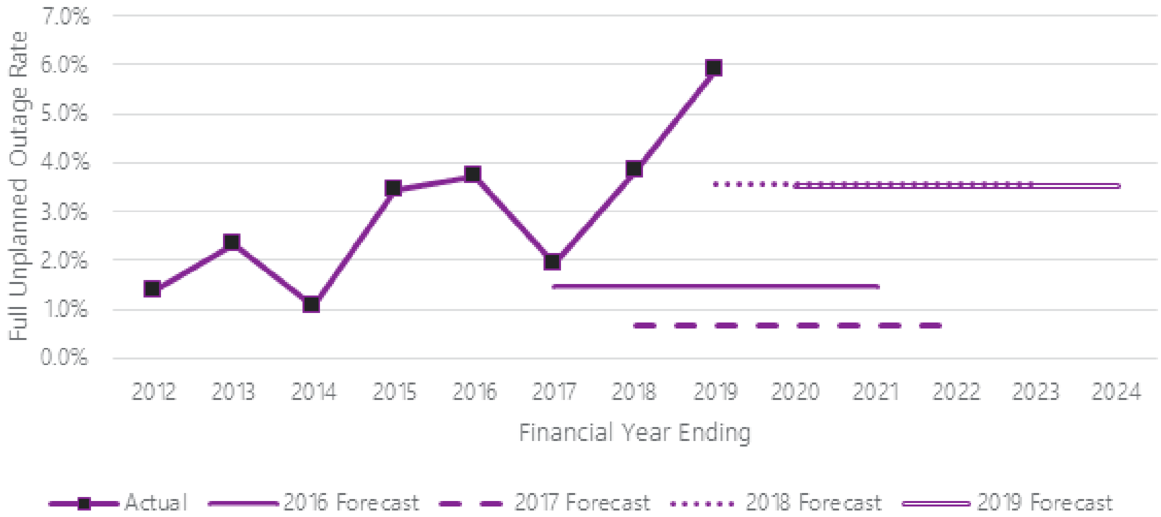
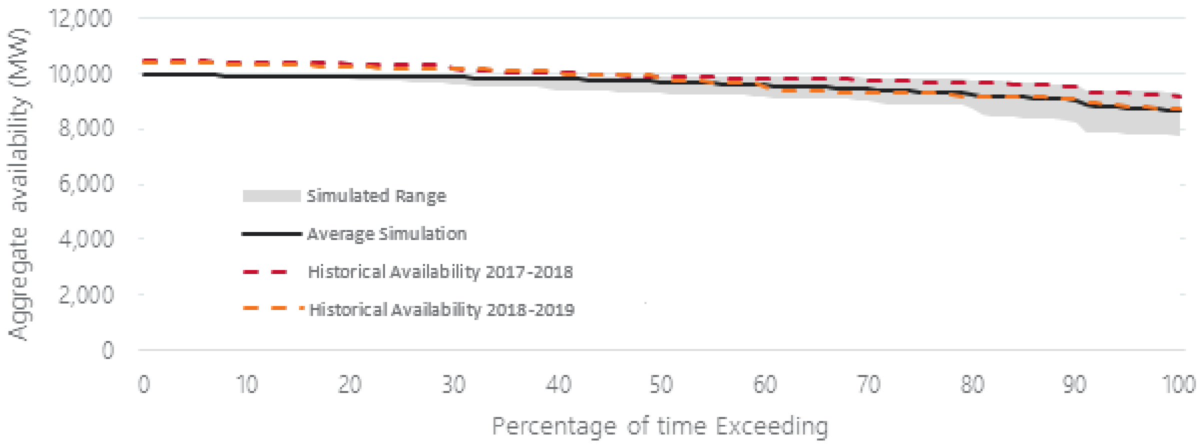


Figure 63 shows the observed availability of all gas- and liquid-fuelled capacity in aggregate against the simulated range. It can be seen that the observed availability has tended towards the upper bound of the 2018 ESOO simulation range. The main reason observed availabilities are higher than simulated outcomes is that many generators outperformed their rated summer capacity.

As discussed in Section 7.1, the summer capacity is based on the summer reference temperature for each region. There are few periods in 2018-19 across the regions where the observed temperature reached or exceeded the reference temperature. As a result, there are many intervals during the identified top 10 hottest days where generator capacity significantly exceeds the summer rating. This is the primary driver of actual availability being above the simulated range.

Future improvements to the modelling of seasonal capacity will be investigated (see Section 9).

Figure 63 Gas and liquid supply availability – top 10 hottest days

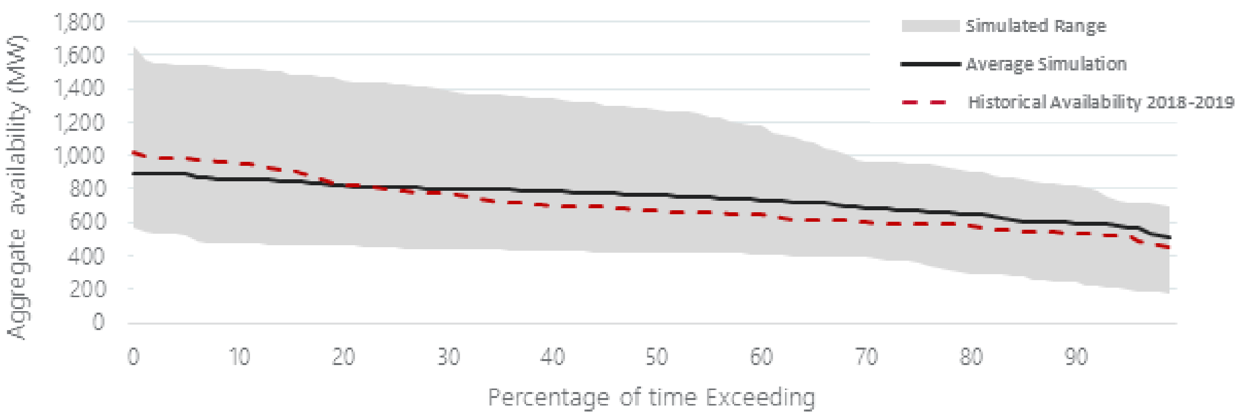


Note: This aggregation includes OCGTs, CCGTs, gas-fired steam turbines, and liquid-fuelled generation (except those in Tasmania).

7.7 New South Wales VRE availability

All VRE, including large-scale grid solar PV and wind in New South Wales, was considered in aggregate. VREVRE is modelled differently from thermal and hydro generation because periods of low or no demand are simulated using historical load traces. As Figure 64 shows, the 2018 ESOO simulated a wide band of possible VRE for New South Wales on the 10 hottest days, based on these historical traces, and observed output for summer 2019 was within the simulation range.

