FORECAST ACCURACY REPORT 2017

FOR THE 2016 NATIONAL ELECTRICITY FORECASTING REPORT

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Purpose

The National Electricity Rules (Rules) require AEMO to report to the Reliability Panel on the accuracy of demand forecasts to date in the *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM) and any improvements made by AEMO or other relevant parties to the forecasting process. In 2016, AEMO published the relevant consumption and maximum demand forecasts used in the NEM ESOO in a standalone *National Electricity Forecasting Report* (NEFR).

This report is based on information available to AEMO as at September 2017.

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Version control

Version	Release date	Changes
1	1/11/2017	Draft report
2	27/11/2017	Final report

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CHAPTER 1. INTRODUCTION

The Australian Energy Market Operator (AEMO) produces a *Forecast Accuracy Report* for the Reliability Panel each year.

This report assesses the accuracy of the annual operational consumption and maximum operational demand (MD) forecasts in AEMO's *2016 National Electricity Forecasting Report* (NEFR), for each region in the National Electricity Market (NEM).[1]

It does this by comparing forecast operational consumption and MD in the 2016 NEFR against actual operational consumption and MD for the financial year 2016–17.

The 2016 NEFR provided AEMO's independent 20-year electricity consumption forecasts for each NEM region.[2] AEMO published the 2016 NEFR with a range of supplementary documents, including the *Forecasting Methodology Information Paper*.[3]

The accuracy of AEMO's operational consumption and MD forecasts depends on AEMO's forecast models, which in turn rely on forecast input data, including economic forecasts.

Terms used in this report are defined in the glossary.

[1] AEMO. *2016 National Electricity Forecasting Report*, June 2016. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.
[2] Queensland, New South Wales, Victoria, South Australia, and Tasmania.
[3] AEMO. *Forecasting Methodology Information Paper: 2016 National Electricity Forecasting Report*, July 2016. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

CHAPTER 2. FORECAST ACCURACY

After assessing key annual consumption forecasts (Operational consumption – sent out,) against actual annual consumption in each NEM region, AEMO found the accuracy summarised in the table below, measured as the mean percentage error (MPE). Details of this assessment by region are in Sections 2.2 to 2.6.

Table 1 MPE by region for annual operational consumption – sent out

State	MPE	Comment
New South Wales	1.1%	Good alignment with forecast
Queensland	-0.7%	Good alignment with forecast
South Australia	-1.1%	Good alignment with forecast
Tasmania	-2.5%	Difference driven by lower industrial consumption than forecast
Victoria	-5.0%	Difference explained by Portland smelter load reduction

At this stage, there is no similar forecast accuracy measure for MD forecasts. A comparison between actual MD and POE forecasts is discussed in each of the regional sections below.

AEMO will develop a project scope in 2018 for a new Forecast Monitoring System, which will monitor forecast performance regularly across a year and will cover metrics for both annual consumption and maximum demand (see Section 3.2 for additional improvements planned for 2018).

2.1 Methodology

Based on industry feedback, AEMO adopted a simpler measure of forecast performance in its 2016 Forecast Accuracy Report than that used in previous annual publications. The current report continues the approach adopted in 2016.

In this report, all forecasts are reported on a “sent out” basis.[4]

2.1.1 Annual consumption forecast

AEMO assessed consumption forecast accuracy by measuring the percentage difference between actual and forecast components of the published forecasts.

The accuracy metric used is MPE, calculated using the formula below:

$$mean\ percentage\ error = \frac{actual_{FYE17} - forecast_{FYE17}}{actual_{FYE17}} \times 100$$

In the formula, FYE17 refers to the financial year 1 July 2016 – 30 June 2017.

To the extent possible, actual and forecast values were split into subcomponents.

Forecast values were based on forecast weather outcomes defined by heating degree days and cooling degree days (HDD and CDD[5]) of a median weather year.

Actual values were not weather-corrected (adjusted to represent in a median weather year).

[4] For the difference between sent out and as generated demand, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Operational-Consumption-definition---2016-update.pdf.

[5] For a detailed description on how HDD and CDD is derived, see page 55 of the 2016 NEFR *Forecasting Methodology Information Paper*, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

2.1.2 Maximum demand forecast

Unlike the consumption forecast, which is a point forecast (single value), the MD forecast is represented by a distribution of possible outcomes.

The distribution of possible MD outcomes is represented by the published 10%, 50%, and 90% probability of exceedance (or POE) forecasts.

