2020 Electricity Statement of Opportunities

June 2020

A report for the Wholesale Electricity Market

Important notice

PURPOSE

AEMO publishes the Wholesale Electricity Market Electricity Statement of Opportunities under clause 4.5.11 of the Wholesale Electricity Market Rules.

This publication has been prepared by AEMO using information available in May 2020. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

Version	Release date	Changes
#1	16/6/2020	Initial release

Executive summary

This Wholesale Electricity Market (WEM) *Electricity Statement of Opportunities* (ESOO) presents AEMO's 10-year Long Term Projected Assessment of System Adequacy (PASA) for the South West interconnected system (SWIS) in Western Australia (WA). It reports peak demand and operational consumption[1] forecasts across a range of weather and demand growth scenarios for the 2020-21 to 2029-30 Capacity Years[2].

The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM), which ensures enough capacity is available to meet the Planning Criterion[3] for the SWIS. The WEM ESOO report highlights the 10% probability of exceedance (POE)[4] peak demand forecast under the expected demand growth scenario[5], which is used to determine the Reserve Capacity Requirement (RCR)[6] for the 2022-23 Capacity Year.

Key findings

- Based on the 10% POE peak demand forecast, the RCR has been determined as 4,421 megawatts (MW) for the 2022-23 Capacity Year.
- Sufficient capacity is expected to be available to meet forecast demand over the outlook period despite the staged retirement of Muja unit 5 in 2022 and unit 6 in 2024 and assuming no other capacity changes.
- The Demand Side Management (DSM) Reserve Capacity Price (RCP) for the 2020-21 Capacity Year is $16,730 per MW[7].
- For the first time, the 10% POE peak demand is forecast to fall, at an average annual rate of 0.2% over the outlook period, compared to an average annual growth of 0.4% in the 2019 WEM ESOO.
- The continued uptake of behind-the-meter photovoltaic (PV)[8] capacity, combined with the installation of battery storage systems and energy efficiency improvements, along with the impacts of the COVID-19 pandemic[9], are expected to dampen peak demand growth in both the short and medium term until 2023-24. Peak demand is expected to remain relatively flat over the remainder of the outlook period.
- Operational consumption is forecast to fall at an average annual rate of 0.4% over the outlook period, in line with the 2019 WEM ESOO.

1 Operational consumption refers to electricity consumption that is met by all utility-scale generation. Consumption met by behind-the-meter PV generation is not included in this value. Operational consumption includes consumption from electric vehicles (EVs).

2 A Capacity Year commences in the Trading Interval starting at 08:00 on 1 October and ends in the Trading Interval ending at 08:00 on 1 October of the following calendar year. All data in this WEM ESOO is based on Capacity Years unless otherwise specified.

3 The Planning Criterion for the Long Term PASA ensures there is sufficient capacity in the SWIS to meet the forecast 10% POE peak demand plus a reserve margin, and limits projected unserved energy to 0.002% of annual energy consumption for each Capacity Year of a 10-year forecast period.

4 POE means 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% POE peak demand forecasts are expected to be exceeded, on average, five years in 10.

5 This 2020 WEM ESOO provides low, expected, and high demand growth scenarios, based on different levels of economic growth. Unless otherwise indicated, demand growth forecasts in this executive summary are based on the expected demand growth scenario.

6 The RCR is AEMO's determination of the total amount of capacity required to satisfy the Planning Criterion for a specific Reserve Capacity Cycle.

7 This DSM RCP is based on the forecast Expected DSM Dispatch Quantity and is published in accordance with clause 4.5.13(i) of the WEM Rules.

8 Including both residential and business behind-the-meter PV that is less than 100 kilowatts (kW) and commercial PV ranging between 100 kW and 10 MW.

9 COVID-19 is an infectious disease caused by severe acute respiratory syndrome coronavirus. The World Health Organisation declared the outbreak to be a Public Health Emergency of International Concern on 30 January 2020, and recognised it as a pandemic on 11 March 2020. See https://www.who.int/dg/speeches/detail/who-director-general-s-opening-remarks-at-the-media-briefing-on-covid-19---11-march-2020.

- The likely timing of peak demand is expected to shift from the period between 17:00 and 18:00 to after 18:30 by 2023-24, due to the effect of distributed energy resources (DER)[10] operation.
- Minimum operational demand is forecast to decline over the first five years of the outlook period, predominantly due to forecast growth in behind-the-meter PV installation, and is expected to fall below the SWIS 700 MW[11] security threshold as early as 2023-24 for the 50% POE forecasts.
- Behind-the-meter PV capacity is forecast to grow at an average annual rate of 6.5% (126 MW per year), to reach an estimated 2,612 MW[12] installed by 2029-30.

Reserve Capacity Requirement and pricing

Table 1 shows the Reserve Capacity Target (RCT), set by the expected 10% POE peak demand requirement of the Planning Criterion, for each Capacity Year of the 2020 Long Term PASA Study Horizon.

The RCT determined for the 2022-23 Capacity Year is 4,421 MW, which sets the RCR for the 2020 Reserve Capacity Cycle.