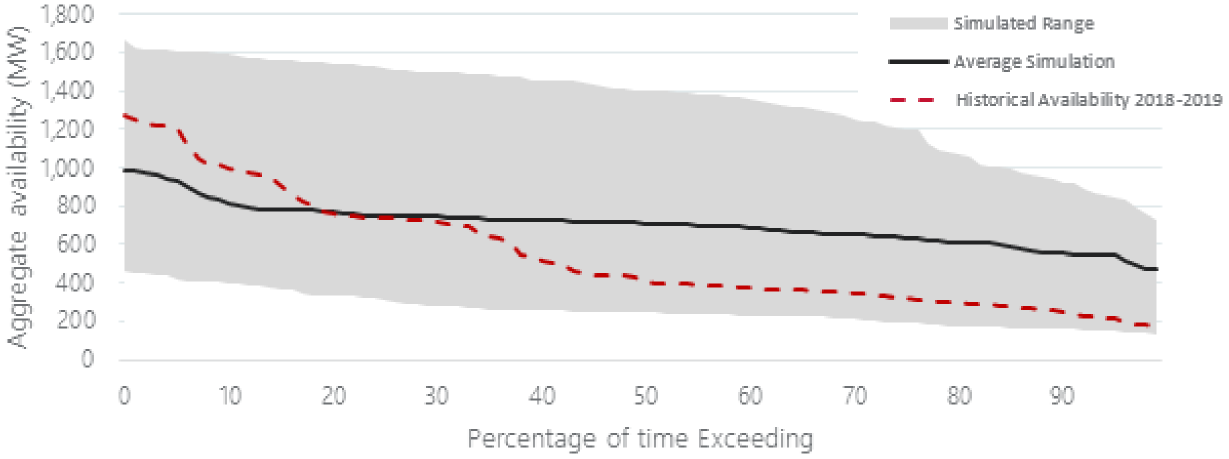
Figure 64 New South Wales VRE availability – top 10 hottest days



7.8 South Australian VRE availability

All VRE for South Australia has been considered in aggregate. As Figure 65 shows, the 2018 ESOO simulated a wide band of possible VRE for South Australia on the identified 10 hottest days, and observed output for summer 2019 tended towards the lower end of the simulation range.

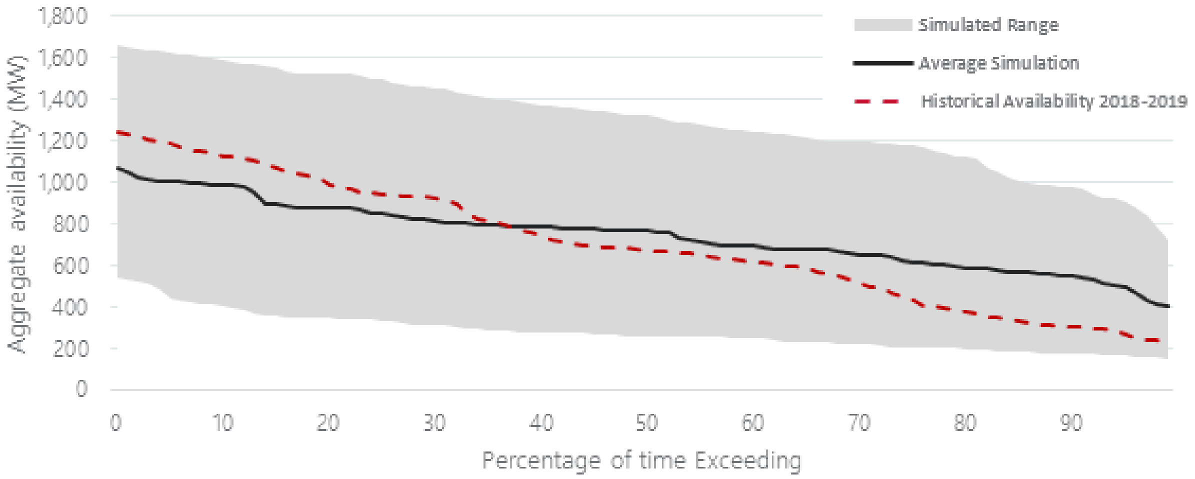
Figure 65 South Australian VRE availability – top 10 hottest days



7.9 Victorian VRE availability

All VRE for Victoria was considered in aggregate. As Figure 66 shows, the 2018 ESOO simulated a wide band of possible VRE for Victoria on the identified 10 hottest days, and observed output for summer 2019 was within the simulation range.

Figure 66 Victorian VRE availability – top 10 hottest days



7.10 Demand Side Participation

AEMO forecast DSP for use in its medium to long term reliability assessments (MTPASA, EAAP and ESOO) as well as the ISP. It represents reduction in demand from the grid in response to price or reliability signals. In AEMO's modelling it is treated similarly to supply options as a way to ensure demand can be met.

AEMO publishes updated DSP forecast typically once per year. The DSP forecast[23] used for the 2018 ESOO was published in March 2018 and is the one assessed in the following section.

Background

The underlying methodology for forecasting DSP has been used since 2013, whereby AEMO assesses demand reduction responses from large industrial loads and any other load market participants. The responses at half hourly level to various price triggers over the previous three years are aggregated to a regional response per event. The forecast aggregate response in a region for a particular trigger is then estimated as the 50th percentile of the recorded historical responses.

To this comes network reliability programs. These are operated by network service providers and assumed only to operate during grid emergencies, in practical terms when the system is in an actual LOR2 or LOR3 state (see NER clause 4.8.4 for definition). These programs are generally only active in summer, causing the difference in forecast DSP between the seasons.

To date, AEMO's DSP forecast excludes[24]

- 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[25].

This is to avoid double-counting for the first three items as these 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 resources cannot therefore be included in the DSP forecasts.

Assessment of DSP forecast accuracy

This is the first formal post-assessment of the accuracy of the DSP forecasts undertaken by AEMO. It is based on two components:

- An assessment of the median (50th percentile) observed DSP response for various wholesale price triggers during the 2018-19 year compared to forecast median response.
- An assessment of the estimated DSP response during the regional maximum demand events against the forecast DSP reliability response.

DSP response by price trigger levels

Price responses of the 2018 DSP forecast are assessed using summer 2018-19 consumption data for the same list of DSP resources as the 2018 forecast and estimating the response when wholesale prices reach the different price triggers.

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 behaviour (adopted for the DSP forecast) is a reasonable indicator of what actually happens. The responses of the DSP resources used in the 2018 forecast is highly variable. 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 unreliable.

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[23] See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Demand-Forecasts/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation.

[24] Further detail on why certain programs are excluded from the DSP that is applied to the ESOO and ISP forecasts is included in AEMO's 2019 release of the DSP Forecast and Methodology report, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.

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

Comparison results are shown in Figure 67 through to Figure 71 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 responses in New South Wales were lower than forecast however only four periods occurred where prices were higher than $500/MWh and this is expected to have contributed to observed responses being low.
- It was not possible to reliably assess Queensland which did not experience enough high price events to apply to the evaluation.
- Median responses in South Australia agreed reasonably well with the forecast, however additional DSP in 24 January led to a higher actual DSP (30 MW, discussed later in this chapter)
- Median responses in Tasmania agreed reasonably well with the forecast.
- Median responses in Victoria agreed reasonably well with the forecast however observed response magnitudes decreased with price in Victoria. This is attributed to increased variability in calculated responses combined with fewer event periods to formulate a stable median response.

