Summer 2019 Forecast Accuracy Update

June 2019

Review of the 2018 Electricity Statement of Opportunities Forecasts

Important notice

PURPOSE

This Summer 2019 Forecast Accuracy Update has been prepared for the purposes of clause 3.13.3(u) of the National Electricity Rules. It reports on the accuracy of demand and supply forecasts to date in the 2018 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM) and improvements made to the forecasting process for the 2019 ESOO.

This publication has been prepared by AEMO using information available at 13th May 2019.

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VERSION CONTROL

Version	Release date	Changes
1	19/06/2019	First Version for Publication

CORRESPONDANCE

Questions and comments should be directed to energy.forecasting@aemo.com.au.

Executive summary

Each year, the Australian Energy Market Operator (AEMO) assesses the accuracy of its electricity demand and consumption forecasts to help inform its continuous improvement program and build confidence in the forecasts produced. The annual report is normally published towards the end of the calendar year following the relevant Electricity Statement of Opportunities (ESOO) publication, to allow time to collect historical observations of annual consumption, and key input drivers. For the first time, AEMO has prepared this Summer Forecast Accuracy Update to enable more timely understanding of the 2018 ESOO forecast performance over summer and implement any identified model improvements ahead of the 2019 ESOO.

Summer 2019 was the warmest on record, with high demand in most regions of the NEM and record demand in Queensland. It was also the highest year for solar PV installations. Renewable generation now supplies more than ever before. The majority of the observed trends fell within the expectations of the 2018 ESOO.

This report has explored the accuracy of key forecast elements, including demand drivers, demand forecasts and supply forecasts for summer 2018-19. It highlights that:

- Forecasts for customer connections and PV uptake were optimistic. While these two demand drivers are important, the net effect of both mostly cancelled each other out.
- Demand forecasts were appropriate, except for Queensland, for which an upward revision is needed and will be implemented in the upcoming ESOO.
- Supply forecasts were mostly appropriate, however some coal generators performed worse than expected and will also be adjusted in the upcoming ESOO.

AEMO will continue to improve the forecasting techniques in use, with improvements expected in time for the 2019 ESOO.

The 2018 ESOO forecast "a relatively high forecast likelihood (1-in-3 chance) of some unserved energy (USE)"[1] in Victoria over summer 2019, especially if high temperatures emerged. Other regions had no material forecast reliability gap. High demand conditions in Victoria did materialise as forecast and coincided with generator outages, resulting in load shedding on the 24th and 25th January 2019[2]. No other region suffered from lack-of-capacity induced load shedding. A performance summary is provided below:

Table 1 Forecast accuracy summary by region – summer 2018-19

Region	Summer Demand Accuracy		Summer Supply Accuracy		Summer Reliability Outcome	
NSW	Green	Good	Green	Good	Green	No load shedding
QLD	Red	Demand higher than forecast	Green	Good	Yellow	Surplus capacity avoided load shedding
SA	Green	Good	Green	Good	Green	No load shedding
TAS	Green	Good	Green	Good	Green	No load shedding
VIC	Green	Good	Yellow	Higher failure rates than forecast	Red	Forecast risk of load shedding eventuated

[1] AEMO. 2018 Electricity Statement of Opportunities for the National Electricity Market, August 2018. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[2] AEMO. Load Shedding in VIC on 24 and 25 January 2019. https://aemo.com.au/Media-Centre/PSOIR-published-for-load-shedding-24-25-Janaury

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1. Introduction

The Australian Energy Market Operator (AEMO) produces a Forecast Accuracy Report for its Electricity Statement of Opportunities (ESOO) each year. In advance of the annual Forecast Accuracy Report, this 2019 Summer Forecast Accuracy Update aims to expedite the accuracy assessment for metrics relevant only to summer. This assessment reviews the accuracy of input assumptions, summer maximum demand, and summer supply availability in AEMO's 2018 ESOO[3], for each region in the National Electricity Market (NEM).

This document is not designed to be a replacement for the annual Forecast Accuracy Report and will not include all metrics published annually. Consultation is ongoing with stakeholders and academics to define appropriate accuracy metrics for the annual publication.

The 2018 ESOO provided AEMO's independent forecast of supply reliability in the National Electricity Market over a 10-year period to inform the decision-making processes of market participants, new investors, and policy-makers as they assess future development opportunities. The forecasts were developed by comparing simulations of customer demand with simulations of available generator supply. This report explores the accuracy of these elements in three parts:

- Trends in demand drivers.
- Demand forecasting.
- Supply forecasting.

1.1 Definitions

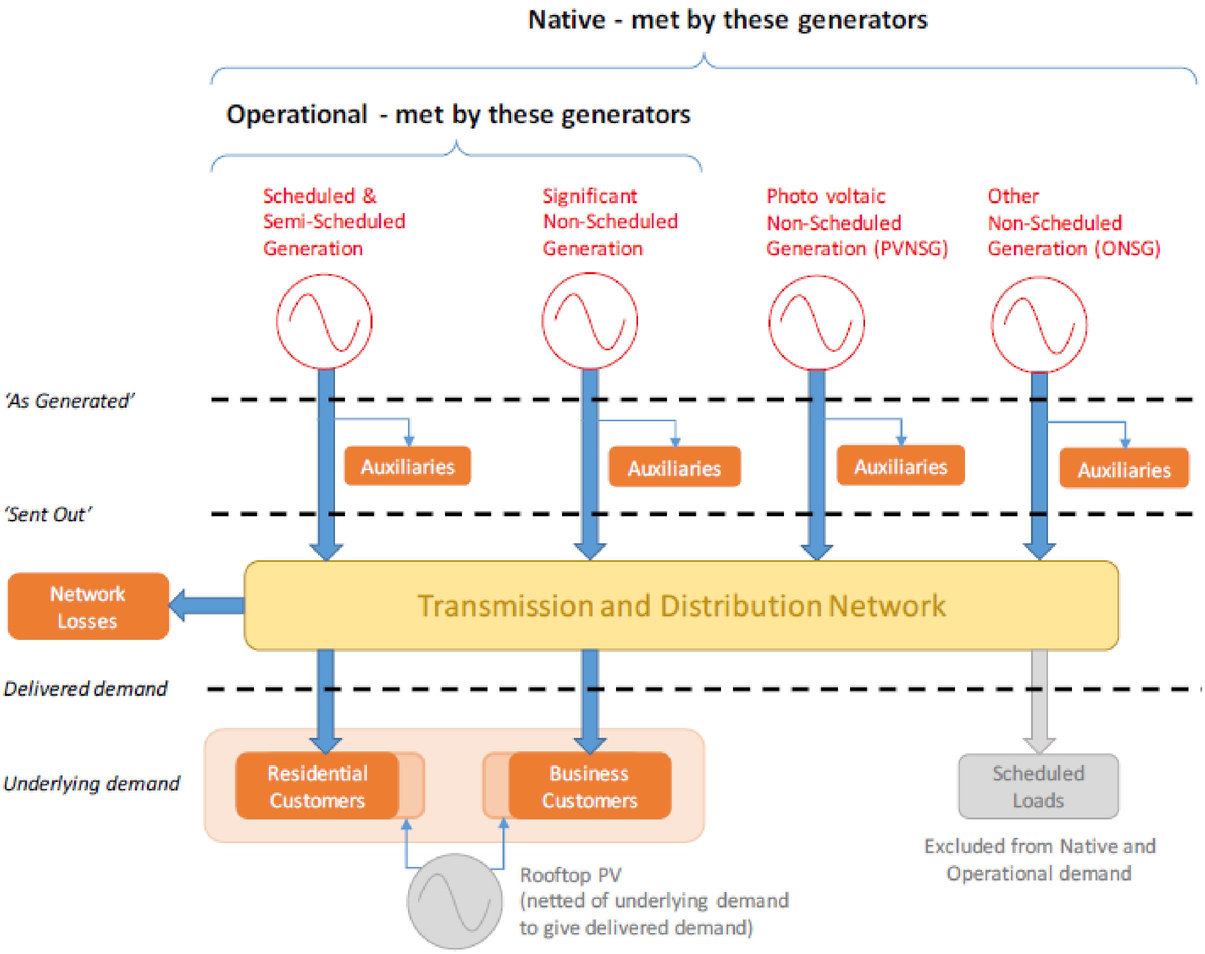
In this report, all forecasts are reported on a "sent out" basis unless otherwise noted. Terms used in this report are defined in the glossary. To assess forecasting performance, historical demand "as generated" is converted to "sent-out" based on estimates of auxiliary load. Figure 1 shows the demand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

- Summer is defined as November to March for all NEM regions, except Tasmania where summer is defined as December to February inclusive.
- This report uses a definition of auxiliary load consistent with the 2018 ESOO. This definition may result in variations from estimates published in 2017 and before.

[3] AEMO. 2018 Electricity Statement of Opportunities for the National Electricity Market, August 2018. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

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



2. Trends in demand drivers

Electricity forecasts are predicated on a wide selection of inputs, drivers and assumptions. The 2018 ESOO laid out the changing social, economic, and political environment in which the Australian electricity market 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.

The 2018 ESOO was published in August 2018, nine months before this publication was written. For some input variables it is too early to comment on performance; these include economic growth and retail price. Other variables have no material impact on the 2019 summer outcome and are not discussed. For example, neither energy storage systems (ESS) nor electric vehicles are yet at meaningful levels of penetration. Input variables suitable for comment are discussed below.

2.1 Population and connections

Population is a main driver of electricity demand, directly affecting the number of residential and non-residential connections. The 2018 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 2 shows the residential connection growth for 2018-19 sourced from AEMO internal monthly connections data, against the three 2018 ESOO scenarios.

Table 2 Forecast and actual residential connections growth rate comparison. 2018-19 (%)

	NSW	QLD	SA	TAS	VIC
Actual (Jan18-Jan19)	1.3%	1.2%	1.2%	1.1%	1.7%
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 predominantly lower than forecast (sometimes in line with the slow scenario, sometimes below), except in the case of Tasmania. The inaccuracy is driven by the assumptions applied in application of the HIA and ABS forecasts. A new connections model has been developed for 2019 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.

2.2 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 2 shows the forecast for the 2018 ESOO and compares it with recently revised actuals.

Table 3 compares the forecast for January 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 average age of systems, and system replacements.

Figure 2 NEM rooftop PV and PVNSG installed capacity comparison, 2015 - 2023

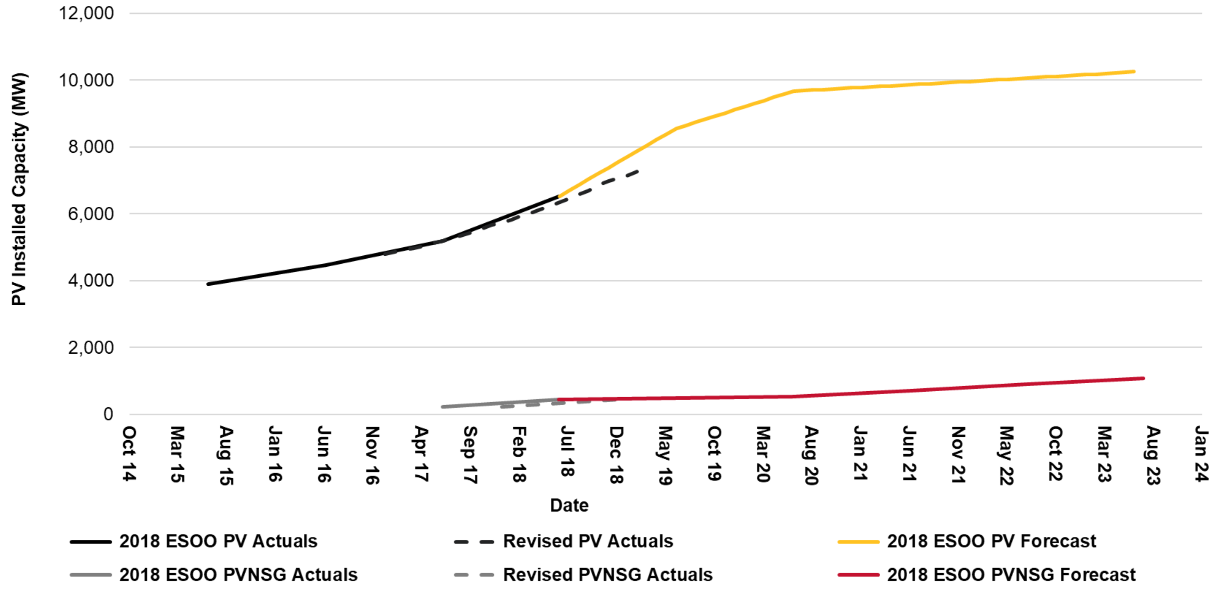


Table 3 Rooftop PV and PVNSG installed capacity comparison by state. January 2019. (MW)

January 2019	NSW	QLD	SA	TAS	VIC
PV Actual (MW)	1981	2426	1021	137	1592
PV Forecast (MW)	2268	2462	1059	161	1768
PV Difference (%)	-13%	-1%	-4%	-15%	-10%
PVNSG Actual (MW)	168	133	53	6	75
PVNSG Forecast (MW)	176	146	51	7	85
PVNSG Difference (%)	-4%	-9%	4%	-19%	-12%

Overall, PV installations have fallen short of the growth trajectories expected, with most of the difference occurring in the residential sector. Tasmanian installations have been substantially slower than forecast.

