2017 ELECTRICITY STATEMENT OF OPPORTUNITIES

FOR THE WHOLESALE ELECTRICITY MARKET

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide market data and technical information about opportunities in the Wholesale Electricity Market in Western Australia. This publication is based on information available to AEMO as at 31 March 2017, although AEMO has incorporated more recent information where possible.

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Version control

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EXECUTIVE SUMMARY

This Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) report presents AEMO's electricity peak demand and operational consumption[1] outlook for the South West interconnected system (SWIS) in Western Australia (WA) for a 10-year period. The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM) that ensures sufficient capacity is available during periods of peak demand to meet reliability targets set for the SWIS.

Last year, AEMO deferred the 2016 Reserve Capacity Cycle[2] for a period of 12 months from 1 May 2016 to 1 May 2017 at the Public Utilities Office's request, to allow for new market arrangements to be finalised.[3]

AEMO is not deferring any cycles this year, and is running the 2016 and 2017 Reserve Capacity Cycles concurrently to bring the cycles back to normal. This WEM ESOO report contains an additional year of data covering two Long Term Projected Assessment of System Adequacy (PASA) Study Horizons and information relevant to the 2016 and 2017 Reserve Capacity Cycles.

This report contains peak demand and operational consumption forecasts across a range of weather and demand growth scenarios.

It highlights the 10% probability of exceedance (POE)[4] peak demand forecast used to determine the Reserve Capacity Targets (RCTs) for the 2018–19 and 2019–20 Capacity Years.[5]

Key findings

- Based on the 10% POE peak demand forecast, the RCTs have been determined as:
  - 4,620 megawatts (MW) for the 2018–19 Capacity Year.
  - 4,660 MW for the 2019–20 Capacity Year.
- The 10% POE peak demand is forecast to grow at an average annual rate of 1.4%[6] over the first five years of the forecast period, and 1.6% over the remainder of the period. The forecast peak demand growth rate is consistent with the 2015 WEM ESOO forecast of 1.4% across the 10-year period.[7]
- Annual operational consumption is forecast to grow slowly, at an average annual rate of 1.2%, over the forecast period. This growth rate is slightly higher than the 2015 WEM ESOO forecast of 1.0% over the 10-year period.
- The rapid adoption of rooftop photovoltaic (PV)[8] continues to reduce operational consumption. The production profile of rooftop PV has contributed to shifting peak demand later in the day

1 Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.

2 Specifically, AEMO deferred the remaining events in Year 1 of the 2016 Reserve Capacity Cycle (which had not occurred as at 1 May 2016) for a period of 12 months, but did not defer Years 2 to 4 of the 2016 Reserve Capacity Cycle.

3 AEMO's deferral notice is available at: http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable.

4 POE refers to the likelihood that a peak demand forecast will be met or exceeded. A 10% POE peak demand forecast is expected to be exceeded, on average, only one year in 10, while 50% and 90% POE peak demand forecasts are expected to be exceeded, on average, five years in 10 and nine years in 10, respectively.

5 A Capacity Year is defined in Chapter 11 (Glossary) of the WEM Rules as a period of 12 months commencing on the start of the Trading Day on 1 October and ending on the Trading Day ending on 1 October of the following calendar year. All data in this report is based on Capacity Years unless otherwise specified.

6 This report provides low, expected and high demand growth cases based on different levels of economic growth. Unless otherwise indicated, demand growth forecasts in this executive summary are based on expected levels of economic growth.

7 The ESOO prepared as part of the deferred 2015 Reserve Capacity Cycle (published in June 2016) is referred to as the 2015 WEM ESOO in this report. Available at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2015/Deferred-2015-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.

8 For the purposes of this report, rooftop PV refers to installed residential and commercial systems that have a capacity of less than 100 kW and are eligible for Small-scale Technology Certificates under the Small-scale Renewable Energy Scheme (SRES).

where is has lesser output. As a result, AEMO expects peak demand to grow at a faster rate than operational consumption over the outlook period.

- Peak demand for the 2016–17 summer was 3,670 MW, observed in the 17:00 to 17:30 trading interval on 1 March 2017. It was the lowest summer peak observed in the SWIS since 2009, and the first time since 2007 that peak demand occurred in March.
  - Rooftop PV systems are estimated to have reduced peak demand on 1 March 2017 by 265 MW, or 7.2%, from 3,935 MW to 3,670 MW.
  - The capacity cost allocation mechanism – the Individual Reserve Capacity Requirement (IRCR)[9] – has provided an effective incentive for contestable customers to reduce electricity consumption during high demand periods. Action taken by 53 customers in response to the IRCR reduced load by 124 MW during the peak demand interval on 1 March 2017, the highest IRCR response observed to date.
- Based on the current level of installed and committed capacity, and assuming there are no changes to the capacity outlook, 5 MW of new capacity may be required in the SWIS in the 2021–22 Capacity Year. This grows in line with demand up to 433 MW by the end of the forecast period.
- The WA Government's Electricity Market Review (EMR) may change the way Capacity Credits are assigned, from the current administered process to a Reserve Capacity Auction.[10] However, the implementation of this change still needs to be finalised as part of the EMR process.
- AEMO investigated the effect of new renewable capacity on the level of capacity in the RCM and the RCP. High levels of solar capacity are expected to affect the RCP more than high levels of wind capacity, due to the higher capacity factor at peak time of solar compared to wind in the SWIS.
- The Demand Side Management (DSM) Reserve Capacity Price (RCP) for the 2017–18 Capacity Year is $17,050 per MW.

Reserve Capacity Target

The RCTs for the 2018–19 and 2019–20 Capacity Years have been determined as 4,620 MW and 4,660 MW, respectively.

These RCTs are calculated as the 10% POE peak demand forecast plus a reserve margin.[11]

Excess capacity fell from 23% for the 2016–17 Capacity Year to 14% for the 2017–18 Capacity Year, predominantly due to a large volume of Demand Side Programme (DSP) capacity (493 MW) exiting the market in response to the EMR-related RCM transitional changes.[12]

On 17 November 2016, a Ministerial Direction was tabled in the WA Parliament to ensure that Synergy will reduce at least 380 MW of non-renewable generation nameplate capacity by 1 October 2018.[13] On 5 May 2017, the WA Government announced its plans to reduce a total of 437 MW of Synergy's non-renewable generation nameplate capacity (equivalent to 387 MW of Capacity Credits).[14] This reduction will affect the capacity supply-demand balance in the SWIS by decreasing excess capacity

[9] For the calculation method for determining the IRCR, see Appendix 5 of the WEM Rules.
[10] The Reserve Capacity auction proposed by the EMR is different to the current Reserve Capacity Auction under clause 4.19 of the WEM Rules.
[11] The reserve margin is calculated as the greater of 7.6% of the 10% POE demand forecast, and the maximum capacity of the largest generating unit in the SWIS – see clause 4.5.9(a) of the WEM Rules.
[12] Further information on the EMR-related RCM transitional changes is available at: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Wholesale_Electricity_Market_Improvements.aspx.
[13] WA Parliament, 2016. *Electricity Corporations Act 2015 – Ministerial Direction*. Available at: http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf.
[14] Government of Western Australia, 2017. *Synergy to reduce electricity generation cap by 2018*. Available at: https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.

from 642 MW (14.1%)[15] in the 2017–18 Capacity Year to 187 MW (4.0%) in 2018–19 Capacity Year, assuming the current level of Capacity Credits assigned to other Facilities remains unchanged.

Based on the current level of installed capacity and known retirements, and assuming no further changes to the Wholesale Electricity Market Rules (WEM Rules), new capacity is expected to be required in the SWIS in the 2021–22 Capacity Year. By the end of the outlook period (2026-27), the level of shortfall is expected to be 433 MW (8.3%).

DSM Reserve Capacity Price

The RCM transitional changes introduced a separate pricing structure for DSM capacity, which will commence on 1 October 2017.[16] The DSM RCP for the 2017–2018 Capacity Year is required to be published in this report.[17]

The DSM RCP for the 2017–18 Capacity Year is $17,050 per MW. The RCP for generators for the 2016 and 2017 Reserve Capacity Cycles cannot be confirmed until after the certification process for these years has been completed.

Peak demand and operational consumption forecasts 2017–18 to 2026–27

AEMO forecasts the 10% POE peak demand to increase at an average annual rate of 1.6% over the next 10 years, as presented in Table 1.

Table 1 Peak demand forecasts for different weather scenarios, expected demand growth

Scenario	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	2021–22 (MW)	5-year average annual growth	10-year average annual growth
10% POE	4,169	4,213	4,253	4,326	4,401	1.4%	1.6%
50% POE	3,927	3,968	4,009	4,076	4,133	1.3%	1.5%
90% POE	3,709	3,739	3,782	3,835	3,893	1.2%	1.4%

Source: AEMO and ACIL Allen

The 10% POE 10-year average annual growth rate listed in Table 1 is marginally different from the growth rate published in the 2015 WEM ESOO, due to incremental improvements in the forecasting methodology, especially in the rooftop PV model and economic forecasts.

The first five years of the forecasts in the 2015 WEM ESOO and this report follow the same annual growth rate, with a slight increase in growth rate for the last five years of the latest forecast. This results in a variance of 101 MW between the two forecasts at the end of the forecast period. AEMO has analysed this variance and considers the difference between the annual peak demand forecasts in the 2015 WEM ESOO and this report to be due to higher forecast population and economic growth over the forecast period and refinements to the forecast methodology.

Operational consumption forecasts for the high, expected, and low growth scenarios are shown in Table 2. These forecasts reflect different economic growth scenarios and corresponding rooftop PV system and electric vehicle (EV) growth scenarios.

[15] AEMO is aware that some of capacity associated with Muja AB will be retired by 1 October 2017, however due to the late timing of this announcement, the earlier retirement is not considered.

[16] Government Gazette No.89 ‘Electricity Industry (Commencement of Electricity Industry (Wholesale Electricity) Market Amendment Regulations) Order 2016’, Perth, Tuesday 31 May 2016.

[17] See clause 4.5.13(i) of the WEM Rules.

Table 2 Operational consumption forecasts[a] for different economic growth scenarios

Scenario	2017–18 (GWh)	2018–19 (GWh)	2019–20 (GWh)	2020–21 (GWh)	2021–22 (GWh)	5 year average annual growth	10 year average annual growth
High	18,947	19,160	19,372	19,650	19,967	1.3%	1.7%
Expected	18,819	18,962	19,110	19,316	19,538	0.9%	1.2%
Low	18,705	18,786	18,866	18,994	19,129	0.6%	0.7%

Source: ACIL Allen with AEMO input
[a] Operational consumption forecasts are per financial year

AEMO expects operational consumption to increase at an average annual rate of 0.9% over the next five years and 1.2% over the 10-year growth period. This is slightly lower than last year's forecast, mainly due to higher forecast rooftop PV system uptake.

Growth in operational consumption is predicated on current policy settings for the non-contestable customer segment. Changes to tariff and regulatory policies may reduce or increase growth in operational consumption compared to AEMO's forecasts over the outlook period.

Table 1 and Table 2 highlight that peak demand is expected to continue growing at a higher rate than operational consumption. This trend is partly due to rooftop PV reducing consumption more during the middle of the day than during peak times.

Trends in SWIS peak demand

Peak demand and associated temperature statistics for the past nine years are outlined in Table 3.

This year's summer peak demand (3,670 MW on 1 March 2017) was 8.5% lower than last year's (4,013 MW), and was the lowest summer peak since 2009. As Table 3 shows, a significant driver of this was a much lower temperature. It was the first time since 2007 that peak demand occurred in March.

Table 3 SWIS system peak, 2009 to 2017

Date	Peak demand (MW)	Maximum temperature during trading interval (°C)	Trading interval commencing	Daily maximum temperature (°C)
1 March 2017	3,670	34.7	17:00	37.7
8 February 2016	4,013	40.2	17:30	42.5
5 January 2015	3,744	40.8	15:30	44.4
20 January 2014	3,702	37.4	17:30	38.3
12 February 2013	3,732	35.4	16:30	40.5
25 January 2012	3,857	40.0	16:30	41.0
16 February 2011	3,735	37.5	16:30	39.0
25 February 2010	3,766	39.5	16:00	41.5
11 February 2009	3,515	39.5	15:30	39.7

Source: AEMO and Bureau of Meteorology

The 2016–17 summer peak demand occurred during the trading interval starting at 17:00, consistent with the trend of peak demand shifting later in the afternoon, observed over the past four years. Between 2011 and 2013, peak demand occurred in the trading interval starting at 16:30. More recently, peak demand has been observed during later trading intervals. This is largely due to strong uptake of rooftop PV systems.

Peak demand has become increasingly volatile in the last five years. Between 2013 and 2015, peak demand was fairly stable at around 3,700 MW. Record peak demand was observed on 8 February 2016, which was followed by the lowest peak demand in eight years on 1 March 2017.

The unpredictable nature of peak demand presents a forecasting challenge. This affects the accuracy of the RCT, which is based on the 10% POE peak demand forecast, and increases the risk of setting an inappropriate RCT and RCP. Since the RCP should reflect the economic value of capacity, an inappropriately high or low RCP risks sending misleading price signals to the market.

Several factors are contributing to making peak demand harder to forecast, including:

- Continuing rapid uptake of rooftop PV.
- Increased customer IRCR response.
- Uncertainty about the effect of battery storage and EVs on peak demand.
- Variation in weather patterns.

AEMO continues to work to better understand these trends and improve the forecasts presented in the WEM ESOO.

Impact of rooftop PV systems

Underlying electricity consumption[18] in the residential sector continues to grow, due to increased use of electrical appliances, including reverse-cycle air-conditioning and entertainment devices. However, a combination of strong uptake of rooftop PV, energy efficiency, and a response to higher prices has contributed to a reduction in average consumption per connection from the electricity network. This has reduced the growth in both operational consumption and peak demand.

Rooftop PV is estimated to have reduced the 2016–17 summer peak demand by 265 MW. This was significantly higher than the 191 MW reduction seen for the 2015–16 summer peak, due to continued strong growth in rooftop PV installations and the 2016–17 peak occurring earlier in the day, when solar generation is higher.

The 265 MW reduction in peak demand is attributed to the following factors:

- A shift in the timing of peak demand by half an hour, from the trading interval starting at 16:30 to the trading interval starting at 17:00. Underlying demand was estimated to be 3,877 MW at 17:00 compared to 3,935 at 16:30. This shift of the peak to a later time reduced demand by 58 MW.
- Generation from rooftop PV during the 17:00 peak. This reduced peak demand by 207 MW from 3,877 MW to 3,670 MW.

Growth of rooftop PV installations has continued to affect the level and timing of peak demand over the last five years. In Table 4, actual peak demand over the six highest demand days for 2012 to 2017 is compared with the estimated peak that would have occurred in the absence of rooftop PV.

Table 4 Effect of rooftop PV on peak demand, 2012 to 2017[a]

Date	Trading interval commencing	Peak demand (MW)	Estimated peak demand without rooftop PV (MW)	Estimated peak trading interval commencing without rooftop PV	Reduction in peak demand from rooftop PV (MW)	Reduction in peak demand from peak time shift (MW)
1 March 2017	17:00	3,670	3,935	16:30	207	58
8 February 2016	17:30	4,013	4,204	16:30	96	95
5 January 2015	15:30	3,744	3,931	14:30	165	32
20 January 2014	17:30	3,702	3,757	15:30	81	29
12 February 2013	16:30	3,732	3,816	13:30	81	6
25 January 2012	16:30	3,857	3,918	15:00	72	19

[a] This table has been updated from previous editions of the WEM ESOO to reflect the latest data from the Australian PV Institute and PVOutput.org.

[18] Underlying electricity consumption refers to everything consumed onsite, and includes electricity provided by localised generation from rooftop PV, battery storage and embedded generators, or by the electricity grid.

AEMO expects the strong growth of rooftop PV capacity in the SWIS to continue. Over the past year, approximately 125 MW of new rooftop PV was installed, representing an increase in total rooftop PV capacity in the SWIS of around 20%. Technological, commercial, and regulatory factors, as well as increasing environmental awareness, continue to drive this strong uptake.

The increasing uptake of rooftop PV is affecting the daily load profile for the SWIS. This change is most noticeable on sunny winter days which now show a strong dip in the middle of the day, coinciding with peak solar generation, an effect known as the “duck curve”. This may require gas peaking generation to start and stop multiple times during the day, potentially increasing costs and, subsequently, wholesale energy prices. In particular, fast-response gas peaking generation may be used more in future for the sharp ramp-up of load between 16:00 and 18:00.

Response to the Individual Reserve Capacity Requirement

The IRCR mechanism financially incentivises large customers to reduce consumption during peak demand periods and consequently reduce their exposure to capacity payments. At the time of the 2016–17 peak demand, 53 customers reduced consumption, resulting in a total load reduction of 124 MW, as outlined in Table 5.

Table 5 IRCR response on peak demand days, 2012 to 2017

Date	Peak demand (MW)	Time of peak	Estimated IRCR reduction (MW)	Number of customers responding
1 March 2017	3,670	17:00	124	53
8 February 2016	4,013	17:30	77	57
5 January 2015	3,744	15:30	42	20
20 January 2014	3,702	17:30	50	44
12 February 2013	3,732	16:30	65	59
25 January 2012	3,857	16:30	50	59

Although a similar number of loads responded to the IRCR compared to previous years, the response was the highest observed to date. Of the 53 customers that responded, nine customers accounted for 104 MW (84%) of the total reduction.

Electricity Market Review

The EMR was launched in 2014 by the WA Government to consider changes to the WEM, with the key objective of reducing the cost of the production and supply of electricity-related services. Aspects of phase two of the EMR are currently underway. This phase consists of four workstreams covering the proposed reform projects, with the WEM improvements workstream focusing on reforms to the RCM and energy market.[19]

As part of this workstream, a Reserve Capacity Auction is expected to be introduced in future. AEMO understands that changes to the WEM Rules to implement the auction will be developed by late 2017 or early 2018. Prior to this, a number of transitional reforms designed to reduce excess capacity have commenced or are scheduled to commence in 2017.[20] These measures are intended to reduce the cost of procuring capacity to meet the RCT in the short and long term, as well as to reduce the current level of excess capacity in the WEM.

[19] More information available at: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx

[20] Government Gazette No.89 ‘Electricity Industry (Commencement of Electricity Industry (Wholesale Electricity) Market Amendment Regulations) Order 2016’, Perth, Tuesday 31 May 2016.

Excess capacity fell from 23% for the 2016–17 Capacity Year to 14% for the 2017–18 Capacity Year, predominantly due to a large volume (454 MW) of DSM capacity exiting the market in response to the RCM transitional changes.

Emissions reduction and renewable energy policy

Australia has committed to achieving a 26% to 28% reduction in emissions by 2030 (relative to 2005 levels) as part of its obligations to keep global temperature increases to below 2°C, agreed at the 2015 Paris Climate Conference. [21]

While not directly linked, the Large-scale Renewable Energy Target (LRET) will support the Paris commitment. The LRET is a national target for renewable generation to reach 33,000 gigawatt hours (GWh) of Australia's forecast electricity generation by 2020.[22] Although this is a national target and there is no obligation on individual states to meet their pro-rata share, the sale of Large-scale Generation Certificates (LGCs) under the LRET incentivises further investment in renewable generation in the SWIS.

AEMO has recently modelled a hypothetical SWIS LRET to estimate the effects that an increased renewable energy generation mix would have on the RCM.[23] To achieve the hypothetical SWIS LRET target, approximately 2,200 GWh a year of new renewable generation would be required.

The effect on the RCP would depend on the mix of new renewable generation installed. A high concentration of new solar generation would likely reduce the RCP more than a high concentration of wind. This is due to solar having a higher capacity factor[24] during peak times than wind, even though wind generally has a higher overall capacity factor on average.[25]

[21] Australia's 2030 climate change target is available at: http://www.environment.gov.au/climate-change/publications/factsheet-australias-2030-climate-change-target
[22] For more information on the LRET, see https://www.environment.gov.au/climate-change/renewable-energy-target-scheme
[23] AEMO, 2017. *AEMO Insights - Renewables Influence on the Generation Mix and Gas Demand in Western Australia.* Available at: https://www.aemo.com.au/Media-Centre/Renewables-Influence-on-the-Generation-Mix-and-Gas-Demand-in-WA.
[24] Capacity factor is represents the percentage of actual generation relative to the maximum theoretically possible generation based on a Facility's nameplate capacity.
[25] Based on historical SWIS data for large-scale wind and solar generators. The trend towards a later peak may see solar's average capacity factor during peak times fall in the future.

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TABLES

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CHAPTER 1. INTRODUCTION

1.1 Background and context

This Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) report has been developed by the Australian Energy Market Operator (AEMO) as part of the 2016 and 2017 Reserve Capacity Cycles.[26] The information provided by this report relates to generation and Demand Side Management (DSM) capacity required in the South West interconnected system (SWIS) in Western Australia (WA) for the 2018–19 and 2019–20 Capacity Years.[27]

A key purpose of the 2017 WEM ESOO is to set the Reserve Capacity Targets (RCTs) for the 2018−19 and 2019–20 Capacity Years. The RCT is the amount of generation and DSM capacity required to satisfy the Planning Criterion, which AEMO determines in accordance with the WA Wholesale Electricity Market Rules (WEM Rules).[28]

The Planning Criterion ensures there is enough capacity in the SWIS to meet peak demand based on a one-in-ten year peak event, plus a reserve margin to cover outages and ancillary services required to maintain system security.

The 2017 WEM ESOO presents AEMO's outlook for peak demand and operational consumption[29] in the SWIS across a number of scenarios. AEMO uses weather-adjusted historical data[30] in various places throughout this report and focuses on the 10% probability of exceedance (POE)[31] forecasts, used to set the RCTs.

This report has been developed to provide relevant information about market trends and investment opportunities to current and potential stakeholders in the SWIS.

1.1.1 Concurrent operation of the 2016 and 2017 Reserve Capacity Cycles

At the request of the WA Public Utilities Office in March 2016, AEMO deferred the 2016 Reserve Capacity Cycle for a period of 12 months to 1 May 2017. The deferral of the 2016 Reserve Capacity Cycle was requested to allow new market arrangements of the Electricity Market Review (EMR) to be finalised before the process of certification of capacity for the 2018–19 Capacity Year commenced.

As such, this report is relevant to both the 2016 Reserve Capacity Cycle (for the 2018–19 Capacity Year) and the 2017 Reserve Capacity Cycle (for the 2019–20 Capacity Year).

Further information on the deferral of the 2016 Reserve Capacity Cycles is available on AEMO's website.[32]

1.2 Structure of this report

The structure of the report is as follows:

- Chapter 2 provides background information on the WEM, including market mechanisms, load patterns, diversity of capacity supply, and details of existing Facilities in the SWIS.

[26] The 2016 and 2017 Reserve Capacity Cycles are for the 2018–19 Capacity Year and the 2019–20 Capacity Year respectively.

[27] All references to years are Capacity Years throughout this report, unless otherwise specified. A Capacity Year is defined in Chapter 11 (Glossary) of the WEM Rules as a period of 12 months commencing on the start of the Trading Day on 1 October and ending on the Trading Day ending on 1 October of the following calendar year. All data in this report is based on Capacity Years unless otherwise specified.

[28] See clause 4.5.9 of the WEM Rules.

[29] Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.

[30] Adjusted to what would have been expected during a 10% POE weather event.

[31] POE refers to the likelihood that a peak demand forecast will be met or exceeded. A 10% POE peak demand forecast is expected to be exceeded, on average, only one year in 10, while 50% and 90% POE peak demand forecasts are expected to be exceeded, on average, five years in 10 and nine years in 10, respectively.

[32] AEMO. *Reserve Capacity Timetable.* Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable.

- Chapter 3 discusses:
  - The 2016–17 summer peak demand in the SWIS, and historical trends in peak demand since 2008.
  - Factors affecting peak demand, including temperature, the Individual Reserve Capacity Requirement (IRCR), and uptake of commercial and residential rooftop photovoltaic (PV).[33]
  - Recent trends in electricity consumption by residential, commercial, and large industrial customers.
- Chapter 4 explains the forecasting methodology and assumptions for peak demand and operational consumption, and discusses factors affecting the forecasts.
- Chapter 5 presents the peak demand and operational consumption forecasts from the 2017–18 Capacity Year to the 2026–27 Capacity Year.
- Chapter 6 reconciles actual demand and energy data for 2016–17 against the forecasts presented in the 2015 ESOO[34], and discusses revisions in assumptions and improvements made in the 2017 WEM ESOO.
- Chapter 7 presents the RCT for each Capacity Year of the Long Term Projected Assessment of System Adequacy (PASA) Study Horizon and discusses future investment opportunities for the SWIS.
- Chapter 8 discusses issues affecting the WEM, including the EMR, emissions targets, renewable energy policy, and infrastructure developments in the SWIS.
- Appendices provide further information, including the Availability Curves and peak demand and operational consumption forecasts for all scenarios.

A data register containing the data for the figures in this report is available on AEMO's website.[35]

[33] For the purposes of this report, rooftop PV is defined as installed residential and commercial systems with a capacity of less than 100 kilowatts (kW) and eligible for Small-scale Technology Certificates (STCs) under the federal SRES.
[34] The WEM ESOO prepared as part of the deferred 2015 Reserve Capacity Cycle published in June 2016, referred to as the 2015 ESOO in this report. Available at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2015/Deferred-2015-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.
[35] AEMO. Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

CHAPTER 2. CHARACTERISTICS AND EVOLUTION OF THE WEM

This chapter provides background information on the WEM, including an overview of the market mechanisms and load patterns, and information about diversity of supply and existing Facilities.

2.1 Overview

The WEM commenced operation in the SWIS on 21 September 2006. The SWIS consists of approximately 98,000 kilometres of transmission and distribution network. With more than one million customer connections, the SWIS covers an area of 261,000 square kilometres, extending from Albany in the south to Kalgoorlie in the east and Kalbarri in the north, including the Perth metropolitan area, as illustrated in Figure 1.

The SWIS is geographically isolated from the National Electricity Market (NEM). As such, the WEM needs to be self-sufficient for long-term power system security.

Figure 1 Map of the SWIS

2.2 Market mechanisms

The Reserve Capacity Mechanism (RCM) [36] was designed to financially incentivise sufficient electricity generation and DSM capacity in the SWIS to meet forecast peak demand, while achieving the reliability targets specified in the WEM Rules.

[36] The rules establishing and governing the RCM are in chapter 4 of the WEM Rules.

The RCM provides sufficient revenue for capacity investments, particularly for peaking capacity, to avoid high and volatile energy prices in the market.

In conjunction with the RCM, the WEM operates an energy market. The energy market is facilitated through a combination of bilateral contracts (off market), the Short Term Energy Market (STEM), the balancing market, and various ancillary service markets.

Generators may participate in the energy market only, or in both the energy and capacity markets. Capacity payments via the RCM allow generators to recover long run marginal costs, while short run marginal costs are recovered through the energy market. This results in lower energy price caps for the WEM when compared to other, energy-only electricity markets (where generators recover long and short run marginal costs solely through the energy market), such as the NEM.

Table 6 outlines the market mechanisms employed in the WEM.[37] A brief description highlights key features of each mechanism.

Table 6 Market mechanisms in the WEM

Market mechanism	Brief description
Reserve Capacity Mechanism	Ensures sufficient capacity is available to meet the system peak demand.
Short Term Energy Market (STEM)	A day ahead contractual market that allows Market Participants to trade around bilateral positions for the following day.
Balancing market	A market accounting for differences between day-ahead net contract positions, established after the STEM process, and actual outcomes.
Load rejection reserve ancillary service	A market for generators capable of rapidly decreasing output in the event of a sudden loss of demand, such as a system fault.
Load following ancillary service (LFAS)	Ensures the target frequency range (49.8 to 50.2 hertz) is met 99% of the time by balancing demand and supply.
Spinning reserve ancillary service	Capacity (either from a generator, dispatchable load, or interruptible load) held in reserve to respond rapidly in the event of an unexpected outage of an operating Facility.
Dispatch support ancillary service	Generators capable of maintaining voltage levels in the power system, and services not covered by other ancillary service markets.
System restart ancillary service	Enables part of the power network to be re-energised by black start-equipped generation capacity following a system-wide black out.

2.3 Load patterns

The load duration curve represents the variation of electricity demand over time. It reflects the amount of time for which a given level of demand is exceeded, and indicates the extremity of an electricity system's peak demand. The load duration curve provides information for determining the optimal mix of generation, as different generation is suited to different types of load. For example, peaking generators are used for short periods during the year when electricity demand is at its highest.

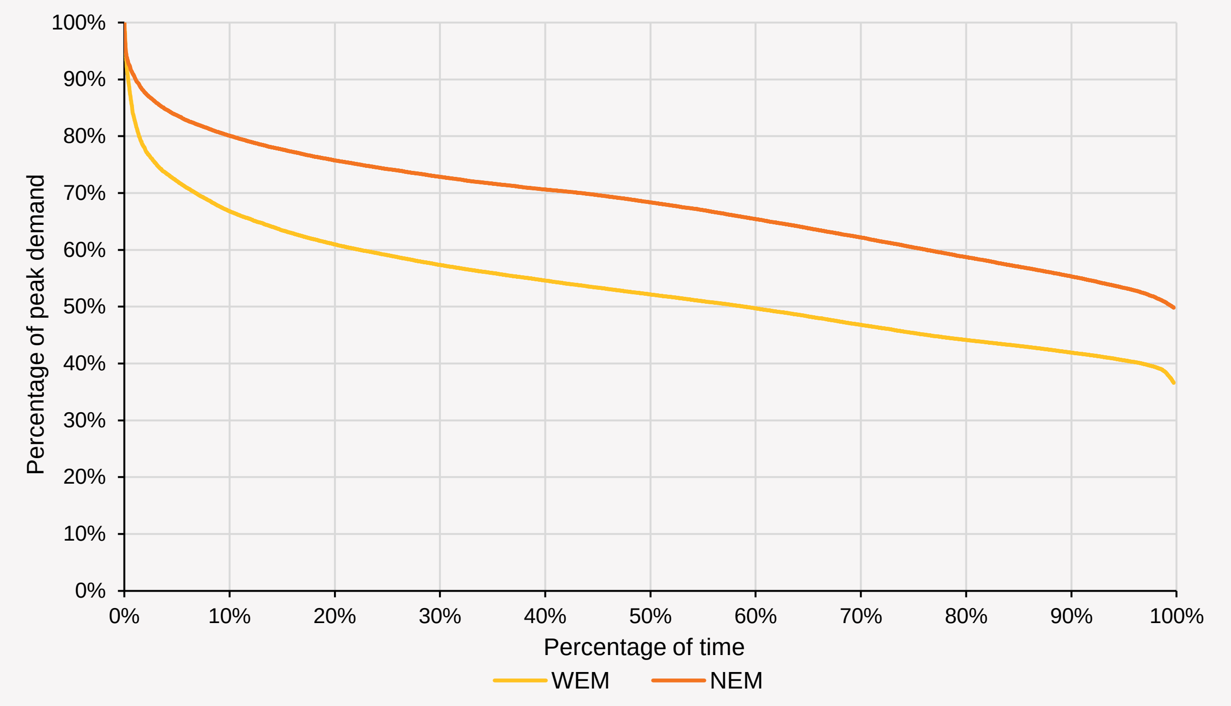
Typically, in the SWIS, maximum demand is highest on hot summer days, with a peak between 15:30 and 17:30. Figure 2 compares load duration curves for the WEM and the NEM for the 2015–16 Capacity Year.