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

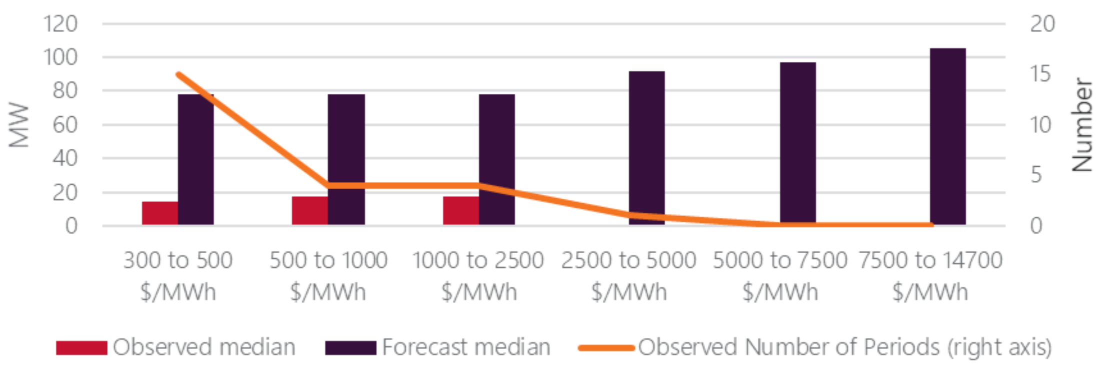


Figure 68 Evaluation of actual compared to forecast price-driven DSP in Queensland

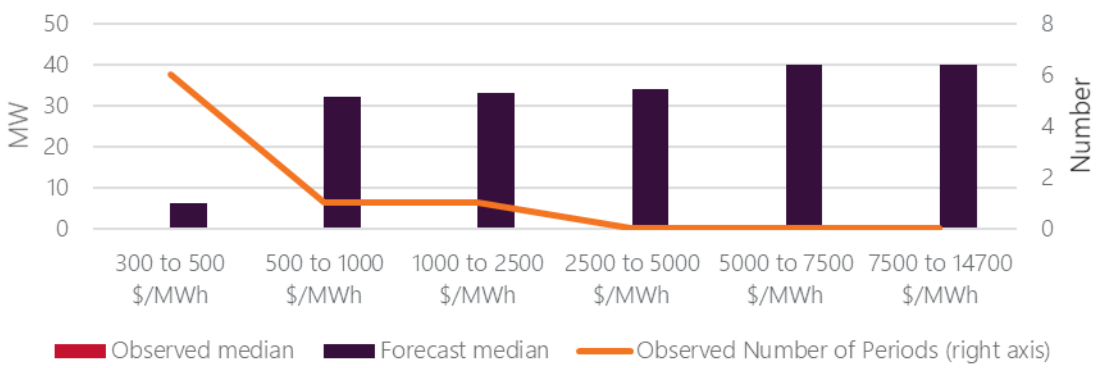


Figure 69 Evaluation of actual compared to forecast price-driven DSP in South Australia

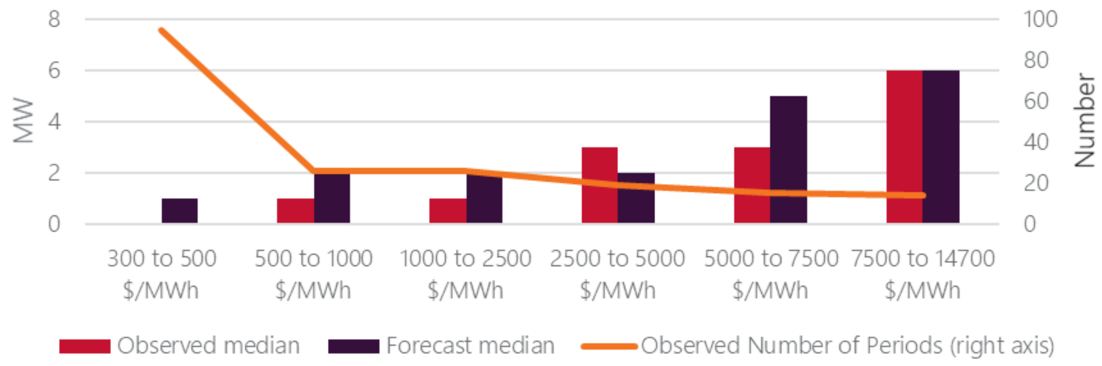


Figure 70 Evaluation of actual compared to forecast price-driven DSP in Tasmania

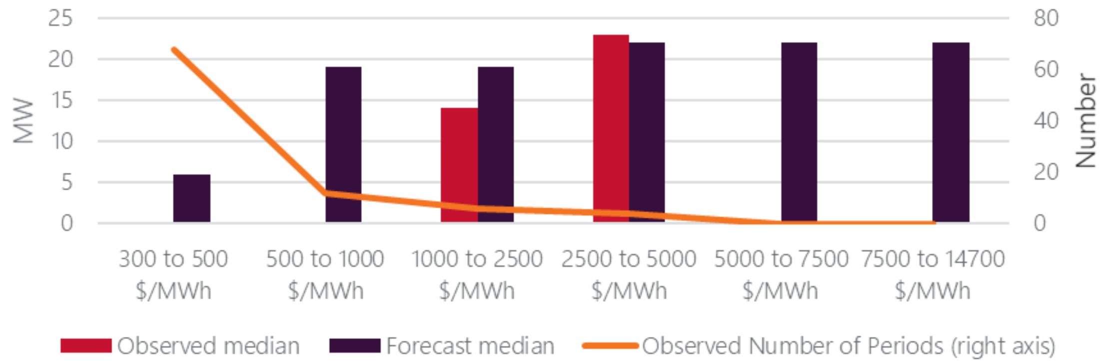
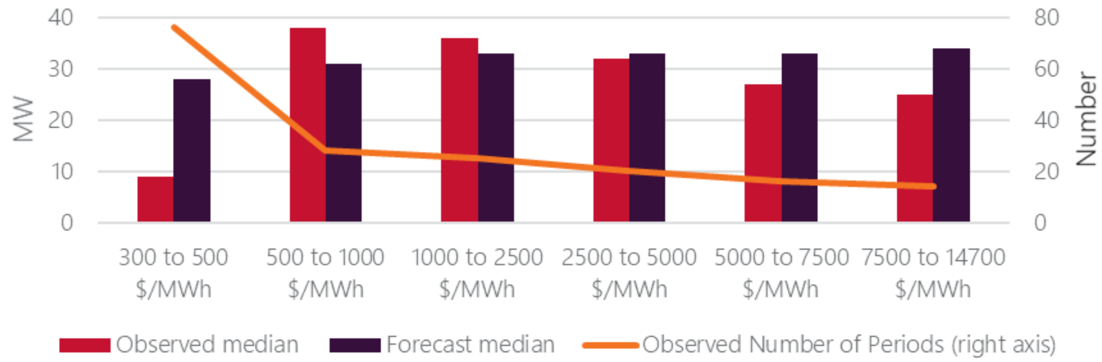


Figure 71 Evaluation of actual compared to forecast price-driven DSP in Victoria



DSP response during reliability events

The reliability response from the 2018 forecast is shown in Table 20. It represents the forecast DSP where the system is in an actual LOR2 or LOR3 state.

Table 20 Forecast reliability response in MW

	NSW	QLD	SA	TAS	VIC
Summer	105	66	6	23	77
Winter	105	46	6	23	40

For comparison, AEMO has assessed the amount of DSP for the peak demand days of the 2018-19 year:

New South Wales: This region had particularly high demand on 18 and 31 January. Only for one half hour on 18 January did the regional wholesale price exceed $300/MWh though. No response to that event can be observed, though one particular load had reduced consumption by 20 MW throughout the late afternoon and early evening on the day.

Queensland: A new record maximum demand was reached on 13 February 2019. The thresholds for LOR2 or LOR3 were however not met. Prices remained well below $300/MWh across the day, so no price driven DSP was recorded. Energy Queensland did operate its controlled air-conditioner program for an expected impact of 20 MW at time of the maximum observed demand.