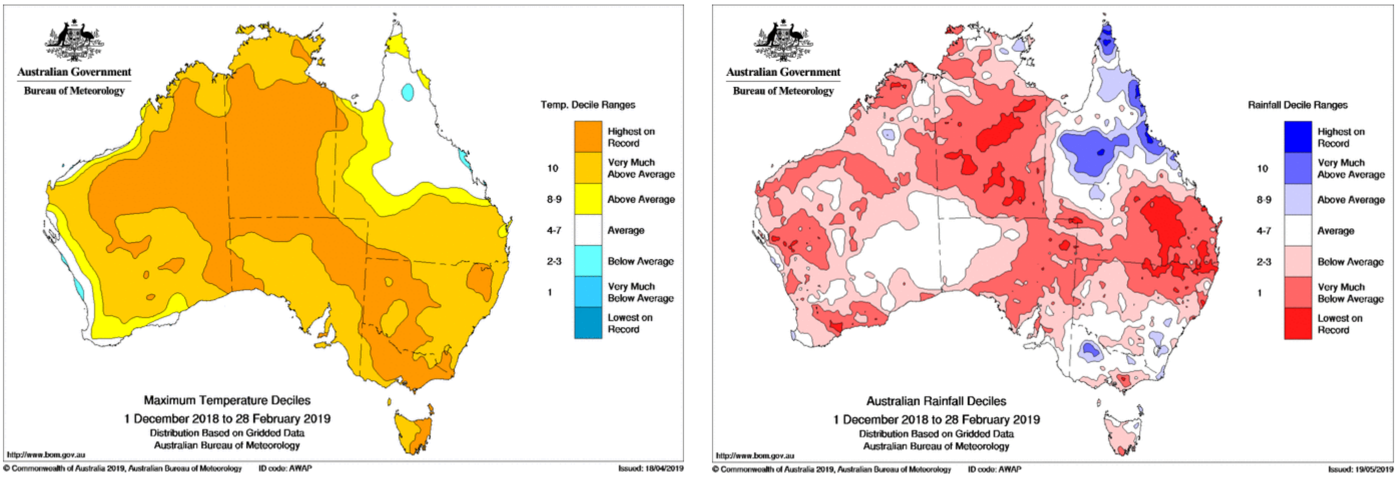
As installed PV capacity is negatively correlated with electricity demand, lower PV uptake may produce higher demand than otherwise forecast. While short-term PV forecast accuracy has been poor, the medium-term forecast is considered relevant given the moderating forecast trend. For 2019, the forecast is being revised. Due to the uncertainty in the rate of uptake, AEMO is seeking the advice of two expert consultants to inform the 2019 forecast.

2.3 Weather and climate

Both customer demand and system supply are 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. As part of the forecasting process, temperatures used in demand forecasting were escalated in line with Representative Concentration Pathway (RCP) 4.5 using publicly available projections data[4]. The Bureau of Meteorology's summary report[5] about the 2018-19 summer included comments that:

- It was Australia's warmest summer on record, marked by persistent widespread heat
- Mean and maximum temperature for the season broke previous records by large margins; both almost one degree above the record set in 2012-13
- It was the warmest on record for New South Wales, Victoria, Western Australia and the Northern Territory
- Exceptional heatwaves occurred during December on the tropical Queensland coast and 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, but above average for large parts of northern Queensland

Figure 3 BoM Seasonal Deciles. summer 2018-19.



Source: Bureau of Meteorology, Australia in summer 2018-19

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 electricity demand, the hot summer may produce a demand result towards the higher end of the probability distribution for applicable regions.

Further work is currently underway to ensure the effects of climate change on the reliability and resilience of the electricity system are considered. Subject to data availability, the choice of RCP in future forecasts should reflect more likely global emissions trajectories.

[4] Sourced from ClimateChangeInAustralia.gov.au accessed as part of the 2018 ESOO process.

[5] Bureau of Meteorology, Australia in summer 2018-19. www.bom.gov.au/climate/current/season/aus/summary.shtml. Accessed 21May19.

3. Demand forecasts

This summer update does not discuss energy consumption and minimum demand. The demand forecast section will focus on the accuracy of the summer maximum demand forecasts only, leaving other variables to be address in the annual Forecast Accuracy Report later in the year.

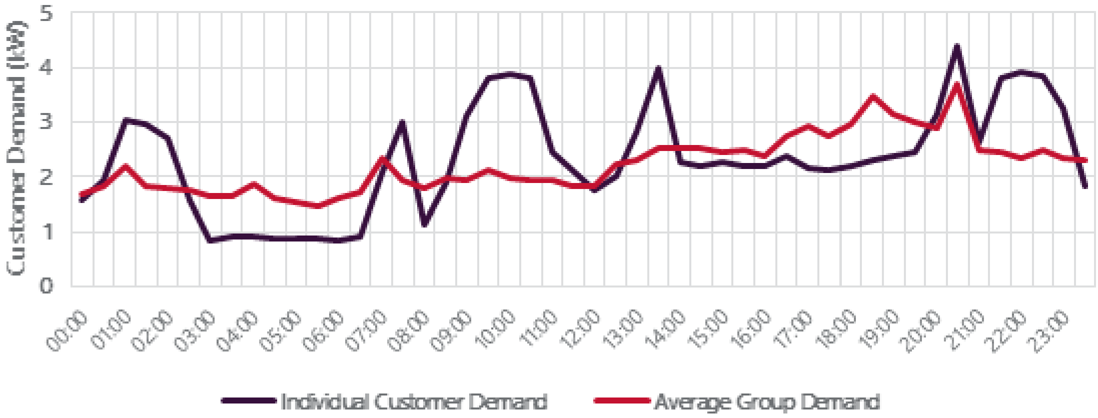
Summer maximum demand is the half-hour period with the highest level of demand in the season. It is the period where customer choices drive more coincident appliance use, typically in response to extreme heat. Understanding the modelling of these consumer choices is important in the evaluation of maximum demand forecast accuracy.

3.1 Modelling consumer behaviour

Individual residential consumers do not behave consistently every day, and can sometimes appear unpredictable. Even on days with identical weather, the choices of individuals are not identical, and reflect the lifestyle of the individual or household. It is only when customer electrical demand is aggregated to a regional level that the group behaviour becomes more predictable. This is because the group demand largely cancels out the idiosyncratic behaviour of the individual.

Figure 4 shows the load profile of an individual customer, compared to the average of a group of similar customers. While the load profile of the individual is spikey and erratic, the group profile has smoothed out some of idiosyncrasies of the customer.

Figure 4 Individual and Group demand shown on one day

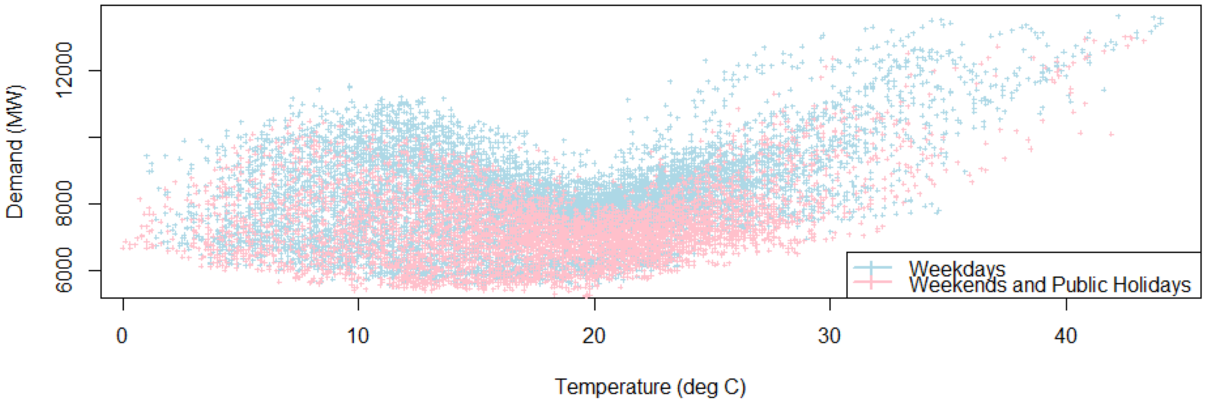


Although demand becomes more predictable when aggregated, it remains a function of individual customer decisions. Periods of high demand only become so because individual customers choose to do the same things at the same time. Peak demand is therefore driven entirely by the degree of coincident appliance use across customers, across regions. There are many factors that drive customers to make similar appliance choices at the same time including:

- Work and school schedules, traffic and social norms around meal times.
- Weekdays, public holidays, and weekends.
- Weather, and the use of heating and cooling appliances.
- Many other societal factors, such as whether the beach is pleasant, or the occurrence of retail promotions.

Figure 5 shows a scatter plot of temperature and electrical load. A strong relationship between temperature and group electrical load can be seen, however the relationship cannot explain all variation. Even when all observable characteristics are considered, the variance attributable to coincident customer choices remains.

Figure 5 Scatterplot of NSW demand and temperature. Example based on 2017 calendar year.

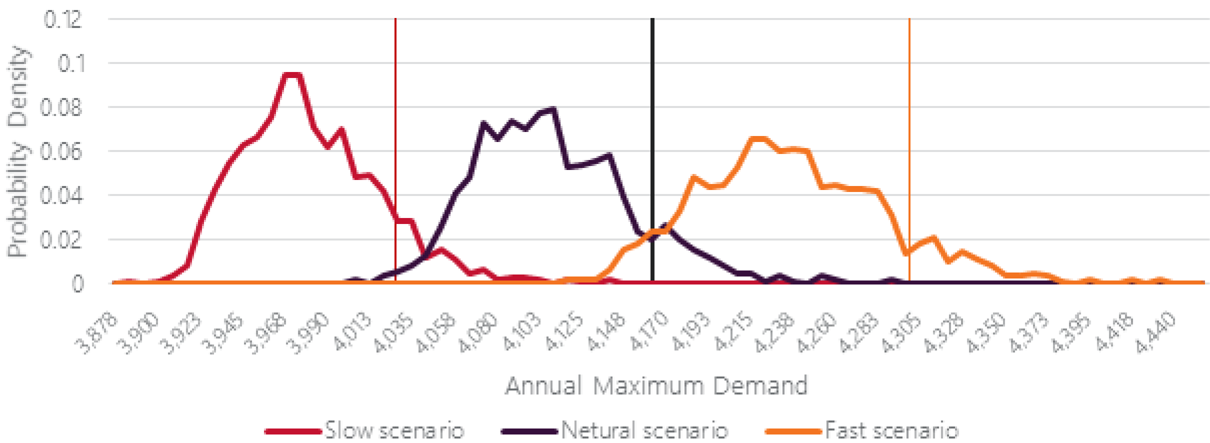


It is standard industry practise to model the drivers of demand in two parts

- structural drivers, which are modelled as scenarios, including considerations such as:
  - population,
  - economic growth,
  - electricity price,
  - technology adoption.
- Random drivers, which are modelled as a probability distribution, including considerations such as:
  - weather driven coincident behaviour,
  - weather driven embedded generation output,
  - non-weather driven coincident behaviour.

Figure 6 shows the modelled probability density functions that represent possible maximum demand outcomes for a typical southern region. Three probability density functions are shown, one for each of the scenarios with unique structural drivers. The 10% Probability of exceedance (POE) estimates are sampled from the probability distributions, shown by the vertical lines.

Figure 6 Conceptual maximum demand probability density functions for 3 scenarios.



3.2 Summer 2019 actuals

AEMO forecasts demand in the absence of load shedding and the occasional customer response to price and/or reliability signals, known as demand side participation (DSP). Comparing actual observed demand with forecast values can only be done if on the same basis. For example, a maximum demand day observed during summer may have happened at a time of supply shortages, leading to load shedding and very high prices, which also would have had a dampening impact on those exposed to market prices. Adjustments have been identified to make 2019 actuals relevant and AEMO forecasts should not be compared without these adjustments.

Adjustments have been grouped in to 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 occurred on the 25th of 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 forced load shedding. The load shedding and RERT is considered firm, while an estimation of voluntary electricity conservation is considered potential.

Table 4 shows the maximum demand periods for the various NEM regions in summer 2019 with calculated adjustments.

Table 4 Summer 2019 maximum demand with adjustments per NEM region.

Region	Time of maximum (NEM time)	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	31 Jan 19 16:30	13821	-501	13320	0	0	13320
QLD	13 Feb 19 17:30	10044	-552	9492	20	0	9512
SA	24 Jan 19 19:30	3240	-100	3140	82	55	3277
TAS	15 Jan 19 15:30	1330	-18	1312	0	0	1312
VIC	25 Jan 19 13:00	9110	-335	8775	510	120	9405

It should be noted that there was an early cool change on the 25 January in Victoria, with temperatures coming down significantly from around 13:00. Had temperatures remained high, an even higher peak would have been expected towards the evening as output from the approximately 1500 MW of installed rooftop PV capacity in the region would have reduced.