In the 2015–16 Capacity Year, peak demand for the WEM and the NEM was around 4,013 megawatts (MW) and 29,019 MW, respectively. The WEM has a sharper peak than the NEM, with the upper 33.2% of the load used for 10% of the time, compared to 19.9% of the time in the NEM. The minimum load in the WEM is 34.7% of peak demand, which is lower than in the NEM (48%).

The peakier load profile of the WEM suggests that load in the SWIS is more temperature sensitive than load in the NEM.

[37] Independent Market Operator, 2012. *Wholesale Electricity Market Design Summary.* Available at: https://www.aemo.com.au/-/media/Files/PDF/wem-design-summary-v1-4-24-october-2012.pdf.

Figure 2 Load duration curves, 2015–16



2.4 Capacity diversity

2.4.1 Capacity Credits by Market Participant

Since market start in 2006, the number of Market Participants has increased three-fold, with 30 Market Participants holding Capacity Credits in the 2017–18 Capacity Year. This increase indicates that the market has facilitated private investment, thus increasing competition.

The total quantity of Capacity Credits assigned for the 2017–18 Capacity Year is 5,194 MW, approximately 50% more than the Capacity Credits allocated in 2005–06.

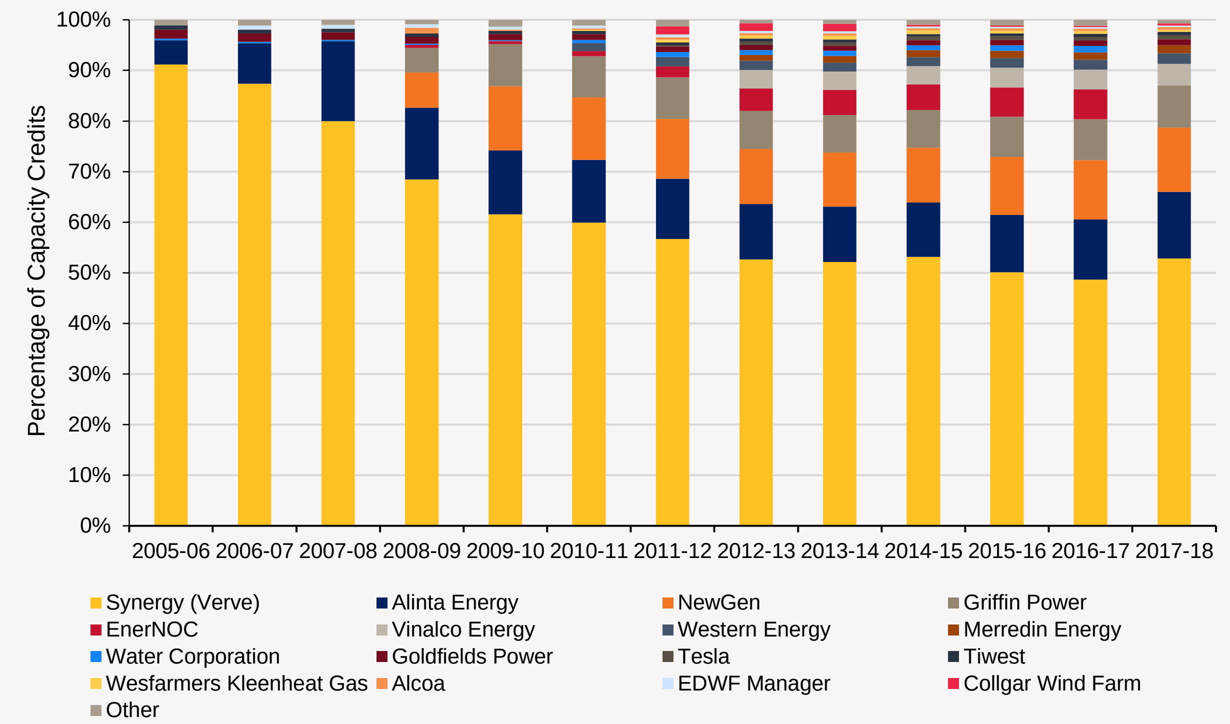
Figure 3 outlines the allocation of Capacity Credits by Market Participant since market start, showing:

- The share of Capacity Credits held by Synergy (formerly Verve Energy[38]) has decreased steadily since market start. In 2017–18, Synergy accounts for 53% of Capacity Credits, falling from 91% at market start. This is largely the result of load growth and market power mitigation measures to support the introduction of new generation in the WEM. [39]
- Alinta Energy and NewGen are the next two largest Capacity Credit holders in 2017–18, each holding approximately 13% of Capacity Credits. Other major Capacity Credit holders include Griffin Power, Vinalco Energy, and Western Energy.

[38] The WA Government merged Verve Energy and Synergy on 1 January 2014, with the new entity trading as Synergy. See: https://www.synergy.net.au/About-us/Vision-and-values/Where-weve-been.

[39] WA Parliament. 2016. *Electricity Corporations Act 2015 – Ministerial Direction*. Available at: http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf. Viewed: 20 January 2017.

Figure 3 Proportion of Capacity Credits by Market Participant, 2005–06 to 2017–18



2.4.2 Capacity Credits by fuel type

Fuel diversity is important to maintaining security of electricity supply in the WEM and supporting competition between technologies and generators. It mitigates events such as fuel supply restrictions which may cause a failure of the electricity system or an electricity supply disruption. In 2008 and 2011, it was essential in minimising the impact of two gas supply disruptions.

The WEM has a diverse mix of fuel types to ensure there is sufficient electricity generation capacity to meet peak demand, as presented in Figure 4.

The WEM's current market share by fuel type is:

- 34% coal.
- 31% dual gas/diesel.
- 27% gas.
- 3% diesel.
- 2% DSM.
- 2% renewables.

DSM market share has fallen from 10% in 2016–17 to 2% in 2017–18, increasing the market share of other capacity types. This is an outcome of the EMR reforms in 2016. See Section 8.1 for more details.

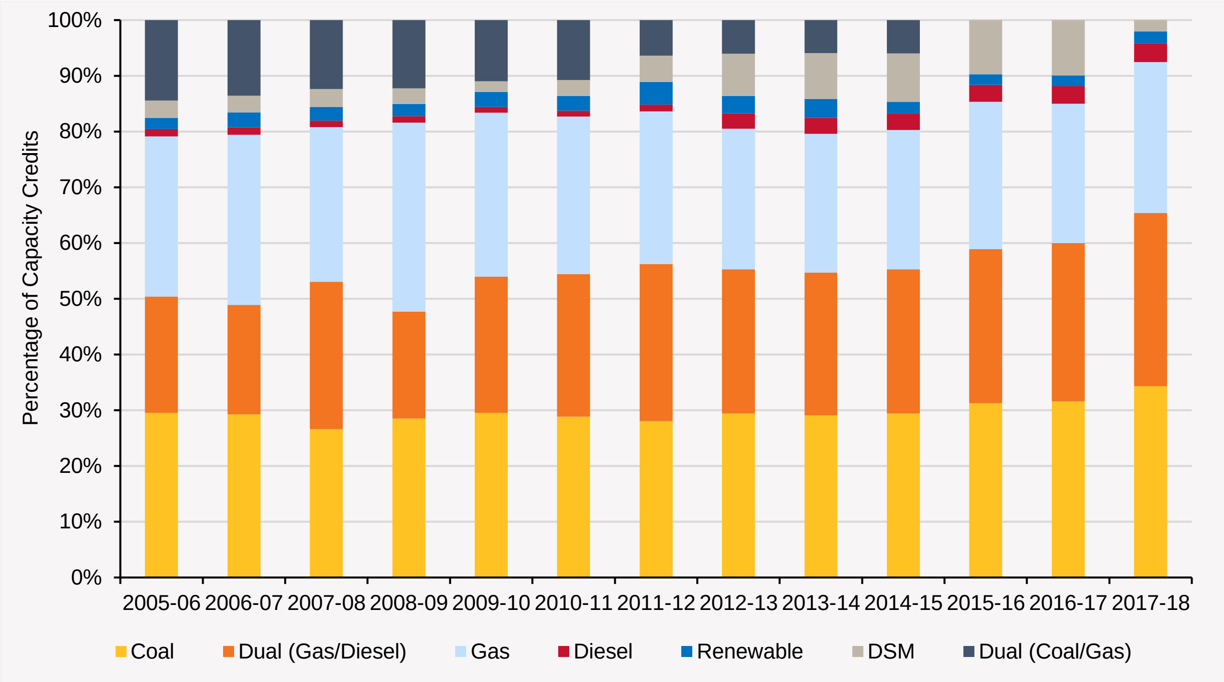
Dual-fuelled coal and gas capacity reduced to zero following the retirement of Synergy's Kwinana Facility between 2014 (177.5 MW) and 2015 (184 MW).

The level of Capacity Credits allocated to renewable generation was at its highest in 2011–12, reaching approximately 4% of market share. The implementation of the new Relevant Level[40] calculation methodology from 2012, intended to more accurately reflect renewables contribution to peak demand, reduced this to around 2% of market share from 2014–15. Renewable generators' share of Capacity

[40] The Relevant Level Methodology is set out in Appendix 9 of the WEM Rules.

Credits is expected to grow over the forecast period in response to the Commonwealth Government's Large-scale Renewable Energy Target (LRET). More information on the LRET is provided in Section 8.2.2.

Figure 4 Proportion of Capacity Credits by fuel, 2005–06 to 2017–18



2.5 Existing Facilities

Currently 76 Facilities are assigned Capacity Credits in the WEM[41], comprising 48 scheduled generators, 18 non-scheduled generators, and nine DSM Facilities. This section outlines the characteristics of these Facilities by age, fuel types, and classification (peaking, mid-merit, or baseload).

2.5.1 Facility characteristics

Facilities currently operating in the SWIS are presented in Figure 5 by age, fuel capability, and classification. The size of the bubbles represents the Capacity Credits assigned for the 2017–18 Capacity Year.

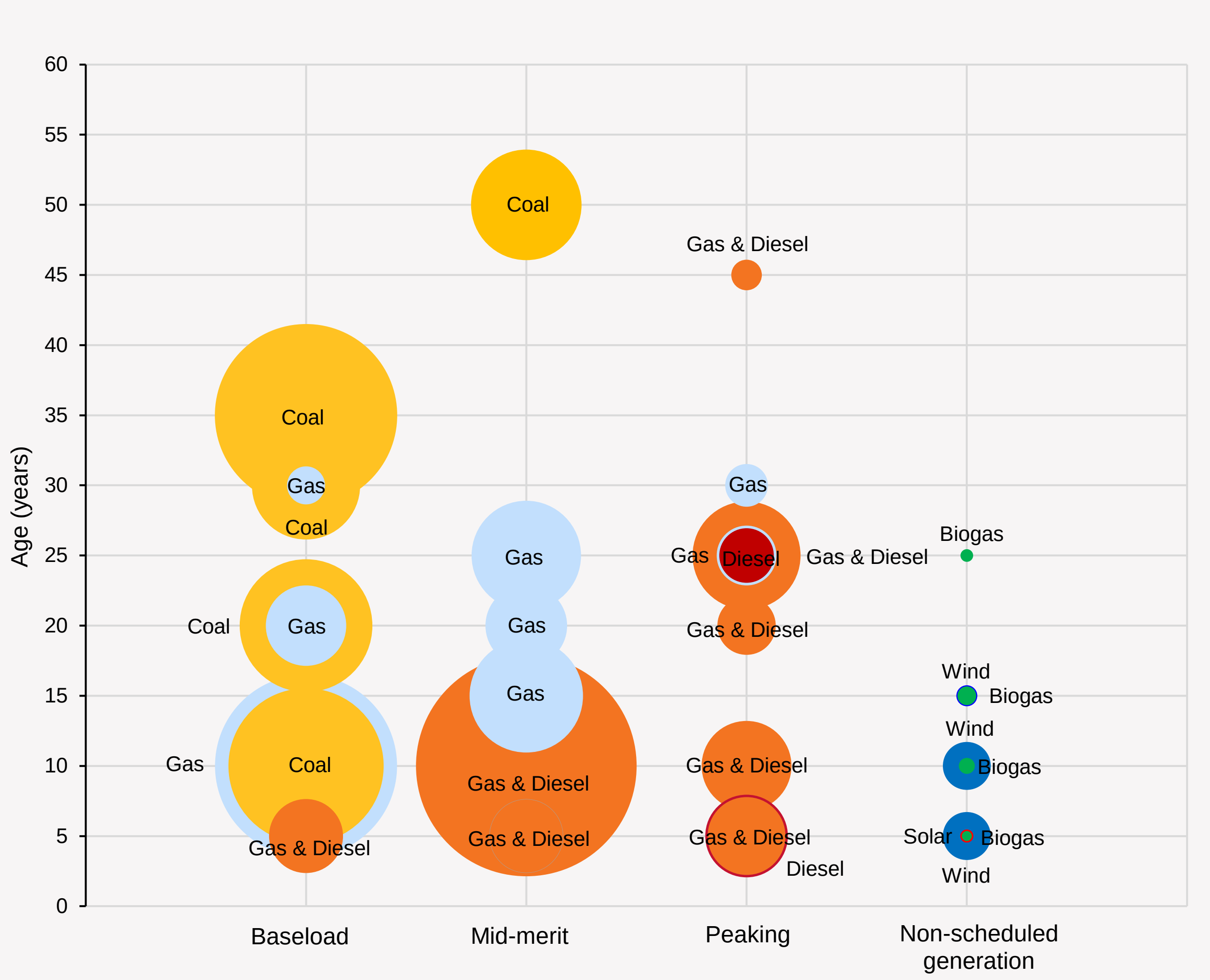
AEMO has classified baseload, mid-merit, peaking, and non-scheduled capacity as follows:

- Baseload capacity is defined as capacity used more than 70% of the time.
- Mid-merit capacity is capacity used between 10% and 70% of the time.
- Peaking capacity is capacity used for less than 10% of the time.

Capacity classification is determined based on the number of intervals each Facility has operated over the 2015−16 Capacity Year, adjusted for full outages.[42]

[41] Individual units for the 2017–18 Capacity Year.
[42] Full outage is defined as a Facility's capacity in outage is equal to its Capacity Credits allocated.

Figure 5 Facilities operating in the SWIS by age, fuel capability, and capacity classification[a]



[a] Facilities' ages are rounded to nearest multiple of five.

In summary:

- Of the 2,399 MW of baseload generation capacity, around 949 MW (40%) is more than 20 years old, 622 MW (26%) is between 10 and 20 years old, and 828 MW (34%) is less than 10 years old.
- Approximately 1,763 MW of capacity serves as mid-merit generation, 816 MW is peaking generation, and 109 MW is non-scheduled generation.
- Of the 1,781 MW of coal-fired capacity, approximately 12% is more than 50 years old, 45% is between 30 and 40 years old, and 42% is less than 20 years old.
- The oldest generation facility in the SWIS is coal-fired and is more than 50 years old.[43]
- The majority of the intermittent generators are less than 15 years old.
- Of the 816 MW of peaking generation, capable of operating on either gas or diesel, 70% is between 10 and 30 years old[44], and 28% is between five and 10 years old.
- Most baseload generation capacity is coal or gas with no alternate fuel capability.

[43] The oldest generation Facility is Muja AB power station, which is scheduled for retirement by September 2018. See: https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.

[44] These include Mungarra gas turbine units 1, 2 and 3 and West Kalgoorlie gas turbine units 2 and 3, which are scheduled for retirement by September 2018. See: https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.

2.5.2 Scheduled generators

The scheduled generators in the SWIS, the quantity of energy generated by each, and the Capacity Credits assigned for the 2015–16 Capacity Year are outlined in Table 7.

Table 7 Scheduled power stations in the SWIS, 2015–16 Capacity Year[a]

Power station (units included)	Participant	Classification	Energy generated[b]		Capacity Credits	
			GWh	Share (%)	MW	Share (%)[c]
Alcoa Wagerup	Alcoa	Baseload	130	0.8	24	0.5
Alinta Pinjarra (1 and 2)	Alinta Energy	Baseload	2056	11.9	257	5.1
Alinta Wagerup (1 and 2)	Alinta Energy	Mid-merit	225	1.3	361	7.2
Bluewaters (1 and 2)	Bluewaters	Baseload	2,918	16.9	434	8.7
Cockburn	Synergy	Mid-merit	639	3.7	232	4.6
Collie	Synergy	Baseload	2,049	11.9	317	6.3
Kalamunda	Landfill Gas & Power	Peaking	0	0.0	1	0.0
Kemerton (11 and 12)	Synergy	Peaking[d]	140	0.8	291	5.8
Kwinana gas turbine	Synergy	Peaking	0	0.0	15	0.3
Kwinana high efficiency gas turbines (2 and 3)	Synergy	Baseload[e]	642	3.7	190	3.8
Merredin	Merredin Energy	Peaking	0	0.0	82	1.6
Muja AB (1, 2, 3 and 4)	Vinalco	Mid-merit	321	1.9	220	4.4
Muja CD (5, 6 , 7 and 8)	Synergy	Baseload	4,180	24.2	807	16.1
Mungarra (1, 2 and 3)	Synergy	Peaking	12	0.1	96	1.9
NewGen Kwinana	NewGen Kwinana	Baseload	1,967	11.4	320	6.4
NewGen Neerabup	NewGen Neerabup	Mid-merit	147	0.8	331	6.6
Parkeston	Goldfields Power	Peaking	1	0.0	61	1.2
Perth Energy Kwinana	Western Energy	Peaking	23	0.1	109	2.2
Perth Power Partnership Kwinana	Synergy	Baseload	516	3.0	80	1.6
Pinjar A (1 and 2)	Synergy	Peaking	8	0.0	64[f]	1.3
Pinjar B (3, 4, 5 and 7)	Synergy	Peaking	20	0.1	148	3.0
Pinjar C (9 and 10)	Synergy	Mid-merit	410	2.4	217[g]	4.3
Pinjar D (11)	Synergy	Mid-merit	216	1.3	120	2.4
Tesla Geraldton	Tesla	Peaking	0	0.0	10	0.2
Tesla Kemerton	Tesla	Peaking	0	0.0	10	0.2
Tesla Northam	Tesla	Peaking	0	0.0	10	0.2
Tesla Picton	Tesla	Peaking	0	0.0	10	0.2
Tiwest Cogeneration	Tiwest	Baseload	186	1.1	33	0.7
West Kalgoorlie (2 and 3)	Synergy	Peaking	2	0.0	53	1.1
Worsley Cogeneration	Synergy	Mid-Merit	463	2.7	107[h]	2.1

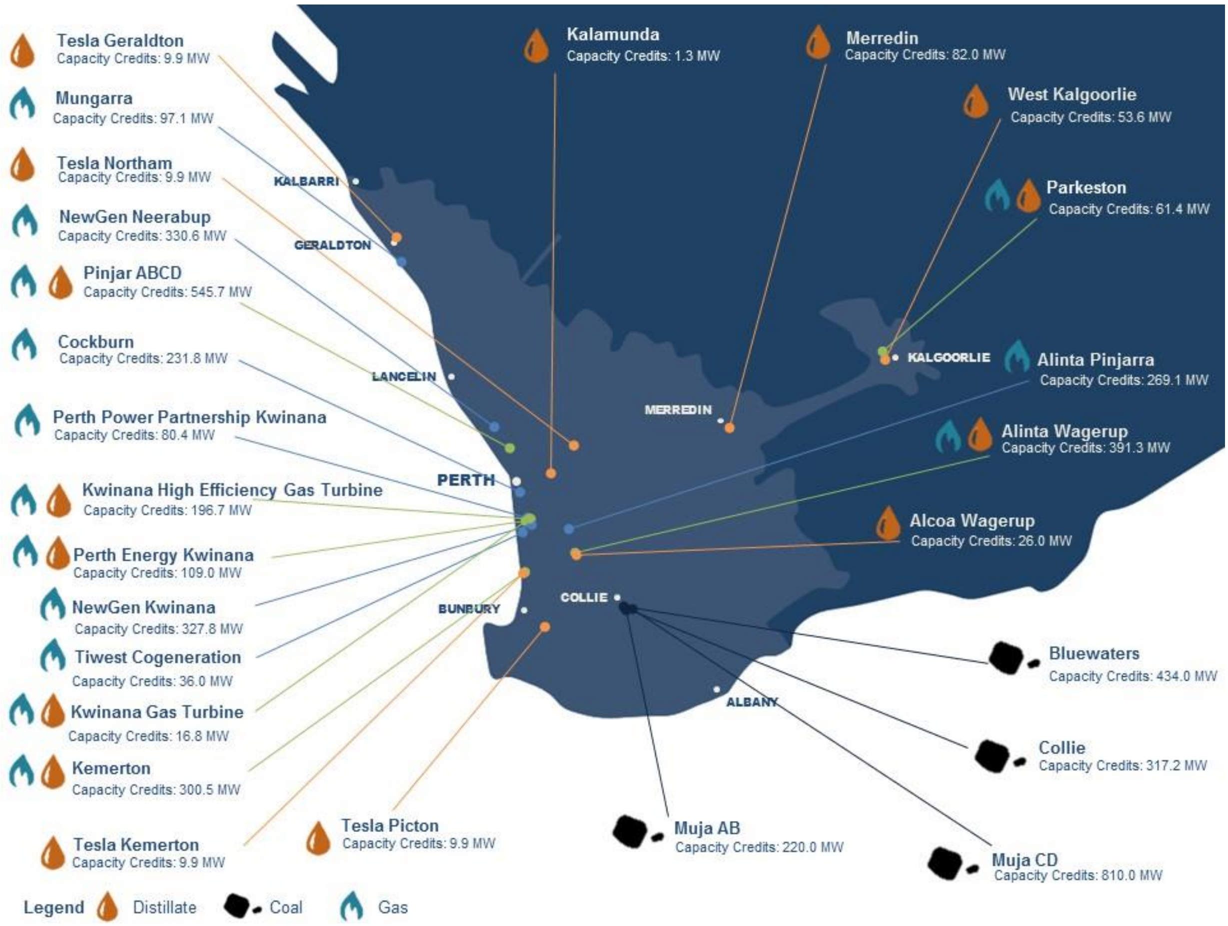
[a] Energy generated and Capacity Credits are rounded to the nearest integer.
[b] Energy generated is calculated from Supervisory Control and Data Acquisition (SCADA) data.
[c] This indicates shares of total Capacity Credits assigned for scheduled generators for the 2015−16 Capacity Year.
[d] Unit 12 operates as mid-merit.
[e] Unit 3 operates as mid-merit.
[f] Pinjar A Capacity Credits were reduced to 63.2 MW from 16 March 2016.
[g] Pinjar C Capacity Credits were reduced to 208.4 MW from 16 March 2016.
[h] Worsley Cogeneration was deregistered on 2 March 2017.

At 807 MW, Muja CD is the largest power station in the SWIS, with four units accounting for 14% of Capacity Credits assigned for the 2015–16 Capacity Year. Pinjar is the next largest power station, with nine units accounting for 549 MW and 10% of the Capacity Credits assigned for the 2015–16 Capacity Year. Their energy outputs accounted for 24% and 4% respectively of the total energy generated by scheduled generators for the 2015–16 Capacity Year.

While the Capacity Credits of a power station indicate its capability to provide capacity during peak demand periods, its actual energy output largely depends on its age, fuel efficiency, and classification. Newer generators are generally able to run for a longer period before requiring maintenance. For example, in the 2015–16 Capacity Year, NewGen Kwinana was around eight years old and operated as baseload, while Pinjar was around 26 years old and most of its units operated as peaking capacity. NewGen Kwinana generated about three times as much energy as Pinjar in this Capacity Year, despite being around half the size.

The location and Capacity Credits assigned for the 2017–18 Capacity Year for the scheduled generators in the SWIS are illustrated in Figure 6.

Figure 6 Scheduled generators map for the SWIS, 2017–18



2.5.3 Non-scheduled generators

Non-scheduled generators in the SWIS, the quantity of energy generated by each, and the Capacity Credits assigned for the 2015–16 Capacity Year are outlined in Table 8.

Table 8 Non-scheduled generators in the SWIS, 2015–16 Capacity Year[a]

Facility	Participant	Energy source	Nameplate capacity (MW)	Energy generated		Capacity Credits[b]	
				GWh	Share (%)	MW	Share (%)[c]
Albany	Synergy	Wind	21.6	59	3.6	8.5	7.9
Atlas	Perth Energy	Biogas	1.123	4	0.2	0.7	0.6
Bremer Bay[d]	Synergy	Wind	1.88	2	0.1	0.0	0.0
Collgar	Collgar Wind Farm	Wind	206	663	40.5	14.6	13.6
Denmark	Denmark Community Windfarm	Wind	1.6	7	0.4	1.3	1.2
Emu Downs	EDWF Manager	Wind	80	229	14.0	17.0	15.8
Grasmere	Synergy	Wind	13.8	42	2.6	5.6	5.2
Greenough River	Synergy	Solar	10	23	1.4	4.0	3.7
Henderson	Waste Gas Resources	Biogas	3.195	16	0.9	2.3	2.1
Kalbarri	Synergy	Wind	1.6	4	0.2	0.3	0.3
Karakin	Blair Fox	Wind	5	6	0.4	1.1	1.0
Mount Barker	Mt. Barker Power Company	Wind	2.43	7	0.4	0.9	0.8
Mumbida	Mumbida Wind Farm	Wind	55	164	10.0	15.7	14.6
Red Hill	Landfill Gas & Power	Biogas	4	26	1.6	2.9	2.7
Rockingham	Perth Energy	Biogas	4	20	1.2	2.6	2.4
South Cardup	Perth Energy	Biogas	3.369	28	1.7	2.4	2.2
Tamala Park	Landfill Gas & Power	Biogas	5.0	40	2.4	4.0	3.7
Walkaway	Alinta Energy	Wind	89.1	289	17.7	23.9	22.2

[a] CleanTech Energy's Richargo Biogas Facility (BIOGAS01) did not hold Capacity Credits for the 2015−16 Capacity Year and is not included in this table.
[b] Rounded to one decimal place.
[c] This indicates shares of total Capacity Credits assigned for non-scheduled generators for the 2015−16 Capacity Year.

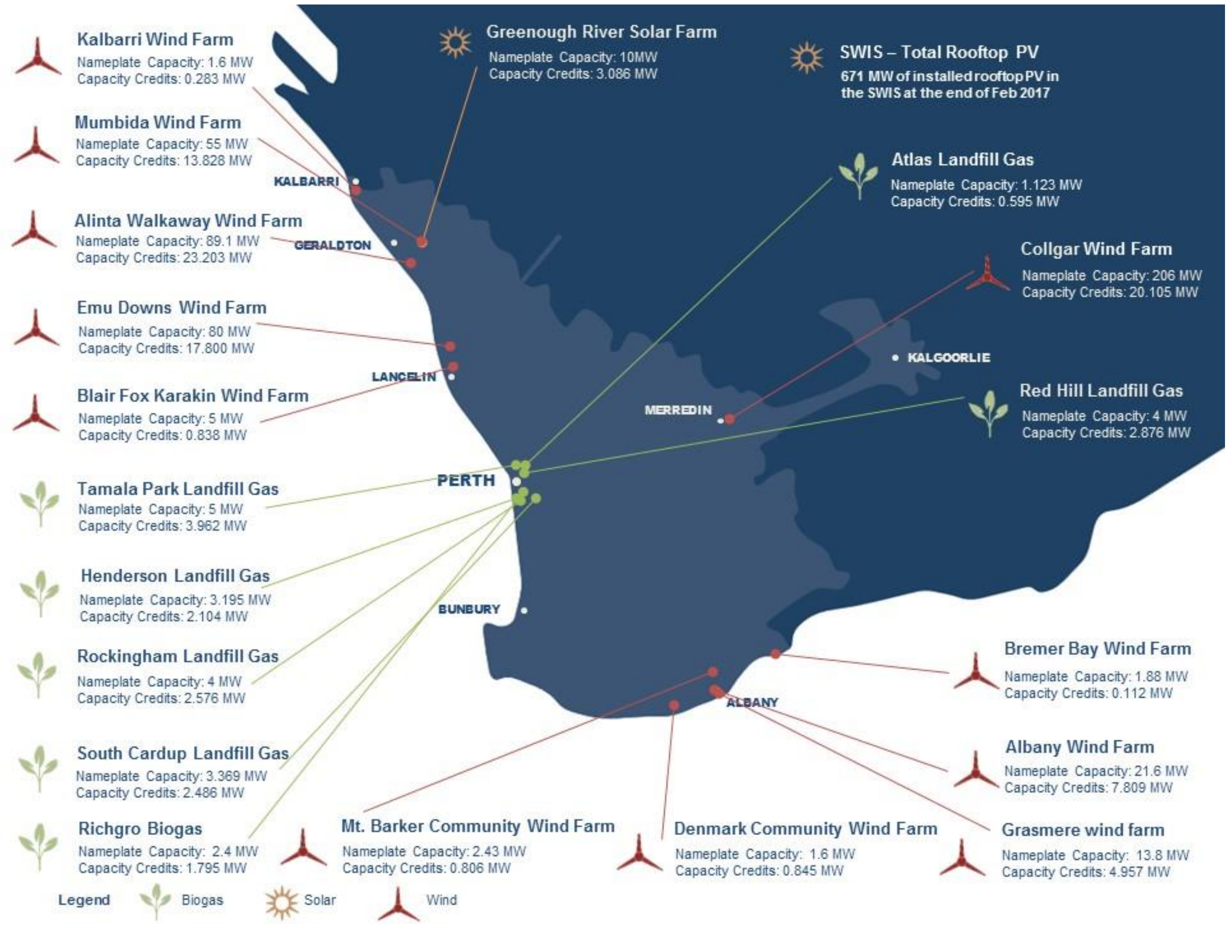
A total of 108 MW of Capacity Credits were assigned to renewable generation facilities for the 2015–16 Capacity Year. Wind generators accounted for 83% of the total renewable Capacity Credits, with biogas and solar making up 14% and 4%, respectively. The four largest wind farms (Collgar, Emu Downs, Mumbida, and Walkaway) account for more than two-thirds of the total Capacity Credits assigned to renewable generators for the 2015–16 Capacity Year.