AEMO compares the actual MD to these POE forecasts, and qualitatively assesses if the forecasts are reasonable in comparison.

The actual MD is highly dependent on a number of factors, in particular temperature, cloud cover and the type of day (weekday versus weekend).

Temperatures are shown for the time of observed maximum demand based on measurements from the capital city of each region[6].

The temperatures for the POE forecasts are indicative only, as high demand can be due to very high temperatures on a sunny day (with rooftop PV generation offsetting demand from the grid) but similar demand can arise from lower temperatures with cloud cover reducing the rooftop PV generation.

[6] Only Sydney is used for New South Wales even though this region includes all of Australian Capital Territory (ACT) as well.

2.2 New South Wales

Table 1 Forecast accuracy of New South Wales 2016 NEFR forecasts for 2016–17

Annual consumption	2016 NEFR forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	**67,812**	**68,545**	**734**	**1.1%**
Auxiliary load (GWh)	3,165	2,821	-344	-12.2%
Operational consumption – as generated (GWh)	**70,977**	**71,367**	**390**	**0.5%**
SNSG (GWh)	1,409	1,619	210	12.9%
Native consumption – as generated (GWh)	**72,386**	**72,986**	**600**	**0.8%**
Significant input forecasts				
Rooftop PV (GWh)	1,579	1,597	18	1.1%
Transmission losses (GWh)	1,481	1,518	37	2.4%
Weather – annual				
Heating degree days (HDD)	685	572	-113	-19.7%
Cooling degree days (CDD)	404	582	178	30.5%
Maximum demand	**Actual**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	**13,670**	**14,151**	**12,760**	**11,306**
Weather – at time of maximum demand				
Temperature (°C)	43.7	40.0	37.5	34.8

SNSG = small non-scheduled generation

- Actual New South Wales operational consumption (sent out) in the 2016–17 financial year was 1.1% above the 2016 NEFR prediction.
  - The 2016–17 financial year was significantly warmer than normal, resulting in more cooling degree days in New South Wales. The consumption increase for additional cooling was partly offset by fewer heating degree days leading to less demand for heating in winter.
- Actual MD occurred in summer on 10 February 2017, when the temperature reached 43.7°C. The actual MD may have been higher if it hadn't been for a general call for reduced consumption (a reduction of approximately 200 MW below expected was observed at the time of peak demand, which may have been due to customer response) and the Tomago smelter's output being reduced.[7] Accounting for an estimated combined 490 MW of load reductions, the adjusted MD would have just exceeded the forecast of 10% POE demand.

[7] For details of the load reductions, see the incident report for 10 February 2017, noting that references to maximum demand in that document is on an as generated basis rather than sent out: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Incident-report-NSW-10-February-2017.pdf.

2.3 Queensland

Table 2 Forecast accuracy of Queensland 2016 NEFR forecasts for 2016–17

Annual consumption	2016 NEFR forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	**52,036**	**51,655**	**-381**	**-0.7%**
Auxiliary load (GWh)	3,441	3,505	64	1.8%
Operational consumption – as generated (GWh)	**55,477**	**55,160**	**-317**	**-0.6%**
SNSG (GWh)	1,737	1,834	97	5.3%
Native consumption – as generated (GWh)	**57,214**	**56,994**	**-220**	**-0.4%**
Significant input forecasts				
Rooftop PV (GWh)	2,361	2,372	11	0.5%
LNG (GWh)	6,284	5,245	-1,039	-19.8%
Transmission losses (GWh)	1,580	1,381	-199	-14.4%
Weather – annual				
Heating degree days (HDD)	257	137	-120	-87.3%
Cooling degree days (CDD)	667	839	171	20.4%
Maximum demand	**Actual**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	**8,930**	**9,631**	**9,106**	**8,633**
Weather – at time of maximum demand				
Temperature (°C)	30.8	38.0	32.5	30.1

SNSG = small non-scheduled generation

- Actual Queensland operational consumption (sent out) in the 2016–17 financial year was 0.7% below the 2016 NEFR prediction.
  - Due to a slower ramp-up of the LNG projects, the forecast overestimated liquefied natural gas (LNG) plants' consumption of electricity (actual 20% lower than forecast).
  - This difference was mostly offset by actual consumption in other sectors being higher than forecast, partly driven by significantly warmer weather than normal driving up need for cooling.
- Actual MD occurred in summer, on 18 January 2017, when the temperature was 30.8°C. This aligns with being between the forecast 50% POE and 90% POE values.