Appendix A1 discusses the highest demand days in each NEM region during the 2018-19 summer and whether any adjustments to observed peak demand were required.

3.3 New South Wales

The electrical demand from New South Wales, shown in Figure 7, has been relatively stationary over the last few years, with expected summer and winter seasonal patterns and distinctive summer peaks. The three-year 2018 ESOO forecast shown is also relatively stationary with a wide distribution of possible annual maximums; this is a distribution reflecting the wide variety of annual weather and coincident customer behaviour observed in New South Wales. There may be a positive bias due to the over forecast of customers, and a negative bias from the over forecast of PV. The 2019 summer maximum fell between the 50% POE and 10% POE forecasts, consistent with the hot weather observed over the period. While only one year out, the forecast appears to have captured the summer maximum trends well.

Figure 7 New South Wales demand history compared to neutral forecast, summer 2016-summer 2021

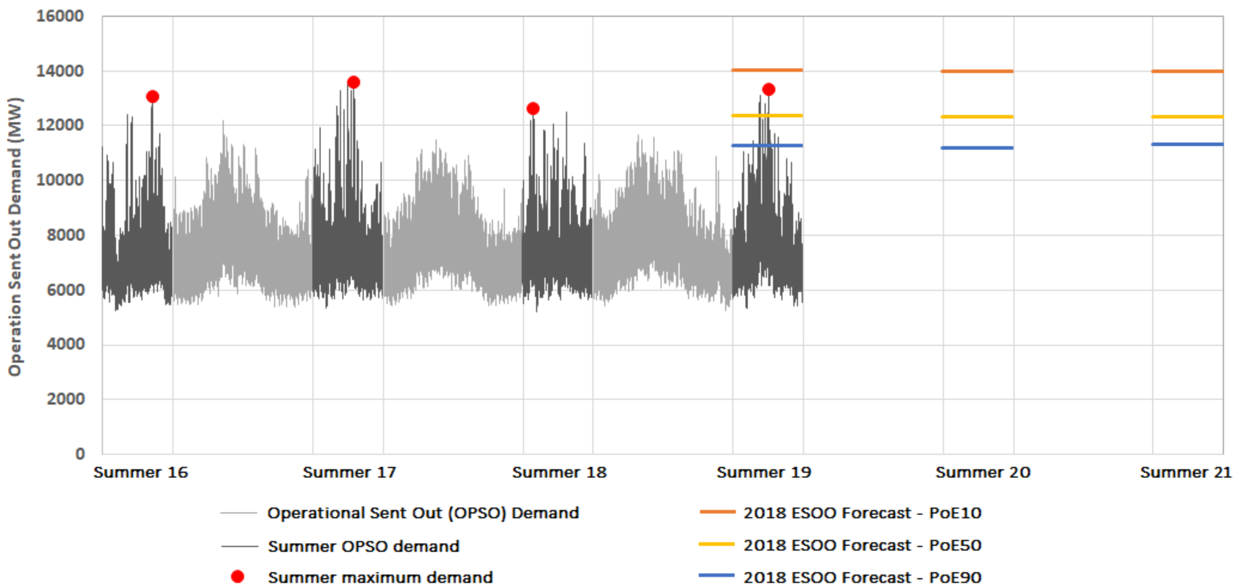


Table 5 describes the demand and temperature characteristics of the observed maximum demand relative to forecast. Rooftop PV output, temperature and heatwave index forecasts are sampled from the 10th – 90th percentile range of the forecast simulations. The ranges demonstrate that annual maximum demand events may occur in a variety of circumstances. In this case, the actual rooftop PV was within the simulated range, and the observed temperature and heatwave index was within the 50% POE simulated temperature range as expected.

Table 5 New South Wales summer 2019 maximum demand and temperature actual compared to forecast

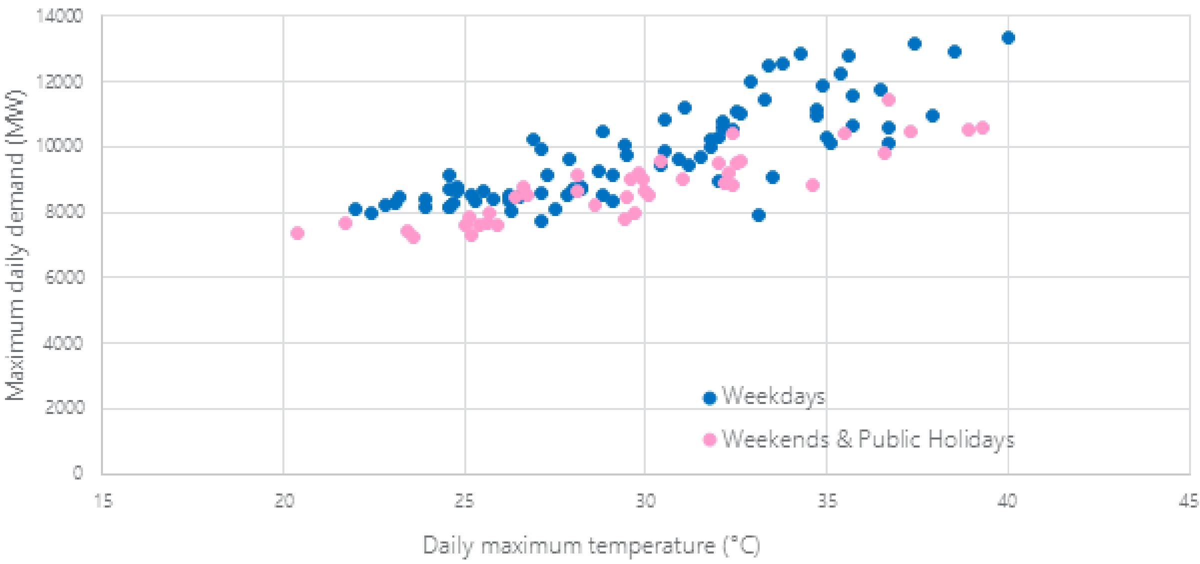
2019 Summer	Actual	Forecast 90% POE	Forecast 50% POE	Forecast 10% POE
Maximum demand – sent out (MW)	13,320	11,262	12,366	14,024
Rooftop PV at time of max demand (MW)[6]	568			363-1,492
Temperature at time of maximum demand (°C)[6]	38.1	32.2-38.0	37.8-41.0	39.9-44.5
3-day rolling heatwave index (°C)[6, 7]	7.0	5.0-8.2	7.0-9.7	8.7-11.9

[6] 10th - 90th percentile of simulations provided for forecast range.

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

Figure 8 shows the relationship between daily maximum demand and daily maximum temperature observed at the Bankstown Airport weather station. In 2019, the day of maximum demand coincided with the day of maximum temperature, however there were several near contenders at marginally lower temperatures.

Figure 8 New South Wales demand and daily maximum temperature scatterplot, summer 2019.



3.4 Queensland

The electrical demand from Queensland, shown in Figure 9, has become more volatile over the last few years, with a single period of high demand throughout summer. Shoulder season load has been declining, while summer loads are increasing, with increasing volatility. The three-year 2018 ESOO forecast shown is stationary with a wide distribution of possible annual maximums. In 2019, summer loads exceeded the 50% POE forecast several times and the maximum was well above the 10% POE forecast. The peak demand forecast did not sufficiently capture the emerging summer trends. Further analysis has shown that the forecast inaccuracy is pre-domninantly driven by changes in the quantity and/or coincident usage of cooling appliances by consumers. It is largely not attributable to industrial activity or connections.

Figure 9 Queensland demand history compared to neutral forecast, summer 2016 - summer 2021

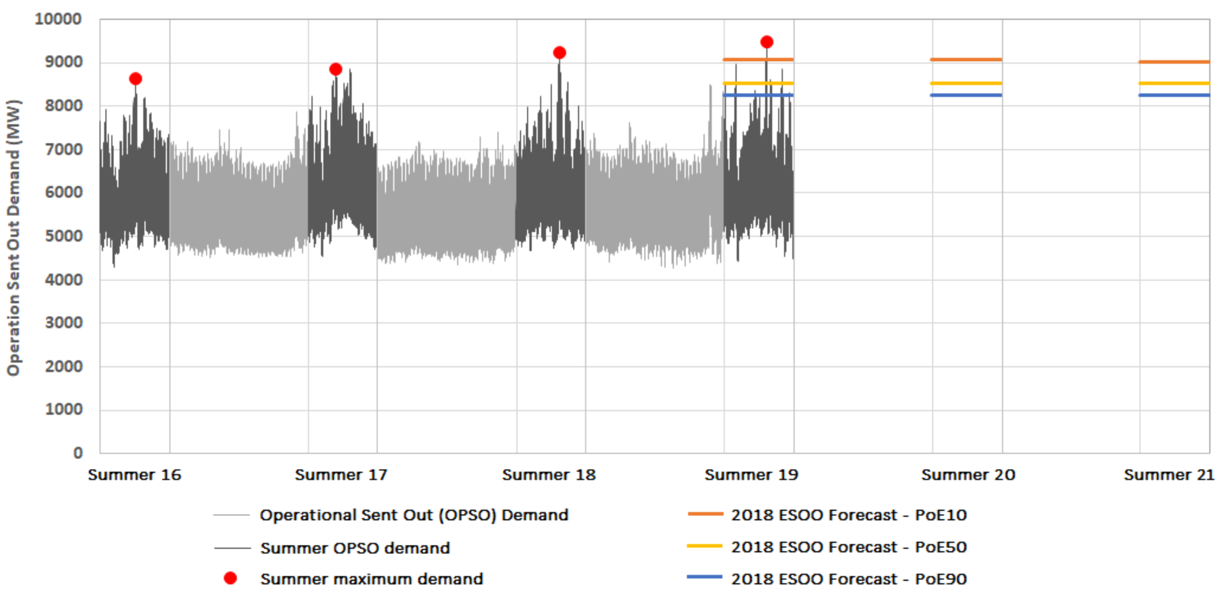


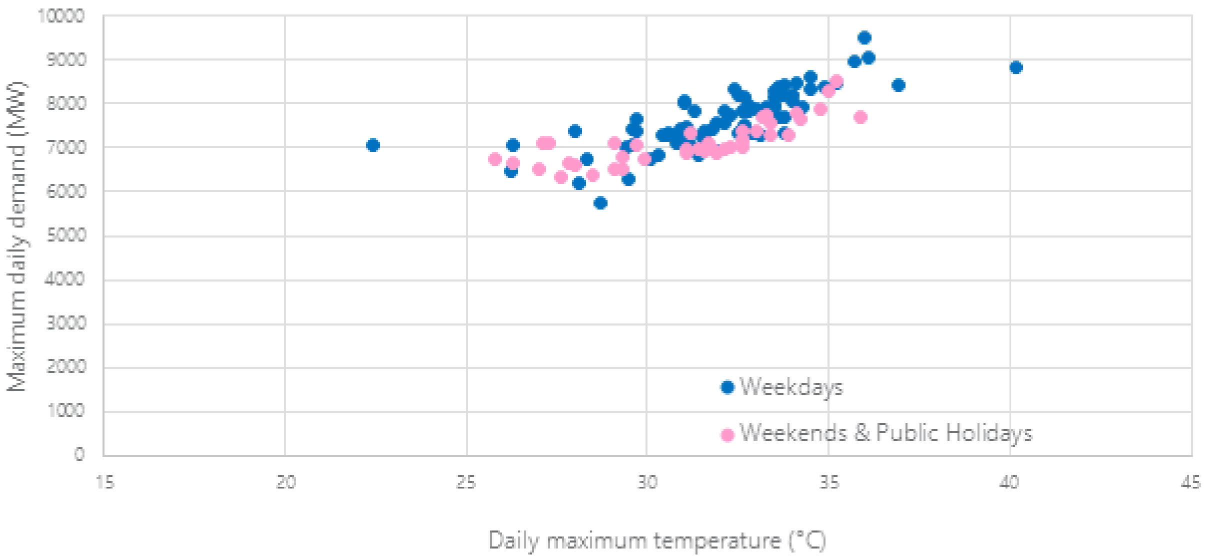
Table 6 describes the demand and temperature characteristics of the observed maximum demand relative to forecast. The actual rooftop PV output and heatwave index was within the 10^{th} – 90^{th} percentile range of the forecast simulations and the observed temperature was between the 90% POE and 50% POE simulated temperature ranges despite a record maximum demand, further confirming poor model performance.

Table 6 Queensland summer 2019 maximum demand and temperature actual compared to forecast

2019 Summer	Actual	Forecast 90% POE	Forecast 50% POE	Forecast 10% POE
Maximum demand – sent out (MW)	9,512	8,252	8,533	9,067
Rooftop PV at time of max demand (MW)	380			223 – 1,493
Temperature at time of maximum demand (°C)	30.3	28.0-35.9	28.3-36.1	32.6-41.6
3-day rolling heatwave index (°C)	5.1	1.4-5.3	2.6-5.5	4.5-7.6

Figure 10 shows the relationship between daily maximum demand and daily maximum temperature observed at the Archerfield Airport weather station. In 2019, the day of maximum demand did not coincide with the day of maximum temperature, due to a combination of weather and non-weather driven coincident behaviours.