Table 1 Reserve Capacity Targets (MW)[A]

Capacity Year	10% POE peak demand	Intermittent loads[B]	Reserve margin	Load following[B,C]	Total
2020-21[D]	4,008	3	331	85	4,427
2021-22[D]	4,018	3	331	85	4,437
2022-23	4,002	3	331	85	4,421
2023-24	3,913	3	331	85	4,332
2024-25	3,923	3	331	85	4,342
2025-26	3,964	3	331	85	4,383
2026-27	3,942	3	331	85	4,361
2027-28	3,959	3	331	85	4,378
2028-29	3,908	3	331	85	4,327
2029-30	3,937	3	331	85	4,356

A. All figures have been rounded to the nearest integer.
B. See Section 6.2 for further information.
C. With increasing levels of behind-the-meter PV, and large and small scale renewable generation connecting to the SWIS, AEMO expects the Load Following Ancillary Services (LFAS) requirement to increase. Any changes will be reflected in future WEM ESOOs. The new Essential System Services framework (which is part of the WA Government's Energy Transformation Strategy [ETS]) is underway, and this may also change the LFAS requirement.
D. Figures have been updated to reflect the current forecasts. However, the RCR of 4,581 MW set in the 2018 WEM ESOO for the 2018 Reserve Capacity Cycle and the RCR of 4,482 MW set in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle do not change.

Excess capacity[13] is forecast to decline from 443 MW (9.9%) for the 2021-22 Capacity Year to 309 MW (7.0%) for the 2022-23 Capacity Year, largely as a result of the retirement of one Muja C unit from 1 October 2022 and assuming no other changes in capacity, as shown in Figure 1. By the end of the outlook period, excess

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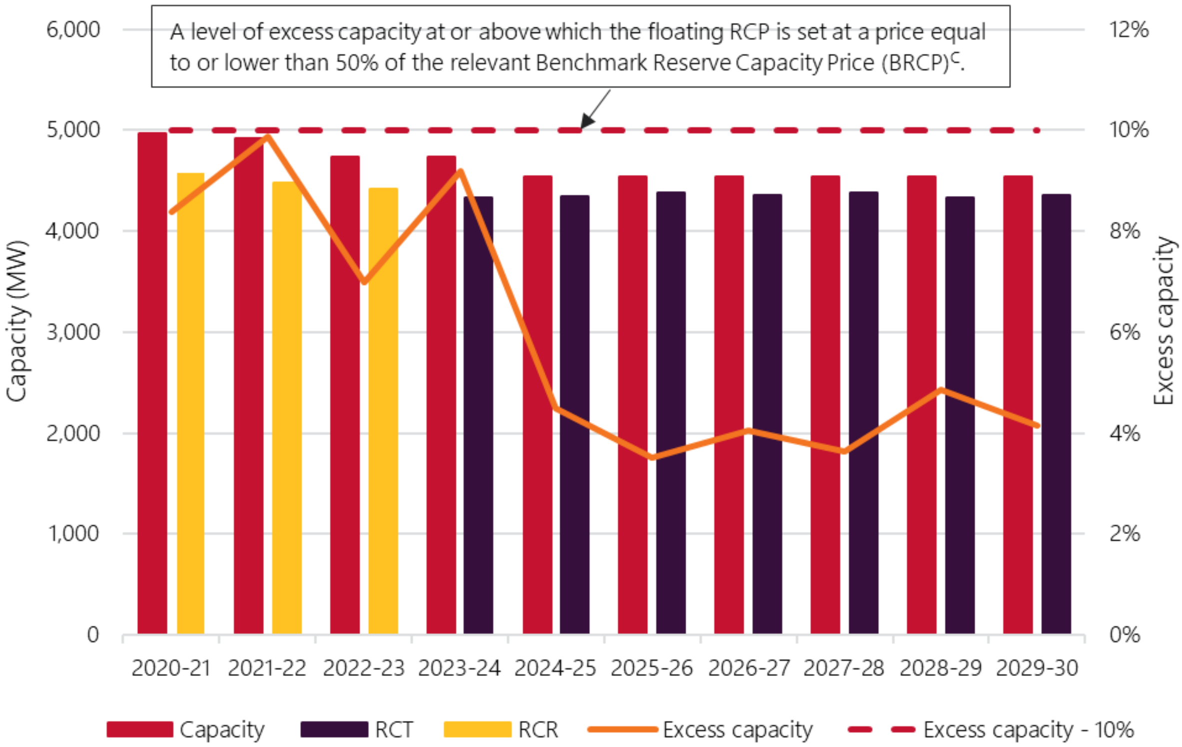
[10] Small-scale embedded technologies including behind-the-meter PV, battery storage systems, and EVs.
[11] See https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf.
[12] Cumulative installed capacity forecasts account for degradation of solar panel output over time. See Section 4.2.1 of this WEM ESOO for further information.
[13] Excess capacity is calculated as: (Total amount of Capacity Credits assigned – RCR)/RCR.

capacity is forecast to fall to 181 MW (4.2%), following the retirement of the second Muja C unit from 1 October 2024[14].