Collgar wind farm is the largest renewable generator, with 206 MW of nameplate capacity. It accounted for around 41% of the total energy generated by intermittent generators in the 2015–16 Capacity Year. The next largest generator, Walkaway wind farm (89.1 MW nameplate capacity), accounted for 18% of energy generated.

The location, nameplate capacity, and Capacity Credits assigned for the 2017–18 Capacity Year for the non-scheduled generators in the SWIS are presented in Figure 7. The map also outlines the total installed rooftop PV capacity at the end of February 2017.[45]

[45] Clean Energy Regulator, 2017. Postcode data for small-scale installations. Available at: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations. Viewed: 30 March 2017.

Figure 7 Non-scheduled generators map for the SWIS, 2017–18



Source: AEMO and Clean Energy Regulator (CER)

2.5.4 Facility outages and availability

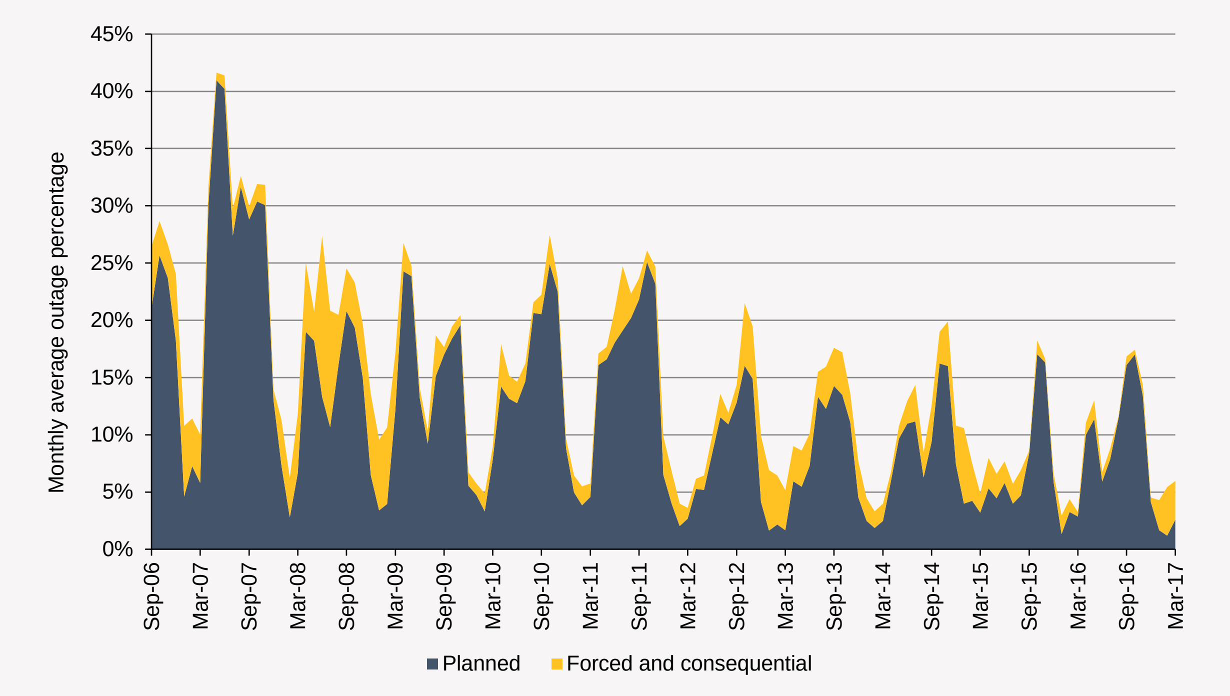
Total monthly outage rates (planned, forced, and consequential[46]) as a percentage of the Capacity Credits assigned since market start are illustrated in Figure 8. This assesses the total average outage rate of all firm capacity in the SWIS.

Average monthly planned, forced, and consequential outages have been declining in the SWIS since 2006. This suggests the majority of generation assigned Capacity Credits has improved availability to meet peak demand.

Planned outage rates are generally lower over summer periods, when demand is expected to be highest. Since 2009–10, typical monthly forced outage rates in summer were less than 3%. However, outages were unusually high during the 2014–15 and 2016–17 summer periods, reflecting higher than normal forced outages.

[46] A consequential outage is an outage defined in clause 3.21.1 of the WEM Rules. In summary, it is an outage unrelated to and not caused by the generator, but by another generator's forced outage or a Network Operator's planned outage.

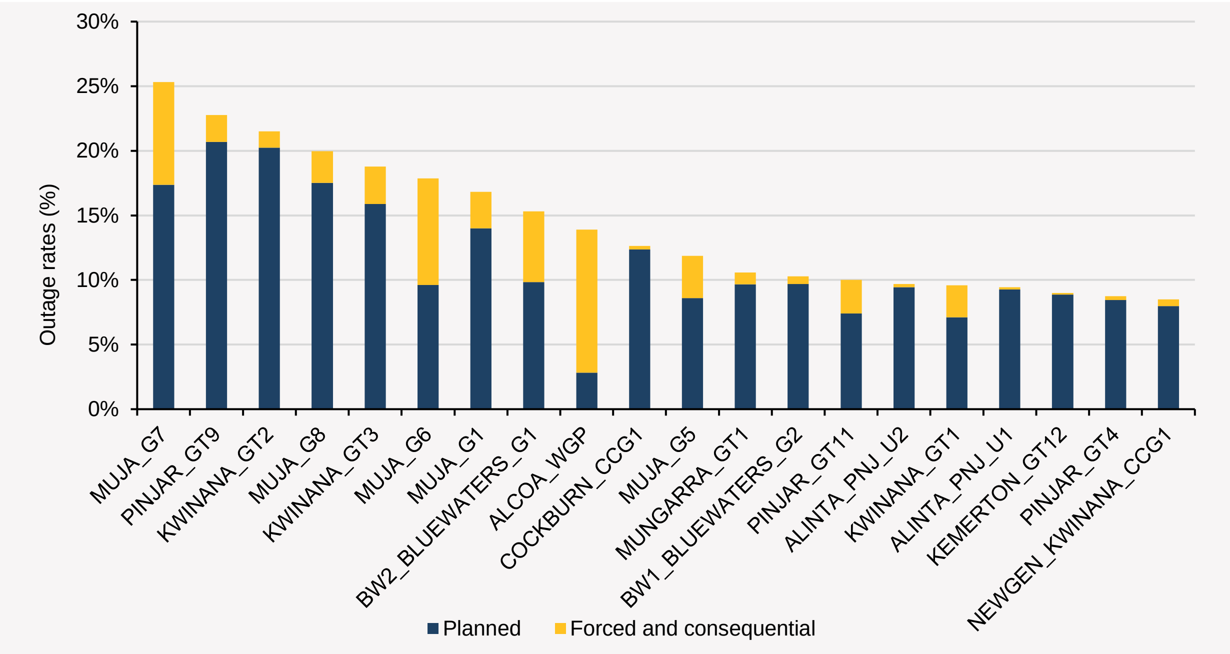
Figure 8 Total monthly average outage percentage, September 2006 to March 2017[a]



[a] The operation date for Muja AB is when refurbishment was completed and the Facilities returned to service.

Figure 9 shows the 20 Facilities with the highest level of outages over the previous 36 months. Combined outage rates for Muja CD (units 5, 6, 7, and 8) were in a range of approximate 12% to 25%. Alcoa's Wagerup Facility and Synergy's Muja unit 6 and unit 7 had the highest forced and consequential outage rates, at around 11.1%, 8.3%, and 8.0% respectively.

Figure 9 Outages by Facility for the 36 months to February 2017[a, b]



[a] Retired Facilities and intermittent generators are excluded.
[b] Top 20 outage rates presented by Facility to show individual unit outages, which can vary with age.

High outage rates, and in particular high forced outage rates, are generally correlated with the age of the Facility and the frequency of operation. For example, Muja CD (average age of 34.5 years), Pinjar (average age of 23 years), and Alcoa Wagerup (32 years) have the highest outage rates in the WEM. Large baseload generators (Muja CD, Bluewaters, and Alinta Pinjarra) also have high outage rates, suggesting that generation capacity for these Facilities may not always be available for dispatch.

CHAPTER 3. PEAK DEMAND AND CUSTOMER CONSUMPTION

Peak demand in the SWIS has historically been driven by several consecutive days of high temperatures in Perth (over 36°C).

This chapter discusses:

- The 2016–17 summer peak demand in the SWIS, the factors that contributed to it, and historical trends since 2009.
- Factors affecting peak demand, including the IRCR and uptake of commercial and residential rooftop PV.
- Recent trends in consumption by residential, commercial, and large industrial customers.

3.1 Peak demand in the SWIS

3.1.1 Summer 2016–17 peak demand

The 2016–17 summer peak demand was 3,670 MW and was observed in the 17:00 to 17:30 trading interval on 1 March 2017.

This was the lowest peak demand observed since 11 February 2009, and is the first time since 2007 that peak demand has occurred in March. Further information about historical peak demand is provided in Section 3.1.2.

The main reason for the low peak demand was weather. The 2016–17 summer was milder than usual, with average monthly temperatures up to 1.7°C lower than the long-term (20-year) average, as outlined in Table 9. In particular, February 2017, when peak demand is usually expected to occur, was cooler than usual. No periods of consecutive hot days were observed during the 2016–17 summer, and many hot days fell on weekends or public holidays.

Table 9 Weather summary, summer 2016–17 compared to the long-term average

	December	January	February	March
2016–17 summer	28.4	31.0	30.1	27.9
Long-term average[a]	29.1	31.2	31.6	29.6

[a] Between 1993 and 2017.
Source: Bureau of Meteorology

Other reasons for the relatively low peak demand include:

- The relatively mild maximum temperature on the peak day (37.7°C), which was cooler than historical peak days.
- High levels of rooftop PV generation, which is estimated to have reduced peak demand by 265 MW at the time of the peak.
- A fairly significant IRCR response which reduced peak demand by 124 MW at the time of the peak.

The reminder of this chapter discusses these effects in greater detail.

3.1.2 Historical peak demand

Peak demand and associated temperature statistics for the past nine years are outlined in Table 10.

This year's peak demand (3,670 MW on 1 March 2017) was 8.5% lower than last year's peak (4,013 MW), and was the lowest peak demand since 2009. It was the coolest peak demand day since before 2009, reflecting the overall milder than usual summer.

Table 10 Comparison of peak demand days, 2007–08 to 2016–17

	Peak demand (MW)	Maximum temperature during trading interval (°C)	Trading interval commencing	Daily maximum temperature (°C)
1 March 2017	3,670	34.7	17:00	37.7
8 February 2016	4,013	40.2	17:30	42.5
5 January 2015	3,744	40.8	15:30	44.4
20 January 2014	3,702	37.4	17:30	38.3
12 February 2013	3,732	35.4	16:30	40.5
25 January 2012	3,857	40.0	16:30	41.0
16 February 2011	3,735	37.5	16:30	39.0
25 February 2010	3,766	39.5	16:00	41.5
11 February 2009	3,515	39.5	15:30	39.7

Source: AEMO and Bureau of Meteorology (BOM)

The 2016–17 summer peak demand occurred in the trading interval starting at 17:00, consistent with the trend (observed over the past four years) of peak demand shifting later in the afternoon. Between 2011 and 2013, peak demand occurred in the trading interval starting at 16:30. More recently, by comparison, peak demand has been observed during later trading intervals, except in 2015 where the peak occurred during a holiday period. This is largely due to strong uptake of rooftop PV systems (see Sections 3.3 and 3.4 for more information).

Peak demand has become increasingly volatile in the last five years. Between 2013 and 2015, peak demand was fairly stable at around 3,700 MW. Record peak demand of 4,013 MW was observed on 8 February 2016, which was then followed by the lowest peak demand in eight years on 1 March 2017. This volatility makes forecasting peak demand challenging.

3.2 Individual Reserve Capacity Requirement

To fund the RCM, AEMO assigns an IRCR to each Market Customer, based on the peak demand usage from its customer base in the previous hot summer season.[47]

Specifically, the IRCR is a quantity (in MW) determined based on the median consumption of each metered load in a Market Customer's portfolio, during the 12 system peak intervals from the previous hot season (defined as 1 December to 31 March).

The IRCR is then used to allocate the cost of Capacity Credits acquired through the RCM.

As a result, the IRCR financially incentivises customers to reduce consumption during periods of peak demand, and consequently reduce their exposure to capacity payments.

At the time of the 2016–17 peak demand, 53 customers reduced consumption, resulting in a total load reduction of 124 MW.

As shown in Table 11, although a similar number of loads responded compared to previous years, the response was the highest observed to date. Of the 53 customers that responded, nine customers accounted for 104 MW (84%) of the total reduction. While these customers have responded in previous

[47] See clause 4.28.7 and Appendix 5 of the WEM Rules.

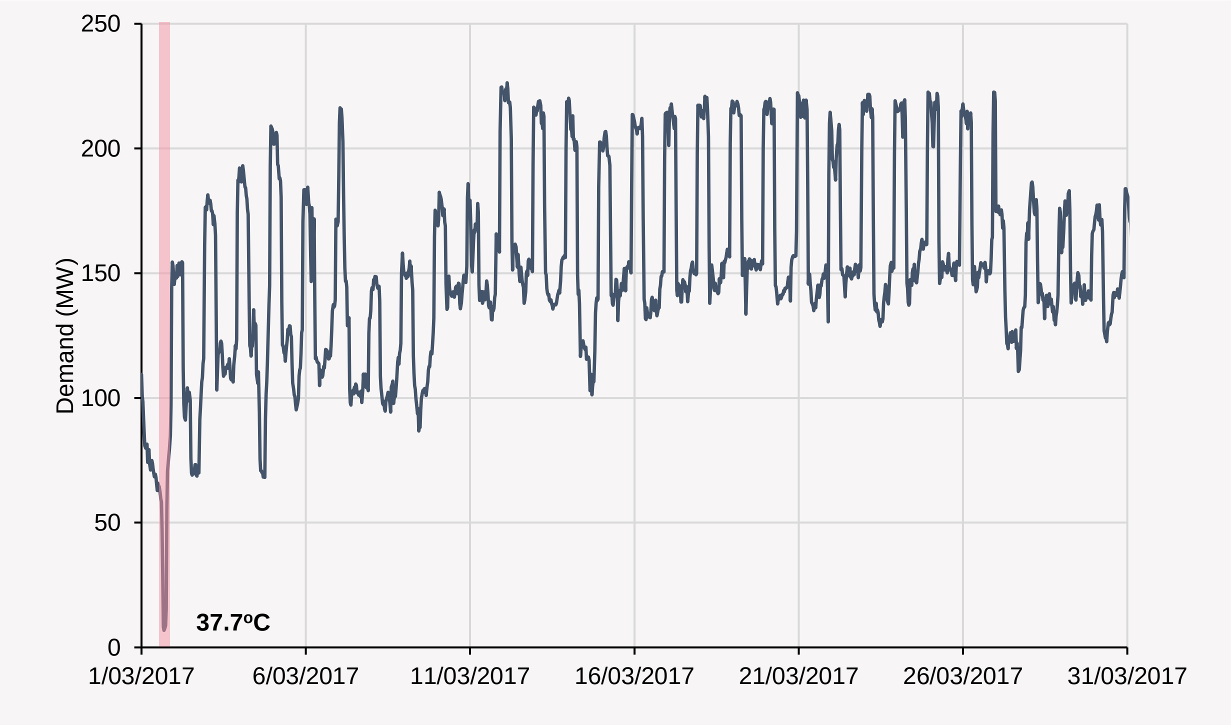
years, their response was higher this year, indicating they are predicting peak demand days better and lowering consumption accordingly.

Table 11 IRCR response on peak demand days, 2012 to 2017

	Daily peak demand (MW)	Time of peak	Estimated IRCR reduction (MW)	Number of customers responding
1 March 2017	3,670	17:00	124	53
8 February 2016	4,013	17:30	77	57
5 January 2015	3,744	15:30	42	20
20 January 2014	3,702	17:30	50	44
12 February 2013	3,732	16:30	65	59
25 January 2012	3,857	16:30	50	59

The consumption of the 53 loads most responsive to the IRCR during March 2017 is illustrated in Figure 10. The shaded area on the graph highlights the afternoon of 1 March 2017 and the day's maximum temperature.

Figure 10 IRCR response for 53 customers, March 2017



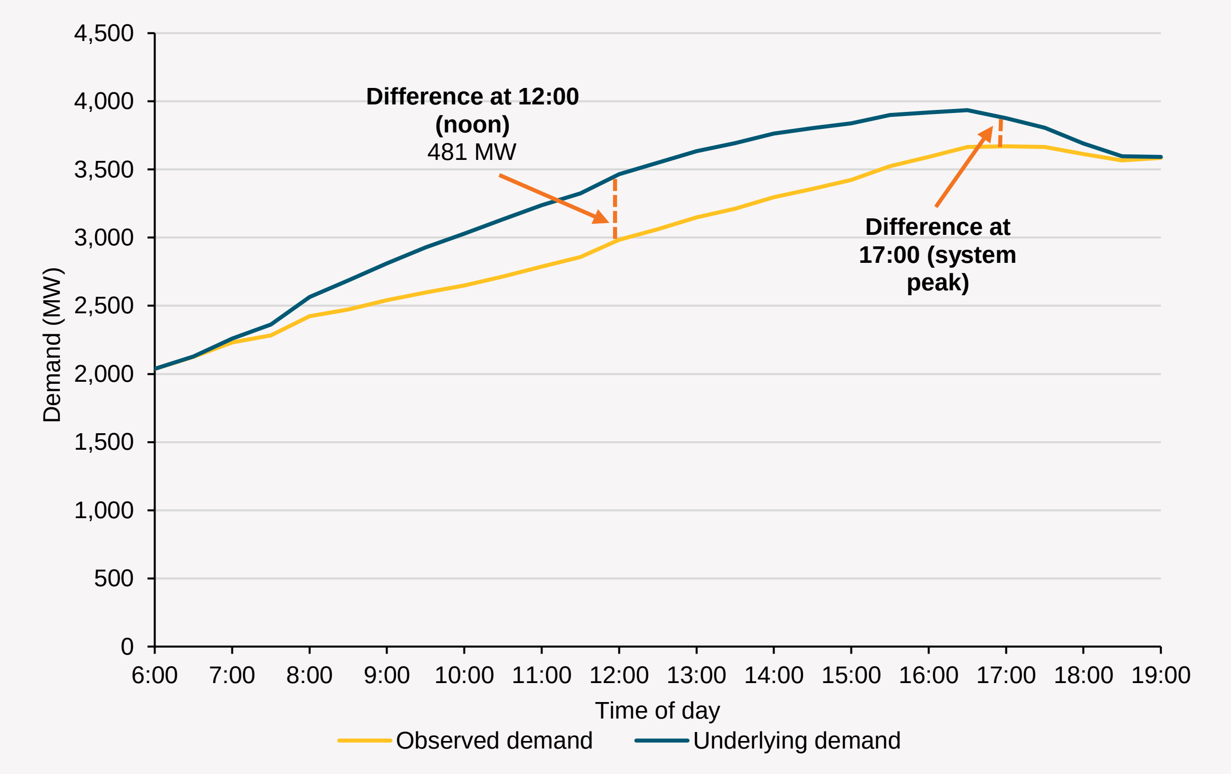
3.3 Effect of rooftop PV on peak demand

The effect of rooftop PV on peak demand depends on the time of day that peak demand occurs, due to the output profile of a PV system which is highest at noon and falls during the afternoon.

In Figure 11, the actual demand profile on 1 March 2017 is compared to AEMO's estimate of the demand that would have occurred if no rooftop PV had been installed (underlying demand[48]).

[48] Underlying demand refers to everything consumed on site, and can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.

Figure 11 Daily daytime demand profile, observed and estimated without rooftop PV, 1 March 2017



Estimated peak demand, excluding the effects of rooftop PV, is estimated as 3,935 MW, 7.2% higher than the observed peak demand of 3,670 MW on 1 March 2017.

Rooftop PV reduced peak demand by 265 MW due to a combination of the following factors:

- A shift in the timing of peak demand by half an hour, from the trading interval starting at 16:30 to the trading interval starting at 17:00. Underlying demand was estimated to be 3,877 MW at 17:00 compared to 3,935 at 16:30. This shift of the peak to a later time reduced demand by 58 MW.
- Generation from rooftop PV during the 17:00 peak. This reduced peak demand by 207 MW from 3,877 MW to 3,670 MW.

The continued growth of rooftop PV installations has affected both the level and timing of peak demand over the last six years. Actual peak demand over the six highest demand days between 2011–12 and 2016–17 is compared in Table 12 with the estimated peak that may have occurred without rooftop PV.

Table 12 Effect of rooftop PV on peak demand, 2011–12 to 2016–17

	Trading interval commencing	Peak demand (MW)	Estimated peak demand without rooftop PV (MW)	Estimated peak trading interval commencing without rooftop PV	Reduction in peak demand from rooftop PV (MW)	Reduction in peak demand from peak time shift (MW)
1 March 2017	17:00	3,670	3,935	16:30	207	58
8 February 2016	17:30	4,013	4,204	16:30	96	95
5 January 2015	15:30	3,744	3,931	14:30	165	32
20 January 2014	17:30	3,702	3,757	15:30	81	29
12 February 2013	16:30	3,732	3,816	13:30	81	6
25 January 2012	16:30	3,857	3,918	15:00	72	19

3.4 Small-scale rooftop PV systems

3.4.1 Rooftop PV system growth

Small-scale residential and commercial rooftop PV systems allow electricity customers to generate a proportion of their electricity needs onsite. Any excess generation is exported to the electricity network, which customers may be paid for.[49] While rooftop PV systems do not directly reduce electricity consumption, they do reduce the quantity of electricity that needs to be delivered from the network during daylight hours, affecting average demand from the network per connection.

Key statistics for rooftop PV systems installed by Synergy's customers eligible for the Renewable Energy Buyback Scheme (REBS), as well as the average new installation size for all customers, published by the Clean Energy Regulator (CER), are outlined in Table 13.

The number of rooftop PV systems grew from 60,913 in 2010–11 to 200,133 in January 2017. Roughly one in four (25.4%) residential customers in WA now has a rooftop PV system installed, ranking in penetration just behind Queensland (31.6%) and South Australia (30.5%).[50]

Average system size for new installations increased from 2.6 kilowatts (kW) in 2010–11 to 5.3 kW in 2015–16. This increase in average system size is associated with falling system prices, and reflects a greater number of rooftop PV systems installed by commercial customers, which would typically be larger than residential systems.

Table 13 Key statistics for residential rooftop PV systems, 2010–11 to January 2017

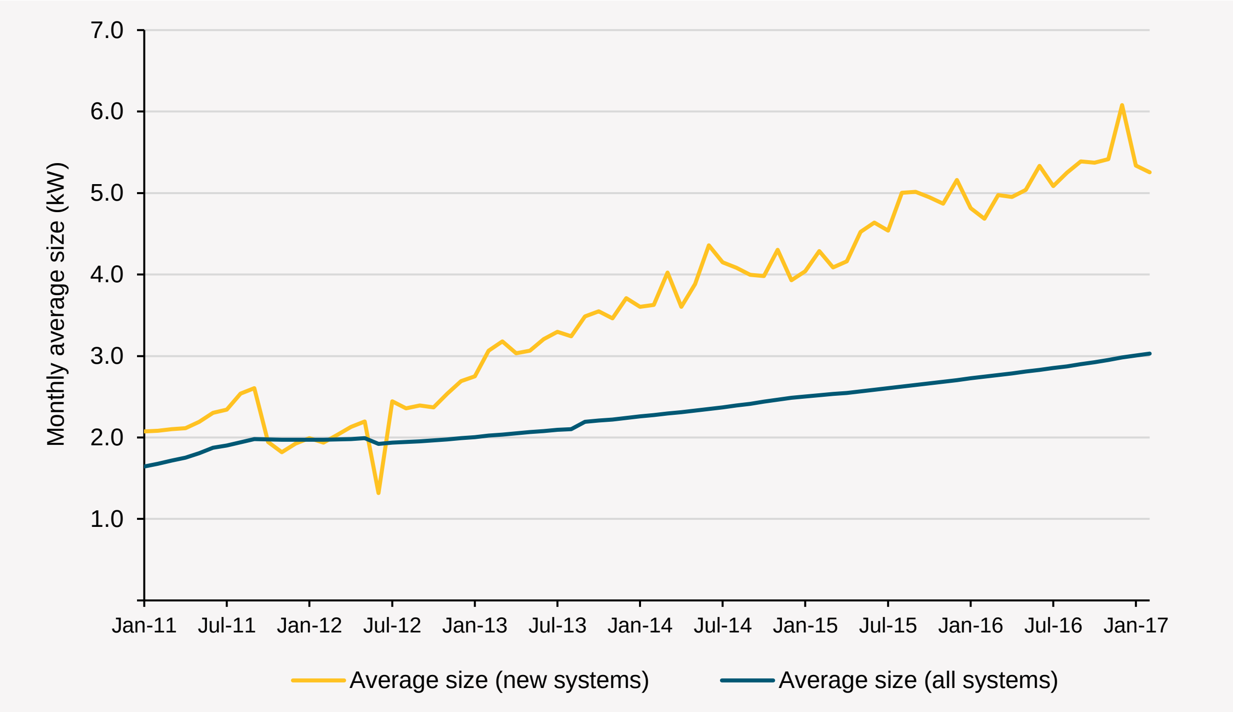
Capacity Year	Number of REBS systems[a]	Proportion of customers with rooftop PV installed[a] (%)	Average system size (kW)[a]	Average new installation size (kW)[b]
2010–11	69,813	7.1	2.1	2.6
2011–12	94,893	9.5	2.2	2.4
2012–13	119,081	11.7	2.4	3.5
2013–14	138,307	13.3	2.6	4.0
2014–15	161,205	15.3	2.7	5.0
2015–16	181,125	16.9	2.9	5.4
2016–17 (to January 2017)	189,960	17.7[c]	3.0	5.3
Average annual growth (2010–11 to 2015–16) (%)	21.0	19.0	6.6	15.7

[a] Source: Synergy
[b] Source: CER
[c] This differs from the percentage given by the Australian PV Institute as it is based on all Synergy customers, not just residential.

The average size of new rooftop PV systems installed per month since January 2011 has grown rapidly, as shown in Figure 12. The fall in installation size in June 2012 was an outlier, related to a government policy decision (Solar Credits multiplier reduction), which led to a large number of small systems being installed. The average size of new systems returned to trend growth levels the following month.

[49] Currently, only residential and some non-profit and charity organisations are eligible to receive payments for exported energy generated from a rooftop PV system. Department of Finance. *Renewable Energy Buyback Scheme*. Available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Energy_Initiatives/Renewable_Energy_Buyback_Scheme_-_Residential.aspx.
[50] Australian PV Institute, 2017. *Mapping Australia Photovoltaic installations*. Available at: http://pv-map.apvi.org.au/historical#4/-26.67/134.12.

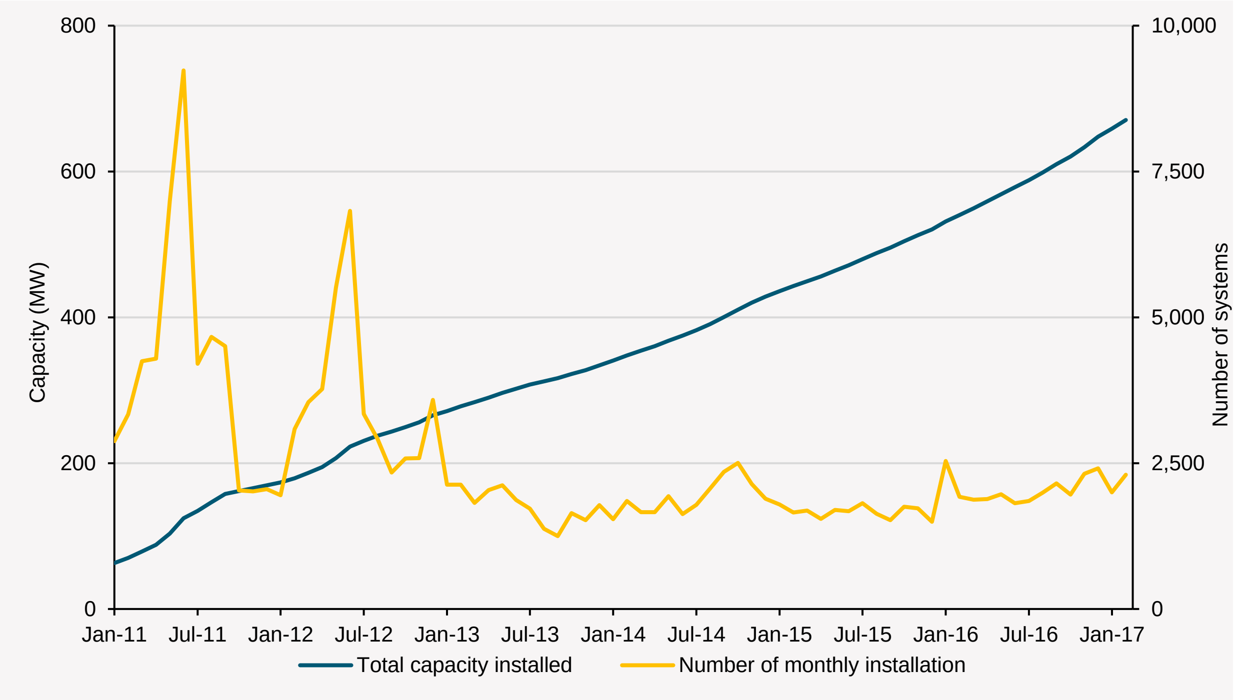
Figure 12 Average size of monthly rooftop PV system installations in the SWIS, January 2011 to February 2017



Source: CER

The SWIS has demonstrated steady growth in rooftop PV system installations since 2011, as illustrated in Figure 13.