2.4 South Australia

Table 3 Forecast accuracy of South Australia 2016 NEFR forecasts for 2016–17

Annual consumption	2016 NEFR forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	**12,627**	**12,484**	**-143**	**-1.1%**
Auxiliary load (GWh)	138	204	66	32.2%
Operational consumption – as generated (GWh)	**12,765**	**12,688**	**-77**	**-0.6%**
SNSG (GWh)	54	78	25	31.6%
Native consumption – as generated (GWh)	**12,819**	**12,767**	**-52**	**-0.4%**
Significant input forecasts				
Rooftop PV (GWh)	976	974	-2	-0.2%
Transmission losses (GWh)	313	409	96	23.4%
Weather – annual				
Heating degree days (HDD)	1,262	1,325	63	4.8%
Cooling degree days (CDD)	407	421	14	3.4%
Maximum demand	**Actual**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	**3,017**	**3,081**	**2,753**	**2,489**
Weather – at time of maximum demand				
Temperature (°C)	40.7	39.6	39.5	36.3

SNSG = small non-scheduled generation

- Actual South Australian operational consumption (sent out) in the 2016–17 financial year was 1.1% below the 2016 NEFR prediction.
  - The 28 September 2016 blackout was a contributing factor.
  - Actual weather, while close to a normal year, resulted in slightly higher heating and cooling needs than forecast.
- Actual MD occurred in summer on 8 February 2017, as temperatures reached 40.7°C. Some large industrial consumers reduced their consumption from normal levels in response to tight supply and high prices at the time. Adjusting for this, South Australian MD was consistent with the forecast 10% POE value.

2.5 Tasmania

Table 4 Forecast accuracy of Tasmania 2016 NEFR forecasts for 2016–17

Annual consumption	2016 NEFR forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	**10,265**	**10,016**	**-249**	**-2.5%**
Auxiliary load (GWh)	144	110	-34	-30.5%
Operational consumption – as generated (GWh)	**10,409**	**10,126**	**-283**	**-2.8%**
SNSG (GWh)	463	423	-40	-9.4%
Native consumption – as generated (GWh)	**10,871**	**10,549**	**-323**	**-3.1%**
Significant input forecasts				
Rooftop PV (GWh)	126	117	-9	-7.9%
Transmission losses (GWh)	323	319	-3	-1.1%
Weather – annual				
Heating degree days (HDD)	1,653	1,233	-420	-34.1%
Cooling degree days (CDD)	0	20	20	100.0%
Maximum demand	**Actual**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	**1,678**	**1,785**	**1,670**	**1,550**
Weather – at time of maximum demand				
Temperature (°C)	3.3	11.7	12.7	12.9

SNSG = small non-scheduled generation

- Actual Tasmanian operational consumption (sent out) in the 2016–17 financial year was 2.5% below the 2016 NEFR prediction.
  - Industrial consumption was lower than forecast.
  - It was also a significantly warmer year, resulting in the heating requirements being down by 34%.
- Actual MD occurred in winter on 27 June 2017 during a temperature of 3.3°C. The 1,678 MW is similar to the forecast 50% POE, though this assumes higher temperatures. However, Tasmanian MD is less sensitive to temperature than in other regions, because the majority of consumption in the region is from industrial customers, and their consumption at the time has a relatively larger impact on the resulting MD.

2.6 Victoria

Table 5 Forecast accuracy of Victoria 2016 NEFR forecasts for 2016–17

Annual consumption	2016 NEFR forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	**43,573**	**41,482**	**-2,091**	**-5.0%**
Auxiliary load (GWh)	3,881	3,751	-130	-3.5%
Operational consumption – as generated (GWh)	**47,454**	**45,232**	**-2,222**	**-4.9%**
SNSG (GWh)	980	844	-136	-16.2%
Native consumption – as generated (GWh)	**48,434**	**46,076**	**-2,358**	**-5.1%**
Significant input forecasts				
Rooftop PV (GWh)	1,279	1,244	-35	-2.8%
Transmission losses (GWh)	1,244	1,275	31	2.4%
Weather – annual				
Heating degree days (HDD)	863	878	15	1.7%
Cooling degree days (CDD)	329	364	35	9.7%
Maximum demand	**Actual**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	**8,230**	**9,934**	**8,922**	**7,918**
Weather – at time of maximum demand				
Temperature (°C)	35.3	40.2	39.3	36.3

SNSG = small non-scheduled generation

- Actual Victorian operational consumption (sent out) in the 2016–17 financial year was 5% below the 2016 NEFR prediction.
  - The key reason was the outage of the Portland smelter in December 2016 forcing it to operate at reduced capacity for the remainder of the financial year.
  - Weather was mostly in line with forecast, although cooling degree days were up slightly.