South Australia: This region had its 2018-19 maximum demand in the evening of 24 January. Prices were at the market price cap ($14,500/MWh) for much of the evening and an actual LOR2 was declared. AEMO estimated the DSP observed at time of the peak to 30 MW. This is higher than forecast, but in line with the 2019 DSP forecast. An additional 6 MW was activated under RERT, which therefore was excluded from the forecast.

Tasmania: Being winter peaking, Tasmania had its annual maximum demand on June 24. 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 close to record demand both on 24 and 25 January following an extreme heat wave causing directed load shedding to occur on both days. At time of the observed maximum demand on 25 January, the price driven DSP response was limited to around 17 MW, with another 56 MW delivered by network reliability programs. Accounting for load shedding and RERT[26], it is estimated that the actual peak would have occurred later on the 25th, with no price driven response observed at that time (the Cumulative Price Threshold[27] had been met and prices capped at $300/MWh) and network reliability programs delivering 54 MW of response.

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

- In South Australia, the observed response of 30 MW was significantly higher than the forecast response of 6 MW. The 2019 DSP forecast[28] estimates a reliability response for South Australia of 33 MW, closely aligned with what was observed last summer.
- Victoria, saw an estimated response at time of the observed peak demand of 73 MW, well aligned with the forecast 77 MW. However, at the time when the estimated peak demand would have occurred in the absence of RERT activation and load shedding, only 54 MW was response, none of it from price driven DSP. The peak occurred early in the day and outside the defined response period of another network reliability program.

It highlights the uncertainty of forecasting DSP and impacts of time of day of the response and whether the CPT is met during potential reliability events.

[26] To minimize involuntary load shedding, significant amounts of demand side resources were activated under the RERT program.

[27] See National Electricity Rules clause 3.14.

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

8. Reliability forecasts

AEMO forecasts and reports on scarcity risk of generation supply availability relative to demand. Reliability in this context does not include outages arising from network capacity shortfall or failure. This forecast of reliability risk is an implementation of the Reliability Standard Implementation Guidelines[29], with the expectation that the market will respond to avoid USE occurring. Further, in operational timeframes, AEMO uses RERT and other operational mechanisms to avoid USE events where possible.

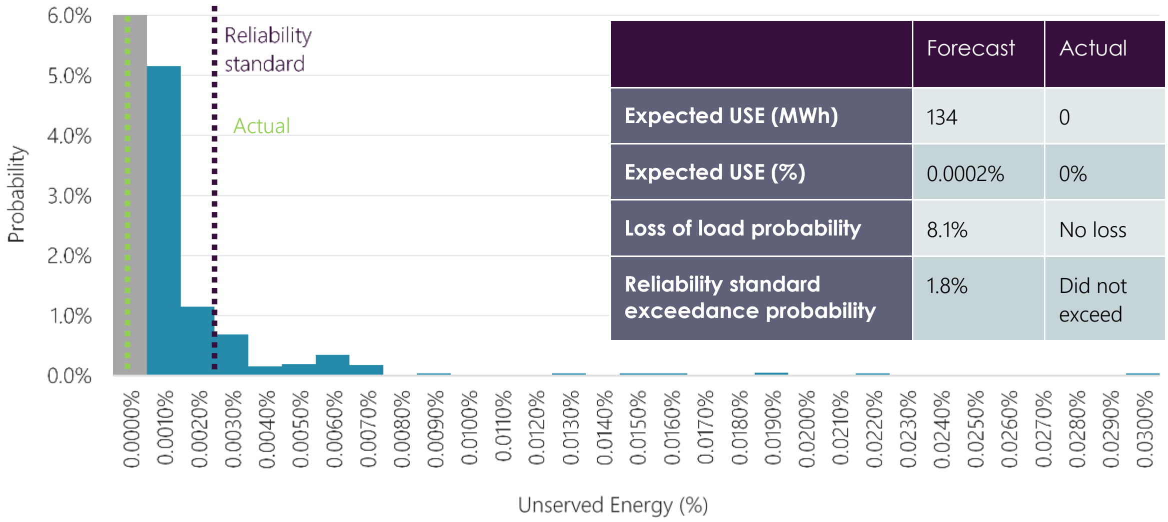
Additionally, risk of USE is forecast as a probability distribution which is long-tailed – that is, most simulations do not involve a USE event, while a small number involve large USE events.

As such, reliability forecasts are not presented for the purposes of assessing forecast accuracy, but rather for information only.

8.1 New South Wales

Figure 72 shows the forecast distribution of USE in New South Wales in the 2018 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 8.1%. In 2018-19 no load was lost, an outcome predicted with 91.9% probability.

Figure 72 New South Wales USE 2018 forecast distribution for 2018-19 summer



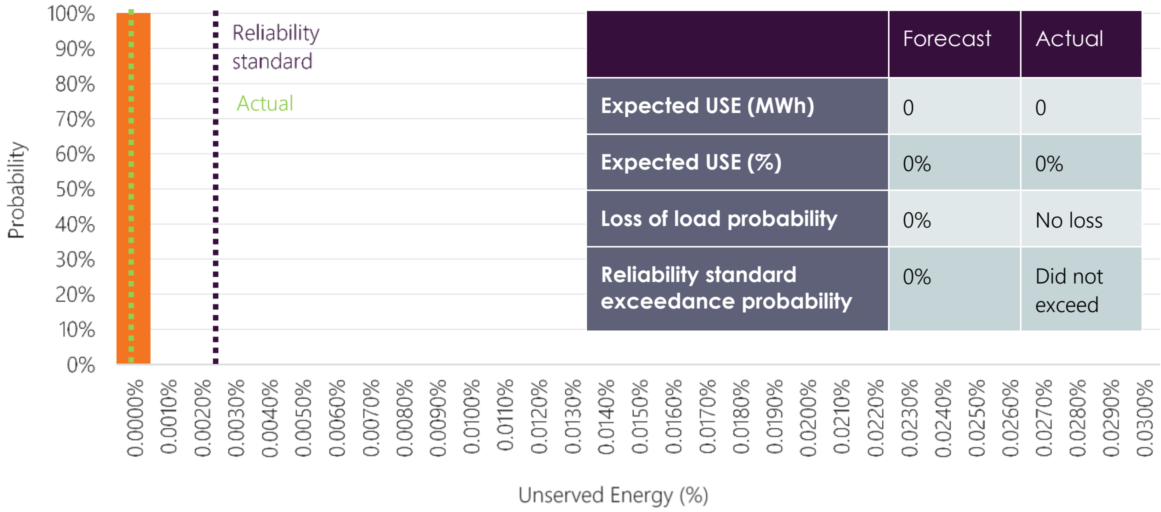
	Forecast	Actual
Expected USE (MWh)	134	0
Expected USE (%)	0.0002%	0%
Loss of load probability	8.1%	No loss
Reliability standard exceedance probability	1.8%	Did not exceed

8.2 Queensland

Figure 73 shows the forecast distribution of USE in Queensland in the 2018 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2018-19, despite the summer load exceeding expectation, no load was at risk, due to surplus supply availability.

[29] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2018/Reliability-Standard-Implementation-Guidelines---MT-PASA-Final-May-2018.pdf.