Figure 13 Total capacity of rooftop PV system installations and number of monthly installations in the SWIS, January 2011 to February 2017



Source: CER

The total installed capacity of rooftop PV systems in the SWIS reached 671 MW at the end of February 2017, roughly 10 times the capacity of rooftop PV installed in January 2011. Between 2011 and 2012, on average approximately 3,854 rooftop PV systems were installed each month.

The number of monthly installations peaked in June 2011 in response to the WA government's feed-in tariff scheme reduction from July 2011. Another surge of installations in June 2012 was due to the reduction of the Solar Credit multiplier from July 2012.

On average, around 1,868 systems have been installed per month since 2013, resulting in around 221,385[51] of rooftop PV systems in the SWIS by February 2017.

The growth of rooftop PV capacity in the SWIS is expected to continue, due to:

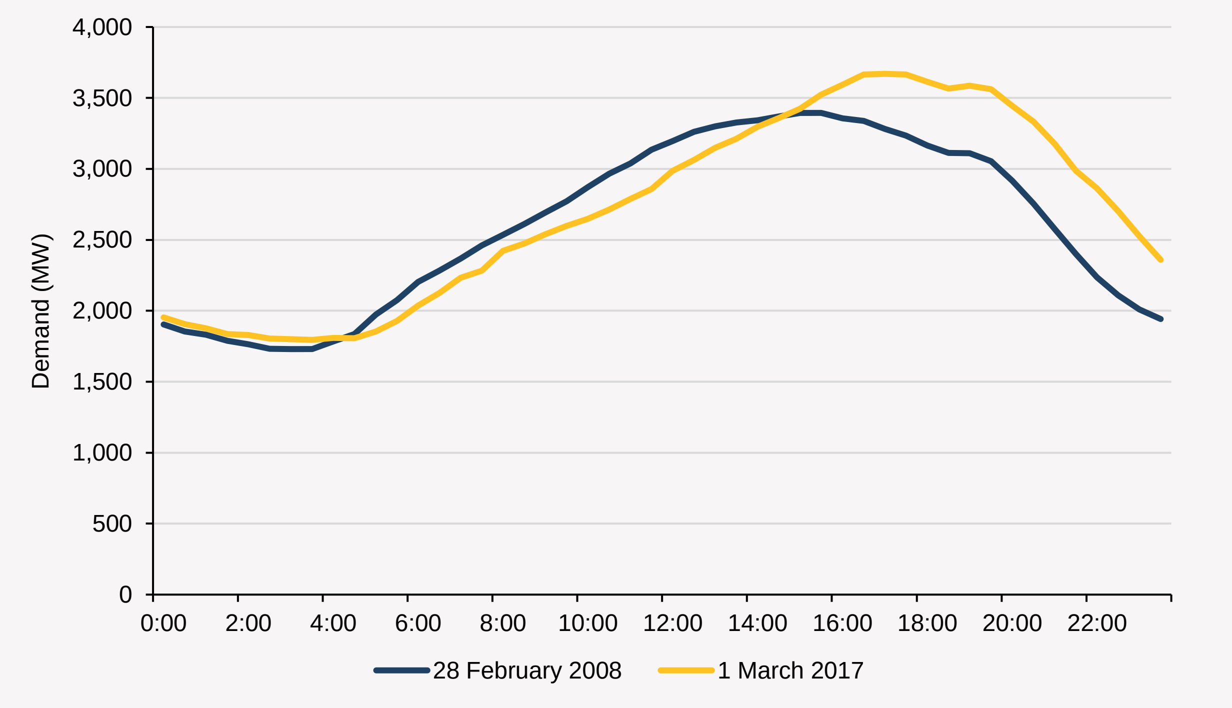
- Government incentives – the State Government's REBS and the Commonwealth Government's Renewable Energy Target (RET) continue to provide financial incentives for residential and commercial rooftop PV installations.
- Falling system costs – rooftop PV system costs continue to decline, improving affordability.
- Rising electricity tariffs – electricity tariffs continue to increase, incentivising customers to generate some of their electricity needs onsite through rooftop PV systems.
- Changing consumer behaviour – electricity consumers are becoming more aware of existing and emerging technologies such as rooftop PV and battery storage, and are considering ways to optimise their electricity consumption behaviour.

3.4.2 The effect on the daily demand profile of increased rooftop PV generation

Rooftop PV has changed the shape of the daily demand profile, by reducing demand that needs to be supplied from the electricity network during daylight hours, as well as shifting the timing of peak demand.

The daily demand profiles for peak days for 2007–08 and 2016–17 are presented in Figure 14.

Figure 14 Daily daytime demand profiles for peak days, 2007–08 and 2016–17

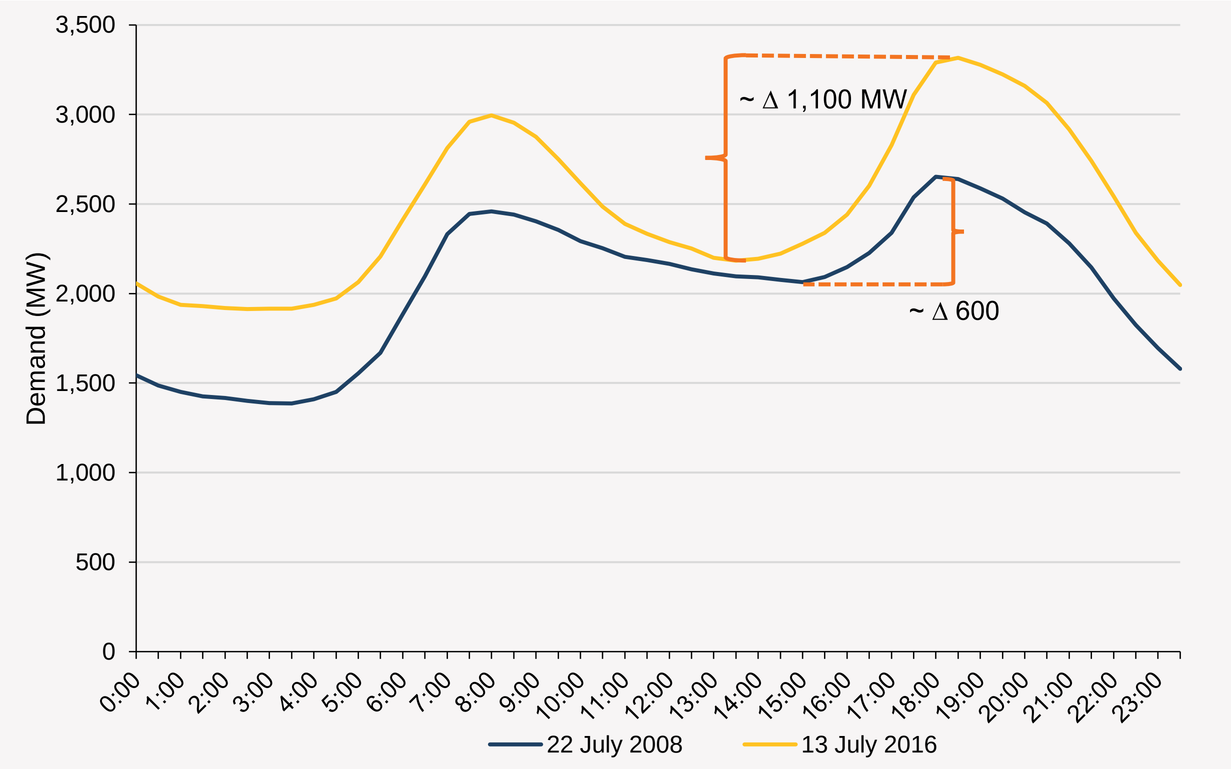


[51] Based on CER data, which includes both REBS eligible and non-REBS installations.

As a result of increased rooftop PV generation, demand during the morning and early afternoon (between 6:00 and 14:00) has decreased by, on average, 7% over the past eight years. However, peak demand increased by 8% over this period, and shifted to a later time in the afternoon (approximately an hour and a half later).

The effect of rooftop PV generation on the daily demand profile is more pronounced in winter than in summer. The daily demand profile in winter shows two distinct peaks – one in the morning, as residential customers prepare to leave for work, and one in the evening as they arrive home. This is particularly evident on sunny winter days, as presented in Figure 15, which compares representative winter daily demand profiles in 2008 and 2016. The days illustrated in the graph were chosen because they were sunny days when rooftop PV generation would have been relatively high.

Figure 15 Winter daily demand profiles for selected days, 2008 and 2016



The daily load profile now shows a strong dip in the middle of the day, coinciding with peak solar generation, an effect known as the “duck curve”. On 22 July 2008, the difference between the minimum and maximum daylight load was around 600 MW, compared to about 1,100 MW on 13 July 2016.

The timing of minimum daylight demand has shifted, from the trading interval commencing at 15:00 in 2008 to the trading interval commencing at 14:00 in 2016, reflecting the shape of the rooftop PV generation profile.

This new pattern may require gas peaking generation to start and stop multiple times during the day, potentially increasing generation costs and, subsequently, wholesale energy prices. In particular, fast-response gas peaking generation may be dispatched outside of the balancing merit order more frequently in the future to cater to a sharper ramp-up of load between 16:00 and 18:00.

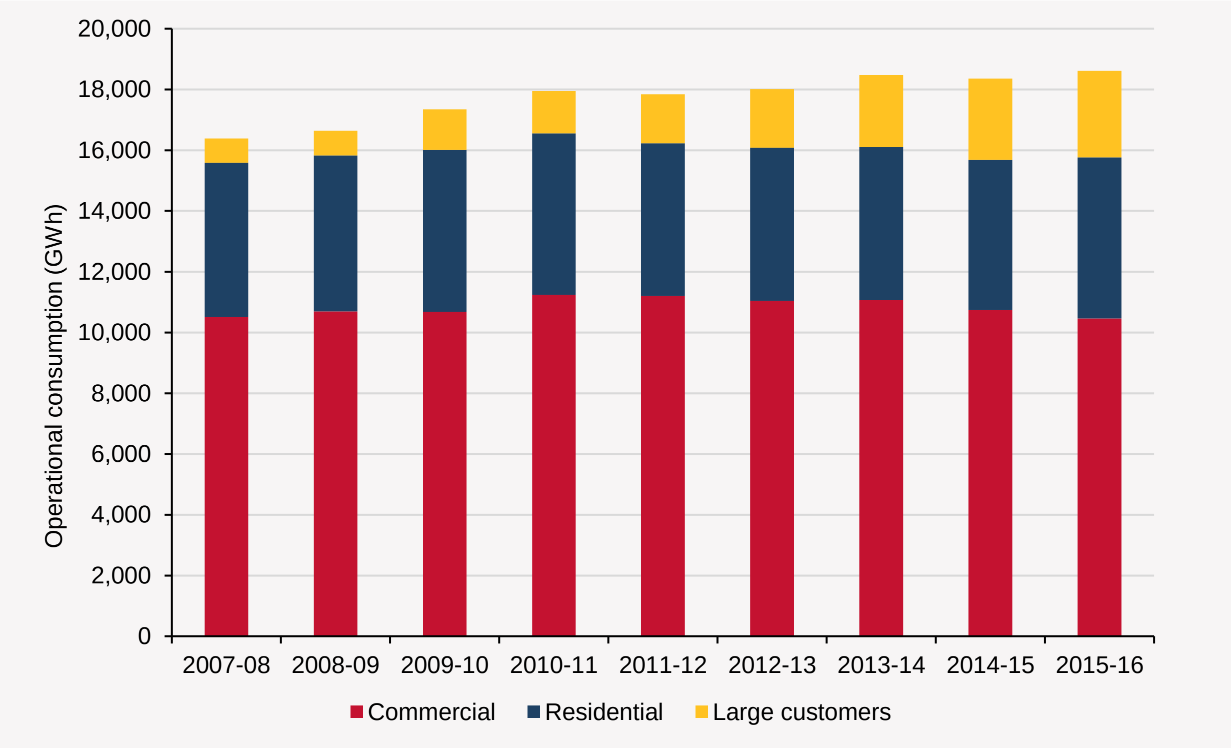
3.5 SWIS electricity consumption

Underlying electricity consumption continues to grow due to increased use of electrical appliances, including reverse cycle air-conditioning and entertainment devices. However, average consumption per connection from the electricity network has fallen, largely as a result of growth in rooftop PV, which has allowed residential and commercial customers to generate some of their electricity needs onsite. This has reduced the growth rate in operational consumption.

Figure 16 provides a breakdown of total operational consumption in the SWIS between 2007–08 and 2015–16. Commercial consumption accounted for approximately 72% of total SWIS electricity consumption in 2015–16. A fifth of commercial consumption related to nine large users (individual customers with average demand of at least 20 MW each).

Total operational consumption grew by approximately 9.6% from 2007–08 to 2010–11, compared to 2.9% from 2011–12 to 2014–15. From 2014–15 to 2015–16, total operational consumption increased by approximately 1.4% and reached 18,612 gigawatt hours (GWh), primarily driven by an increase in consumption from residential and large users.

Figure 16 Total operational consumption in the SWIS, 2007–08 to 2015–16 financial years



3.5.1 Residential

WA population growth is an important contributor to SWIS residential electricity consumption. However, recent residential consumption data shows increases in residential connections do not necessarily lead to a corresponding increase in total electricity consumption.

Between 2007–08 and 2009–10, residential consumption per customer grew at a rate roughly consistent with population growth, as outlined in Table 14. However, consumption per customer fell by 10% between 2010–11 and 2015–16.

In 2015–16, residential consumption per customer increased as a result of a strong rise (7.4%) in total residential consumption. The increase in residential consumption during 2015–16 is likely to have been caused by a colder than usual winter in the south-west region of WA, requiring greater use of heating than in a more typical year.

Table 14 Key statistics for residential customers, 2007–08 to 2015–16

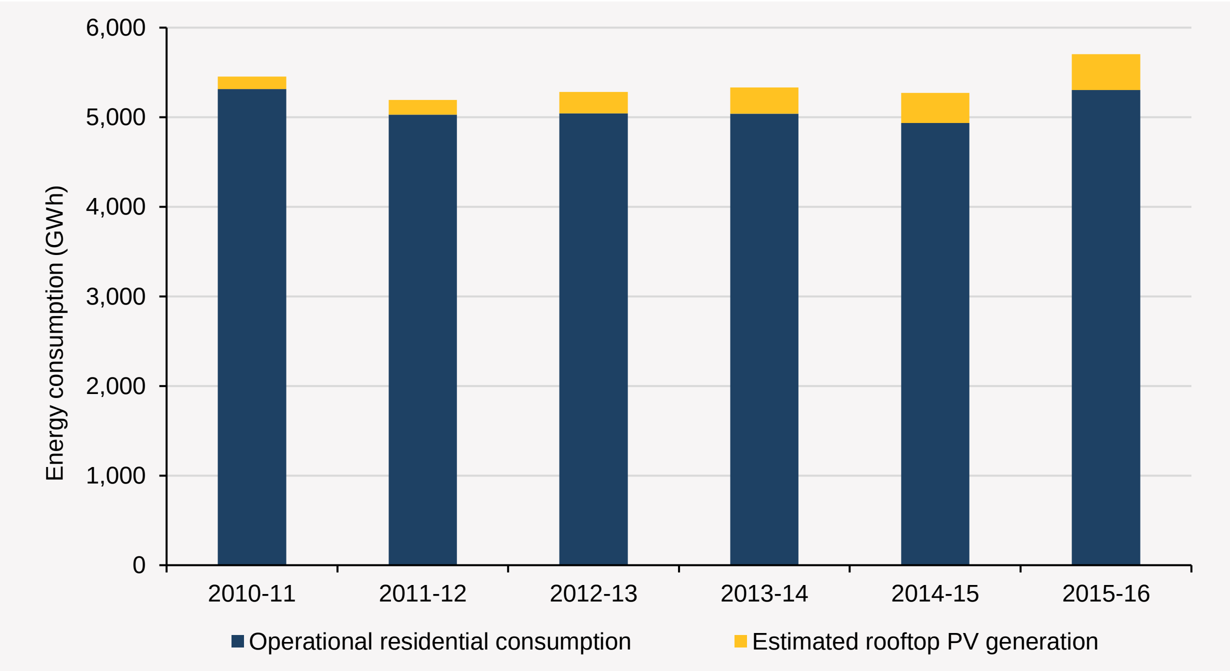
Capacity Year	Total number of residential customers[a]	Growth in customer numbers (%)	Residential electricity sales (GWh)	Growth in sales (%)	Average annual consumption per residential customer (kWh)	Growth in consumption per residential customer (%)
2007–08	921,790	NA	4,929	NA	5,347	NA
2008–09	946,970	2.7	5,013	1.7	5,294	-1.0
2009–10	966,342	2.0	5,328	6.3	5,514	4.2
2010–11	985,447	2.0	5,315	-0.3	5,393	-2.2
2011–12	1,000,539	1.5	5,028	-5.4	5,025	-6.8
2012–13	1,017,611	1.7	5,042	0.3	4,954	-1.4
2013–14	1,037,459	2.0	5,041	0.0	4,859	-1.9
2014–15	1,056,242	1.8	4,937	-2.1	4,674	-3.8
2015–16	1,071,959	1.5	5,302	7.4	4,946	5.8

[a] The total number of residential customers includes regulated and unregulated tariffs based on contract counts.
Source: Synergy

AEMO's estimates of underlying residential electricity consumption between 2009–10 and 2015–16 is presented in Figure 17. There are several reasons why residential consumption per connection has fallen over the past nine years, including:

- Tariff increases since 2009, driving consumers to use less energy.
- Strong uptake in rooftop PV systems, allowing customers to generate some of their energy onsite.
- Installation of more energy-efficient appliances to replace old ones.

Figure 17 Underlying residential consumption in the SWIS, 2008–09 to 2015–16 financial years



Source: AEMO estimates based on Synergy data

3.5.2 Large customers

Nine large customers in the SWIS account for around 15% of total electricity consumption in the 2015−16 Capacity Year, with average demand ranging from 20 MW to 140 MW per customer.

Between 2009–10 and 2015–16, large commercial consumption grew following the commencement of several large projects connected to the SWIS.

Average demand for these customers over the 2015–16 Capacity Year was 304 MW. Since these customers are not temperature sensitive, their consumption does not increase during periods of peak demand. At the time of system peak on 1 March 2017, the nine large customers accounted for 290 MW (7.9%) of demand, fairly consistent with their average load over the previous Capacity Year.

CHAPTER 4. FORECAST METHODOLOGY AND ASSUMPTIONS

This chapter describes the methodology and assumptions used to forecast peak demand and operational consumption for this report. It includes a summary of the input assumptions used in the forecasts, including:

- Economic outlook.
- Population growth.
- New block loads.
- Rooftop PV, battery storage, and electric vehicle (EV) uptake.
- IRCR response during peak periods.

AEMO has adopted a similar approach to forecasting as in previous years, with enhancements made to the rooftop PV and economic models. Assumptions related to the uptake of EVs have been introduced for the first time.[52]

4.1 Methodology

AEMO engaged ACIL Allen to develop the peak demand and energy forecasts for this WEM ESOO. The remainder of this section describes the general methodology ACIL Allen has adopted to forecast SWIS peak demand and operational consumption. Section 4.2 to Section 4.6 provide further detail on the methodology and assumptions used to develop the inputs for the forecasts.

ACIL Allen's methodology report, *Peak demand and energy forecasts for the South West interconnected system*, has been published on AEMO's website.[53]

The forecasts and associated methodology have been reviewed by AEMO analysts and forecasting specialists as part of the forecast approval process. This ensures that the forecast improves on previous results and is based on sound assumptions.

4.1.1 Peak demand forecasts

ACIL Allen developed peak demand forecasts based on three different POE[54] weather scenarios, as required by clause 4.5.10 of the WEM Rules:

- 10% POE.
- 50% POE.
- 90% POE.

Economic growth is a factor in determining the system peak demand. ACIL Allen applied three forecasts of economic growth (high, expected, and low) to each of the weather scenarios. This resulted in a total of nine peak demand forecasts. The high, expected, and low case forecasts referred to in this report reflect different economic scenarios and different levels of rooftop PV and battery storage uptake.

The methodology for calculating peak demand is shown in Figure 18.

52 AEMO. 2016. *AEMO Insights: Electric Vehicles*. Available at: http://aemo.com.au/Media-Centre/AEMO-Insights---Electric-Vehicles.

53 ACIL Allen, 2017. *Peak demand and energy forecasts for the South West interconnected system.* Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

54 A POE reflects the likelihood of the forecast peak demand being exceeded as a result of extremely hot weather or prolonged high temperatures. For example, a 10% POE forecast represents a forecast that has a 10% probability of being exceeded (one in ten years), whereas a 90% POE forecast represents a lower forecast, which is likely to be exceeded nine in ten years. A 50% POE forecast (the median forecast) is expected to be exceeded, on average, one in two years. A 10% POE forecast will be more conservative for capacity planning purposes than a 90% POE forecast.

Figure 18 Components of peak demand forecasts

Temperature insensitive + Temperature sensitive + Block loads − Embedded generation − IRCR = Peak demand

- **Temperature insensitive** load includes the proportion of residential and commercial consumption that does not vary according to temperature. This includes electricity for general office use, industrial equipment, cooking, lighting, entertainment equipment, and standby use.
- **Temperature sensitive** load is electricity used for heating and cooling, and is therefore directly related to temperature.
- **Block loads** are large industrial customers (greater than 20 MW) in the SWIS and are generally considered to be temperature insensitive. They are forecast separately from the rest of the system based on historical operating patterns.
- **Embedded generation** is typically the electricity generated by rooftop PV or released by battery storage.
- **IRCR** is the estimated reduction in demand from commercial and industrial customers on peak demand days to minimise their exposure to capacity costs.

Peak demand forecast assumptions

The high, expected, and low economic growth scenarios (which are applied to the 10%, 50% and 90% POE weather scenarios), are based on the following economic forecasts:

- High case – 4.5% average annual gross state product (GSP) growth, 2.2% average annual population growth.
- Expected case – 3.3% average annual GSP growth, 2.0% average annual population growth.
- Low case – 2.1% average annual GSP growth, 1.8% average annual population growth.

4.1.2 Operational consumption forecasts

The operational consumption forecasts are based on an econometric model. Key economic, demographic, and weather parameters were identified as the major factors affecting energy consumption, and forecasts for these parameters were used to develop the operational consumption forecasts.

Energy sales are split into two classes, residential and non-residential (including commercial and industrial). As Synergy currently supplies all residential connections, Synergy provided customer numbers and tariff data to AEMO to split customers into the classes for the development of the forecasts. The amount of historical consumption attributed to non-residential consumption was calculated as the difference between residential consumption (from Synergy) and total consumption.

Operational consumption forecast assumptions

The high, expected, and low operational consumption forecast scenarios assumed the same GSP and population growth as the scenarios used in the peak demand forecasts, and included the following additional assumptions:

- High case:
  - 0.5% average annual 10 year growth in residential energy sales.
  - 2.2% average annual 10 year growth in non-residential energy sales.
- Expected case:

  - 0.3% average annual 10 year growth in residential energy sales.
  - 1.5% average annual 10 year growth in non-residential energy sales.
- Low case:
  - 0.3% average annual 10 year growth in residential energy sales.
  - 0.9% average annual 10 year growth in non-residential energy sales.

4.2 Temperature sensitive and temperature insensitive demand

Temperature sensitive and insensitive demand forecasts are affected by the economic outlook and population growth. These are discussed in the following sections.

4.2.1 Economic outlook

AEMO engaged an independent economic forecaster to provide high, low, and expected projections for WA GSP. These GSP forecasts were provided to ACIL Allen to complete the peak demand and operational consumption forecasts. ACIL Allen tested state final demand as an alternative to GSP in the electricity forecast model, but found GSP to be a better fit.

The GSP forecasts for the expected, high, and low cases are presented in Table 15. High commodity export volumes are expected to drive economic growth over the outlook period, particularly from iron ore and liquefied natural gas (LNG). However, government investment is expected to be low as a result of high levels of debt.

Table 15 Gross state product for WA, 2016–17 to 2021–22

Scenario	2016–17 (%)	2017–18 (%)	2018–19 (%)	2019–20 (%)	2020–21 (%)	2021–22 (%)	Average annual growth (%)[a]
High	2.5	4.2	4.0	4.4	5.1	4.7	4.5
Expected	1.4	3.0	2.8	3.2	3.9	3.5	3.3
Low	0.3	1.8	1.6	2.0	2.6	2.3	2.1

Source: Independent economic forecaster
[a] Calculated over the period 2016-17 to 2027-28 (financial years)

In the long term, GSP is a function of population, productivity and labour force participation. The high level assumptions underpinning the GSP forecasts are as follows:

- Population growth assumptions are discussed in Section 4.2.2.
- Productivity growth (measured by output per worker) is applied to the population estimates, and is based on historical observations.
- Participation is assumed to decline because of the ageing Australia population. Long-run assumptions for participation are taken from the 2015 Intergenerational Report.[55] The participation rate is consistent across all cases.
- The price of commodity exports for the high and low cases are assumed to be 33% higher or lower than expected case commodity forecasts respectively after five years. Prices follow a linear trend to get to this point and are expected to be permanently higher or lower.

4.2.2 Population growth

Population growth is correlated with peak demand and operational consumption, but the effect is partly offset by rooftop PV and energy efficiency improvements (particularly around building energy

[55] The Treasury of Australian Government, 2015. *2015 Intergenerational Report*. Available at: http://www.treasury.gov.au/PublicationsAndMedia/Publications/2015/2015-Intergenerational-Report. Viewed: 20 April 2017.

efficiency). The population forecasts for the expected scenario are based on the State Government's Band C population forecasts.[56]

In the absence of detailed SWIS-specific data, WA population growth rates are assumed to be in line with SWIS population growth rates. The population supplied by the SWIS is estimated to have been 2.61 million in 2015–16, with population forecast to grow at an average of 2% per annum over the forecast period.

4.3 Block loads

Block loads are large loads that operate near continuously and are temperature insensitive. AEMO considers 20 MW to be the minimum size for a new block load. Information about historical block load consumption is provided in Section 3.5.2.

ACIL Allen has included block loads in its forecasts of peak demand and operational consumption. Forecasts for these loads are based on historical consumption and anticipated new block loads.

No new block loads are anticipated in the expected case for the forecast period. However, two new block loads have been included in the high case forecasts – an upgrade to an existing mine site, and the development of a new mineral processing plant. These projects are anticipated to increase demand by approximately 36 MW, and are expected to come online between 2018 and 2019.

AEMO engaged with external industry stakeholders, including Western Power and the Department of State Development, in deciding to include the new block loads in the high case rather than the expected case forecasts.

4.4 Rooftop PV assumptions

The following forecasts have been developed by AEMO with input from Jacobs and ACIL Allen:

- Installed capacity.
- The effect on peak demand.
- Annual energy generation.

AEMO has taken an approach to forecasting rooftop PV capacity in the SWIS that is consistent with the methodology used for AEMO's 2017 *Electricity Forecasting Insights*.[57] An overview of the methodology and assumptions used to develop these forecasts is presented in the following sections.[58]

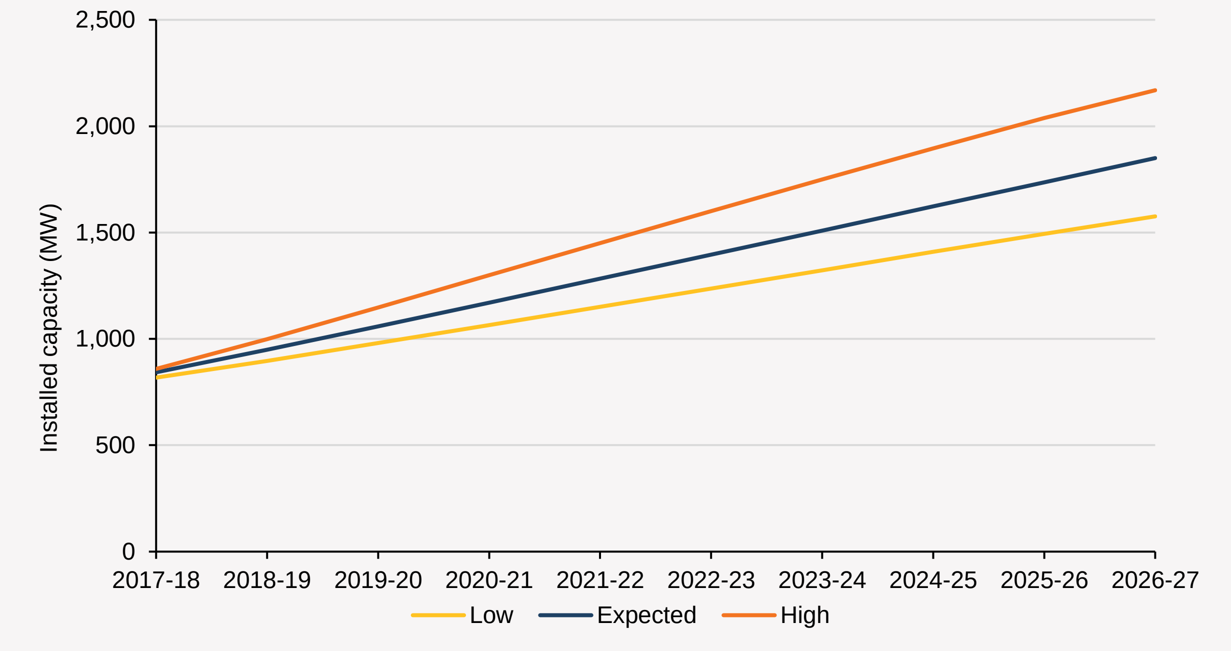
4.4.1 Installed capacity

AEMO engaged Jacobs to forecast rooftop PV capacity for the SWIS and the NEM. Jacobs' detailed methodology report: *Projections of uptake of small-scale systems*, has been published on AEMO's website.[59]

The forecast installed capacity of rooftop PV systems in the SWIS in the high, expected, and low cases is depicted in Figure 19. [60]

[56] WA Tomorrow is a set of forecasts representing estimates of WA's future population. The forecasts are broken down into different 'Bands'. Band C is the median forecast range. Available at: https://www.planning.wa.gov.au/publications/6194.aspx.
[57] To be published on the AEMO website in late June 2017
[58] All rooftop PV assumptions reported in this section refer to gross quantities (total energy generated from all rooftop PV systems in the SWIS).
[59] Jacobs, 2017. *Projections of uptake of small-scale systems.* Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.
[60] These forecasts include all residential and commercial rooftop PV up to 100 kW nameplate capacity so exclude generation-scale PV such as Greenough River.