Figure 10 Queensland demand and daily maximum temperature scatterplot, summer 2019.



3.5 South Australia

The electrical demand from South Australia, shown in Figure 11, has a declining trend, with expected summer and winter seasonal patterns and distinctive summer peaks. Despite the declining trend, summer loads have become more volatile and peakier. The three-year 2018 ESOO maximum demand forecast shown is stationary with a wide distribution of possible annual maximums; this distribution reflects the wide variety of annual weather and coincident customer behaviour observed in South Australia. There may a positive bias due to the over forecast of customers, and a negative bias from the over-forecast of PV. The 2019 summer maximum fell just above the 10% POE forecast, consistent with the hot weather observed over the period. While only one year out; the forecast appears to have captured the summer maximum trends well.

Figure 11 South Australian demand history compared to neutral forecast, summer 2016 – summer 2021

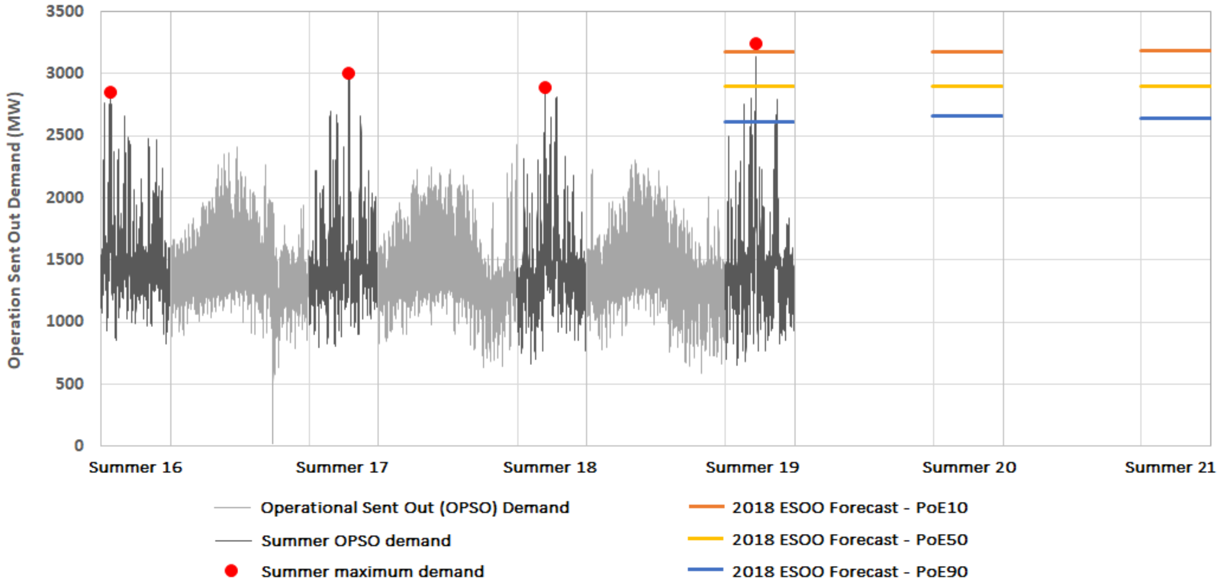


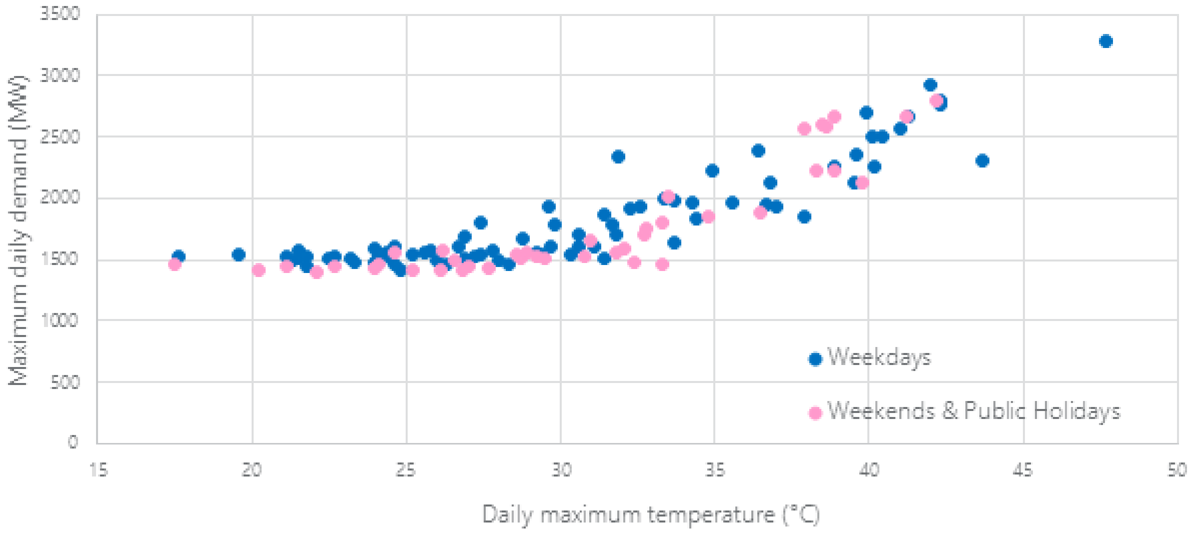
Table 7 describes the demand and temperature characteristics of the observed maximum demand relative to forecast. The actual rooftop PV output was within the 10th – 90th percentile range of the forecast simulations and the observed temperature and heatwave index fell within the 10% POE simulated temperature range, as expected.

Table 7 South Australian summer 2019 maximum demand and temperature actual compared to forecast

2019 Summer	Actual	Forecast 90% POE	Forecast 50% POE	Forecast 10% POE
Maximum demand – sent out (MW)	3,277	2,614	2,901	3,176
Rooftop PV at time of max demand (MW)	26			0-334
Temperature at time of maximum demand (°C)	44.3	36.4-40.3	38.1-42.1	40.5-44.4
3-day rolling heatwave index (°C)	13.1	2.0-10.9	5.0-10.9	5.6-14.3

Figure 12 shows the relationship between daily maximum demand and daily maximum temperature observed at the Adelaide (Kent Town) weather station. In 2019, the day of maximum demand coincided with the day of maximum temperature by a significant margin.

Figure 12 South Australia demand and daily maximum temperature scatterplot, summer 2019.



3.6 Tasmania

The electrical demand from Tasmania, shown in Figure 13, has an increasing trend, with a single period of high demand throughout winter. The summer load is not of significance to Tasmania but is rising slowly over the forecast period. The 2019 summer maximum fell just below the 90% POE forecast. While only one year out, the forecast appears to have captured the summer maximum trends well.

Figure 13 Tasmania demand history compared to neutral forecast, summer 2016 – summer 2021

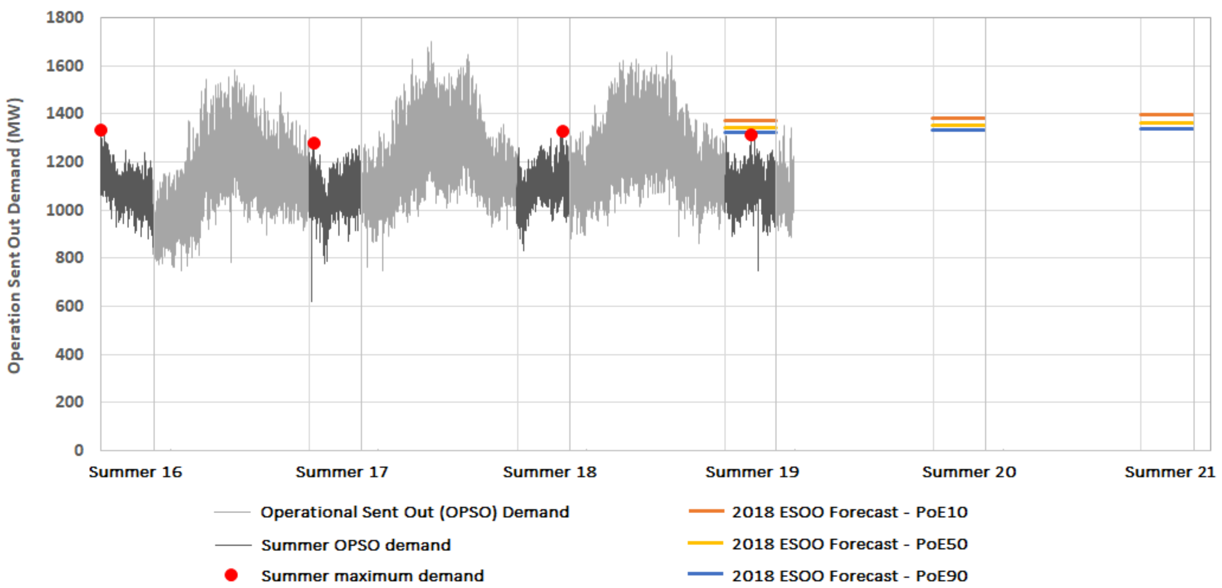


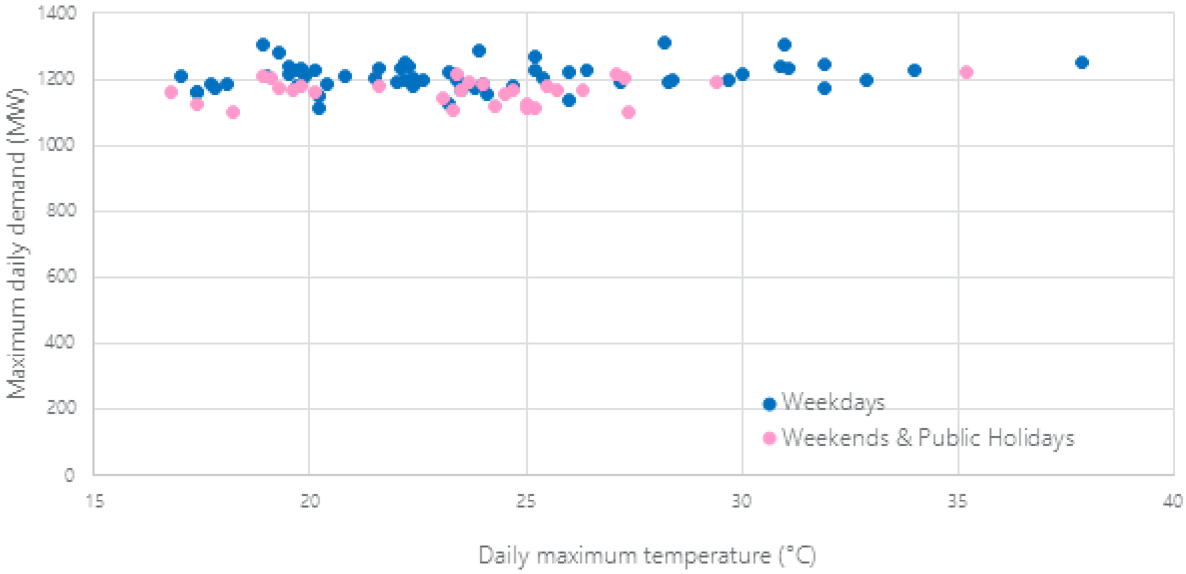
Table 8 describes the demand and temperature characteristics of the observed maximum demand relative to forecast. The actuals for Tasmania are not a good match for the forecast simulation ranges, which predict a summer maximum at a time that is winter-like. In summer 2019, winter-like conditions did not occur, resulting in a truer summer peak.

Table 8 Tasmania summer 2019 maximum demand and temperature actual compared to forecast

2019 Summer	Actual	Forecast 90% POE	Forecast 50% POE	Forecast 10% POE
Maximum demand – sent out (MW)	1,312	1,322	1,344	1,371
Rooftop PV at time of max demand (MW)	63			0-16
Temperature at time of maximum demand (°C)	23.8	9.2-15.0	10-5-17.8	8.5-13.3
3-day rolling heatwave index (°C)	3.3	0-0.7	0-2.4	0-0.6

Figure 14 shows the relationship between daily maximum demand and daily maximum temperature observed at the Hobart (Ellerslie Road) weather station. 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 14 Tasmania demand and daily maximum temperature scatterplot. Summer 2019.



3.7 Victoria

The electrical demand from Victoria, shown in Figure 15, has been relatively stationary over the last few years, with expected summer and winter seasonal patterns and distinctive summer peaks. The three-year 2018 ESOO forecast shown is also stationary with a wide distribution of possible annual maximums; this distribution reflects the wide variety of annual weather and coincident customer behaviour observed in Victoria. The 2019 summer maximum fell between the 50% POE and 10% POE, consistent with the hot weather observed over the period. While only one year out; the forecast appears to have captured the summer maximum trends well.