Figure 73 Queensland USE 2018 forecast distribution for 2018-19 summer

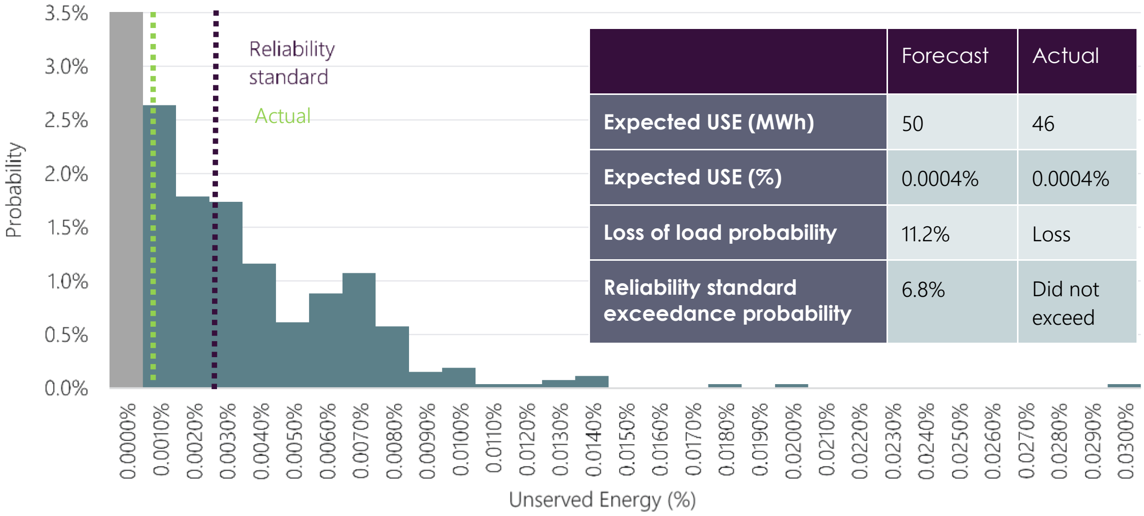


	Forecast	Actual
Expected USE (MWh)	0	0
Expected USE (%)	0%	0%
Loss of load probability	0%	No loss
Reliability standard exceedance probability	0%	Did not exceed

8.3 South Australia

Figure 74 shows the forecast distribution of USE in South Australia in the 2018 ESOO, and overlays the actual level of USE that was observed in the 2018-19 financial year. The distribution shows a long low probability tail of a large USE event, and the probability of an USE event was assessed at 11.2% (88.8% of simulations did not result in an outage). An event occurred in South Australia on 24 and 25 January 2019, resulting in 46 MWh of USE. The USE that did occur in 2018-19 was equivalent to the 78th percentile of forecast USE.

Figure 74 South Australia USE 2018 forecast distribution for 2018-19 summer

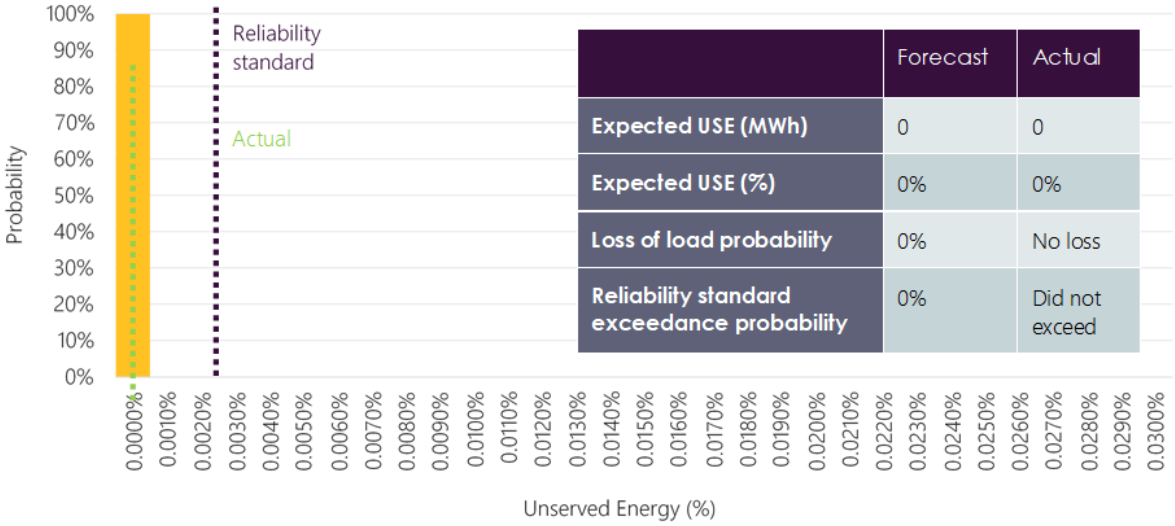


	Forecast	Actual
Expected USE (MWh)	50	46
Expected USE (%)	0.0004%	0.0004%
Loss of load probability	11.2%	Loss
Reliability standard exceedance probability	6.8%	Did not exceed

8.4 Tasmania

Figure 75 shows the forecast distribution of USE in Tasmania in the 2018 ESOO. The distribution shows that no USE events were forecast by the simulations. In 2018-19, no load was lost, consistent with expectation.

Figure 75 Tasmania USE 2018 forecast distribution for 2018-19 summer

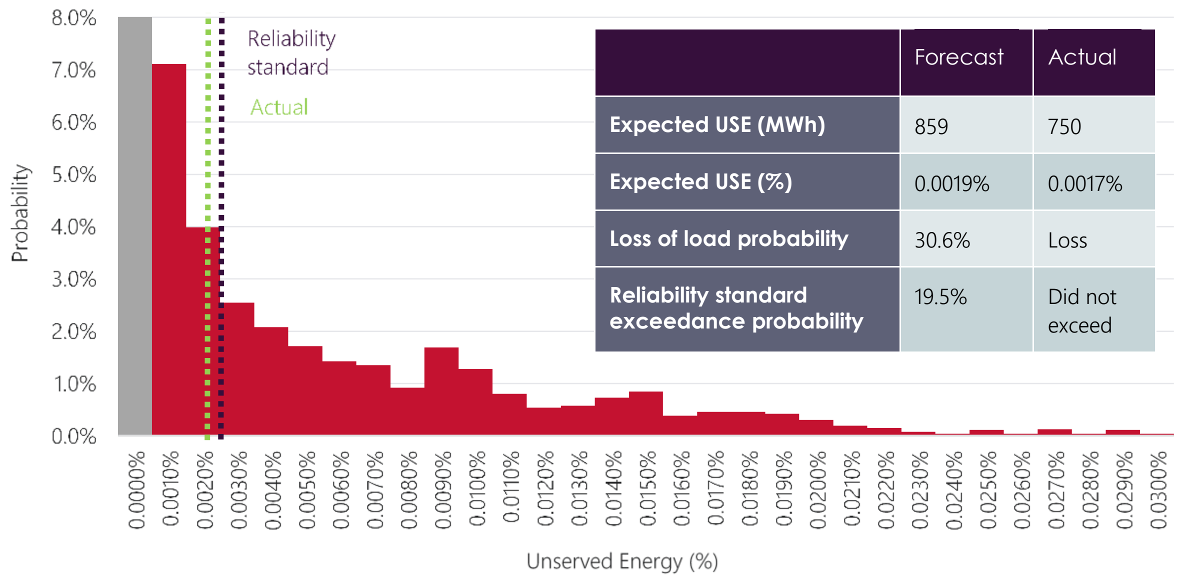


	Forecast	Actual
Expected USE (MWh)	0	0
Expected USE (%)	0%	0%
Loss of load probability	0%	No loss
Reliability standard exceedance probability	0%	Did not exceed

8.5 Victoria

Figure 76 shows the forecast distribution of USE for Victoria in the 2018 ESOO and overlays the actual level of USE that was observed in the 2018-19 financial year. The distribution shows a long low probability tail of a large USE event, and the probability of a USE event was assessed at 30.6% (69% of simulations did not result in an outage). Load shedding events occurred in Victoria on 24 and 25 January 2019, resulting in 750 MWh of USE. The USE that did occur in 2018-19 was equivalent to the 84th percentile of forecast USE.