Figure 19 Installed rooftop PV system capacity, 2017–18 to 2026–27 financial years



Source: Jacobs

These rooftop PV capacity forecasts indicate stronger growth rates across all scenarios than the forecasts presented in the 2015 ESOO. This is due to the following factors:

- Actual take up of rooftop PV in 2016–17 was higher than previously forecast. Last year's expected case forecast for 30 June 2017 was 564 MW. Based on the latest data available from the CER, the actual value is approximately 671 MW as of February 2017.
- The emergence of alternative business models, such as solar leasing, driving further investment by increasing the pool of potential rooftop PV customers.

4.4.2 Annual energy generation

AEMO developed a solar capacity factor trace[61] for this report to provide an estimate of historical rooftop PV generation for each half-hour trading interval from June 2011 to February 2017. The trace is based on time-series generation data from 173 rooftop PV systems, primarily in the Perth region.[62]

Each system trace was normalised using its rated capacity to produce a trace indicating the power output of the system as a proportion of its maximum capacity for each available half-hour interval (half hourly capacity factors[63]). The system traces were then aggregated to produce a single trace, by averaging the output of each of the contributing systems.

This trace was multiplied by the forecast installed capacity of rooftop PV systems connected to the SWIS to estimate the future reduction in operational consumption from rooftop PV.

As this solar trace is based on actual data it implicitly incorporates variations in the physical alignment of panels, lifecycle performance degradation, and an averaged effect of variations in solar irradiance.

[61] Solar capacity factor traces are a measure of the capacity factor of solar panels for each half-hour trading interval.
[62] Sourced from the PVOutput.org database.
[63] A capacity factor represents the percentage of actual generation relative to the maximum theoretically possible generation based on a Facility's nameplate capacity.

4.4.3 Effect on peak demand

AEMO calculated the expected effect of rooftop PV on peak demand by accounting for:

- The time of day that system peak demand occurs.
- The expected level of solar irradiance at the time of system peak.

The process for calculating the effect of rooftop PV on peak demand has been modified from last year to reflect the use of the solar traces as follows:

1. Developed average traces for each month (see Section 4.4.4) based on the solar capacity factor trace discussed in Section 4.4.2.
2. Selected the average capacity factor for rooftop PV at 17:30 in February (the assumed peak time) from the monthly average solar trace, which gives 21.2%.
3. Multiplied the capacity factor of 21.2% by the expected case rooftop PV capacity forecast to obtain the expected case peak demand reduction from rooftop PV.
4. For the high and low peak demand reduction from rooftop PV cases, adjusted the capacity factor of 21.2% for variations in solar irradiance (see Section 4.4.5) as follows:
   a) Low case – applied a derating factor of 0.523 to account for a cloudier than normal day to give an adjusted capacity factor of 11.1%. This was applied to the high case forecast for installed rooftop PV capacity to give the effect on peak demand.
   b) High case – applied an uprating factor of 1.134 to account for a sunnier than normal day to give an adjusted capacity factor of 24.1%. This was applied to the low case forecast for installed rooftop PV capacity to give the effect on peak demand.

The forecast assumes that the low peak demand case corresponds to the low rooftop PV capacity case. This is because a low peak demand is correlated to lower than expected economic growth, and lower economic growth is also correlated to lower uptake of rooftop PV. Conversely, the higher than average solar irradiance factor (assuming a sunnier day than average) was applied to the low peak demand case to maximise the effect of rooftop PV output on the low peak demand case. The opposite was applied to the high peak demand case. This process is outlined graphically in Figure 20.

Figure 20 Methodology for high and low case peak demand reduction from rooftop PV

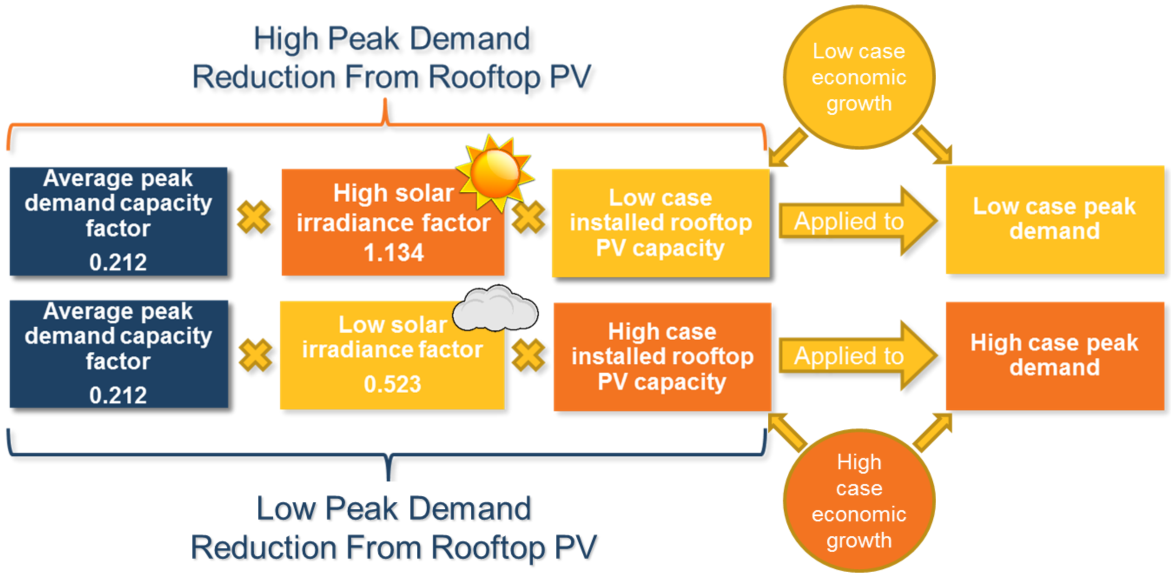
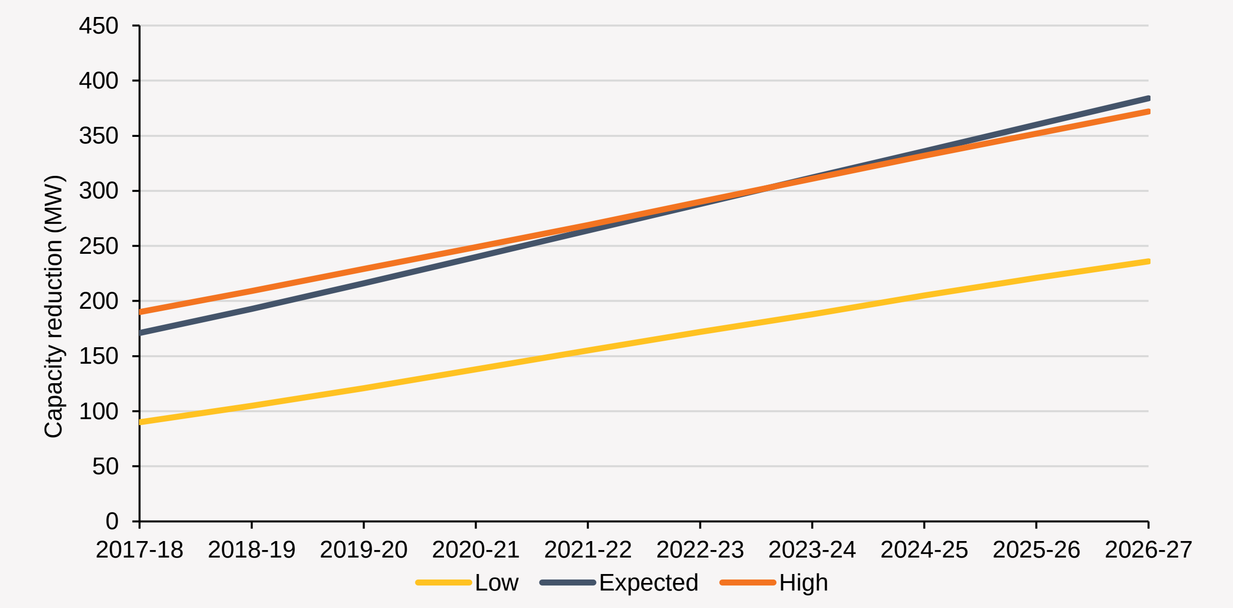


Figure 21 shows the high, low, and expected forecast reductions from rooftop PV developed using this process.[64] The high and expected rooftop PV peak demand reductions converge, due to the low case rooftop PV capacity forecast being applied to the high peak demand reduction from rooftop PV. The effect of the low case capacity forecast offset the higher solar irradiance factor past 2024.

Figure 21 Peak demand reduction from rooftop PV systems, 2017–18 to 2026–27



4.4.4 Averaged daily capacity factor traces

The average monthly solar capacity factor traces described in Section 4.4.3 are displayed in Figure 22.

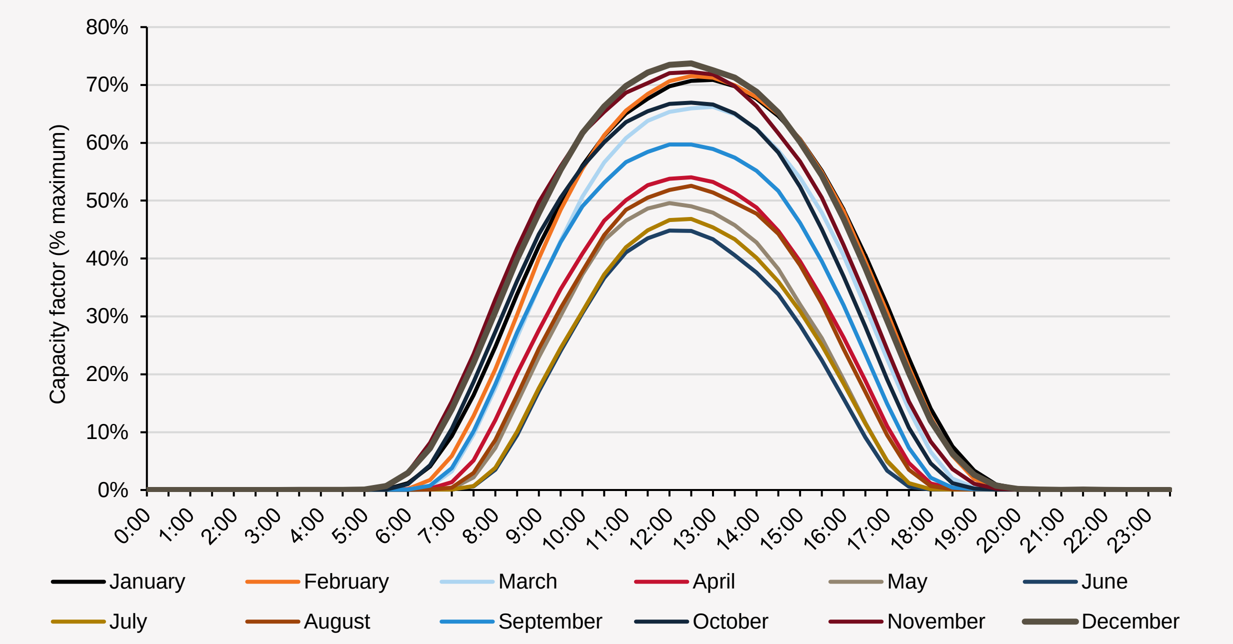
These were used to calculate the capacity factors at the time of system peak, and to determine the effect of rooftop PV on peak demand.

The capacity factor is highly sensitive to assumptions around the time of the system peak, which is becoming increasingly unpredictable. The forecast assumes that peak demand will occur in February in the trading interval commencing at 17:30, based on recent observations as discussed in Section 3.1.2. This shift has been primarily driven by the uptake of rooftop PV systems.

With continued high PV uptake and the introduction of battery storage it is possible that peak demand could shift further into the evening. However, this peak demand shift will depend on several variables including future battery uptake, tariff structures, and IRCR response. AEMO continues to investigate the underlying drivers of this trend to better understand the probability of later peaks.

[64] The forecasts presented in the figure use slightly different rooftop PV capacity values than those in Appendix E as they have been adjusted to align to a February peak.

Figure 22 Solar capacity factor traces, averaged by month, for rooftop PV in the SWIS



Source: AEMO and ACIL Allen based on PVOutput.org input data

4.4.5 Solar irradiance effects

As part of the 2015 WEM ESOO, AEMO investigated the historic relationship between peak demand and solar irradiance levels in the SWIS. The analysis found there is weak correlation between daily solar irradiance and peak demand days in the SWIS, indicating that it is necessary to account for varying levels of solar irradiance when considering the effect of rooftop PV on peak demand. AEMO has accounted for this by calculating rating factors to represent the expected reduction or increase in rooftop PV system performance based on variations in solar irradiance.

The irradiance figures determined for the Perth metropolitan region were averaged over the past seven years. In using irradiance levels as a proxy for system generation, AEMO has implicitly assumed a linear relationship between irradiance and rooftop PV performance.

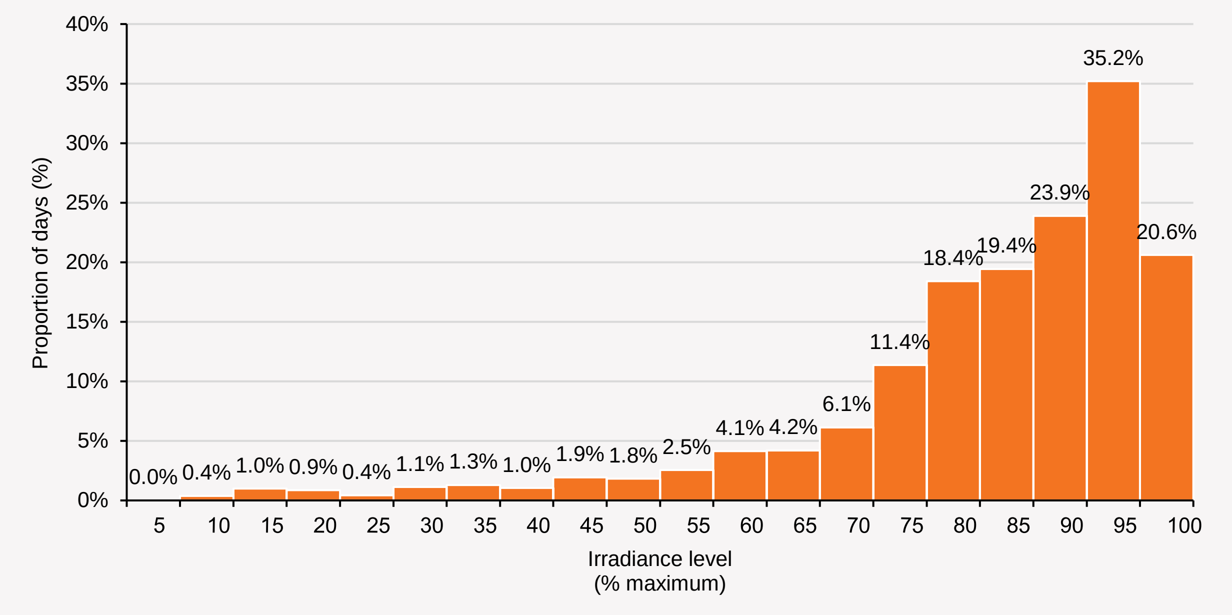
The solar capacity factor traces developed for this ESOO are based on actual data, which account for an average solar irradiance level. Therefore, no irradiance factor adjustment was applied to the expected case. For the high peak demand case, solar irradiance was assumed to be lower than average, so a derating factor was applied to calculate a lower rooftop PV output. For the low peak demand case, solar irradiance was assumed to be higher than average, so an uprating factor was applied.

The following assumptions were developed out of the irradiance analysis presented in Figure 23:

- High solar reduction at peak (associated with low peak demand case) - ninety-fifth percentile irradiance level equalling 113.4% of rooftop PV output.
- Expected solar reduction at peak: median irradiance levels equalling rooftop PV output based on the average monthly solar capacity factor traces.
- Low solar reduction at peak (associated with high peak demand case) - fifth percentile irradiance levels equalling 52.3% of rooftop PV output.

The distribution of daily solar irradiance measured at six sites across the Perth metropolitan region for January to March (the likely timing of the system peak), is shown in Figure 23. This figure shows that Perth has a high level of solar irradiance over summer, with around 90% of summer days observing more than 50% of the maximum possible solar irradiance.

Figure 23 Variability in daily solar irradiance levels during summer, 2011 to 2017



Source: Bureau of Meteorology

4.5 Battery storage forecasts

AEMO engaged Jacobs to forecast the installed capacity of small-scale grid connected battery storage systems in the SWIS. This is the same approach as that taken for forecasting battery storage in the NEM for the 2017 *Electricity Forecasting Insights*.

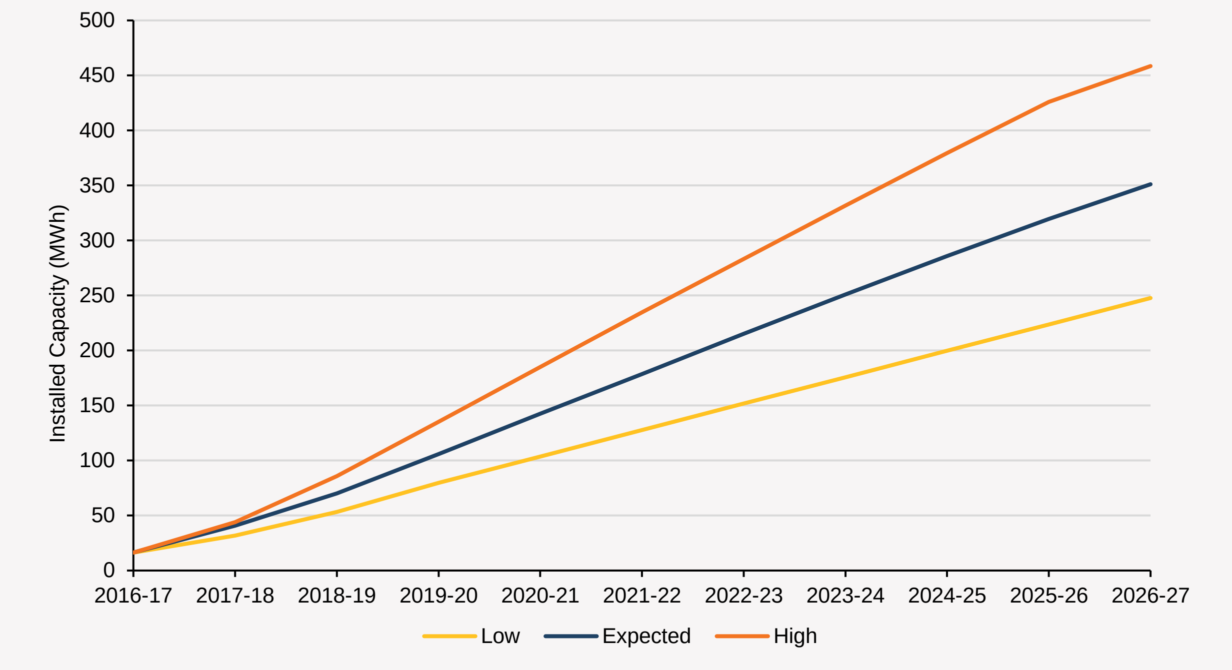
The battery storage forecasts are for small-scale residential and commercial customers only, and exclude grid-scale systems used for energy arbitrage or network stability purposes.

The assumptions used to forecast battery storage installed capacity and the effect on peak demand were:

- Batteries are charged at a constant rate from a rooftop PV system between 06:00 and 14:00.
- The battery systems do not charge from the grid due to existing tariff structures that would result in a net loss of income for the owner.
- The battery discharges at a constant rate over a four hour period which includes the system peak.
- Assumed charge and discharge rates do not breach the technical constraints of currently available battery storage technology.
- Battery systems are not sensitive to small changes in the availability or timing of rooftop PV generation.
- The battery system is only used to time-shift the consumption of generation from rooftop PV systems.
- There are no time-of-use tariff signals to encourage non-contestable customers to optimise storage decisions to align with periods of high demand in the SWIS.

The installed capacity forecasts in the high, expected, and low case scenarios are shown in Figure 24. The forecasts assume that each battery storage installation is paired with a rooftop PV system.

Figure 24 Installed capacity of battery systems, 2016–17 to 2026–27 financial years

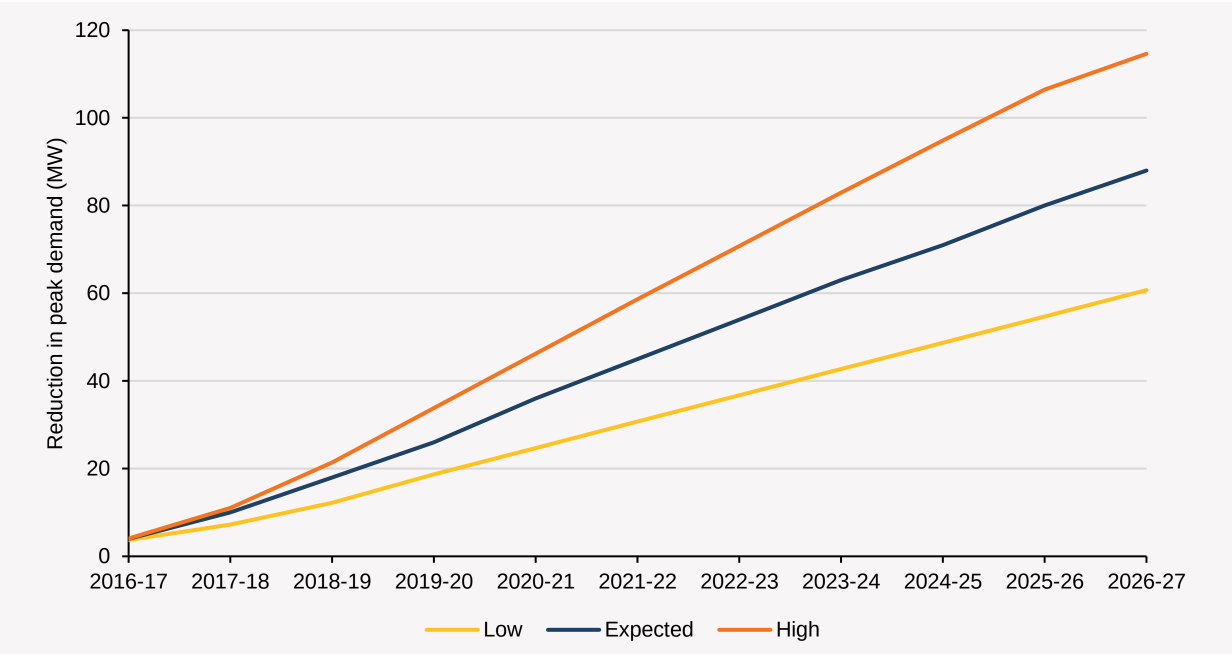


Source: Jacobs

4.5.1 Impact on peak demand

The assumed impact of battery storage on peak demand is shown in Figure 25.

Figure 25 Reduction in peak demand from battery storage, 2016–17 to 2026–27



The impact of batteries on peak demand depends on how the unit is operated. There are currently insufficient battery storage units installed in the SWIS to derive an output profile, and consumers currently have no price incentive to increase the discharge rate of the battery during periods of peak demand, particularly considering that this would decrease the efficiency and operating life of the battery system.

For these reasons a linear discharge over a four hour period that includes the system peak was assumed when modelling the impact of battery storage on peak demand.

As of October 2016 there were approximately 250 distributed battery installations in Western Australia, corresponding to a total capacity of around 1.5 megawatt hours (MWh)[65]. AEMO continues to monitor trends in battery uptake and usage. The forecasting methodology for batteries will be updated as further units are installed and more information becomes available.

4.6 Individual Reserve Capacity Requirement

Peak demand forecasts were adjusted to account for the effect of customers reducing consumption during peak times to minimise capacity costs allocated through the IRCR mechanism.

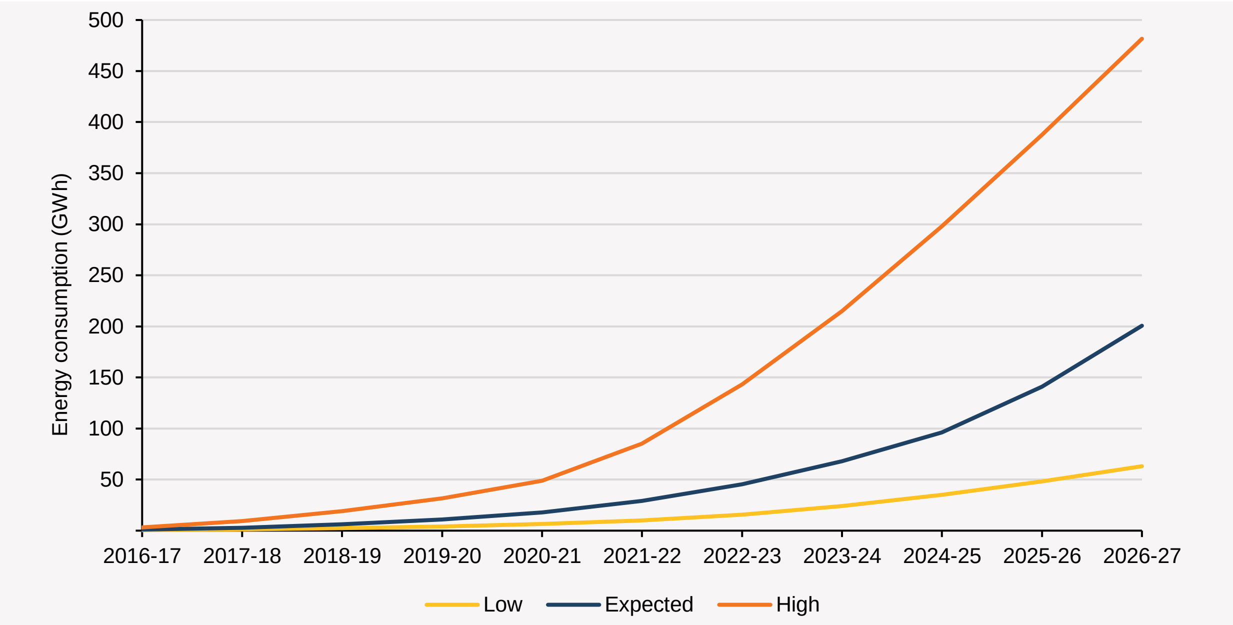
AEMO assumed that the IRCR response would remain consistent with that observed during the peak trading interval on 8 February 2016 at 77 MW throughout the forecast period. This is the second highest IRCR response observed in the SWIS to date, with this year's response being the only year to exceed it at 124 MW on 1 March 2017.

Changes to certification requirements and payments for DSM capacity as a result of the EMR caused some DSM to exit the RCM. AEMO expects a proportion of the loads associated with Facilities that previously provided DSM may start responding to the IRCR mechanism, thus increasing the total response. However, as the timing of future peaks is difficult to predict, it is uncertain how consistent greater responses will be in the future. AEMO will consider revising the IRCR response forecast as future responses become available.

4.7 Electric vehicle assumptions

AEMO engaged an external consultant to forecast the energy consumption of electric vehicles on future energy demand. The forecasts presented in this section are taken from *AEMO Insights: Electric Vehicles*.[66] The effect of EVs on operational consumption in the SWIS is provided in Figure 26.

Figure 26 Electric vehicle contribution to operational consumption, 2016–17 to 2026–27 financial years



Projections for EV uptake assume a slow start due to limited infrastructure, the narrow range of models currently available, and the cost relative to conventional petrol or diesel vehicles.

65 Source: CER
66 AEMO. 2016. *AEMO Insights: Electric Vehicles*. Available at: http://aemo.com.au/Media-Centre/AEMO-Insights---Electric-Vehicles.

The range between the high and low forecasting cases is quite wide, due to uncertainty around decisions on industry policy, such as vehicle fleet emission standards, which could influence EV uptake.

The analysis assumes that new tariff structures will discourage the charging of EVs during peak demand before EVs achieve a level of penetration where a noticeable effect on peak demand is possible. Therefore EVs are assumed to have a negligible impact on peak demand over the forecast period.

CHAPTER 5. PEAK DEMAND AND OPERATIONAL CONSUMPTION FORECASTS, 2017–18 TO 2026–27

This chapter presents the peak demand and operational consumption forecasts for the 10-year forecast period 2017–18 to 2026–27. These forecasts have been developed in line with the peak demand and operational forecast methodology described in Chapter 4, using forecast data from ACIL Allen with input from AEMO. These forecasts are compared to the 2015 ESOO forecasts in Chapter 6.