Actual MD occurred in summer, on 9 February 2017, during a temperature of 35.3°C. On this day, as for most of the Summer, Portland was operating below its normal level following an outage early December 2016. In addition to this, Ausnet Services called a Critical Peak Day reducing the combined load for participating customers. If these effects are also included, the adjusted MD would have been higher but still below the 50% POE forecast, consistent with relative mild temperatures compared to those seen on typical maximum demand days other years.

CHAPTER 3. IMPROVEMENTS TO THE FORECASTING PROCESS

Since the publication of the 2016 NEFR, AEMO has changed its forecasting methods to improve accuracy and the quality of forecasting insights.

3.1 2017 demand forecasting improvements

2016 saw a major transformation of how AEMO undertakes demand forecasting, adding more detailed ‘bottom-up’ models based on customer meter data which better reveals dynamics that originate beyond the grid. The models employed also put greater weight on more recent historical data, compared to using longer time series where demand relationships can differ.

The 2017 demand forecasts have kept this framework, with minor updates to capture changes, such as:

- Updating PV and battery storage forecasts to account for lower prices during the “solar trough” – the period in the middle of the day when supply from rooftop and utility scale PV systems will meet an increasing share of the customer demand, causing wholesale prices to fall. This “trough” will:
  - Lower the incentives for installing additional PV, as supply during times when PV is generating is generally cheaper compared to other times of the day.
  - Increase the value of combined PV and battery installations, as the owner can choose to use the power when supply from the grid would be more expensive.
- Adopting the electricity consumption forecasts for electric vehicles that were presented in an AEMO Insights paper[8] in August 2016.
- Undertaking climate change normalisation of historical weather input data and long-range climate forecasts, based on advice from CSIRO and Bureau of Meteorology.

3.2 2018 demand forecasting improvements

Concurrently with the 2017 improvements, AEMO has been developing a forecasting insights analytics platform. This will be used for the 2018 forecasts.

This system will:

- Allow more regular updates to forecasts
- Allow tracking of the impacts changes to any forecasting component make on overall forecasts.

Linked to this system is the planned forecasting accuracy dashboard, which will allow industry stakeholders to see forecasting accuracy data, split by components where possible, on an online portal.

To further enhance AEMO’s understanding of what is happening behind the grid, AEMO is undertaking an analytics program, studying historical detailed meter data to observe consumption patterns down to individual consumer segments.

As in previous years, AEMO will consult with industry and stakeholders on the energy forecasting methodology improvements via the Forecasting Reference Group.

[8] See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/AEMO-insights_EV_24-Aug.pdf.

GLOSSARY

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
auxiliary load	The load from equipment used by a generating system for ongoing operation. Auxiliary loads are located on the generating system's side of the connection point, and include loads to operate generating systems co-located at coal mines.
cooling degree days (CDD)	A sum of the number of degrees that the ambient temperature is above the threshold temperature for each day of the year.
heating degree days (HDD)	A sum of the number of degrees that the ambient temperature is below the threshold temperature for each day of the year.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
large industrial load	There are a small number of large industrial loads – typically transmission-connected customers – that account for a large proportion of annual energy in each National Electricity Market (NEM) region. They generally maintain consistent levels of annual energy and maximum demand in the short term, and are weather insensitive. Significant changes in large industrial load occur when plants open, expand, close, or partially close.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
native electricity consumption	The electrical energy supplied by scheduled, semi-scheduled, significant non-scheduled, and small non-scheduled generating units.
operational electricity consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a POE10 maximum demand for any given season is expected to be met or exceeded, on average, one year in 10 – in other words, there is a 10% probability that the projected maximum demand will be met or exceeded.
rooftop photovoltaic (PV)	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity. The 2015 NEFR forecasts considered only rooftop systems (systems installed to generate electricity primarily for self-consumption by residential or commercial consumers, including projects above 100 kW as well as smaller systems). It did not consider PV installations above 100 kW like solar farms or community projects which are designed to sell electricity into the market. These are part of the SNSG.
small non-scheduled generation (SNSG)	Small non-scheduled generation, generally representing generation projects up to 30 MW in size.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.