Figure 76 Victoria USE 2018 forecast distribution for 2018-19 summer



	Forecast	Actual
Expected USE (MWh)	859	750
Expected USE (%)	0.0019%	0.0017%
Loss of load probability	30.6%	Loss
Reliability standard exceedance probability	19.5%	Did not exceed

9. Improvement plan

This year's Forecast Accuracy Report has been expanded to reflect the importance of forecast accuracy to industry decision-making and to improve 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.

The following section:

- Summarises key observations on the performance of the 2018 forecasts from this year's Forecast Accuracy Report.
- Discusses a high-level action plan for priority improvements in 2020.
- Lists improvements already made in the 2019 forecasts that may already help improve accuracy in areas needing focus.

9.1 2018 forecasts – summary of findings

Input drivers of demand

Input variable forecasts were not well aligned with actuals in several cases.

Economic growth and connections growth did not reach expectation in many regions, however, are not a large driver in year-ahead accuracy. In the case of Tasmania and Victoria, connections growth met or exceeded forecasts, however energy consumption actuals were below forecast, confirming a weak year-ahead relationship.

Growth in rooftop PV also failed to reach forecast levels for most regions, with significant implications for year-ahead accuracy. The lower number of PV systems installed compared to forecast resulted in an under forecast of grid supplied consumption and an over estimate of the rate of decline in minimum demand in the 2018 ESOO.

Revision to loss factors also had an impact on accuracy for energy consumption and demand forecasts, particularly in South Australia. As the forecasts were determined pre-revision, some actuals have varied from forecast, however revisions are infrequent and are not typically forecastable.

Demand forecasting processes are not fitted to a specific weather prediction, or seasonal outlook. Instead they consider short, medium and long term weather and climate trends through numerous simulations. Weather observed was consistent with those simulated including the above average temperatures in 2018-19 summer.

Energy consumption

The annual operational consumption (sent out) actuals were within 3% of forecast for South Australia, Tasmania, and New South Wales, while Queensland and Victoria were not.

The +3.1% error for Queensland is mostly explained by higher than forecast demand from the CSG/LNG sector and lower than forecast uptake of PV capacity. Where possible, AEMO is working with Powerlink and LNG producers to improve its understanding of future demand from the CSG sector

The -3.8% error for Victoria cannot be explained by model inputs, and appears to be impacted by poor alignment between energy consumption history and forecast component based trends. In this case, medium-term trends may be appropriate based on the structural drivers of the scenario in question, including components, but accuracy may be improved by overlaying shorter-term dynamics to help ensure a smooth transition from history to scenario forecast.

Once variations in model inputs were considered for other regions, energy consumption models performed well, although there is some evidence of minor misalignment.

Extreme demand events

The summer maximum demand actuals occurred within forecast expectation given observed weather for all regions, except Queensland, for which the actual exceeded forecast expectation.

The winter maximum demand actuals occurred within forecast expectation for all regions, except Queensland and South Australia, which exceeded expectation, and Victoria, which was below expectation.

The annual minimum demand forecasts did not perform particularly well; actuals were above forecast in New South Wales, South Australia, and Victoria, while actuals were below forecast in Tasmania.

In most cases, the discrepancy can be explained by model inputs. For example:

- PV is a significant driver of daytime minimums. The overforecast of PV therefore had a material impact on minimum forecasts across most regions.
- Energy consumption forecasts are used within demand models to shape trends. The underforecast of LNG/CSG in Queensland resulted in an underforecast of all Queensland maximums and minimums.

The energy consumption and extreme demand forecasts are further implemented in connection point forecasts and demand traces. In both cases, the implementations mirrored the observed regional trends. For example, monthly maximum demand forecasts taken from demand traces for Queensland showed a similar discrepancy to the annual summer value. Additionally, the high summer maximum observed in South Australia was also observed across many of the connection points within South Australia.

Input drivers of supply

AEMO collects generation information reported from generation industry participants, via a web-based online system, and regularly publishes updates of information collected.

There were a number of projects that were delayed and were not available during summer as expected. The largest discrepancy was in Queensland, where nine expected generator projects were not commissioned in time for summer.

Despite the discrepancy, the impact on summer generator supply availability was not material.

Supply availability

Actual supply availability was well aligned with forecast for New South Wales and Queensland coal generators.

The 2018 ESOO over-forecast the reliability of brown coal in Victoria and CCGTs in the NEM. Observed brown coal aggregated forced outage rates were over five times the rate observed between 2011-12 and 2014-15. The impact of the higher than expected brown coal-fired generation forced outage rates produced a material impact on supply availability, contributing to observed supply scarcity, particularly in Victoria.

The actual supply availability for Hydro, OCGTs, and VRE was well aligned with forecast.

Reliability

South Australia and Victoria experienced supply shortfalls driven by high demand and coincident generator outages. These incidents were within the wide range of reliability outcomes forecast possible.

Despite higher than forecast demand in Queensland and lower than forecast newly installed VRE capacity, surplus supply capacity avoided any supply scarcity risk.

All demand was met in Tasmania and New South Wales; in both cases, demand and supply availability were within forecast expectation.

9.2 Forecast improvement priorities

Based on these findings, priority improvements have been identified that are expected to have the most material impact on forecast accuracy. Some of these improvements were able to be implemented in time for the 2019 ESOO. These include:

- Development of a multi-model ensemble for forecasting maximum and minimum demand – improving the performance of demand and reliability forecasts.
- Improvement of demand traces – which helps improve the monthly shape of demand for operational management of outage scheduling and the months at risk to be identified in any RRO reliability instrument.
- Generator new entrant modelling – ensuring supply assumptions use the best information available for reliability forecasting.

Two specific areas of new focus have been identified for 2020. These are:

- Operational energy consumption forecast methodology – greater accuracy will improve the performance of maximum demand and reliability forecasts in the next three to five years.
- PV forecasting – greater accuracy will improve the performance of operational energy consumption, demand, and reliability forecasts.

Other improvements of note are further discussed, including:

- Evidence of trends in forced outage rates of ageing coal generation – capturing the forward projections of plant reliability with more accuracy will improve the performance of supply and reliability forecasts.
- Changes to summer generation derations – to improve forecasts of generator availability by including both a "typical" summer rated capacity as well as an "extreme heat" summer rated capacity in future reliability forecasts.

AEMO invites written submissions on these proposed improvements and any other improvements stakeholders believe should be prioritised. Further details of these improvements will be discussed at the January 2020 Forecasting Reference Group (FRG).

Energy consumption forecast methodology

In some regions, Victoria in particular, poor alignment was observed between energy consumption history and forecast trends. Medium-term trends may be appropriate based on the structural drivers of the scenario in question, including components, but accuracy may be improved by overlaying shorter-term dynamics to help ensure a smooth transition from history to scenario forecast. The development of multi-model ensemble for energy consumption forecasts is proposed per region, specifically:

- Retain the existing annual component based scenario forecasts.
- Develop monthly time-series energy consumption forecasts for next three years.
- Use the short-term forecasts for reconciliation and comparison to ensure a smooth transition from history to scenario-based forecasts.