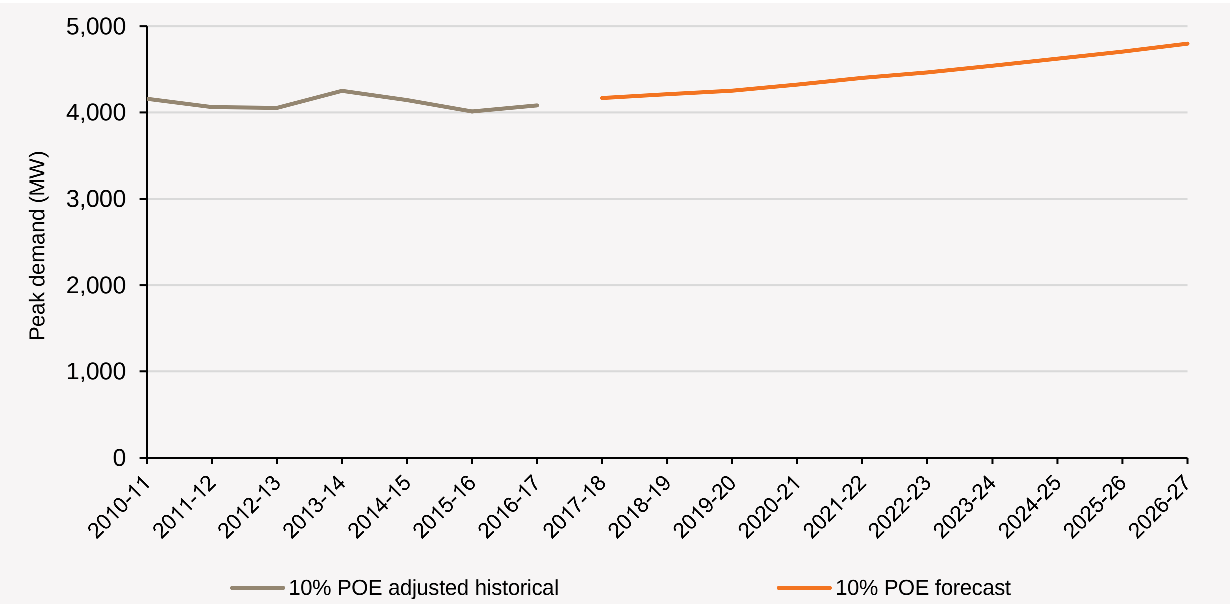
5.1 Peak demand forecasts

Over the 10-year period 2017–18 to 2026–27:

- The 10% POE summer peak demand forecast grows from 4,169 MW in 2017−18 to 4,799 MW by 2026−27, growing at an average annual rate of:
  - 2.6% in the high demand growth scenario.
  - 1.6% in the expected demand growth scenario.
  - 0.9% in the low demand growth scenario.
- The 50% and 90% POE summer peak demand forecasts grow at an average annual rate of 1.5% and 1.4% for the expected scenario.
- The 10%, 50%, and 90% POE winter peak demand forecasts grow at an average annual rate of 1.4% for all expected scenarios.

The 10% POE peak demand forecasts over the forecast period and adjusted historical peak demand since 2010–11 are shown in Figure 27. Actual observed historical peak demand and temperature values were adjusted to a 10% POE level to allow for the forecasts to be compared. A full set of peak demand forecasts is in Appendix F.

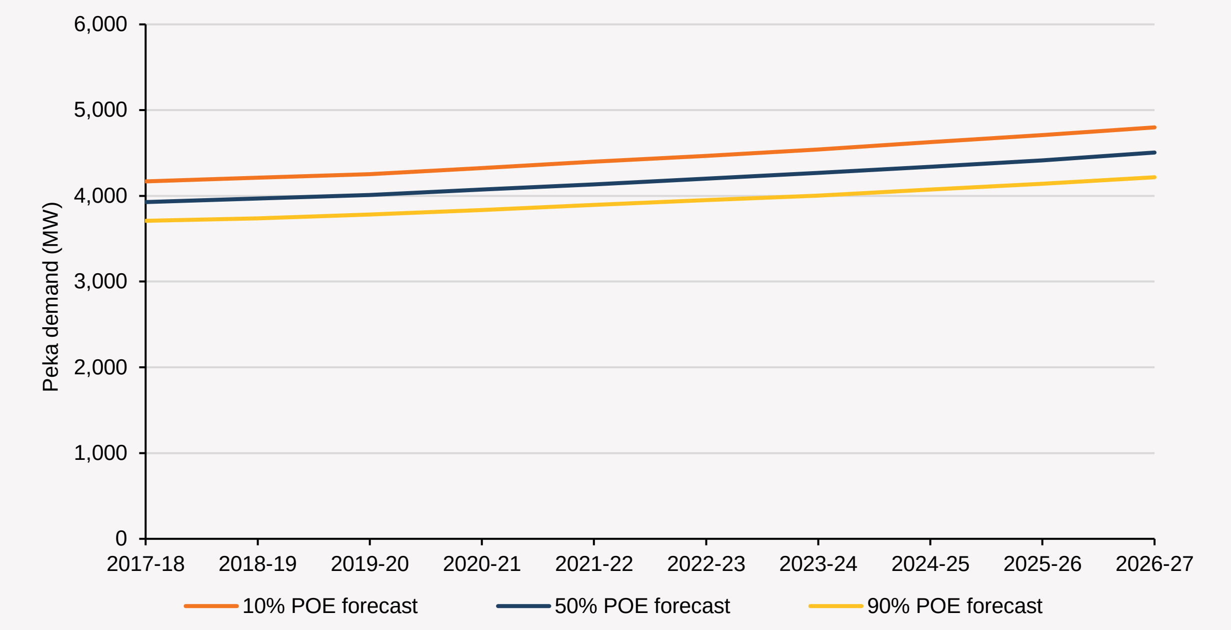
Figure 27 Historical and forecast peak demand, 10% POE, 2010–11 to 2026–27



Source: ACIL Allen

The 10%, 50% and 90% POE summer peak demand forecasts are shown in Figure 28 and Table 16.

Figure 28 Peak demand growth forecasts under different POE scenarios, 2017–18 to 2026–27



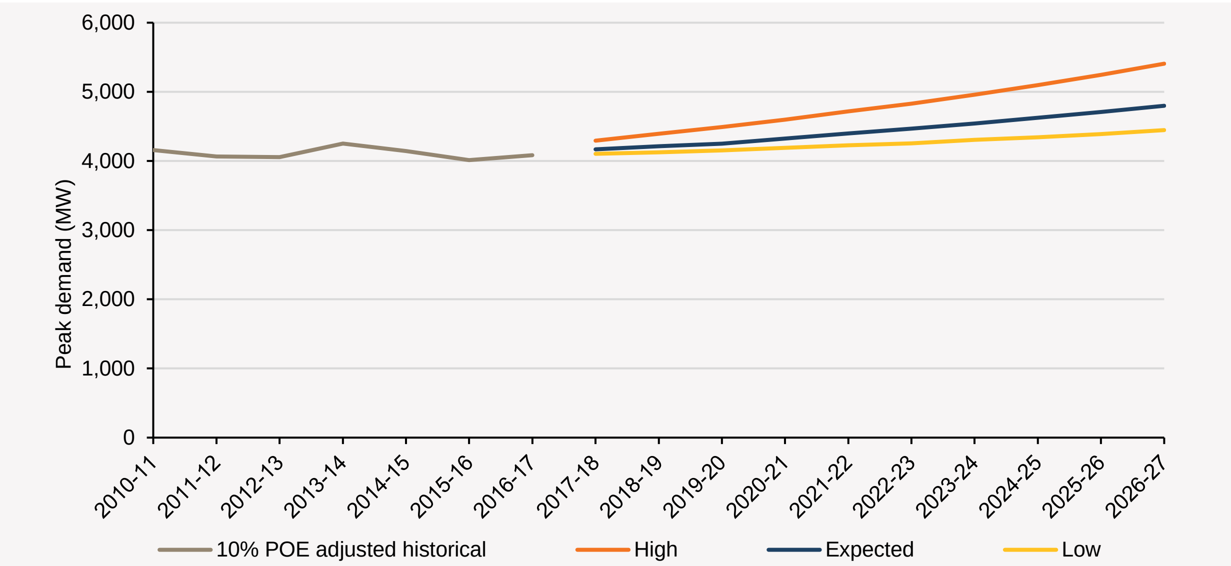
Source: ACIL Allen

Table 16 Peak demand growth forecasts for different POE scenarios

Scenario	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	2021–22 (MW)	5-year average annual growth	10-year average annual growth
10% POE	4,169	4,213	4,253	4,326	4,401	1.4%	1.6%
50% POE	3,927	3,968	4,009	4,076	4,133	1.3%	1.5%
90% POE	3,709	3,739	3,782	3,835	3,893	1.2%	1.4%

The 10% POE forecasts for all three demand growth scenarios (high, expected, and low) are in Figure 29 and Table 17.

Figure 29 Peak demand, 10% POE, under different demand growth scenarios, 2010–11 to 2026–27



Source: ACIL Allen

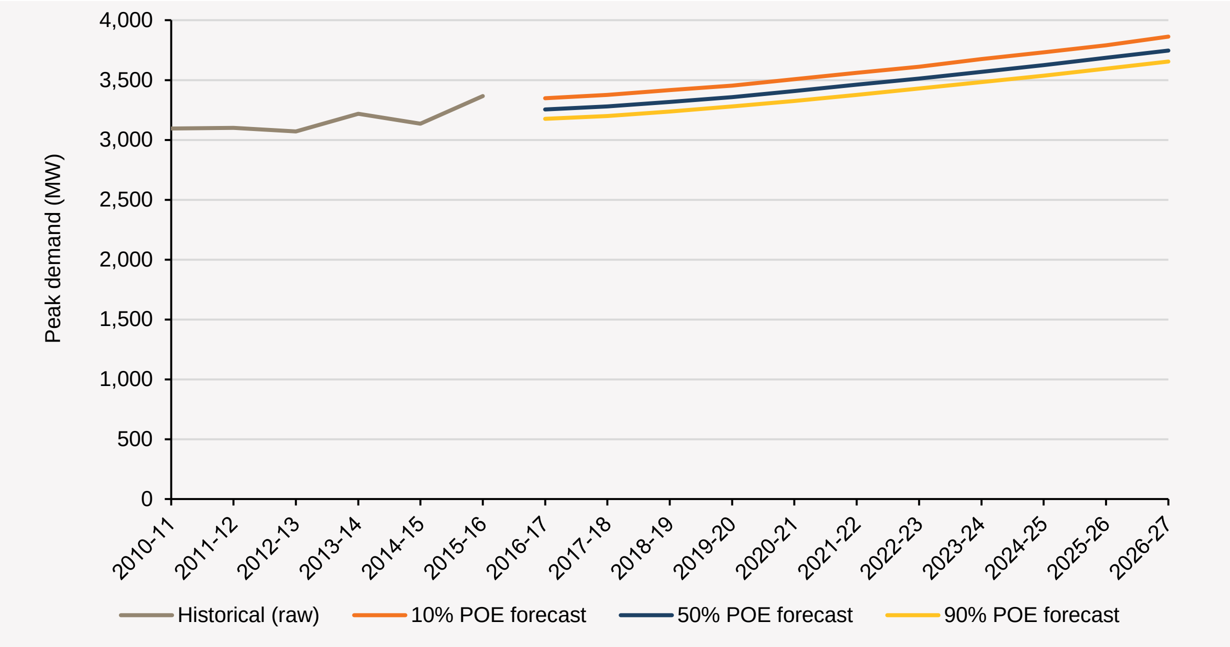
Table 17 Peak demand forecasts for different demand growth scenarios, 10% POE

Scenario	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	2021–22 (MW)	5-year average annual growth	10-year average annual growth
High	4,294	4,392	4,490	4,597	4,716	2.4%	2.6%
Expected	4,169	4,213	4,253	4,326	4,401	1.4%	1.6%
Low	4,104	4,126	4,153	4,192	4,227	0.7%	0.9%

The variation in growth rates reflects different economic growth forecasts, as well as different rooftop PV and battery storage assumptions. A full set of 10% POE forecasts is in Appendix F.

The 10%, 50%, and 90% POE expected demand growth scenario winter peak forecasts are shown in Figure 30. The full set of winter peak demand forecasts is in Appendix G.

Figure 30 Winter peak demand, expected case forecasts, 2010−11 to 2026−27



Source: ACIL Allen

Consistent with current demand patterns in the SWIS, winter peak demand is forecast to remain lower than summer peak demand across all scenarios over the forecast period.

5.2 Operational consumption forecasts

From 2017–18 to 2026–27[67], operational consumption is forecast to grow at an average annual rate of:

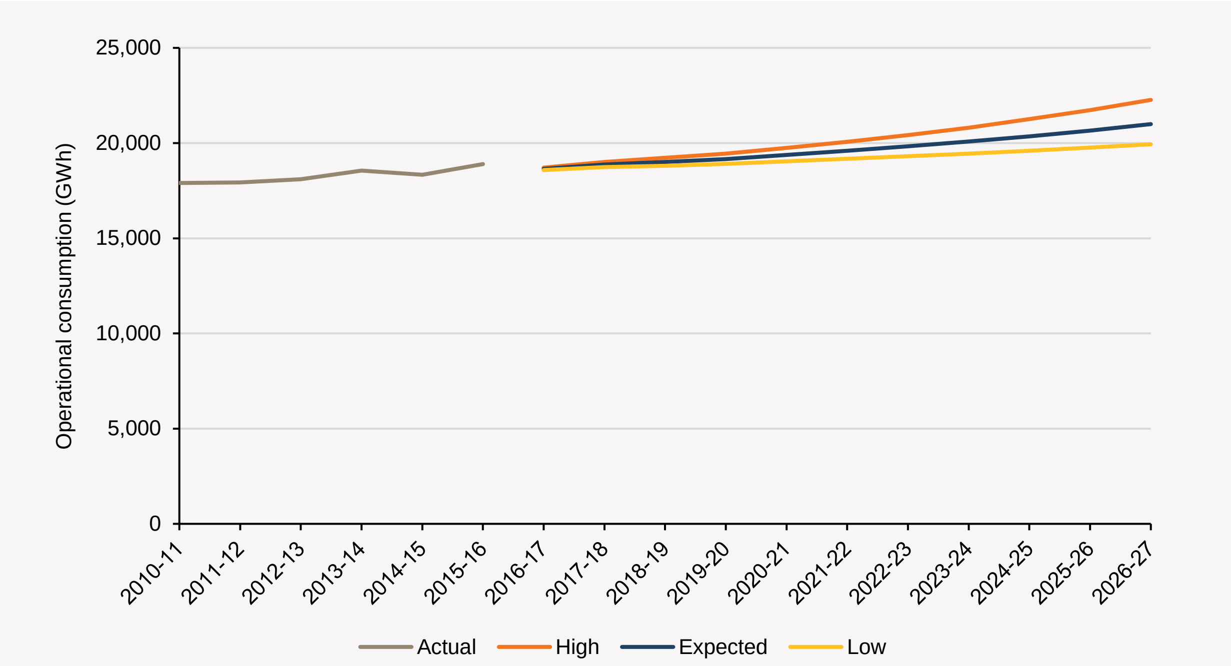
- 1.7% in the high demand growth scenario.
- 1.2% in the expected demand growth scenario.
- 0.7% in the low demand growth scenario.

Under the expected scenario, operational consumption in the WEM is forecast to grow from approximately 18,819 GWh in 2017–18 to 20,996 GWh by 2026–27. This is despite rooftop PV generation growing from approximately 1.1 GWh to 3.4 GWh over the same period, an average growth of 9.9% per annum.

[67] Operational consumption is forecast in financial years.

The high, expected, and low demand growth scenario operational consumption forecasts are shown in Figure 31 and Table 18. As for peak demand forecasts, the variation in growth rates reflects different economic growth forecasts, as well as different rooftop PV and battery storage assumptions. A full set of operational consumption forecasts is provided in Appendix H.

Figure 31 Operational consumption forecasts under different demand growth scenarios, with historical actual consumption, 2010–11 to 2026–27 financial years



Source: ACIL Allen

Table 18 Operational consumption[a] forecasts for different economic growth scenarios

Scenario	2017–18 (GWh)	2018–19 (GWh)	2019–20 (GWh)	2020–21 (GWh)	2021–22 (GWh)	5-year average annual growth	10-year average annual growth
High	18,947	19,160	19,372	19,650	19,967	1.3%	1.7%
Expected	18,819	18,962	19,110	19,316	19,538	0.9%	1.2%
Low	18,705	18,786	18,866	18,994	19,129	0.6%	0.7%

[a] Operational consumption forecasts are per financial year

CHAPTER 6. FORECAST RECONCILIATION

This chapter discusses forecast performance against actual observations, and how peak demand and operational consumption forecasts have changed in the 2017 ESOO compared to previous ESOO forecasts.

6.1 Base year reconciliation

6.1.1 Peak demand

AEMO develops forecasts based on different weather conditions (the 10%, 50%, and 90% POE forecasts). When reviewing the variance between forecast and actual peak demand, it is important to separate the effect of warmer or cooler than average temperatures from other sources of variance, to understand how much variance can be attributed to weather, and how much to other factors such as customer behaviour and economic activity. AEMO weather-adjusts the actual peak demand to estimate what would have happened if the peak occurred during a one in ten year extreme weather event.

Actual peak demand for the 2016–17 summer was 3,670 MW. The peak demand trading interval occurred on 1 March 2017, with the maximum temperature reaching 34.7°C at the time of peak.

This was the lowest peak demand observed since 2009, and the first time since 2007 peak demand has occurred in March.

AEMO has weather-adjusted the actual peak to estimate what would have occurred on a 10% POE day, separating the impact of weather. The 2016–17 weather-adjusted peak demand was 4,083 MW, which is 10 MW (0.25%) higher than was forecast in 2016.

6.1.2 Operational consumption

Actual operational consumption in 2016–17[68] was 18,549 GWh, which was 0.05% lower than forecast in 2016. This small variation can be attributed to inherent forecasting errors.

6.2 Changes between previous forecasts

6.2.1 Peak demand

Peak demand forecasts since 2015, compared in Figure 32, demonstrate:

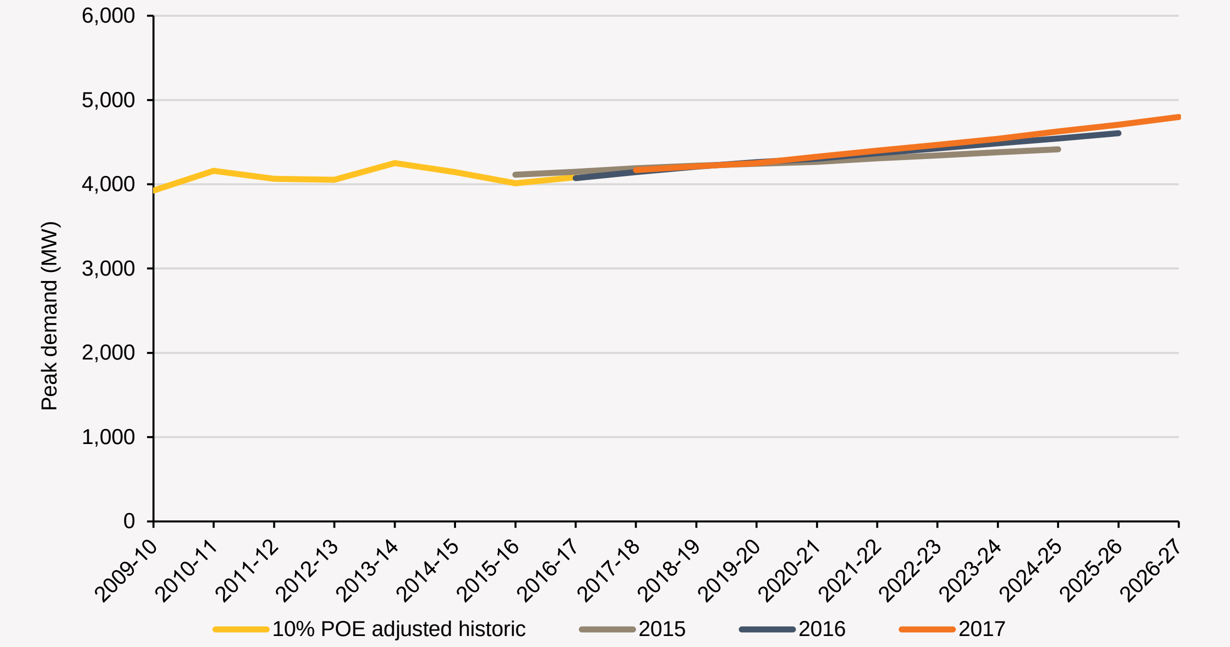
- Peak demand forecasts have been consistent for the past three years.
- The 10% POE 10-year average annual growth rate in this year's ESOO is 1.6%, which is higher than the growth rate of 1.4% forecast in 2016.
- The 2017–18 forecast peak demand is 4,169 MW, 0.6% (24 MW) higher than the forecast in 2016.

This increase in peak demand forecasts compared to 2016 can be attributed to:

- An upward revision in WA's economic forecast, and a slight increase in expected population growth (see Section 4.2.1 for more information).
- A shift in the forecast time of peak demand from the 16:30 to 17:30 trading interval, which decreases the effect of rooftop PV on the peak. At 16:30 it is assumed that the average capacity factor of rooftop PV is 39.6%, however by 17:30 the average capacity factor has dropped to 21.2% (see Section 4.4.4 for more information).

[68] Financial year, AEMO has used nine months of actual data and three months of forecasts.

Figure 32 Change between peak demand 10% POE expected case forecasts, 2015 to 2017



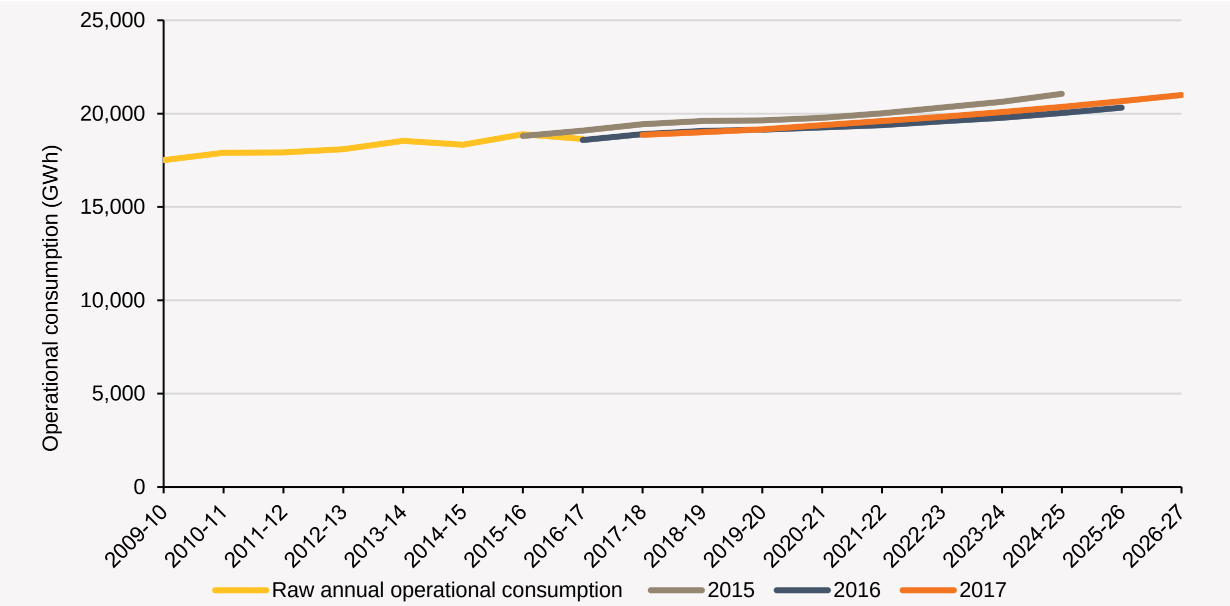
Source: National Institute of Economic and Industry Research (NIEIR) and ACIL Allen

6.2.2 Operational consumption

Operational consumption forecasts since 2015, compared in Figure 33, demonstrate:

- Forecasts have been consistent for the past three years.
- Operational consumption is forecast to grow at an average annual rate of 1.2% across the 10-year outlook period, an increase from the growth rate of 1% forecast in 2016.

Figure 33 Change between operational consumption expected case forecasts, 2015 to 2017



Source: AEMO, NIEIR and ACIL Allen

This change in the 2017 ESOO can be attributed to:

- The inclusion of EVs in AEMO's forecast for the first time. EVs are expected to increase consumption from the grid by 216 GWh by 2027.
- A slight increase in WA's economic forecasts and population growth (see Section 4.2.1 for more information).
- The forecast impact of EVs and economic growth being partly offset by an expected continuing increase in rooftop PV systems.

CHAPTER 7. RESERVE CAPACITY TARGET

This chapter discusses future opportunities for investing in capacity in the SWIS, and sets the RCT for each year of the Long Term PASA Study Horizon (2016–17 to 2026–27 for the 2016 and 2017 Reserve Capacity Cycles).[69]

7.1 Planning Criterion

The RCT ensures there is sufficient generation and DSM capacity in each Capacity Year during the Long Term PASA Study Horizon to meet two elements of the Planning Criterion (outlined in clause 4.5.9 of the WEM Rules):

a) Meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

   i. 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

   ii. The maximum capacity, measured at 41°C, of the largest generating unit

   while maintaining the Minimum Frequency Keeping Capacity[70] for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten.

b) Limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses).

Part (a) of the Planning Criterion relates to meeting the highest demand in a half-hour trading interval. Part (b) ensures adequate levels of energy can be supplied throughout the year.

The Planning Criterion applies to the provision of generation and DSM capability. It does not specifically include transmission reliability planning, or cover for a major fuel disruption such as a sudden or prolonged gas supply interruption.

To date the peak demand-based capacity requirement in part (a) has exceeded the energy-based requirement in part (b) and set the RCT.

The RCT for each year in the Long Term PASA Study Horizon is outlined in Section 7.2.

7.1.1 Part (a) of the Planning Criterion

Between 2016–17 and 2021–22 in the Long Term PASA Study Horizon, the capacity of the largest generating unit, NewGen Neerabup (331 MW),[71] measured at 41°C, has set the level of reserve margin, being greater than 7.6% of the forecast peak demand.

For the 2021–22 Capacity Year and beyond, the reserve margin is set by 7.6% of the forecast peak demand, due to an increase in forecast peak demand over the outlook period. The quantity of load following ancillary service (LFAS) capacity required for maintaining system frequency is 72 MW for the foreseeable future, assuming there are no changes to the WEM Rules.

7.1.2 Part (b) of the Planning Criterion

Although annual peak demand in the SWIS occurs in summer, the availability of capacity is crucial for system reliability throughout the year. Generators undergo regular maintenance to ensure ongoing reliability. These outages are typically scheduled in the lower load periods of autumn, spring, and, to a

[69] The Long Term PASA Study Horizon is defined as the 10-year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle (1 October 2016 for the 2016 Reserve Capacity Cycle, 1 October 2017 for the 2017 Reserve Capacity Cycle).

[70] Also known as load following ancillary service (LFAS) capacity.

[71] Based on the level of Capacity Credits assigned for the 2017–18 Capacity Year.

lesser extent, winter. The scheduling process in the WEM Rules is designed to ensure sufficient capacity is available to meet the short-term demand forecast.

Detailed modelling of the entire power system is completed to ensure there is sufficient capacity to accommodate plant maintenance and unplanned (or 'forced') outages throughout the year. The result is an estimate of the percentage of demand that would not be met due to insufficient available capacity. Part (b) of the Planning Criterion requires this shortfall to be no more than 0.002% of the annual forecast demand (see the Availability Curves in Section 7.3).

To date, the RCT has been set by part (a) of the Planning Criterion, relating to annual forecast peak demand, due to sufficiently high levels of plant availability.

7.2 Forecast capacity requirements

The RCT, set by the peak demand requirement of the Planning Criterion, for each year of the Long Term PASA Study Horizon is shown in Table 19.

Table 19 Reserve Capacity Targets[a]

Capacity Year	Peak demand (MW)	Intermittent loads	Reserve margin (MW)	Load following (MW)	Total (MW)
2016–17[b]	4,073	4	331	72	4,480
2017–18[b]	4,169	4	331	72	4,576
2018–19	4,213	4	331	72	4,620
2019–20	4,253	4	331	72	4,660
2020–21	4,326	4	331	72	4,733
2021–22	4,401	4	335	72	4,812
2022–23	4,466	4	340	72	4,882
2023–24	4,541	4	345	72	4,962
2024–25	4,626	4	352	72	5,054
2025–26	4,707	4	358	72	5,141
2026–27	4,799	4	365	72	5,240

[a] All figures have been rounded to the nearest integer.
[b] Figures have been updated to reflect the current forecasts. However, the RCTs set in the 2014 and 2015 ESOOs will not change.

The RCTs determined for the 2018–19 and 2019–20 Capacity Year are 4,620 MW and 4,660 MW respectively. These are higher than the 2017–18 RCT (4,552 MW) published in the 2015 ESOO, and is the result of an increase in peak demand forecasts.

7.3 Availability Curves

Capacity in the SWIS is assigned between two Availability Classes, defined as follows:

- Availability Class 1 relates to generation capacity and any other capacity that is available to be dispatched for all trading intervals other than when an outage applies.
- Availability Class 2 relates to capacity that is not expected to be available to be dispatched for all trading intervals.

Capacity from Class 1 can be used to meet the requirement for Class 2.

Assuming the RCT is just met, the Availability Curve indicates the minimum amount of capacity that must be provided by generation capacity to ensure the energy requirements of consumers are met.

The Availability Curves for the 2017–18, 2018–19, and 2019–20 Capacity Years are shown in Table 20.

Table 20 Availability Curves

	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)
Capacity associated with Availability Class 1	3,701	3,955	3,823
Capacity associated with Availability Class 2	875	665	837

Source: Robinson Bowmaker Paul (RBP)

The variability in capacity associated with each Availability Class between the 2017–18 and 2019–20 Capacity Years is a result of:

- Changes in expected available generation capacity.
- Peak demand and operational consumption forecasts.
- The timing of planned outages.

The increase in the minimum generation requirement associated with Availability Class 1 in the 2018–19 Capacity Year is a result of simultaneous planned outages scheduled for non-peak periods when DSM cannot be dispatched.

A more detailed explanation and graphs of the capacity requirements are provided in Appendix A and the associated methodology report.[72]

When assigning Capacity Credits, the WEM Rules do not limit the amount of Capacity Credits assigned to any Availability Class where the Market Participant nominates an intention to trade capacity.

7.4 DSM Reserve Capacity Price

AEMO is required to calculate the Expected DSM Dispatch Quantity (EDDQ) and the DSM Activation Price in accordance with a Market Procedure.[73] The formula used to determine the DSM Reserve Capacity Price (RCP) is as follows:

$$\text{DSM RCP} = (\text{Expected DSM Dispatch Quantity} + 0.5) \times \text{DSM Activation Price}$$

A detailed explanation of the methodology used to calculate all DSM RCP parameters is provided in Appendix B. The DSM RCP for the 2017–18 Capacity Year is $17,050/MW. AEMO has assigned 106 MW of DSM Capacity Credits for the 2017–18 Capacity Year and the DSM Activation Price is $33,460/MWh.