Figure 15 Victoria demand history compared to neutral forecast, summer 2016 – summer 2021

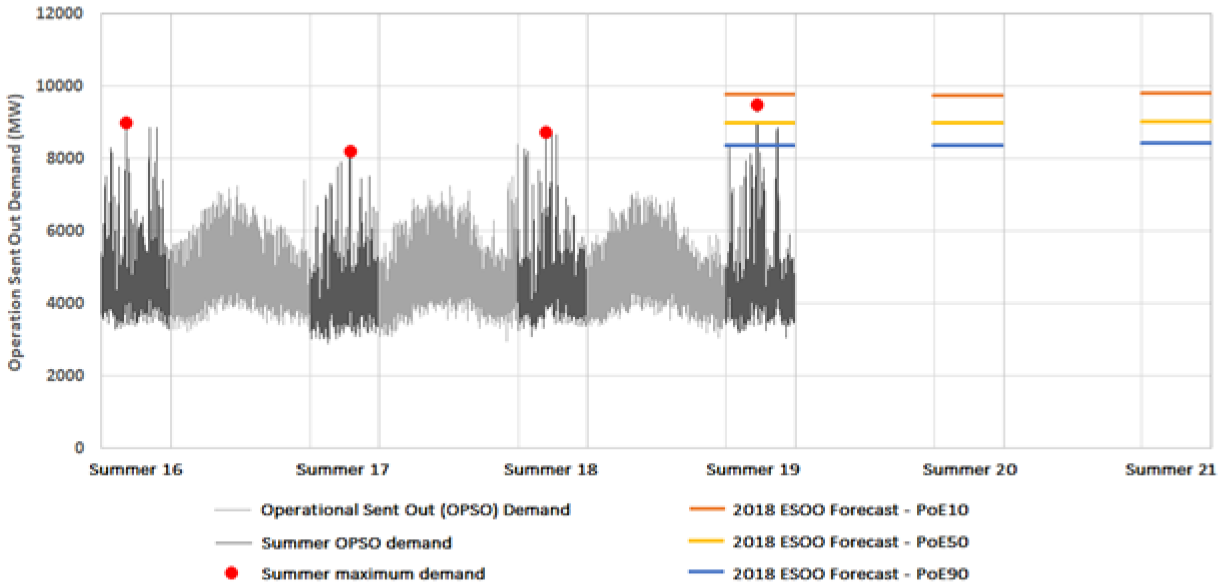


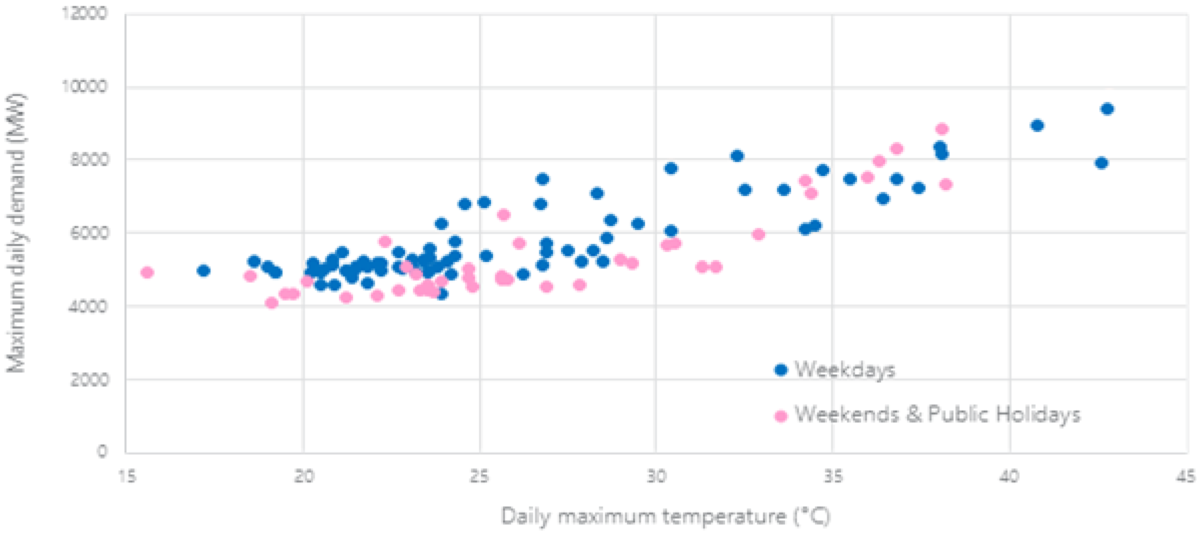
Table 9 describes the demand and temperature characteristics of the observed maximum demand relative to forecast. The actual rooftop PV output was towards the upper end of the percentile range of the forecast simulations and the observed temperature and heatwave index fell within the 10% POE simulated range, as expected.

Table 9 Victoria summer 2019 Maximum demand and temperature actual compared to forecast

2019 Summer	Actual	Forecast 90% POE	Forecast 50% POE	Forecast 10% POE
Maximum demand – sent out (MW)	9,405	8,366	8,983	9,764
Rooftop PV at time of max demand (MW)	841	209-883		
Temperature at time of maximum demand (°C)	42.3	33.3-38.3	36.5-40.6	40.4-42.9
3-day rolling heatwave index (°C)	7.5	2.5-9.1	3.7-9.9	6.0-11.9

Figure 16 shows the relationship between daily maximum demand and daily maximum temperature observed at the Melbourne (Olympic Park) weather station. In 2019, the day of maximum demand coincided with the day of maximum temperature, however there were several other contenders at lower temperatures.

Figure 16 Victoria demand and daily maximum temperature scatterplot, summer 2019.



3.8 Demand forecast improvements

In all regions except Queensland, the 2018 ESOO model specification and assumptions produced appropriate outcomes. To better reflect the demand trends evident amongst the regions, AEMO is implementing several forecasting process improvements, including the development of 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. In 2019, AEMO has tested two additional demand models that will be considered alongside the half hourly model:

1. Half-hourly demand model (current model)
2. Weekly Generalised Extreme Value (GEV) model simulation
3. Annual Generalised Extreme Value point process model fitted to daily maximums[8]

While 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 models are better at forecasting short-term maximum demand (1-3 years ahead) but are unlikely to capture complex interactions between variables evident longer term. These models will be compared to develop an ensemble forecast, harnessing the strengths of each model over the forecast horizon.

Queensland

For the 2018 ESOO, only the half-hourly demand model was used. Using the default model specification at that time, maximums in summer 2018 were considered to be within normal ranges driven by variance in coincident customer behaviour. With another year of observations, it is now evident that coincident customer behaviour is changing and is not just a statistical fluctuation. The new pattern observed is representative of behavioural change whereby customers generally conserve electricity but have a reduced tolerance to heat on extreme days. There may also be an interaction with the lower prices observed during recent periods of high demand relative to history, whereby price exposed customers now have less incentive to reduce consumption in response.

[8] Li, Y & Jones, B. The use of extreme value theory for forecasting long-term substation maximum electricity demand. 2019.

The Queensland half-hourly demand model will therefore be updated to include variables that will reflect this new pattern in coincident customer behaviour. Additionally, the new weekly GEV model will capture this emerging trend, as it focuses only on weekly maximum demand. The focus on weekly maximum demand allows greater explanation of the maximums without having to explain the complex interactions between variables at the half-hour level, increasing short term accuracy. Combined, the use of a model ensemble and model specification changes are expected to result in an upward revision to the Queensland forecast in the 2019 ESOO.

Progress against improvements identified in 2018 Forecast Accuracy Report

Beyond the additional demand models, other improvements were scheduled in the 2018 Forecast Accuracy Report[9] that are still relevant. These improvements are shown in Table 10.

Table 10 Demand forecast improvements from the 2018 Forecast Accuracy Report

Observation	Action already taken	Further actions to be taken
Improve ability to explain forecast differences	Increased information provided in the 2018 Forecast Accuracy Report, prepared a new summer update, and consulted with industry on new performance metrics that could be used to measure accuracy of probabilistic forecasts.	Retain more modelling data for better explanation of non-weather-related coincident behaviour explanation. Further stakeholder and academic consultation on the forecast accuracy report requirements.
Forecast values fluctuate between forecast years	Doubled simulations in 2018 to smooth forecasts between years.	Same as 2018 or more simulations.
Need to understand interaction of weather variables, including subregional weather	Improved modelling of climate change, particularly extreme temperature and heatwave trends.	Further improvements to model formulation, considering other combinations of weather variables, enabled by greater access to climate and weather data.
Poor distribution alignment in some regions.	Reformulated model – POE spread more representative of historical values.	Continuous review of model formulation, and inclusion of an ensemble of models to improve accuracy, particularly in Queensland

[9] AEMO. 2018 Forecast Accuracy Report. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/Forecast-Accuracy-report-2018.pdf

4. Supply forecasts

Generator supply availability is particularly important in reliability studies given it is commonly a key driver of Unserved Energy (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 during extreme temperature periods in summer 2019.

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:

- Available capacity considering de-rating.
- Full unplanned outages.
- Partial unplanned outages.

The method for assessing supply forecast performance involves:

- Selecting historical availability data for the 10 hottest days over summer 2018 and summer 2019 per region.
  - Eight intervals were chosen per day including the time of maximum temperature and the seven half-hour periods that followed.
  - This selection of historical data was used to observe generator performance at times of high temperature. High temperature periods are very likely to be linked with periods of tight supply-demand balance and also represent periods where the physical capability of generator units is most at risk of physical issues including temperature derating.
  - Units with availability below their listed seasonal availability during these periods are assumed to be experiencing a partial or full outage, rather than a strategic withdrawal of capacity.
- Selecting equivalent forecast availability from 2018 ESOO simulations.
  - Simulated availability was taken from 1,000 samples of 10 random days/iterations. The availability data from these days is taken from the maximum temperature period and the seven half-hourly periods that follow (this is to match the number of hours with historical). The 97.5th and 2.5th percentiles of the simulation outcomes are shown to represent the forecast band and eliminate outliers that may occur with very low probabilities.
- Aggregating historical and forecast data for comparison with respect to generation fuel types and regions, plotting duration curves to compare the data sets.
  - Historical trends per fuel type were cleaned such that only units currently operating were considered.

Capacity

AEMO models the capabilities of generators by applying inputs sourced from market participants. The maximum capacity of each generating unit is provided by market participants through the Generation Information survey process. Through this process, each participant provides expected summer and winter available capacity over the 10-year modelling horizon. These capacities represent the expected capability during temperatures consistent with a 10% POE maximum demand in each region.

Unplanned Outages

Generators are assumed to be available at their summer or winter capacity unless they experience an unplanned outage. Planned outages are not modelled in the ESOO, because these are assumed to be planned in lower demand periods or shifted if low reserve conditions occurred so should not impact USE outcomes in summer.

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. To protect the confidentiality of this data, AEMO may publish calculated outage parameters for a number of technology aggregations.

The rates used by AEMO in the 2018 ESOO are shown in Table 11:

Table 11 Outage and derating rates used in 2018 ESOO.

	Full Unplanned Outage Rate (%)	Partial Unplanned Outage Rate (%)	Partial derating (%)
Brown coal- VIC	5.34	13.32	19.18
Black coal- QLD	2.42	13.51	16.94
Black coal- NSW	6.56	25.81	19.98
CCGT	1.33	0.36	42.76
OCGT	3.56	0.28	26.91
Steam turbine	4.58	11.25	22.85
Hydro	1.59	0.01	17.26

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.

4.1 New South Wales black coal generation availability

Black coal generation in New South Wales has had consistent rates of unplanned outages, although partial unplanned outages have been rising. Figure 17 shows how the rates of unplanned outages have changed over time relative to the 2018 ESOO assumptions.