Development of multi-model ensembles was implemented within demand forecasting processes in 2019 and has proven successful. Implementation of multi-model ensembles for energy forecasts is expected to improve year-ahead forecast accuracy while preserving the structure and explainability of the component-based models.

Prototype models have been developed to test the improvement in accuracy. These models were developed such that 2018-19 was not included and is being tested out-of-sample. While past performance is not a guarantee of future performance, the following improvement was identified.

Table 21 Forecasting performance comparison

2018-19 year ahead forecast error	Actual performance	Prototype ensemble model performance
Mean Absolute Percentage Error	2.1%	1.0%

PV forecasts (already partially implemented in 2019 ESOO)

Rooftop PV and PV NSG are challenging to forecast, and remain a material driver of energy and demand forecast inaccuracy. For 2019, AEMO acquired expert forecasts from multiple consultants, yet short-term trends in installations and output are still problematic.

Specifically, AEMO intends to:

- Use the DER register and work more closely with the CER on the development of cleaned historical spatial series.
- Work more closely with consultant forecasters to ensure insights from historical installations are captured in short-term trends, possibly at lower spatial granularity.
- Continue to use scenarios to test the substantial uncertainty in long-term installation and system output rates.

Extreme demand forecast methodology (already implemented in 2019 ESOO)

To better reflect demand trends evident amongst the regions, AEMO has implemented several modelling techniques that will be used together as an ensemble. In 2018 and before, AEMO used a single half hourly demand model that was simulated to sample the range of maximums and minimums. In 2019, AEMO has tested an additional demand model that will be considered alongside the half hourly model:

1. Half-hourly demand model (current model)
2. Weekly Generalised Extreme Value (GEV) model simulation

The half-hourly model is better at forecasting the transition in timing of demand due to disruptive technology such as PV, battery systems and electric vehicles; higher resolution models have greater variability. The GEV model is better at forecasting short-term maximum demand (1-3 years ahead) but is unlikely to capture complex interactions between variables evident longer term. These models have been compared to develop an ensemble forecast, harnessing the strengths of each model over the forecast horizon.

Demand traces (already implemented in 2019 ESOO)

As part of the 2019 ESOO implementation, a new demand trace scaling method was developed. This method scales historically observed demand traces to fit forecast: maximum demand, minimum demand, energy consumption and embedded technology. Overall, monthly maximum demand simulations taken from these traces performed well, however Victoria had numerous months where actual monthly maximum demand was outside simulation bounds. Figure 77 shows the range of monthly maximum demand previously shown.

Figure 77 Victoria 2018 simulated monthly maximum demand with actuals

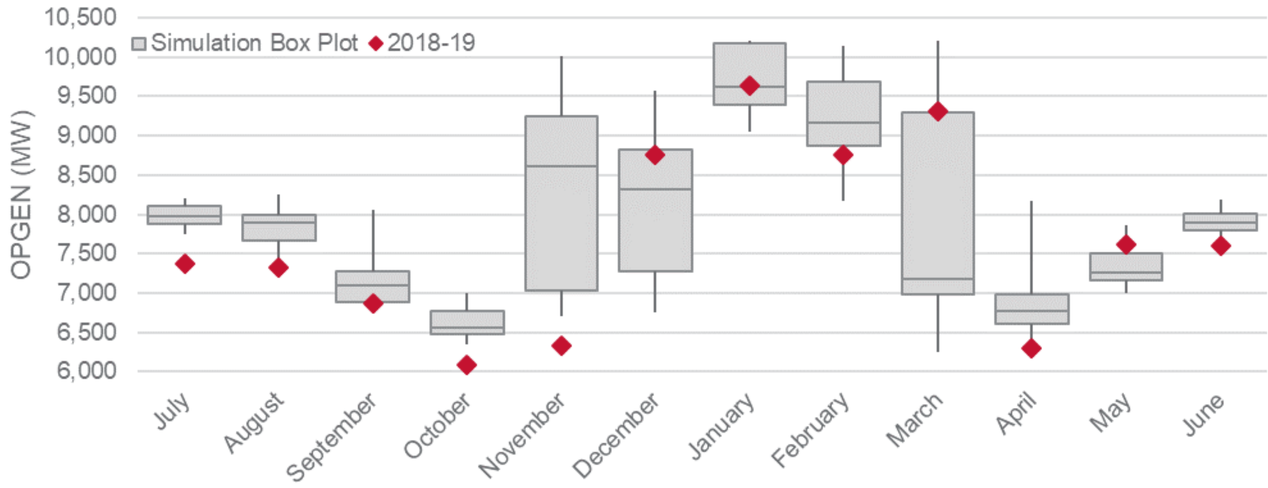
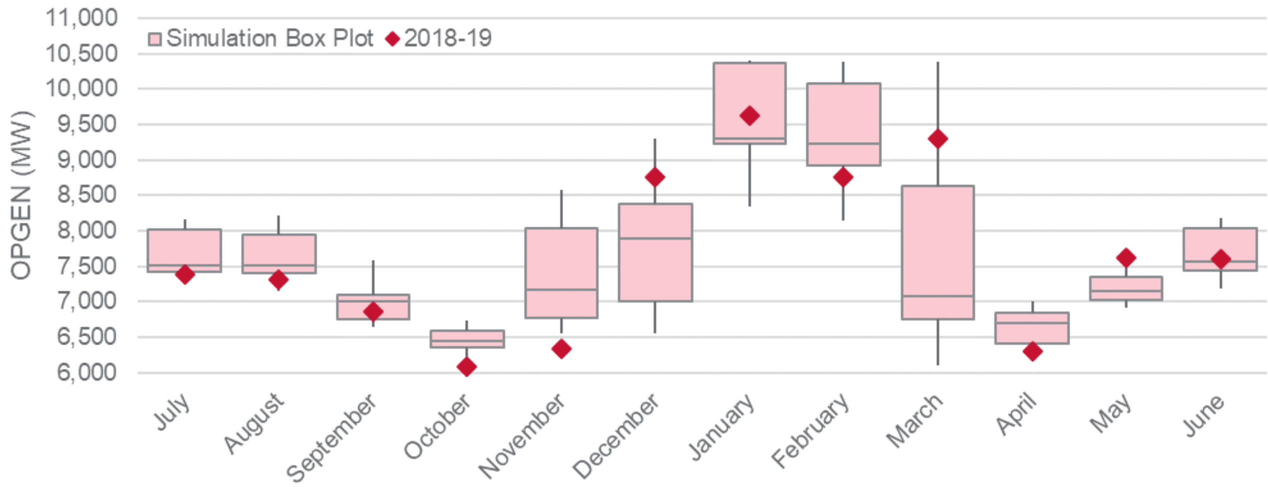


Figure 78 shows the range of maximum demand simulations taken from the updated demand trace method. While some monthly events are outside simulation bounds, the difference is reduced. In both cases, there are nine simulation years included.

Figure 78 Victoria 2019 simulated monthly maximum demand with actuals



Generator new entrant modelling (already implemented in 2019 ESOO)

The Reliability Forecasting Methodology Final Report outlined AEMO's changes to commitment criteria and modelling of new entrant generation, whereby the criteria for Com* was tightened and Com* projects are assumed to be delayed until after the T-1 RRO window. Should this method have been used in the 2018 ESOO, the difference between forecast and actual capacity would have been 29 MW instead of 996 MW.