AEMO has assumed the level of assigned DSM Capacity Credits and the DSM Activation Price remains unchanged throughout the forecast period to estimate the expected DSM RCP in Table 21.

[72] RBP, 2017. *Assessment Of System Reliability And Development Of The Availability Curve For The South West Interconnect System*. Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[73] Market Procedure: *Determination of the DSM Dispatch Quantity and DSM Activation Price*. Available at: http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Procedures.

Table 21 Expected DSM dispatch and DSM RCP, 2017–18 to 2026–27

Capacity Year	Expected DSM Dispatch Quantity (MWh)	DSM RCP ($/MW)[a]
2017–18	0.0096	17,050
2018–19	0.0597	18,727
2019–20	0.5186	34,083
2020–21	0.0655	18,922
2021–22	0.0137	17,189
2022–23	0.0000	16,730
2023–24	0.0055	16,914
2024–25	0.0072	16,972
2025–26	0.4351	31,287
2026–27	0.0189	17,361

[a] Rounded to the nearest dollar.

The DSM RCP is expected to remain consistent over the outlook period. However, in the 2019–20 and 2025–26 Capacity Years the DSM RCP is expected to significantly increase. This can be attributed to major planned outages in these Capacity Years submitted by Market Participants during AEMO's request for information.

Market Participants may lodge outages for future years as this will increase their chances of such outages being approved, however AEMO has no obligation to approve such outages until closer to the event. AEMO is currently unable to assess the probability of these outages being approved as this will depend on a number of significant factors (such as forced outages, weather, and system security) which cannot be predicted at this point in time. For this reason, all outage information provided by Market Participants has been included in the EDDQ calculation. The inclusion of major planned outages has increased the EDDQ, due to the increase in the forecast level of unserved energy.

The EDDQ estimates from the 2018–19 Capacity Year to the end of the outlook period will be updated in the 2018 WEM ESOO. AEMO will reassess all outage information and request new information from Market Participants.

7.5 Opportunities for investment

7.5.1 Supply-demand balance

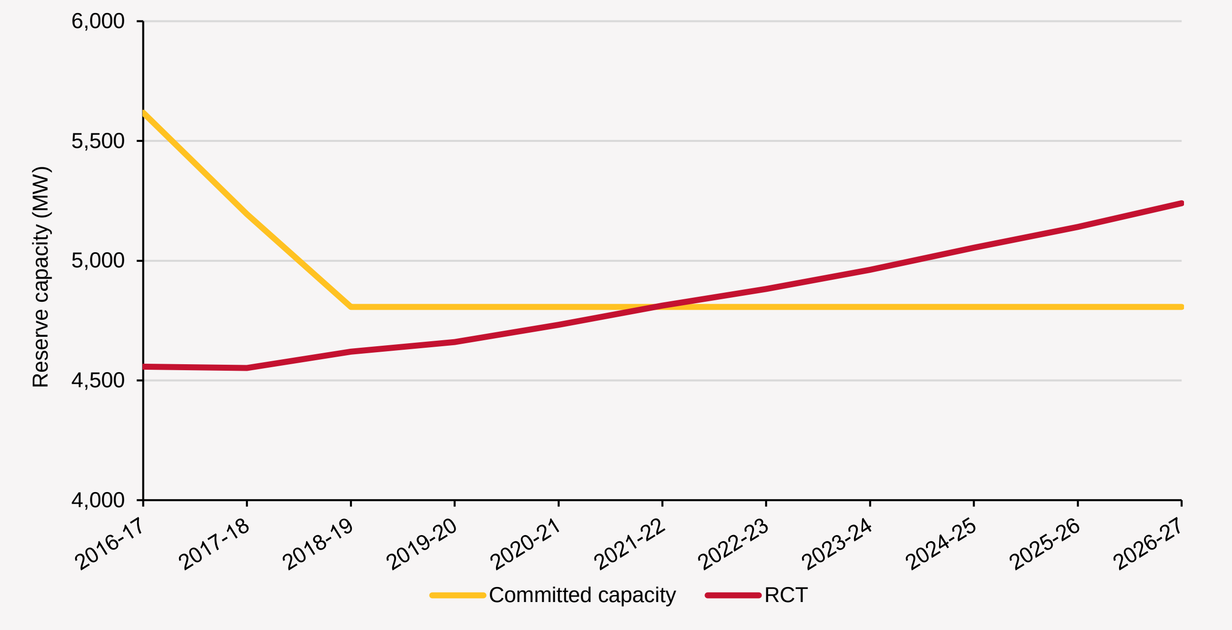
To assess the supply-demand balance, AEMO has assumed that:

- Synergy retires 437 MW of generation nameplate capacity (387 MW of Capacity Credits) by 1 October 2018.[74,75]
- No additional generation is retired over the forecast period.
- The total quantity of DSM Facilities for the entire forecast period remains unchanged at 106 MW from the 2017–18 Capacity Year.
- No new capacity commences operation over the forecast period.

The expected supply-demand balance between 2016–17 and 2026–27 is shown in Figure 34. This compares the RCT with the expected level of capacity for each Capacity Year of the Long Term PASA Study Horizon. The supply-demand balance for the high and low demand growth scenarios can be found in Appendix C.

[74] See: https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.
[75] AEMO is aware that some of capacity associated with Muja AB will be retired by 1 October 2017, however due to the late timing of this announcement, the earlier retirement is not considered.

Figure 34 Supply-demand balance excluding 2016 and 2017 EOI submissions, 2016–17 to 2026–27



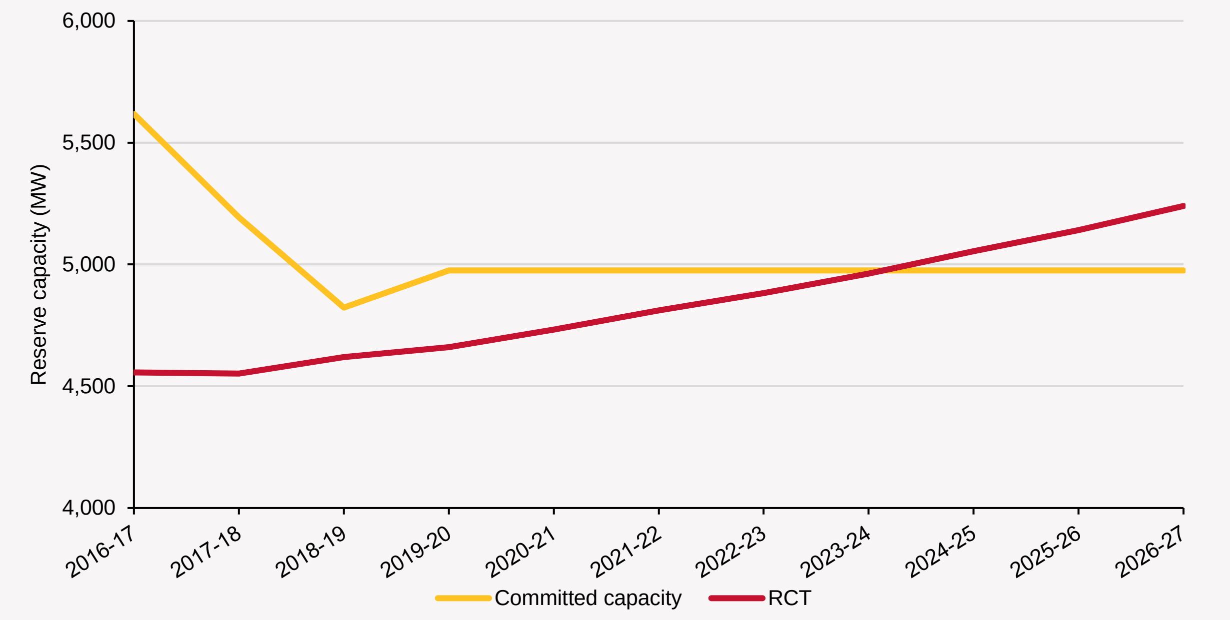
Installed and committed capacity is expected to be sufficient to meet the RCT until 2020–21, provided there are no further generation or DSM capacity retirements, long-term outages, or further changes to the WEM Rules.

Beyond the 2020–21 Capacity Year, new capacity is expected to be required in the SWIS, due to a 0.1% (5 MW) shortfall in 2021–22, which is expected to increase to 8.3% (433 MW) by the end of the outlook period.

AEMO does not include capacity offered through Expressions of Interest (EOIs) submissions in the expected supply-demand balance, because only a few proposed projects normally progress through the certification process (See Section 7.5.2 for more information).

If all capacity offered in the 2016 and 2017 EOIs is assigned its proposed level of Capacity Credits, AEMO estimates there will be sufficient capacity to meet the RCT until 2023–24, as demonstrated in Figure 35. Beyond the 2023–24 Capacity Year, there will be an expected 1.6% (79 MW) shortfall, which is expected to increase to 5.1% (265 MW) by the end of the outlook period.

Figure 35 Supply-demand balance including 2016 and 2017 EOI submissions, 2016–17 to 2026–27



The capacity outlook for the 2016 and 2017 Reserve Capacity Cycles is outlined in Table 22. Total capacity has decreased from the 2016–17 to the 2017–18 Capacity Year, predominately due to 454 MW of DSP capacity exiting the market in response to the EMR RCM transitional changes.

Table 22 Capacity in the SWIS, 2016–17 to 2019–20 Capacity Year

	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)
Existing generating capacity	5,058	5,088	4,701	4,701
Existing DSM capacity	560	106	106	106
Retired capacity	122	0	387	0
Committed new capacity [a]	18	12	0	0
Proposed projects (from EOI)[b]	0	0	16	152
Total capacity	5,618	5,194	4,807	4,807
RCT	4,557	4,552	4,620	4,660
Excess capacity	1,061 (23.3%)	642 (14.1%)	187 (4.0%)	147 (3.2%)

[a] Includes upgrades to existing Facilities
[b] Based on the Capacity Credit level proposed in the EOI submission.

Excess capacity is expected to continue to decrease, from 14.1% in the 2017–18 Capacity Year to 4% in the 2018–19 Capacity Year, due to the retirement of 387 MW of Synergy's Capacity Credits. By the 2019–20 Capacity Year, excess capacity is expected to fall to 3.2% as expected peak demand increases.

The supply-demand analysis suggests 5 MW of new capacity will be required in the SWIS for the 2021–22 Capacity Year, increasing to 433 MW by the 2026–27 Capacity Year. This is a result of:

- 454 MW of DSP capacity exiting the market in the 2017–18 Capacity Year.
- The retirement of Synergy Facilities, leading to a 387 MW reduction in capacity for the 2018–19 Capacity Year.
- A 15.1% increase in forecast peak demand by the 2026–27 Capacity Year.

However, circumstances may change over the forecast period. In particular, the quantity of capacity offered is expected to be affected by changes to the WEM Rules implemented under the EMR. It is uncertain whether DSM capacity will return to the market once the Reserve Capacity auction commences. Project proponents, investors, and developers should make their own independent assessments of future possible supply and demand conditions.

7.5.2 Expressions of Interest and excess capacity in the SWIS

Under clause 4.1.4 of the WEM Rules, AEMO is required to run an EOI process each year. The EOI for the 2017 Reserve Capacity Cycles closed on 1 May 2017. Five intermittent generation projects with a total nameplate capacity of 323 MW were proposed for the 2019–20 Capacity Year.[76]

While the EOI process provides an indication of potential future capacity, an EOI submission does not necessarily translate into certified capacity. Alternatively, some projects submitted under the EOI process may potentially be developed for subsequent Reserve Capacity Cycles.

Table 23 shows the amount of nameplate capacity offered for each Capacity Year under the EOI process, compared with the amount of EOI capacity that was eventually certified and the total new capacity certified for that Capacity Year.

Table 23 Capacity offered through the EOI compared to capacity certified, 2014–15 to 2019–20

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–2020
Capacity offered (MW)[a]	214	59	56	0	42	323
Capacity offered and certified (MW)	0	0.4	0	0	NA	NA
Total other new capacity certified (MW)	31	35	18	0	NA	NA

[a] Nameplate capacity

AEMO received 329 MW of nameplate capacity offered through EOI submissions between the 2014–15 and 2017–18 Capacity Years. However, only 0.4 MW of this capacity has progressed to be assigned Capacity Credits.

[76] 2017 Expressions of Interest Summary Report. Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Expressions-of-interest.

CHAPTER 8. OTHER ISSUES

This chapter provides information about government reforms affecting the RCM, as well as analysis of how the LRET may affect the SWIS generation mix and infrastructure developments in the SWIS.

8.1 The WA Government's Electricity Market Review

The Minister for Energy launched the Electricity Market Review in March 2014. The review has been undertaken by the Public Utilities Office (PUO) with one of the key objectives to reduce the cost of production and supply of electricity and electricity related services. Phase two of the EMR commenced in March 2015. It consists of four work streams that capture proposed reform projects. The WEM improvements work stream aims to reform the current RCM and energy market operations and processes.

In April 2016, a ministerial direction was announced reducing Synergy's plant generation capacity cap to 2,275 MW by 1 October 2018.[77] In May 2017, the Minister for Energy announced Synergy will be retiring 10 Facilities with a total Capacity Credits allocation of 387 MW.[78] These retirements will contribute to the reduction of excess capacity in the SWIS (see Section 7.5 for more information).

8.1.1 Transitional reforms to the Reserve Capacity Mechanism

The EMR objective for reforming the RCM is to reduce the cost of procuring capacity to meet the RCT. In the long term, the PUO has decided to introduce a Reserve Capacity auction to ensure consumers are paying a price that is more reflective of the value of incremental capacity in achieving SWIS reliability targets. A number of transitional reforms, designed to reduce excess capacity and promote a smooth transition to the auction, have commenced or are scheduled to commence in 2017[79], including:

- A revised formula for calculating the RCP.
- Lower capacity pricing for DSM Facilities.
- Harmonising DSM and generator availability requirements.
- Improving incentives for capacity to be available for dispatch, by linking capacity refunds to market conditions and returning refunds to Market Generators rather than Market Customers.

The PUO estimated, in the *Final Report: Reforms to the Reserve Capacity Mechanism*[80], that 250 MW of DSM capacity would remain in the market following the transitional changes to the RCM. However, after the commencement of these reforms, only 106 MW of DSM capacity was certified for the 2017–18 Capacity Year, 454 MW[81] less than the 2016–17 Capacity Year.

In future, large loads associated with the 454 MW of exiting DSM capacity may choose to reduce their capacity liability as an IRCR liable customer. AEMO will continue to monitor the effects exiting DSM capacity has on the IRCR response.

77 See http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf.
78 See https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.
79 Refer to the Government Gazette No.89 'Electricity Industry (Commencement of Electricity Industry (Wholesale Electricity) Market Amendment Regulations) Order 2016', Perth Tuesday 31 May 2016.
80 PUO, 2016. *Final Report: Reforms to the Reserve Capacity Mechanism.* Available at: https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Reforms-to-the-Reserve-Capacity-Mechanism-Final-Report.pdf.
81 This is calculated from the Capacity Credit level as at 1 October 2016, AEMO notes there have been 71.36 MW of voluntary reductions from DSM capacity so far in the 2016–17 Capacity Year.

8.1.2 Reserve Capacity Auction

On 31 January 2017, the PUO published a paper[82] outlining the final design of the Reserve Capacity auction. At present, the WEM Rules to implement the auction are expected to be gazetted in late 2017 or early 2018.

The final high level design features include:

- Auctions are held three years before the delivery year (for example, an auction held in 2019 would be for the 2022–23 Capacity Year).
- Auctions comprise single round, closed bids.
- Auctions are mandatory for all existing capacity providers[83] but optional for new entrants.
- The demand curve slopes, so the quantity of capacity cleared varies year to year. This will allow the auction to clear at quantities less than the RCT, where it is more efficient to do so.
- One-year delivery period and price lock-in.
- Rebalancing auction is held one year prior to the delivery year to enable:
  - Capacity providers that have cleared in the base auction, but who are not able to deliver in the Capacity Year, to trade out of their position.
  - AEMO to buy or sell back capacity from the market where there is a change in demand forecasts.
- The IRCR continues to be used to allocate capacity costs to Market Customers.

The EMR reforms to the RCM will have substantial impacts on current and future Reserve Capacity Cycles. More information on the proposed reforms is on the Department of Finance's website.[84]

8.1.3 Reforming the energy market operations and processes

In July 2016, the PUO published a paper[85] outlining the final changes to the energy and ancillary services markets and mechanisms. These proposed reforms are intended to improve the WEM's efficiency and reduce costs to Market Participants, and include:

- Adopting a security-constrained market design.
- Co-optimisation of energy and ancillary services.
- Facility bidding for all Market Participants.
- Five minute dispatch cycle.
- Ex-ante pricing.

At the time the Final Report was published, it was intended that the reforms to the energy and ancillary service market would take effect at the same time as the commencement of the national framework for network regulation, which incorporates a constrained network access model. The WA Government commenced the process of adopting the national framework through the Network Regulation Reform Bills that were introduced in parliament in June 2016.[86] However, the WA Government was unable to enact the Bills by the close of parliament in 2016. As a result, Western Power will continue operating under the current State-based regulatory framework in accordance with the *Electricity Networks Access Code 2004*. The PUO is currently considering the approach to implementing the energy and ancillary service market reforms.

[82] PUO, WA Department of Finance. *Reserve Capacity Auction – Final Design and Implementation*, 23 January 2017. Available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Wholesale_Electricity_Market_Improvements.aspx
[83] Capacity providers that have cleared in the previous auction.
[84] See https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx.
[85] PUO, WA Department of Finance. *Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*, July 2016. Available at: http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Final-Report-Design-Recommendations-for-Wholesale-Energy-and-Ancillary-Market-Reforms.pdf.
[86] National Electricity (Western Australia) Bill 2016 and the Energy Legislation Amendment and Repeal Bill 2016.

8.2 Federal government policy

8.2.1 Emissions reduction policy

Australia has committed to achieving a 26% to 28% reduction in emissions by 2030 (relative to 2005 levels) as part of its obligations to keep global temperature increases to below 2°C, as agreed at the 2015 Paris Climate Conference.[87] A number of schemes and mechanisms are in place which will contribute to achieving this target, most notably the LRET discussed in Section 8.2.2.

The effects of emissions targets on the WEM are unclear at this stage. There is currently 1,781 MW of coal-fired capacity[88] operating in the WEM, 75% of which is owned by the WA Government through Synergy. As announced by the Minister of Energy, Synergy will retire 220 MW of coal-fired generation by 1 October 2018, which will decrease the total market share of coal from 34% to 30%.[89] The remaining 167 MW of Synergy's fleet to be retired is a mixture of diesel and gas generation. All retiring Facilities will contribute to Australia's emission reduction policy.

8.2.2 Renewable energy policy

The LRET is a national target for renewable generation to reach 33,000 GWh, or about 23.5%[90] of Australia's forecast electricity generation, in 2020. This is a national target, and no obligations are conferred on individual states to meet a specified proportion of the target. WA's State Government does not currently intend to introduce a state-specific renewable energy target.[91]

In addition to the LRET, the Commonwealth Government maintains the Clean Energy Finance Corporation, the Australian Renewable Energy Agency (ARENA), and the Clean Energy Innovation Fund to encourage the development of renewable energy. The Commonwealth Government policies and funding available are expected to increase penetration of renewable energy over the next 10 years.

As these are national schemes, it is unclear how much investment in renewable energy will occur in the WEM. However, in 2016 ARENA's Advancing Renewable Program[92] announced $92 million of funding awarded to 480 MW of large scale solar PV across Australia.[93] Of this 480 MW, 20 MW was awarded to APA Group for the Emu Downs solar farm in WA.

A number of expressions of interest for renewable energy projects have been received in the past two years (see Section 7.5.2) with a total nameplate capacity of 365.2 MW. However, no new large-scale renewable energy generators have been installed in the SWIS since 2013.[94]

AEMO has recently modelled a hypothetical SWIS LRET to estimate the effects that an increased renewable energy generation mix would have on the RCM. To achieve a hypothetical SWIS LRET target of 23.5% renewables penetration by 2020, approximately 2,200 GWh a year of generation from new renewable sources would be required.

AEMO has modelled three scenarios of potential new renewable generation mix to meet this assumed 2,200 GWh a year requirement. The following assumptions have been used to support this analysis:

- Average capacity factors of 34.5% for wind and 24.3% for solar.
- The Capacity Credit level is based on the 2017–18 Capacity Year, but includes the reduction of 387 MW of Synergy's Capacity Credits (4,806.925 MW).

[87] See http://www.environment.gov.au/climate-change/publications/factsheet-australias-2030-climate-change-target
[88] Based on Capacity Credits assigned for the 2017–18 Capacity Year.
[89] Ibid
[90] Australian Federal Minister for the Environment and Minister for Industry and Science media release, "Certainty and growth for renewable energy", 23 June 2015. Available at: http://www.environment.gov.au/minister/hunt/2015/pubs/mr20150623.pdf.
[91] Mark McGowan, WA Labor Leader, "Statement from Shadow Energy Minister Bill Johnston", 9 February 2017. Available at: https://www.markmcgowan.com.au/news/statement-from-shadow-energy-minister-bill-johnston-1315.
[92] See https://arena.gov.au/programs/advancing-renewables-program/.
[93] See https://arena.gov.au/programs/advancing-renewables-program/large-scale-solar-pv/.
[94] Most recent to start up in 2013 are Mumbida, Blair Fox Karakin, and Denmark wind farms, with a total capacity of 15.511 MW (based on Capacity Credits assigned for the 2017–18 Capacity Year).

- Capacity Credit allocation for solar and wind is 36.4% and 28.3% of nameplate capacity respectively.
- RCT for the 2019–20 Capacity Year (4,660 MW) does not change.
- Benchmark Reserve Capacity Price for the 2019–20 Capacity Year ($149,800) does not change.
- The RCP has been calculated using the administered price table scheduled to commence on 1 October 2017.[95]

The results of AEMO's analysis are shown in Table 24.

Table 24 Hypothetical SWIS LRET effects on the RCP

	Wind	Solar	Nameplate (MW)	Capacity Credits (MW)	Surplus (MW)	Estimated RCP for 2019–20 Capacity Year (per MW)	Estimated RCP for 2020–21 Capacity Year (per MW)
Scenario 1	50%	50%	895.18	295.99	10%	$110,592	$107,652
Scenario 2	80%	20%	802.26	244.27	8%	$114,079	$111,309
Scenario 3	20%	80%	988.11	347.71	11%	$107,313	$104,228

A hypothetical SWIS LRET may increase the level of excess capacity in the 2019–20 Capacity Year by up to 11%. Excess capacity is currently estimated at 3.2% (see Section 7.5 for more information). This would result in a decrease in the RCP of approximately $23,000 per MW per year.

However, as demonstrated in Scenario 3, solar is forecast to have a greater impact on the decrease in the RCP than wind. Despite solar on average having a lower capacity factor, solar generators tend to be assigned a higher level of Capacity Credits compared to wind, due to their higher contribution at times of system peak. With a lower capacity factor, more solar is required to be installed to meet the 2,220 GWh assumed annual target.

There are 103 MW more Capacity Credits assigned in Scenario 3, where solar makes up the majority of the new installed renewable capacity, in comparison to Scenario 2. This would be expected to reduce the RCP by up to $27,000 per MW per year.

AEMO has recently published a more detailed analysis of the forecast effects of an increase in renewable generation installation on the total generation mix in the SWIS in *AEMO Insights: Renewables Influence on the Generation Mix and Gas Demand in Western Australia*.[96]

8.3 Infrastructure developments in the SWIS

8.3.1 Western Power's Applications and Queuing Policy

Western Power's Applications and Queuing Policy (AQP) sets out how connection applications and access offers are managed. The AQP underpins and regulates the connection process, which is designed to progress customers along a pathway consisting of several milestones, leading to an Access Offer for connection to the Western Power network. These milestones provide the customer opportunities to review their connection requirements, grid integration requirements, and to monitor project costs as they mature in order to make informed decisions on how to progress.

[95] See clause 4.29.1 of the WEM Rules (Schedule B Part 3) at: https://www.erawa.com.au/rule-change-panel/rules.
[96] AEMO, 2017. *AEMO Insights - Renewables Influence on the Generation Mix and Gas Demand in Western Australia*. Available at: https://www.aemo.com.au/Media-Centre/Renewables-Influence-on-the-Generation-Mix-and-Gas-Demand-in-WA.

As well as understanding the AQP, potential generators and loads should be aware of their obligations under the Technical Rules[97] governing connection to the Western Power network. More information on Western Power's connection process and the AQP can be found on the Western Power website.[98]

8.3.2 Transmission network current state and future strategy

Western Power's Annual Planning Report[99] (APR) describes the network configuration and available capacity to support new load and generation connections. In cases where network capacity is limited at the nominated connection location, this may result in additional requirements for network augmentation or mitigation measures such as a requirement for curtailment under certain conditions, or a requirement to procure Network Control Services (NCS).

To date, the development of the Western Power network has been managed prudently to minimise the requirement for the construction of new lines, terminals, substations and circuits in order to reduce capital costs.

Much of the existing ageing asset base is either approaching its design life or has already exceeded it. The objective of network planning is to develop, over a reasonable period, a highly efficient electricity network that presents the optimal balance between performance and cost. One of the key requirements to meeting this objective is improving load sharing among existing 330 kilovolt (kV) and 132 kV assets to relieve congestion at 132 kV, particularly through the increased utilisation of 330 kV infrastructure.

Given the deferral of the constrained network access model, Western Power and the PUO are developing the Generator Interim Access (GIA) solution with inputs from AEMO, which will support new connections in a timely manner.

The objectives of the approach are to:

- Curtail new generators (only) to maintain system security (i.e. not affect the contracted unconstrained access of existing generators).
- Have a dispatch objective consistent with that proposed under the EMR's WEM reforms, i.e. a proxy for least-cost dispatch using a 'minimise-runback' approach based on contribution to network constraint (or coefficient).

The GIA solution will affect the certification of new Facilities in the 2016 and 2017 Reserve Capacity Cycles, but the effect of this is currently unclear.

8.3.3 Summary of opportunities for Market Participants

The Network Access Code requires Western Power to demonstrate that it has efficiently minimised costs when implementing a solution to remove a network constraint. Prior to committing to a solution, Western Power must consider both network and non-network options.

Both the Network Access Code and WEM Rules contemplate application of non-network solutions to address network limitations. Non-network options may be provided by generator NCS and/or demand management.

Where Western Power identifies a network limitation, network augmentation as well as alternative options (such as NCS and demand management) will be considered. Proponents who have (or are planning on installing) generation capacity or demand management capacity, capable of providing network support should contact Western Power to discuss these opportunities.

More information is contained in Section 6 of Western Power's 2015–16 APR[100], including maps identifying existing transmission limitations which may impact load and generation proposals.

[97] Available at: https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/technical-rules.
[98] Available at: http://www.westernpower.com.au/electricity-retailers-generators-generator-and-transmission-connections.html.
[99] Available at: https://www.westernpower.com.au/about/reports-publications/.
[100] Ibid

APPENDIX A. DETERMINATION OF THE AVAILABILITY CURVE

The Availability Curve ensures there is sufficient capacity at all times to satisfy both elements of the Planning Criterion outlined in clause 4.5.9 of the WEM Rules (10% POE peak demand forecast plus reserve margin and 0.002% unserved energy), as well as ensuring that sufficient capacity is available to satisfy the criteria for evaluating outage plans.

Assuming the RCT is just met, the Availability Curve indicates the minimum amount of capacity that must be provided by generation capacity to ensure the energy requirements of users are met. The remainder of the RCT can be met by further generation capacity or by DSM.

Consistent with clause 4.5.12 of the WEM Rules, the determination of the Availability Curve is outlined below.

1. A load curve is developed from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% POE demand profile, so it is then scaled up to match the 10% POE peak demand and expected energy consumption for the relevant year. The peak demand interval is then set at the 10% POE forecast.
2. Experience from the most recent year with a 10% POE peak demand event in the SWIS (2015–16) indicates that the 50% POE load level was exceeded for less than 24 hours. Consequently, the Availability Curve from the twenty-fourth hour onwards would be the same, regardless of whether the 50% POE peak demand forecast or 10% POE peak demand forecast was used for the peak demand interval.
3. The reserve margin is added to the load curve (including the allowances for frequency keeping and intermittent loads) to form the Availability Curve.
4. A generation availability curve is developed by assuming that the level of generation matches the RCT for the relevant Capacity Year, then allowing for typical levels of plant outages and for variation in the output of intermittent generators. For existing Facilities, future outage plans (based on information provided by Market Participants under clause 4.5.4 of the WEM Rules) are included in this consideration.
5. Generation capacity is then incrementally replaced by DSM capacity, while maintaining the total quantity of capacity at the RCT until either the Planning Criterion or the criteria for evaluating outage plans is breached. If the RCT has been set based on the peak demand criterion (10% POE plus reserve margin), then the minimum capacity required to be provided by Availability Class 1 capacity will be the quantity of generation at which either:
    a. The total unserved energy equals 0.002% of annual energy consumption, thus breaching the Planning Criterion; or
    b. The spare generation capacity drops below 520 MW[101], thus breaching the criteria for evaluating outage plans.