Figure 17 New South Wales black coal historic unplanned outage rates

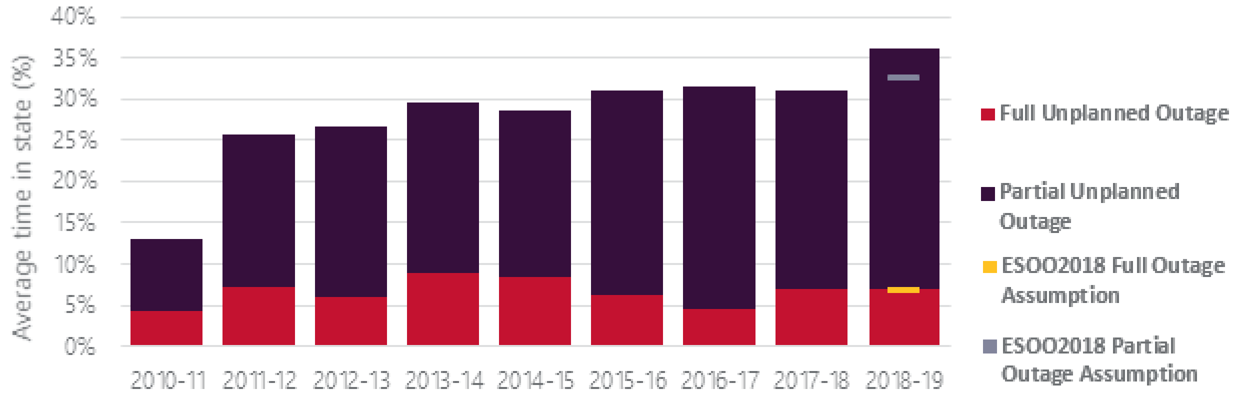
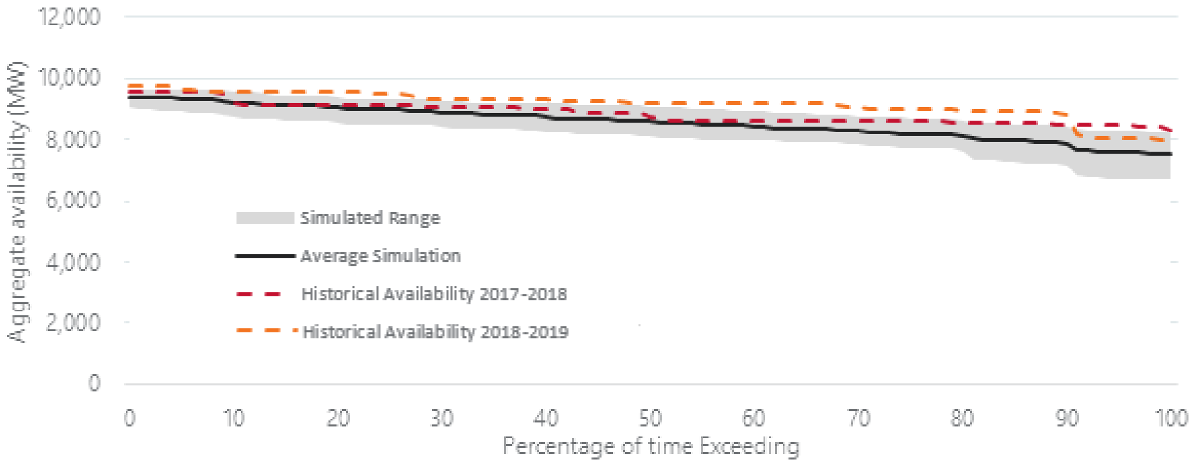


Figure 18 shows the availability over the top 10 hottest days slightly exceeded the simulated availability.

Figure 18 New South Wales black coal supply availability – top 10 hottest days



Despite the number of partial unplanned outages exceeding expectation, the observed availability was above forecast. The maximum temperature over the top 10 days in New South Wales in 2018-19 was between 36.0 and 39.6° and did not exceed the reference temperature upon which further derating is expected. It is likely that some generators exceeded their rated summer capacities and the effective outage rate during the high temperature periods was lower than average outage rates throughout the year.

4.2 Queensland black coal generation availability

Black coal generation in Queensland has had relatively consistent rates of unplanned outages, and slowly growing rates of partial unplanned outages. Figure 19 shows how the rates of unplanned outages have changed over time relative to the 2018 ESOO assumptions.

Figure 19 Queensland black coal historic unplanned outage rates

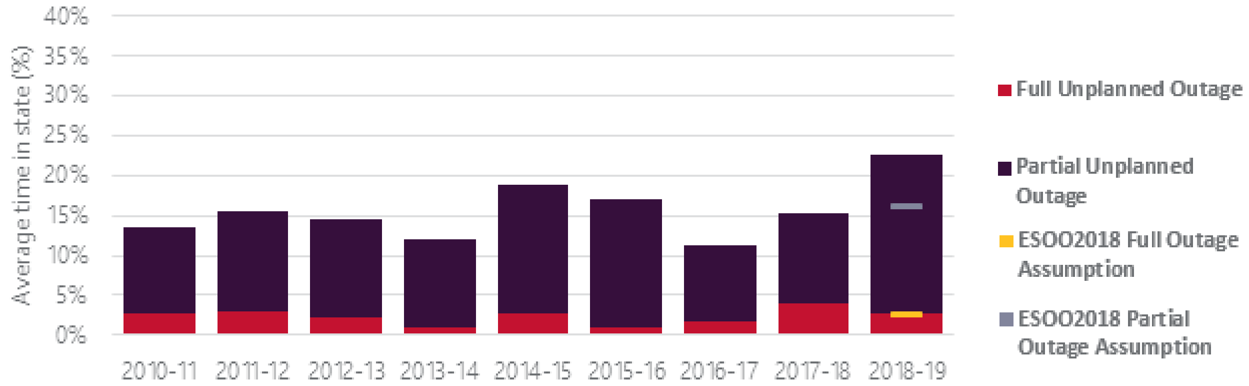
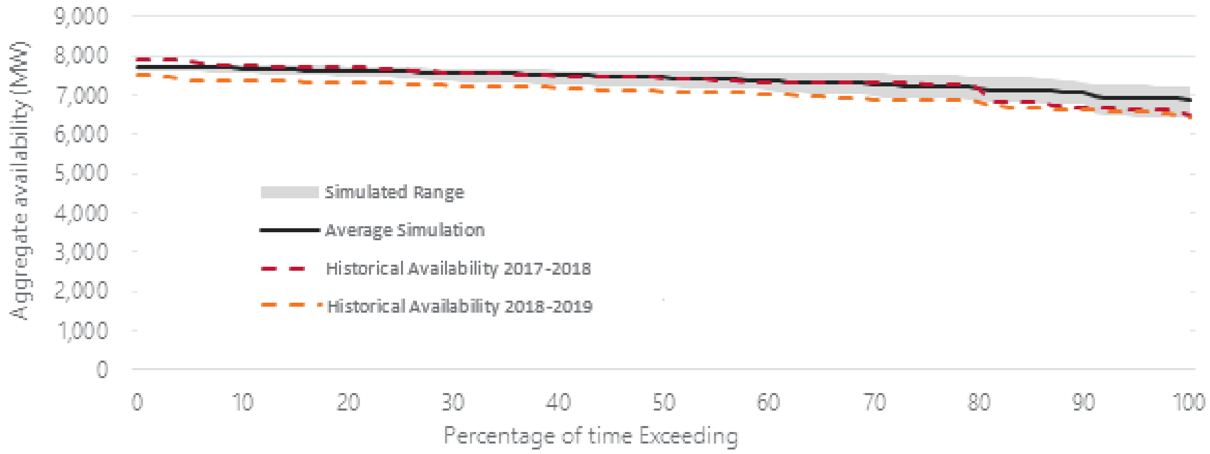


Figure 20 shows the availability over the top 10 hottest days was less than the simulated availability.

Figure 20 Queensland black coal supply availability – top 10 hottest days

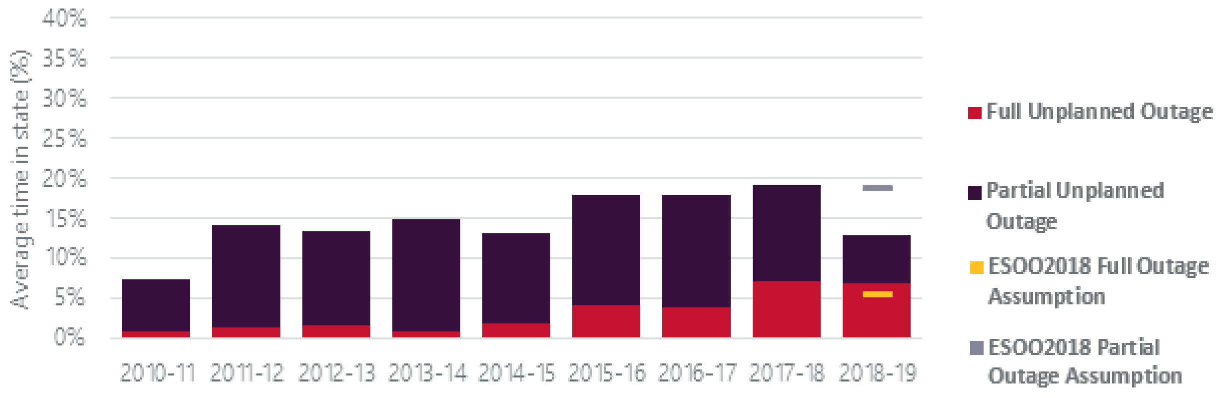


The observed availability in 2018-19 is lower than the simulated range due to outages and/or unavailable capacity at several units. Queensland has a surplus of available capacity relative to maximum demand, so there are periods where capacity may not be offered as available, as it was not required despite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

4.3 Victorian brown coal generation availability

Brown coal generation in Victoria has a strong upward trend in full unplanned outages, and rates of partial unplanned outages have been relatively stationary before 2018-19. Figure 21 shows how the rates of unplanned outages have changed over time relative to the 2018 ESOO assumptions.

Figure 21 Victorian brown coal historic unplanned outage rates

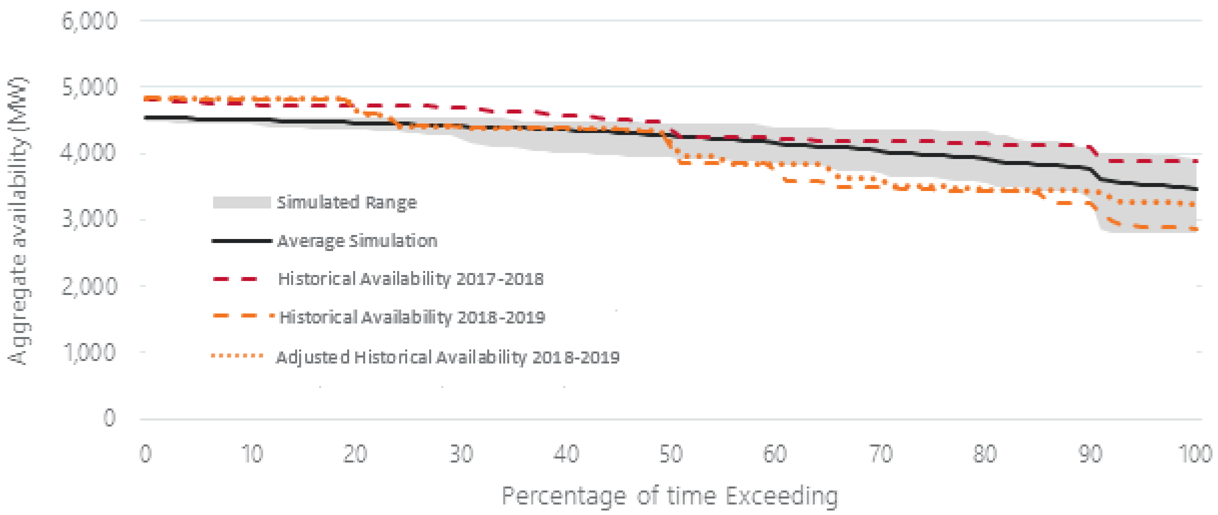


Because the assumptions used in the 2018 ESOO are fitted to historical observed outage rates, the outage assumption was lower than the observed full outage rate.

Figure 22 shows the availability over the top 10 hottest days was 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 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 25th January 2019 Victorian load shedding event.

Figure 22 Victorian brown coal supply availability – top 10 hottest days



4.4 Hydro generation availability

Hydro generation has had consistent rates of unplanned outages, and almost no partial unplanned outages. Figure 23 shows how the rates of unplanned outages have changed over time relative to the 2018 ESOO assumptions.