AEMO will continue to monitor the performance of the Generation Information commercial use dates for both Committed and Com* projects, and may make further adjustments to more accurately reflect generator commissioning, if appropriate.

Changes to the DSP forecast process in 2019 and onwards (already partially implemented in 2019 ESOO)

Under NER 3.7D, registered participants in the NEM must provide DSP information to AEMO in accordance with the demand side participation information guidelines. This information source meant the 2019 DSP forecast was based on a larger data set.

Building on the enhanced information collected by AEMO, from 2019, the DSP forecast has been verified against reported potential response. In the 2019 DSP forecast the assessment found the forecast generally was consistent with the reported level of potential DSP[30].

For 2020, AEMO plans to include response for peaking type ONSG generators in the DSP forecast to improve the transparency of response that is typically driven by price triggers.

Also, it should be noted that AEMO will consult on both the DSP methodology and DSP Information Guidelines in 2020.

Evidence of trends in forced outage rates of ageing coal generation

As committed to in RRO consultation, AEMO is undertaking an international review to examine the evidence of trends in forced outage rates of ageing coal generation. Depending on whether anything conclusive can be drawn from this analysis, this could inform future changes to the methodology applied to model future trends in generator forced outages.

Changes to summer generation derations

To improve forecasts of generator availability at both extreme and less-extreme temperatures, AEMO will request and apply two summer capacity ratings per generator. These ratings include a "typical" summer rated capacity as well as an "extreme heat" summer rated capacity. A description of the methodology that will be applied in the 2020 ESOO to better model summer temperature derating was presented at the November FRG.

Table 22 Forecast improvement register

Observation	Action already taken for the 2019 ESOO and related products	Further actions to be taken for the 2020 ESOO and related products
Input drivers of demand		
Rooftop PV and PVNSG forecast inaccuracy	Automated processes to prepare rooftop PV and PVNSG capacity actuals and generation estimates from the CER. Automated and more timely estimates of solar irradiance and normalized rooftop PV generation. Consultant forecasts were revised downwards, though there may have been an over-correction as actuals are now exceeding forecasts.	Investigate use of the DER register to get a better understanding of the level of DER currently in the market. Work closely with the CER and AEMO's consultant forecasters to ensure short term trends are well understood and captured.
Customer connection forecast inaccuracy	None	AEMO now has 5+ 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.
Increase ability to measure and verify input component into the forecast	DER Register will commence at the end of 2019 which has an aim to supplant the current CER data feed used for estimating PV capacity. Relevant government jurisdictions are now contacted to verify energy efficiency schemes used in the forecast.	Where directly measurable inputs can be verified (such as number of EVs sold in Australia) AEMO will look to enhance its indicators. Where the component is indirectly measurable (for example, usage changes from price, energy efficiency, fuel switching) the use of historical meter data will be relied on for verification.

[30] See section 2.5 in the *Demand Side Participation Forecast and Methodology*, August 2019, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf

Observation	Action already taken for the 2019 ESOO and related products	Further actions to be taken for the 2020 ESOO and related products
Energy consumption forecasts		
CSG consumption inaccurate in Queensland	Forecast revised upwards based on AEMO's 2019 Gas Statement of Opportunities.	Work closely with Powerlink and its direct connect customers to improve understanding of future consumption expectations.
Short term trend misalignment, especially in Victoria	All regional models re-fitted.	Use of statistical trend based sub-regional model to verify regional trend disaggregation and/or use of sub-regional forecast input information where possible as internal validation checks.
Customer segment visibility	Large industrial loads were forecast separately, allowing for more granular accuracy assessments.	Continue to investigate the use of metering data for understanding and reporting on residential and business consumption uncertainties.
Demand forecasts		
Demand forecast methodology review	Implemented two demand models in ensemble. Combined a half hourly long term model for exploring load shape changes in the long term with an extreme value model to more accurately describe the probability distribution in the shorter term.	Continual improvement of methods, processes and quality assurance.
Inaccuracy in Queensland	Forecast revised upwards based on updated PV, CSG, energy consumption inputs; and new model specification.	None
Minimum demand forecasts only published for summer and winter	Minimum demand was forecast for summer, winter and shoulder, yet shoulder was not published externally.	Modify system to allow publication of all seasonal minimums rather than just summer/winter.
Understand climate, interaction of weather variables and subregional weather	Engaged with the Bureau of Meteorology (BoM) to continue to understand climate change through the ESCI project and the impact on climate change on demand. Investigated the use of multiple weather stations at subregional level to improve region forecasts. Not implemented due to limited weather data quality and availability.	Investigate the use of reanalysis weather data and downscaled climate data.
Transmission network losses	None	Investigate the use of metering and marginal loss factor data for loss factor forecasting.
Demand forecasts – connection points		
Regional model inputs unavailable at sub-regional levels	None	Use the DER register and enhanced PV and connections forecast models to develop sub-regional component forecasts.
Minimum demand forecasts unavailable	None	Data quality issues have hampered efforts to deploy to date. Further work to clean connection point data will accompany minimum demand model deployment.

Observation	Action already taken for the 2019 ESOO and related products	Further actions to be taken for the 2020 ESOO and related products
Industrial connections points understate variability	None	Develop a method to sample historical variability of non-weather sensitive industrial demand to estimate POE levels. Explore adaptation of regional industrial estimation methods.
Demand forecasts - traces		
Consistency in trace scaling	Developed new scaling method to better capture realistic customer interactions in demand at time of summer maximum, winter maximum and annual minimums considering technology adoption.	Continual improvement of methods, processes and quality assurance.
Drivers of supply		
Delays in new generation entrants	The Reliability Forecasting Methodology Final Report outlined AEMO's changes to commitment criteria and modelling of new entrant generation whereby the criteria for Com* was tightened and Com* projects are assumed to be delayed until after the T-1 RRO window.	AEMO will continue to monitor the performance of the Generation Information commercial use dates and may make further adjustments to more accurately reflect generator commissioning. This may apply to both Committed and Com* projects.
Supply forecasts		
Generator outage rates have not matched expectation for some regions	Adjusted methodology to sample discretely from the past four years of generator reliability, adjusted based on information provided by participants where applicable. Modifications to the simulation of unplanned outages was implemented, to better reflect the variation observed in history.	As committed to in the RRO consultation, AEMO is undertaking an international review to examine the evidence of trends in forced outage rates of ageing coal generation. This could inform future changes to the methodology applied to model generator forced outages.
Summer availability sometimes exceeds expectation	None	AEMO will apply two summer capacity ratings to better capture available capacity at differing temperatures. A description of the methodology that will be applied in the 2020 ESOO to better model summer temperature derating was presented at the November FRG.
Demand side participation forecasts	Collected insights from the demand side participation requests	Include responses for peaking type ONSG generators in the DSP forecast to improve the transparency of response that is typically driven by price triggers
Auxiliary load	None	Estimates of auxiliary load will be requested from generators directly through the GenInfo data collection process, rather than AEMO estimates.
Historical VRE traces may contain inconsistencies from market operation, transmission constraints and commissioning	Developed VRE generation traces directly from weather estimates using power curves in addition to historically derived traces.	Continue to investigate the use of reanalysis weather data and downscaled climate data for all generation and line rating traces.

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
ESOO	Electricity Statement of Opportunities

Abbreviation	Full name
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