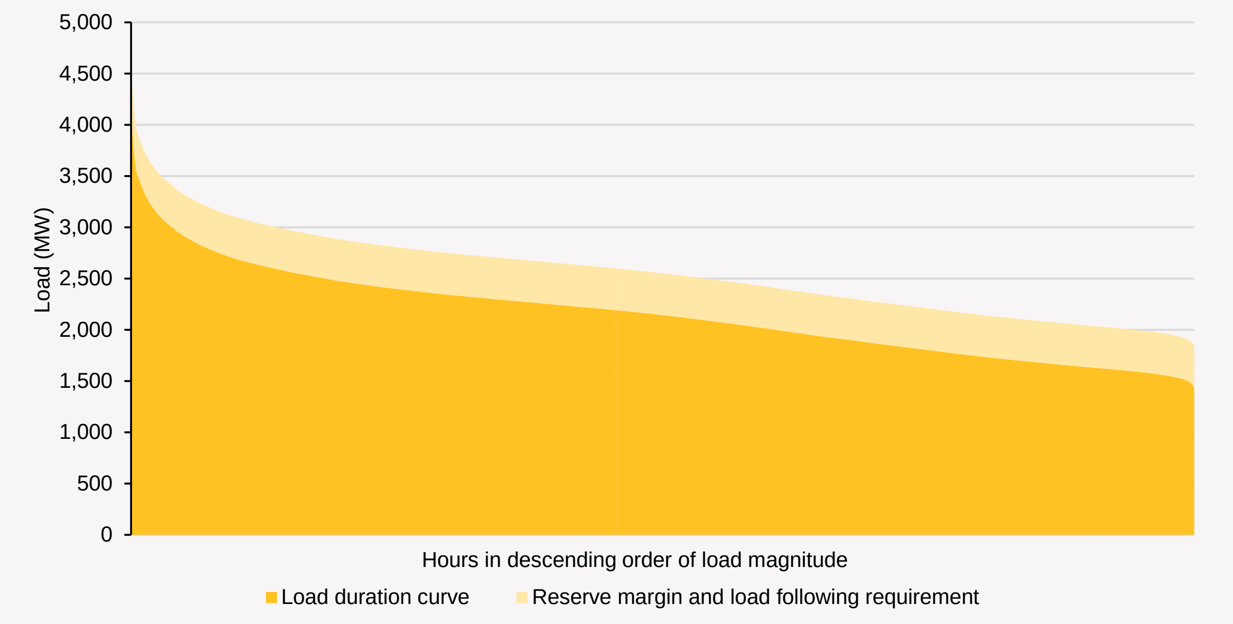
The capacity associated with Availability Class 2 is the RCT less the minimum amount of capacity required to be provided by Availability Class 1. For further information on the methodology for determining the Availability Curves, please refer to the RBP final report.[102]

The Availability Curves for the 2017–18, 2018–19, and 2019–20 Capacity Years are shown in Figure 36, Figure 37, and Figure 38.

[101] The quantity required to provide ancillary services and satisfy the ready reserve standard, consistent with the information published in the Medium Term PASA available at: http://wa.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Projected-assessment-of-system-adequacy/Medium-term-PASA-report.

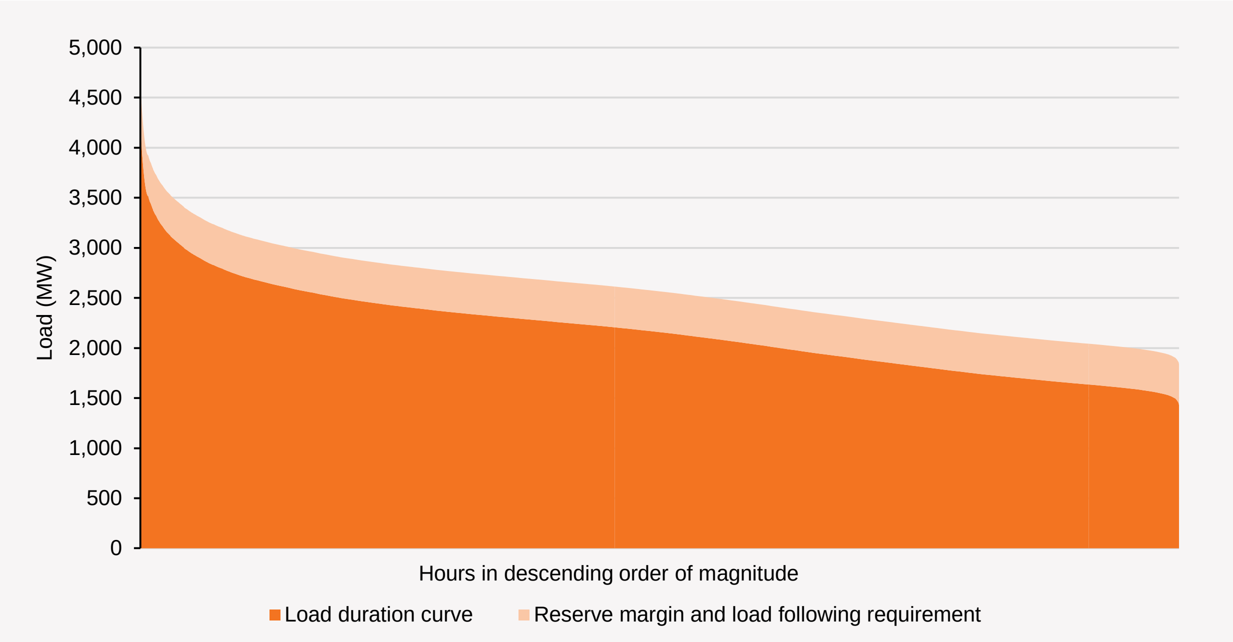
[102] RBP, 2017. *Assessment Of System Reliability And Development Of The Availability Curve For The South West Interconnect System*. Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

Figure 36 Availability Curve for 2017–18



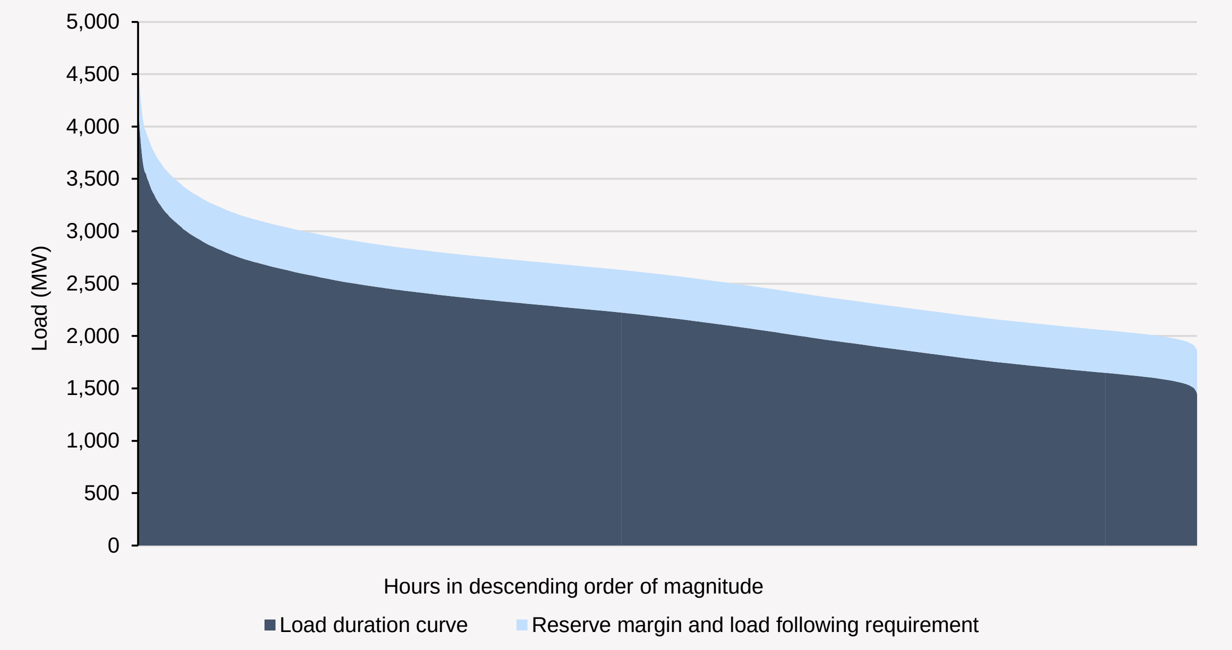
Source: RBP

Figure 37 Availability Curve for 2018–19



Source: RBP

Figure 38 Availability Curve for 2019–20



Source: RBP

APPENDIX B. EXPECTED DSM DISPATCH QUANTITY AND DSM ACTIVATION PRICE

AEMO has recently published a new Market Procedure[103] which outlines the methodology AEMO must follow when calculating the EDDQ and DSM Activation Price.

B.1 Expected DSM Dispatch Quantity

The EDDQ is the level of Expected Unserved Energy (EUE) avoided in a given Capacity Year as a result of each DSP with Capacity Credits being dispatched for 200 hours in that Capacity Year. EUE is energy demanded, but not supplied as a result of involuntary load shedding.

The EDDQ is calculated as follows:

$$\mathrm{EDDQ}_t = \frac{\mathrm{EUE}_{(\mathrm{t},0)} - \mathrm{EUE}_{(\mathrm{t},200)}}{\mathrm{CC}_\mathrm{t}}$$

where:

- $\mathrm{EUE}_{(\mathrm{t},0)}$ denotes the EUE where no DSM are dispatched.
- $\mathrm{EUE}_{(\mathrm{t},200)}$ denotes the EUE where all DSM with Capacity Credits are dispatched for 200 hours.
- CC_t denotes the sum of all DSM Capacity Credits assigned.

RBP has forecast the EDDQ over the Long Term PASA horizon by using a combination of approaches used to model part (b) of the Planning Criterion (see Section 7.1.2) and the determination of the minimum generation component of the Availability Curves (see Appendix A). That is, the EDDQ is forecast using a combination of fundamental market modelling, stochastic Monte Carlo simulation and DSM dispatch optimisation (to ensure DSM facilities are dispatched to minimise peak load while respecting availability constraints). The approach is summarised in further detail below:

1. Forecast EUE when DSM is dispatched for zero hours.

   This involved repeating the assessment of part (b) of the Planning Criterion and setting the capacity of all DSM in the market to zero. The total reserve capacity available is now equal to only the available generation capacity. The WEM is simulated over a large number of iterations using assumptions regarding the load profile (based on a 50% POE peak and expected annual demand), availability of intermittent generators and outages. Load and forced outages are randomised so that each iteration returns a stochastic estimate of unserved energy; these unserved energy estimates are averaged to estimate EUE which is divided by forecast annual demand (to represent EUE as a percentage of annual demand).

2. Forecast EUE when DSM are dispatched for 200 hours.

   Here, DSM is modelled separately using an optimisation tool which dispatches all DSM dispatched for exactly 200 hours in a manner that minimises the peak load while taking into account availability constraints. The hourly DSM dispatch (calculated from the optimisation model) is then subtracted from the load profile used in Step 1 above; the new load profile is used as an input into the WEM model from Step 1. The market and Monte Carlo simulation in Step 1 is then repeated and EUE recalculated.

3. The EDDQ is then calculated using the EUE estimates derived in Steps 1 and 2 and applying the EDDQ formula above.

For more detailed information on the methodology used to calculate the EDDQ, refer to the RBP's final report: *Assessment of System Reliability and Development of the Availability Curve for the South West*

[103] Market Procedure: *Determination of the DSM Dispatch Quantity and DSM Activation Price.* Available at: http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Procedures.

Interconnect System provided as supporting documentation to this ESOO. The forecast EDDQ over the Long Term PASA horizon is shown in Table 25.

Table 25 EDDQ, 2017–18 to 2026–27

Capacity Year	EUE No DSM dispatched (MWh)	EUE DSM dispatched for 200hr (MWh)	DSM Capacity Credits	EDDQ (MWh)
2017–18	1.22	0.21	106	0.01
2018–19	9.25	2.93	106	0.06
2019–20	69.08	14.11	106	0.52
2020–21	8.84	1.90	106	0.07
2021–22	1.45	0.00	106	0.01
2022–23	0.00	0.00	106	0.00
2023–24	0.58	0.00	106	0.01
2024–25	0.77	0.00	106	0.01
2025–26	68.48	22.37	106	0.44
2026–27	2.00	0.00	106	0.02

B.2 DSM Activation Price

The DSM Activation Price represents the Value of Customer Reliability (VCR) for a given Capacity Year. The VCR is an estimate of the dollar value customers place on the reliable supply of electricity, or an indicator of the customers' willingness to pay for supply to not be interrupted. The DSM Activation Price aims to reflect the dollar value derived through a reduction of unserved energy as a result of the dispatch of DSM.

To determine the VCR, AEMO is required to conduct a VCR study that includes estimating the value of customer reliability across a number of customer groups in the SWIS.[104] This involves modelling a number of outage scenarios with varying degrees of severity. AEMO will then calculate the DSM Activation Price by using a load-weighted average of each customer group's VCR estimate, based on each customer group's share of consumption in the 12 peak Trading Intervals during the most recent Hot Season.

AEMO must undertake an annual assessment to determine the requirement to conduct a VCR study. The assessment will consider the following:

- The expected study duration and associated costs.
- Whether an allowance for a study has been made in AEMO's Allowable Revenue determination.
- Any relevant studies brought to AEMO's attention.
- The views of the Market Advisory Committee and other stakeholders.

As a VCR study is yet to be undertaken, AEMO will determine the VCR price to be $33,460/MWh in accordance with clause 4.5.14F of the WEM Rules. This is based on the VCR in the National Electricity Market.

APPENDIX C. SUPPLY-DEMAND BALANCE UNDER DIFFERENT DEMAND GROWTH SCENARIOS

Table 26 Supply-demand balance, high demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2016–17	4,589	5,618	1,029
2017–18	4,701	5,194	493
2018–19	4,799	4,807	8
2019–20	4,897	4,807	-90
2020–21	5,004	4,807	-197
2021–22	5,127	4,807	-320
2022–23	5,246	4,807	-439
2023–24	5,380	4,807	-573
2024–25	5,527	4,807	-720
2025-26	5,682	4,807	-875
2026-27	5,848	4,807	-1,041

Table 27 Supply-demand balance, expected demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2016–17	4,480	5,618	1,138
2017–18	4,576	5,194	618
2018–19	4,620	4,807	187
2019–20	4,660	4,807	147
2020–21	4,733	4,807	74
2021–22	4,812	4,807	-5
2022–23	4,882	4,807	-75
2023–24	4,962	4,807	-155
2024–25	5,054	4,807	-247
2025-26	5141	4,807	-334
2026-27	5240	4,807	-433

Table 28 Supply-demand balance, low demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2016–17	4,446	5,618	1,172
2017–18	4,511	5,194	683
2018–19	4,533	4,807	274
2019–20	4,560	4,807	247
2020–21	4,599	4,807	208
2021–22	4,638	4,807	169
2022–23	4,673	4,807	134
2023–24	4,728	4,807	79
2024–25	4,773	4,807	34
2025-26	4,822	4,807	-15
2026-27	4,888	4,807	-81

APPENDIX D. ECONOMIC GROWTH FORECASTS

Table 29 Growth in Australian gross domestic product (financial year basis)

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006–07	3.8			
2007–08	3.7			
2008–09	1.7			
2009–10	2.0			
2010–11	2.2			
2011–12	3.6			
2012–13	2.7			
2013–14	2.5			
2014–15	2.2			
2015–16	2.8			
2016–17		2.0	2.8	1.3
2017–18		3.1	3.8	2.3
2018–19		3.0	3.8	2.2
2019–20		2.9	3.7	2.1
2020–21		3.2	4.0	2.4
2021–22		3.0	3.8	2.2
2022–23		3.0	3.8	2.2
2023–24		3.0	3.8	2.1
2024–25		3.0	3.8	2.1
2025–26		2.9	3.8	2.1
2026–27		2.9	3.8	2.1
2027–28		2.8	3.7	2.0
Average growth		**2.9**	**3.7**	**2.1**

Source: Independent economic forecaster

Table 30 Growth in WA gross state product (financial year basis)

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006–07	6.2			
2007–08	4.0			
2008–09	4.3			
2009–10	4.2			
2010–11	4.1			
2011–12	7.3			
2012–13	5.1			
2013–14	5.5			
2014–15	3.5			
2015–16	1.9			
2016–17		1.4	2.5	0.3
2017–18		3.0	4.2	1.8
2018–19		2.8	4.0	1.6
2019–20		3.2	4.4	2.0
2020–21		3.9	5.1	2.6
2021–22		3.5	4.7	2.3
2022–23		3.6	4.8	2.4
2023–24		3.6	4.8	2.3
2024–25		3.6	4.8	2.4
2025–26		3.7	4.9	2.4
2026–27		3.7	4.9	2.5
2027–28		3.6	4.8	2.4
Average growth		3.3	4.5	2.1

Source: Independent economic forecaster

APPENDIX E. ROOFTOP PV FORECASTS

Table 31 Reduction in peak demand from rooftop PV systems

Year	Expected (MW)	High (MW)	Low (MW)
2017–18	171	90	190
2018–19	193	105	209
2019–20	216	121	229
2020–21	240	138	249
2021–22	264	155	269
2022–23	288	172	290
2023–24	312	188	311
2024–25	336	205	332
2025–26	360	221	352
2026–27	384	236	372

Table 32 Annual energy generated from rooftop PV systems (financial year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2017–18	1,269	1,282	1,249
2018–19	1,437	1,490	1,375
2019–20	1,616	1,727	1,511
2020–21	1,789	1,962	1,641
2021–22	1,968	2,205	1,777
2022–23	2,149	2,447	1,914
2023–24	2,339	2,697	2,060
2024–25	2,512	2,925	2,193
2025–26	2,695	3,158	2,330
2026–27	2,877	3,377	2,464

Table 33 Annual energy generated from rooftop PV systems (Capacity Year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2017–18	1,303	1,321	1,275
2018–19	1,471	1,535	1,401
2019–20	1,652	1,775	1,538
2020–21	1,825	2,011	1,668
2021–22	2,005	2,254	1,804
2022–23	2,186	2,496	1,942
2023–24	2,375	2,745	2,089
2024–25	2,549	2,973	2,220
2025–26	2,732	3,203	2,357
2026–27	2,914	3,418	2,490

APPENDIX F. SUMMER PEAK DEMAND FORECASTS

Table 34 Summer peak demand forecasts with expected demand growth

Year	Actual (MW)[a]	10% POE (MW)	50% POE (MW)	90% POE (MW)
2006–07	3,474			
2007–08	3,806			
2008–09	3,818			
2009–10	3,926			
2010–11	4,160			
2011–12	4,064			
2012–13	4,054			
2013–14	4,252			
2014–15	4,145			
2015–16	4,013			
2016–17	4,083			
2017–18		4,169	3,927	3,709
2018–19		4,213	3,968	3,739
2019–20		4,253	4,009	3,782
2020–21		4,326	4,076	3,835
2021–22		4,401	4,133	3,893
2022–23		4,466	4,201	3,951
2023–24		4,541	4,267	4,005
2024–25		4,626	4,338	4,073
2025–26		4,707	4,414	4,139
2026-27		4,799	4,505	4,217
Average growth (%)		1.6	1.5	1.4

[a] 10% POE adjusted historical.
Source: ACIL Allen with AEMO input

Table 35 Summer peak demand forecasts with high demand growth

Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2017–18	4,294	4,053	3,844
2018–19	4,392	4,138	3,911
2019–20	4,490	4,219	3,986
2020–21	4,597	4,328	4,088
2021–22	4,716	4,437	4,187
2022–23	4,830	4,547	4,283
2023–24	4,959	4,665	4,383
2024–25	5,099	4,791	4,502
2025–26	5,248	4,922	4,616
2026-27	5,407	5,080	4,767
2027-28	5,587	5,234	4,909
Average growth (%)	2.6	2.5	2.4

Source: ACIL Allen with AEMO input

Table 36 Summer peak demand forecasts with low demand growth

Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2017–18	4,104	3,868	3,658
2018–19	4,126	3,887	3,669
2019–20	4,153	3,903	3,689
2020–21	4,192	3,931	3,717
2021–22	4,227	3,971	3,744
2022–23	4,257	4,006	3,772
2023–24	4,307	4,048	3,796
2024–25	4,345	4,075	3,836
2025–26	4,388	4,119	3,866
2026-27	4,447	4,161	3,901
2027-28	4,491	4,212	3,945
Average growth (%)	0.9	0.8	0.7

Source: ACIL Allen with AEMO input

APPENDIX G. WINTER PEAK DEMAND FORECASTS

Table 37 Winter peak demand forecast with expected demand growth

Year	Actual (MW)	10% POE (MW)	50% POE (MW)	90% POE (MW)
2006-07	2,705			
2007–08	2,774			
2008–09	2,943			
2009–10	3,029			
2010–11	3,095			
2011–12	3,100			
2012–13	3,071			
2013–14	3,217			
2014–15	3,135			
2015–16	3,366			
2016–17		3,348	3,254	3,176
2017–18		3,375	3,279	3,201
2018–19		3,415	3,316	3,238
2019–20		3,455	3,358	3,281
2020–21		3,507	3,407	3,326
2021–22		3,560	3,460	3,376
2022–23		3,612	3,513	3,430
2023–24		3,676	3,568	3,482
2024–25		3,731	3,625	3,535
2025–26		3,791	3,686	3,596
2026-27		3,863	3,746	3,654
Average growth (%)		1.4	1.4	1.4

Source: ACIL Allen with AEMO input

APPENDIX H. OPERATIONAL CONSUMPTION FORECASTS

Table 38 Forecasts of operational consumption (financial year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007–08	16,387			
2008–09	16,639			
2009–10	17,346			
2010–11	17,952			
2011–12	17,841			
2012–13	18,009			
2013–14	18,479			
2014–15	18,358			
2015–16	18,612			
2016–17	18,549			
2017–18		18,819	18,947	18,705
2018–19		18,962	19,160	18,786
2019–20		19,110	19,372	18,866
2020–21		19,316	19,650	18,994
2021–22		19,538	19,967	19,129
2022–23		19,766	20,318	19,262
2023–24		20,004	20,698	19,393
2024–25		20,274	21,133	19,546
2025–26		20,570	21,600	19,706
2026-27		20,901	22,119	19,882
Average growth (%)		1.2	1.7	0.7

Source: ACIL Allen with AEMO input

Table 39 Forecasts of operational consumption (Capacity Year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007–08	16,520			
2008–09	16,701			
2009–10	17,507			
2010–11	17,902			
2011–12	17,926			
2012–13	18,099			
2013–14	18,548			
2014–15	18,341			
2015–16	18,895			
2016–17		18,644	18,710	18,582
2017–18		18,865	19,012	18,733
2018–19		19,006	19,223	18,812
2019–20		19,163	19,445	18,899
2020–21		19,382	19,739	19,036
2021–22		19,602	20,063	19,169
2022–23		19,835	20,424	19,303
2023–24		20,077	20,813	19,436
2024–25		20,352	21,257	19,592
2025–26		20,660	21,736	19,756
2026-27		20,996	22,267	19,935
Average growth (%)		1.2	1.8	0.7

Source: ACIL Allen with AEMO input

APPENDIX I. FACILITY CAPACITIES

Table 40 Registered generation Facilities – existing and committed

Participant	Facility	Capacity Credits (2017–18)
Alcoa of Australia	ALCOA_WGP	26.000
Alinta Sales	ALINTA_PNJ_U1	134.208
Alinta Sales	ALINTA_PNJ_U2	134.930
Alinta Sales	ALINTA_WGP_GT	194.450
Alinta Sales	ALINTA_WGP_U2	196.848
Alinta Sales	ALINTA_WWF	23.203
Blair Fox	BLAIRFOX_KARAKIN_WF1	0.838
Blair Fox	BLAIRFOX_WESTHILLS_WF3*	0.000
CleanTech Energy	BIOGAS01	1.795
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	20.105
Denmark Community Windfarm	DCWL_DENMARK_WF1	0.845
EDWF Manager	EDWFMAN_WF1	17.800
Goldfields Power	PRK_AG	61.400
Greenough River	GREENOUGH_RIVER_PV1	3.086
Griffin Power 2	BW2_BLUEWATERS_G1	217.000
Griffin Power	BW1_BLUEWATERS_G2	217.000
Landfill Gas & Power	KALAMUNDA_SG	1.300
Landfill Gas & Power	RED_HILL	2.876
Landfill Gas & Power	TAMALA_PARK	3.962
Merredin Energy	NAMKKN_MERR_SG1	82.000
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.806
Mumbida Wind Farm	MWF_MUMBIDA_WF1	13.828
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	327.800
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600
Perth Energy	ATLAS	0.595
Perth Energy	GOSNELLS*	0.000
Perth Energy	ROCKINGHAM	2.576
Perth Energy	SOUTH_CARDUP	2.486
Southern Cross Energy	STHRNCRS_EG*	0.000
Synergy	ALBANY_WF1	7.809
Synergy	BREMER_BAY_WF1	0.112
Synergy	COCKBURN_CCG1	231.800
Synergy	COLLIE_G1	317.200
Synergy	GRASMERE_WF1	4.957
Synergy	KALBARRI_WF1	0.283
Synergy	KEMERTON_GT11	145.500
Synergy	KEMERTON_GT12	155.000
Synergy	KWINANA_GT1	16.809
Synergy	KWINANA_GT2	98.500
Synergy	KWINANA_GT3	98.200
Synergy	MUJA_G5	195.000
Synergy	MUJA_G6	193.000

Participant	Facility	Capacity Credits (2017–18)
Synergy	MUJA_G7	211.000
Synergy	MUJA_G8	211.000
Synergy	MUNGARRA_GT1	32.800
Synergy	MUNGARRA_GT2	32.800
Synergy	MUNGARRA_GT3	31.500
Synergy	PINJAR_GT1	31.738
Synergy	PINJAR_GT2	30.226
Synergy	PINJAR_GT3	37.000
Synergy	PINJAR_GT4	37.000
Synergy	PINJAR_GT5	37.000
Synergy	PINJAR_GT7	37.000
Synergy	PINJAR_GT9	107.000
Synergy	PINJAR_GT10	108.700
Synergy	PINJAR_GT11	120.000
Synergy	PPP_KCP_EG1	80.400
Synergy	WEST_KALGOORLIE_GT2	34.250
Synergy	WEST_KALGOORLIE_GT3	19.300
Tesla	TESLA_GERALDTON_G1	9.900
Tesla	TESLA_KEMERTON_G1	9.900
Tesla	TESLA_NORTHAM_G1	9.900
Tesla	TESLA_PICTON_G1	9.900
Tiwest	TIWEST_COG1	36.000
Vinalco Energy	MUJA_G1	55.000
Vinalco Energy	MUJA_G2	55.000
Vinalco Energy	MUJA_G3	55.000
Vinalco Energy	MUJA_G4	55.000
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.104
Western Australia Biomass	BRIDGETOWN_BIOMASS_PLANT*	0.000
Western Energy	PERTHENERGY_KWINANA_GT1	109.000

* Registered Facilities that do not currently participate in the capacity market.

Table 41 Registered DSM Facilities – existing and committed

Participant	Facility	Capacity Credits (2017–18)	Availability Class
EnerNOC Australia	ENERNOC_DSP_01	0.000	2
EnerNOC Australia	ENERNOC_DSP_02	0.000	2
EnerNOC Australia	ENERNOC_DSP_03	0.000	2
Synergy	SYNERGY_DSP_01	10.000	2
Synergy	SYNERGY_DSP_02	5.000	2
Synergy	SYNERGY_DSP_03	5.000	2
Synergy	SYNERGY_DSP_04	42.000	2
Synergy	SYNERGY_DSP_05	20.000	2
Wesfarmers Kleenheat Gas	PREMPWR_DSP_02	24.000	2

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
AQP	Applications Queuing Policy
ARENA	Australian Renewable Energy Agency
CER	Clean Energy Regulator
DSM	Demand Side Management
DSP	Demand Side Programme
EDDQ	Expected DSM Dispatch Quantity
EMR	Electricity Market Review
EOI	Expressions of Interest
ESOO	Electricity Statement of Opportunities
EUE	Expected Unserved Energy
EV	Electric Vehicle
GSP	Gross state product (for WA)
IRCR	Individual Reserve Capacity Requirement
LFAS	Load following ancillary service
LRET	Large-scale Renewable Energy Target
NCS	Network Control Services
NEM	National Electricity Market
NIEIR	National Institute of Economic and Industry Research
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PUO	Public Utilities Office
PV	Photovoltaic
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCT	Reserve Capacity Target
REBS	Renewable Energy Buyback Scheme

Abbreviation	Expanded name
RET	Renewable Energy Target
SCADA	Supervisory Control and Data Acquisition
SRES	Small-scale Renewable Energy Scheme
STEM	Short term energy market
SWIS	South West interconnected system
WA	Western Australia
WEM	Wholesale Electricity Market
WEM Rules	Wholesale Electricity Market Rules

GLOSSARY

Term	Definition
Block loads	The largest customers in the SWIS that are considered to be temperature insensitive. AEMO considers 20 MW to be the minimum threshold for a new block load.
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equivalent to 1 MW of capacity.
Capacity Factor	The percentage of actual generation relative to the maximum theoretically possible generation based on a Facility's nameplate capacity.
Capacity Year	A period of 12 months commencing on 1 October and ending on 1 October of the following calendar year.
DSM	A type of capacity that can reduce its consumption of electricity from the SWIS in response to a dispatch instruction. Usually made up of several customer loads aggregated into one Facility.
DSP	A Facility registered in accordance with clause 2.29.5A of the WEM Rules.
Energy sales	The quantity of electricity delivered to the customer, including losses.
Embedded generation	The energy produced by rooftop PV systems and battery systems (for the forecast period).
IRCR	The proportion of the total cost of Capacity Credits acquired through the RCM paid by each Market Customer. Determined based on the Market Customer's contribution to peak demand during 12 peak trading intervals over the previous summer period (December to March).
Intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind speed).
Long Term PASA	A study conducted in accordance with section 4.5 of the WEM Rules to determine the Reserve Capacity Target for each year in the Long Term PASA Study Horizon and prepare the ESOO.
Long Term PASA Study Horizon	The 10 year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
Operational electricity consumption	The electrical energy supplied by scheduled and non-scheduled generating units, less the electrical energy supplied by rooftop PV.
Peak demand	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) for the SWIS.
POE	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
REBS customers	Residential customers, not-for-profit organisations or educational institutions who install a rooftop PV system between 500 watts and 5 kW.
Reserve Capacity Cycle	A four year period covering the cycle of events described in section 4.1 of the WEM Rules.
RCM	The capacity market in the SWIS that ensures sufficient capacity is available to meet peak demand.
RCP	The price for capacity paid to Capacity Credit holders and determined in accordance with clause 4.29.1 of the WEM Rules.
RCT	AEMO's estimate of the total amount of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion.
Rooftop PV	Small-scale commercial and residential PV systems less than 100 kW.
Solar irradiance	A measure of cloud-cover used to de-rate the output of rooftop PV systems.
Underlying electricity consumption	All electricity consumed on site, and can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.