Figure 23 Hydro historic unplanned outage rates

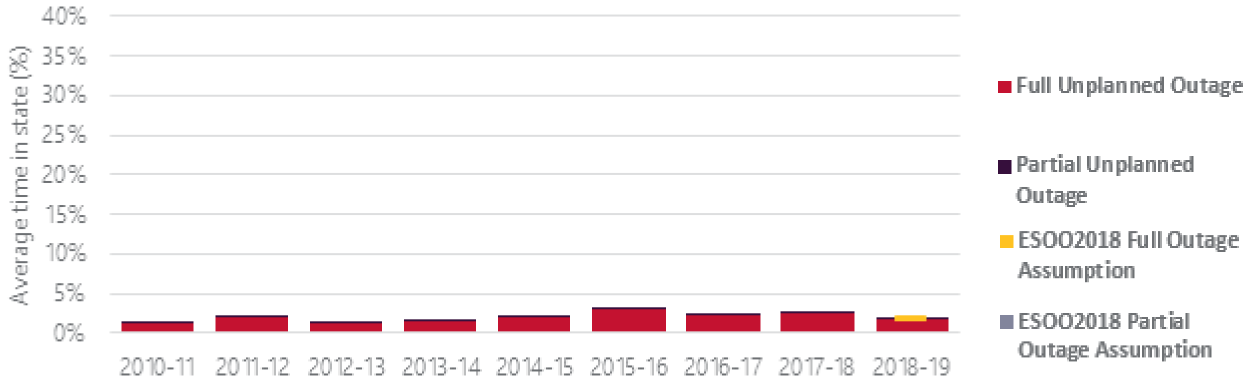
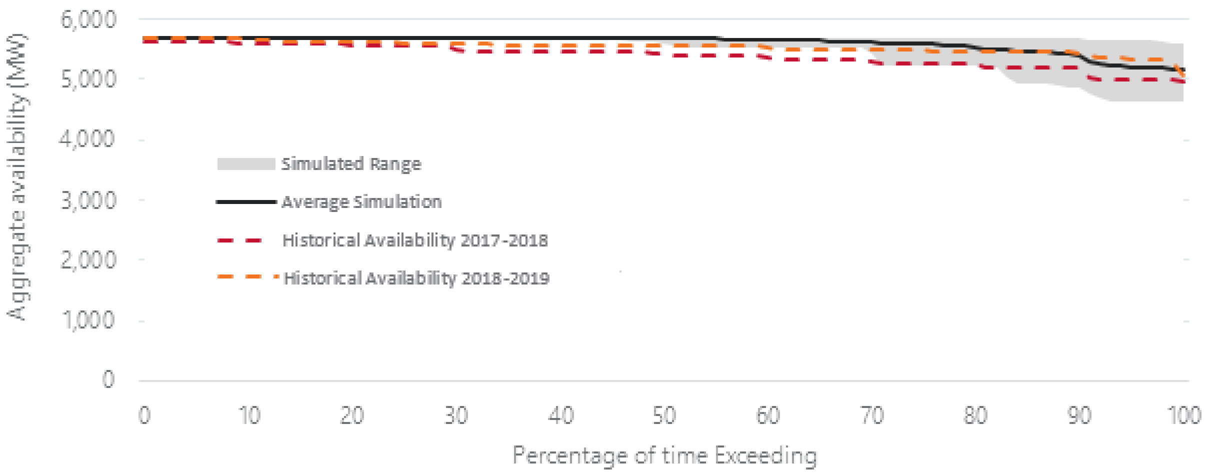


Figure 24 shows the availability over the top 10 hottest days was broadly consistent with the 2018 ESOO simulation for mainland NEM hydro generation.

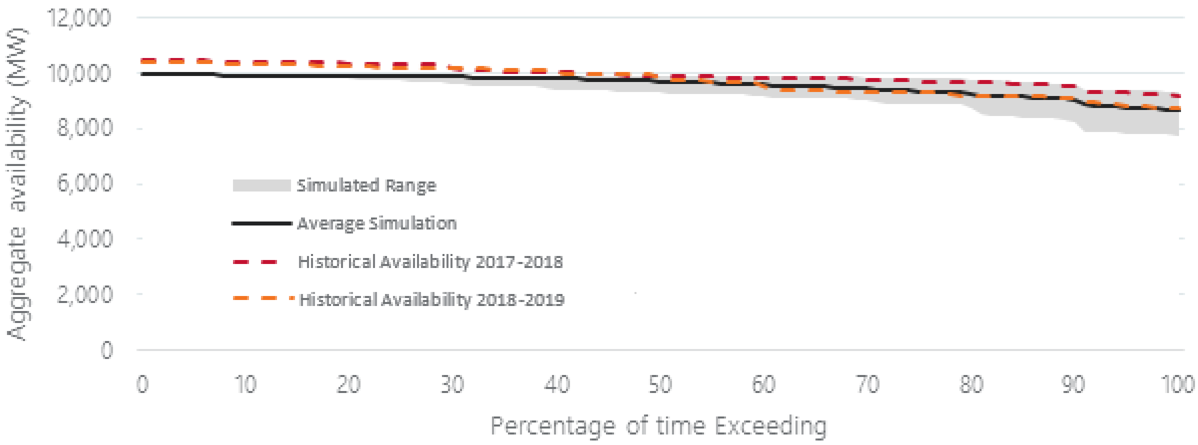
Figure 24 Mainland hydro supply availability – top 10 hottest days



4.5 Gas and liquid fuel generation availability

For gas-fired and liquid-fired generators[10], the mainland NEM has been considered in aggregate. As Figure 25 shows, observed availability has tended towards the upper bound of the 2018 ESOO simulation range.

Figure 25 Gas and liquid supply availability – top 10 hottest days

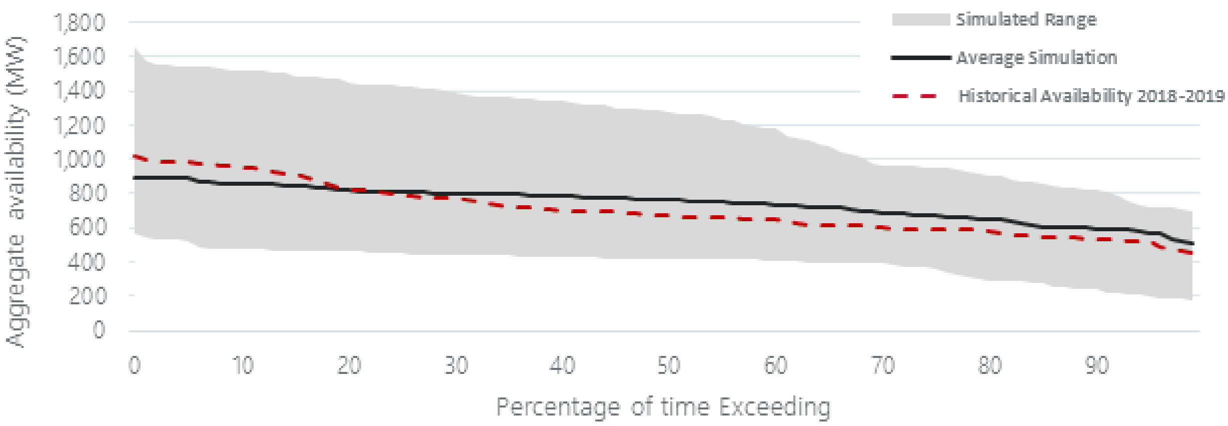


The main reason observed availabilities are higher than simulated outcomes is that many generators outperformed their rated summer capacity. Seasonal availabilities are provided to AEMO with respect to certain reference temperatures. The majority of the periods used in this analysis are below the reference temperatures, while the model always assumes the provided capacity limits. Future improvements to the modelling of seasonal capacity will be investigated, provided in Section 4.9. Beyond the variation in observed available capacity, outage rates were as expected.

4.6 New South Wales intermittent generation availability

All intermittent generation, including large scale grid solar PV and wind in New South Wales was considered in aggregate. Intermittent generation is modelled differently from thermal and hydro generation because periods of low or no demand are simulated using historical load traces. As Figure 26 shows, the 2018 ESOO simulated a wide band of possible intermittent generation 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 26 New South Wales intermittent generation availability – top 10 hottest days



[10] This aggregation includes OCGTs, CCGTs, gas-fired steam turbines, and liquid-fuelled generation (except those in Tasmania)

Table 12 shows the forecast and actual characteristics of all intermittent generation for New South Wales in summer 2019. Total summer capacity was less than the 2018 ESOO forecast, as a new facility was behind schedule in commissioning all capacity.

Table 12 New South Wales intermittent generation capacity, forecast and actual.

February 2019	Facilities operating (count)	Total summer capacity (MW)	Output during top 10 hottest days relative to summer capacity
2018 ESOO forecast	20	1,871	9%-88%
Actual[11]	20	1,768	26%-57%

4.7 South Australian intermittent generation availability

All intermittent generation for South Australia has been considered in aggregate. As Figure 27 shows below, the 2018 ESOO simulated a wide band of possible intermittent generation for South Australia on the 10 hottest days and observed output for summer 2019 tended towards the lower end of the simulation range.

Figure 27 South Australian intermittent generation availability – top 10 hottest days

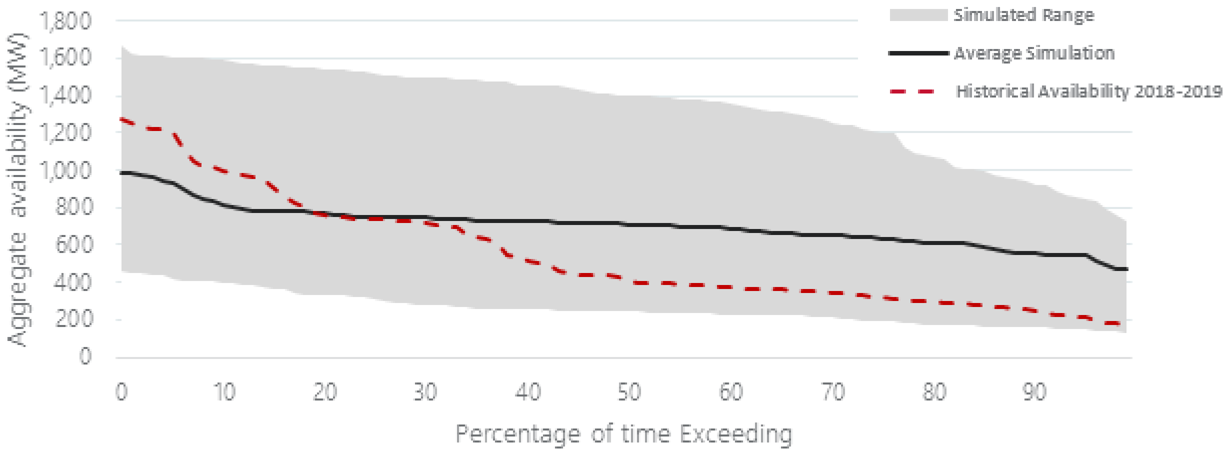


Table 13 shows the forecast and actual characteristics of all intermittent generation for South Australia in summer 2019. Total summer capacity was less than the 2018 ESOO forecast, as multiple facililties were behind schedule in commissioning all capacity.

Table 13 South Australia intermittent generation capacity, forecast and actual.

February 2019	Facilities operating (count)	Total summer capacity (MW)	Output during top 10 hottest days relative to summer capacity
2018 ESOO forecast	23	2,012	7%-83%
Actual[11]	23	1,856	9%-69%

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

4.8 Victorian intermittent generation availability

All intermittent generation for Victoria was considered in aggregate. As Figure 28 shows, the 2018 ESOO simulated a wide band of possible intermittent generation for Victoria on the 10 hottest days, and observed output for summer 2019 was within the simulation range.

Figure 28 Victorian intermittent generation availability – top 10 hottest days

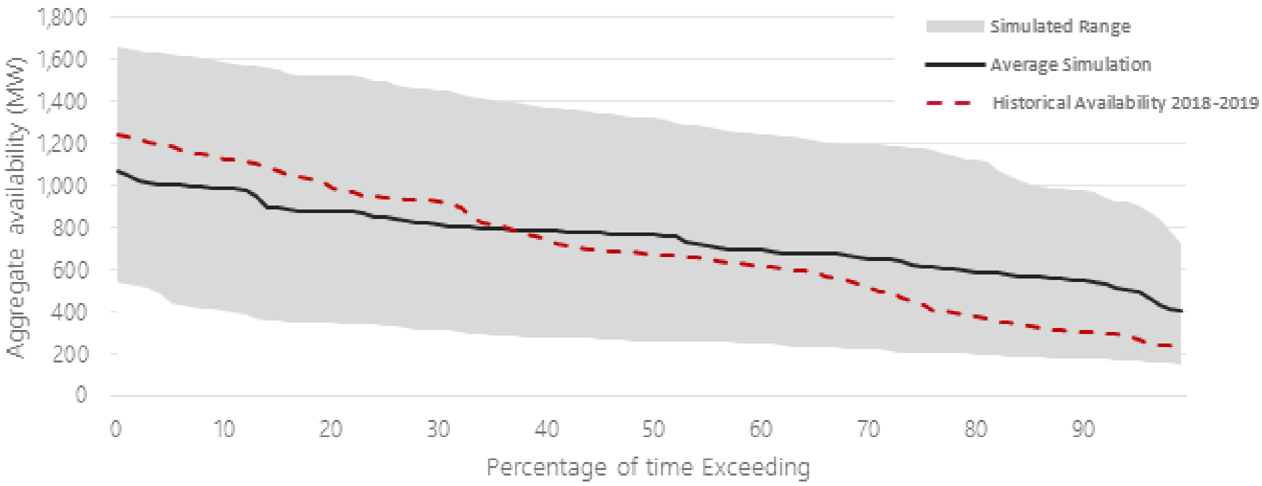


Table 14 shows the forecast and actual characteristics of all intermittent generation for Victoria in summer 2019. Total summer capacity was less than the 2018 ESOO forecast, as several facililties were behind schedule in commissioning all capacity, while one smaller facility began partial operation ahead of schedule.

Table 14 Victoria intermittent generation capacity, forecast and actual.

February 2019	Facilities operating (count)	Total summer capacity (MW)	Output during top 10 hottest days relative to summer capacity
2018 ESOO forecast	19	1,977	8%-84%
Actual[11]	19	1,881	12%-66%

4.9 Supply forecast improvements

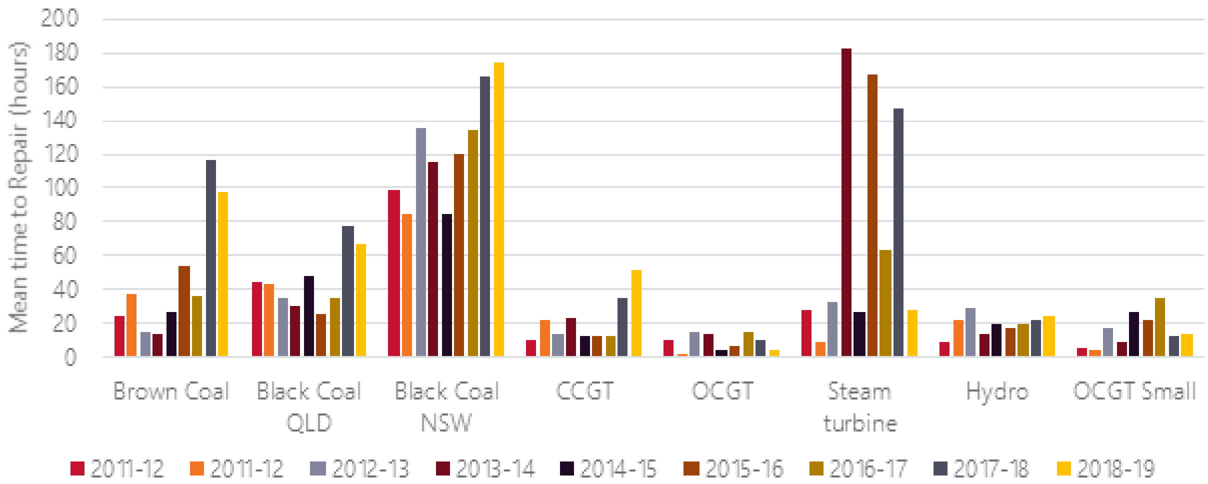
For the majority of regions and fuel types, the assumptions used in the 2018 ESOO delivered aggregate availability estimates that were appropriate. For Victorian brown coal however aggregate availability was overestimated, due to the combination of outages and a planned outage.

Several categories showed trends in the unplanned outage rate. This rate is a combination of two factors:

- The count/frequency of unplanned outages,
- The mean time to repair (MTTR).

In most cases, the trend was driven entirely by the MTTR as shown in Figure 29.

Figure 29 Estimated mean time to repair in hours by region and fuel type



There are many possible explanations for the increasing repair time including:

- More complex fault types, which might be indicative of ageing plant.
- Changed business process regarding the urgency of unplanned faults.
- A statistical abnormality.

With respect to brown coal, the trend is so strong that it can no longer be considered a statistical abnormality. A standard t-test with full unplanned outage rates sampled for 2010-11 to 2014-15 and 2015-16 to 2018-19 indicates less than 1% probability that the two samples are from the same population.

In 2018, AEMO implemented unplanned outage rates that were the average rate of the last three years. In 2019, a similar period is under consideration. This method was developed on the principle that recent maintenance spend would affect outage rates and would be best reflected in more recent performance.

For most plant this will be appropriate, but where there is a strong trend, further consideration will be given to better capture changes attributable to equipment ageing and/or business process changes. Generator owners can provide alternative rates with reasoning and are encouraged to do so if it is believed their rate will be different over the forecast horizon.

AEMO also intends to make modifications to the simulation of unplanned outage rates to better capture the uncertainty and variation observed in the history, as detailed in the Retailer Reliability Obligation Issues Paper[12].

[12] AEMO. Reliability forecasting methodology issues paper. http://aemo.com.au/Stakeholder-Consultation/Consultations/Reliability-Forecasting-Methodology-Issues-Paper

Improvements to modelling summer capacity

Beyond the 2019 ESOO, AEMO will investigate improvements to the modelling of generator seasonal capacity. Currently a single summer capacity is applied consistently across the entire summer period. This means that a generator's capacity will be reflective of summer peak conditions in many days where the temperature is well below the regional reference temperature. AEMO will investigate modelling approaches whereby two capacity values will be used in the summer period. One of the capacity values will be based on temperatures reflective of 10% POE demand conditions and would only be applied for a small set of summer days. In the remainder of summer periods, a capacity value that reflects a lower temperature would be applied. It is not expected that this would significantly impact the assessment of expected USE as the vast majority of USE in the modelling occurs on the few days with the highest demand.

5. Summary

The 2018 ESOO provided AEMO's independent forecast of supply reliability in the NEM over a 10-year period to inform the decision-making processes of market participants, new investors, and policy-makers as they assess future development opportunities.

This report explored the accuracy of the forecast elements, including demand drivers, demand forecasts and supply forecasts. Its conclusions can be summarised as follows:

- Customer connection forecasts were optimistic, as were installed PV capacity forecasts. While these two demand drivers are significant, the inaccuracy from each likely cancelled each other out.
- Demand forecasts were appropriate, except for Queensland, for which an upward revision is needed.
- Supply forecasts were appropriate, excluding Victorian brown coal generation, for which an upward revision to unplanned outage rates is needed.

AEMO will continue to improve the forecasting techniques in use, with improvements expected in time for the 2019 ESOO.

5.1 List of relevant improvements for the 2019 ESOO

Demand driver improvements

- A new customer connections model has been developed that incorporates greater visibility and consideration for the history.
- The consultant responsible for the 2018 ESOO PV forecast has revised the trajectory downwards in line with the updated actuals. Due to the uncertainty in the rate of uptake, AEMO is seeking the advice of two expert consultants to inform the 2019 forecast.
- Further work is being done to capture relevant climate trends in both supply and demand modelling.

Demand forecast improvements

- New extreme value models are being implemented to form a model ensemble.
- More modelling data will be retained for better explanation of non-weather-related coincident behaviour explanation.
- AEMO will continue to increase the number of simulations to minimise sampling error.
- The half-hourly model specification will be improved, particularly for Queensland, for which an upward revision is expected.

Supply driver improvements

- More recent fault data will be used to inform the simulator, while alternative rates that better capture consideration for equipment ageing and/or business process change will be considered.
- Modifications to the simulation of unplanned outages are being implemented, to better reflect the variation observed in history.
- Multiple summer capacity ratings will be explored to better capture available capacity at differing temperatures.

A1. 2019 summer adjustments

Table 15 lists the peak demand days in the various NEM regions for the summer 2018-19[13] based on metering generation (operational demand is defined as the generation required from scheduled, semi-scheduled and significant non-scheduled generation):

Table 15 Summer 2019 peak demand days in NEM regions.

NEM Region	Time of peak	Operational as generated	Auxiliary load	Operational sent out
SA	24-01-2019 19:00	3240	100	3140
VIC	25-01-2019 13:00	9110	335	8775
NSW	31-01-2019 16:30	13821	501	13320
QLD	13-02-2019 17:30	10044	552	9492
TAS	15-01-2019 17:30	1330	18	1312

Any adjustments to the peak demand days are discussed below, to account for what demand is estimated to have been under normal circumstances. Two types of adjustments are discussed:

- Firm – these are possible to estimate based on metering data (of individual loads and non-scheduled generators)
- Potential – these adjustments are more speculative and is based on expectation of differences in behaviour, but it cannot be verified (easily) by meter data analysis.

New South Wales

The spot price in New South Wales on 21 January 2019 peaked at $1913/MWh (average for the half hour ending 16:30) but remained below $300/MWh for the remaining half-hours of the day. Looking at metering data, there is no estimated DSP response, possibly because the price spike was not predicted in pre-dispatched assessment of system adequacy (PD PASA).

Earlier that day Ausgrid lost power to 45,000 customers due to a network outage. Power was however fully restored before the regional peak.

[13] Note that for all mainland regions, Summer is defined as from November to March (both included), while Summer for Tasmania is defined as December to February (both included).

Table 16 New South Wales maximum demand adjustments

NEM Region	Time of peak	Operational sent out	Adjustment (firm)	Firm adjusted operational sent out	Adjustment (potential)	Potential adjusted operational sent out
NSW	31-01-2019 16:30	13320	0	13320	0	13320

Queensland

The Queensland maximum demand day had prices remaining low (under $300/MWh) and thus no price response (DSP), normal operation of controlled hot water load, but Energy Queensland did trigger its controlled 'peak smart' air conditioner program. The estimated impact on peak of this program is about 20 MW, operating from 17:20 to 19:20 capping the controlled air conditioners to 50% of their maximum load during that period. This is shown in the table below.

Table 17 Queensland maximum demand adjustments

NEM Region	Time of peak	Operational sent out	Adjustment (firm)	Firm adjusted operational sent out	Adjustment (potential)	Potential adjusted operational sent out
QLD	13-02-2019 17:30	9492	20	9512	0	9512

South Australia

A number of adjustments must be made to the observed actual maximum demand in South Australia to compare against AEMO's forecast.

At time of the maximum demand at 19:00 (NEM time), the following firm adjustments should be made:

- 6 MW load reduction (RERT).
- 19 MW non-scheduled generation directed on.
- 30 MW of DSP.

Just following the recorded time of peak, SA Power Network had an outage with 15,000 customers in Adelaide losing power due to blown fuses (increasing to more than 20,000 later that evening). AEMO has estimated, based on network information provided by SA Power Networks, that for the half-hour ending 19:30 (NEM time), approximately 31 MW of load was not delivered, with all load restored by 21:30.

In addition to the firm adjustments above, both the state government and utilities called for all electricity users to conserve electricity usage, when possible. Based on estimated daily load profiles per appliance type and an assumed reduction in lighting usage (20% of what otherwise would have been on), 50% washers and dryers, 50% dishwashers, 10% computers, and 10% home entertainment, AEMO estimates approximately 45 MW of load reduction. Customers were also asked to set thermostat for air conditioners a couple of degrees higher than normal, with an assumed impact of those who responded of another 10 MW, for a 55 MW response in total[14].

[14] For this, AEMO has used appliance data from the 2015 report "Residential Baseline Study for Australia 2000 – 2030", available at: www.energyrating.com.au.

Table 18 South Australia maximum demand adjustments

NEM Region	Time of peak	Operational sent out	Adjustment (firm)	Firm adjusted operational sent out	Adjustment (potential)	Potential adjusted operational sent out
SA	24-01-2019 19:00	3140	55	3195	55	3250
SA	24-01-2019 19:30	3140	82	3222	55	3277

Tasmania

There were no adjustments required to the observed actual maximum demand in Tasmania.

Table 19 Tasmania maximum demand adjustments

NEM Region	Time of peak	Operational sent out	Adjustment (firm)	Firm adjusted operational sent out	Adjustment (potential)	Potential adjusted operational sent out
TAS	15-01-2019 17:30	1312	0	1312	0	1312

Victoria

A number of adjustments must be made to the observed actual maximum demand in Victoria to compare against AEMO's forecast.

On the 25th January 2019, at time of the maximum demand at 11:00 (NEM time), the following firm adjustments should be made:

- 120 MW of RERT.
- 56 MW reduction from voltage reduction scheme.

Market-based DSP at the time is estimated to be negligible (though DSP contributed significantly to the RERT and voltage scheme reductions listed above).

AEMO estimates, however, that demand would have been even higher later in the day, after adjusting from the load shedding that commenced just after 11:00.

Estimated time of when demand would have peaked is 13:00 (NEM time), accounting for load shedding, RERT and other responses that may have reduced demand compared to a normal day:

- 272 MW of load shedding.
- 184 MW of RERT.
- 54 MW reduction from voltage reduction scheme.

In addition to the firm adjustments above, both the state government and utilities called for all electricity users to conserve electricity usage, when possible. Based on estimated daily load profiles per appliance type and an assumed reduction in lighting usage (20% of what otherwise would have been on), 50% washers and dryers, 50% dishwashers, 10% computers, and 10% home entertainment, AEMO estimates approximately 67 MW of load reduction. Customers were also asked to set thermostat for air conditioners a couple of degrees higher than normal, with an assumed impact of those who responded of another 50 MW, for a 117 MW response in total at 11:00, and a slightly higher estimate of 120 MW for 13:00.

Table 20 Victoria maximum demand adjustments

NEM Region	Time of peak	Operational sent out	Adjustment (firm)	Firm adjusted operational sent out	Adjustment (potential)	Potential adjusted operational sent out
VIC	25-01-2019 11:00	8956	176	9132	117	9249
VIC	25-01-2019 13:00	8775	510	9285	120	9405

It should be noted that there was an early cool change on 25 January 2019, with temperatures coming down significantly from around 13:00. Had temperatures remained high, an even higher peak would have been expected towards the evening as the output of the approximately 1,500 MW of installed rooftop PV capacity in the region would have reduced.

A2. 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
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

Abbreviation	Full name
ESB	Energy Security Board
ESS	Electricity Storage System
ESOO	Electricity Statement of Opportunities
FRG	Forecasting Reference Group
GSP	Gross State Product
HDI	Household Disposable Income
HIA	Housing Industry Association
ISP	Integrated System Plan
LOLP	Loss of Load Probability
LRET	Large-scale Renewable Energy Target
MT PASA	Medium Term Projected Assessment of System Adequacy
MTTR	Mean time to repair
NABERS	National Australian Built Environmental Rating System
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
STC	Small-scale Technology Certificate
USE	Unserved energy
VRET	Victorian Renewable Energy Target