Figure 1 Forecast capacity supply-demand balance, 2022-23 to 2029-30[A,B]



A. The 2020-21 and 2021-22 available capacity values are actuals, while the remaining years are forecasts.
B. Excludes 2020 Expressions of Interest submissions.
C. The BRCP represents the marginal cost of providing one additional megawatt (MW) of Reserve Capacity in the relevant Capacity Year; see https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/benchmark-reserve-capacity-price.

For the 2020-21 Capacity Year, the DSM RCP is $16,730 per MW[15]. The DSM RCP is published three months before the price takes effect, in line with the WEM Rules.

For the 2021-22 Capacity Year, DSM Facilities will receive the floating RCP of $78,573 per MW as a result of the Reserve Capacity pricing amendments implemented in February 2020[16].

The RCPs for all Facilities for the 2022-23 Capacity Year will be determined once Capacity Credits have been assigned for the 2020 Reserve Capacity Cycle[17].

Peak demand and operational consumption forecasts

If peak demand forecasts are inaccurate, there is a risk of setting an inappropriate RCT (which is based on the 10% POE peak demand forecasts) and RCP. Since the RCP reflects the economic value of capacity, an inappropriately high or low RCP risks sending misleading price signals to the market.

An additional challenge to this year's demand forecasting was to incorporate the impacts of the COVID-19 pandemic. AEMO has endeavoured to adjust the demand forecasts to account for the COVID-19 impacts

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[14] Government of Western Australia, 2019. Media Release, "Muja Power Station in Collie to be scaled back from 2022", August 2019, at https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/Muja-Power-Station-in-Collie-to-be-scaled-back-from-2022.aspx.
[15] All DSM information required under the WEM Rules is provided in Chapter 7 of this WEM ESOO.
[16] Further information on the Reserve Capacity Pricing amendments is provided in Section 8.1.2 of this WEM ESOO.
[17] The 2020 Reserve Capacity Cycle timetable can be found at http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable.

based on external consultants' best available estimates, including the economic growth outlook and DER uptake projections[18].

AEMO forecasts the 10% POE peak demand to fall at an average annual rate of 0.2% over the 10-year outlook period, as presented in Table 2. Peak demand is forecast to reduce from 4,008 MW in 2020-21 to 3,913 MW in 2023-24. It is expected to remain relatively flat for the remainder of the outlook period, largely due to the diminishing impact of behind-the-meter PV generation as the time of peak shifts to later in the day.

These forecasts are lower than the peak demand forecasts published in the 2019 WEM ESOO. The 72 MW variance between the two forecasts in the 2022-23 Capacity Year can be attributed to improved modelling of DER impacts and energy efficiency improvements, and the COVID-19 pandemic impacts.

The likely timing of peak demand is expected to shift from between 17:00 and 18:00 to after 18:30 by 2023-24, due to DER impacts.

Table 2 Peak demand forecasts for different weather scenarios, expected demand growth (MW)

Scenario	2020-21	2021-22	2022-23	2023-24	2024-25	5-year average annual growth	2029-30	10-year average annual growth
10% POE	4,008	4,018	4,002	3,913	3,923	-0.5%	3,937	-0.2%
50% POE	3,774	3,782	3,758	3,707	3,684	-0.6%	3,720	-0.2%
90% POE	3,544	3,525	3,520	3,465	3,438	-0.8%	3,492	-0.2%

Operational consumption forecasts for the high, expected, and low demand growth scenarios[19] are shown in Table 3. These forecasts mainly reflect different assumptions about economic growth, electric vehicle (EV) uptake, energy efficiency improvement, new large industrial loads, and new connection points[20].

Table 3 Operational consumption forecasts[A] for different demand growth scenarios (GWh)

Scenario	2020-21	2021-22	2022-23	2023-24	2024-25	5-year average annual growth	2029-30	10-year average annual growth
High	18,000	17,987	17,889	17,966	18,144	0.2%	19,778	1.1%
Expected	17,589	17,467	17,208	17,009	16,841	-1.1%	17,029	-0.4%
Low	17,082	16,868	16,580	16,289	16,079	-1.5%	15,846	-0.8%

A. Operational consumption forecasts are by financial year.

In the expected growth scenario, operational consumption is forecast to decline at an average annual rate of 1.1% over the next five years. This represents a higher annual average reduction rate compared to the 2019 WEM ESOO (-0.5%), largely driven by lower business consumption due to COVID-19 in the short to medium term.

[18] See Sections 4.2 and 4.3 of this WEM ESOO for more information.

[19] As defined in clause 4.5.10 of the WEM Rules.

[20] For behind-the-meter PV, expected case forecasts have been applied to all three demand growth scenarios. This is because behind-the-meter PV uptake has been observed to be strongly driven by the payback period and customers' technology adoption preferences in WA, rather than general macroeconomic drivers like GSP growth.

Operational consumption is forecast to fall at an average annual rate of 0.4% over the outlook period, in line with the 2019 WEM ESOO. Continued uptake of behind-the-meter PV and energy efficiency improvements are expected to reduce energy consumption throughout the outlook period.

Trends in peak demand and impact of behind-the-meter PV

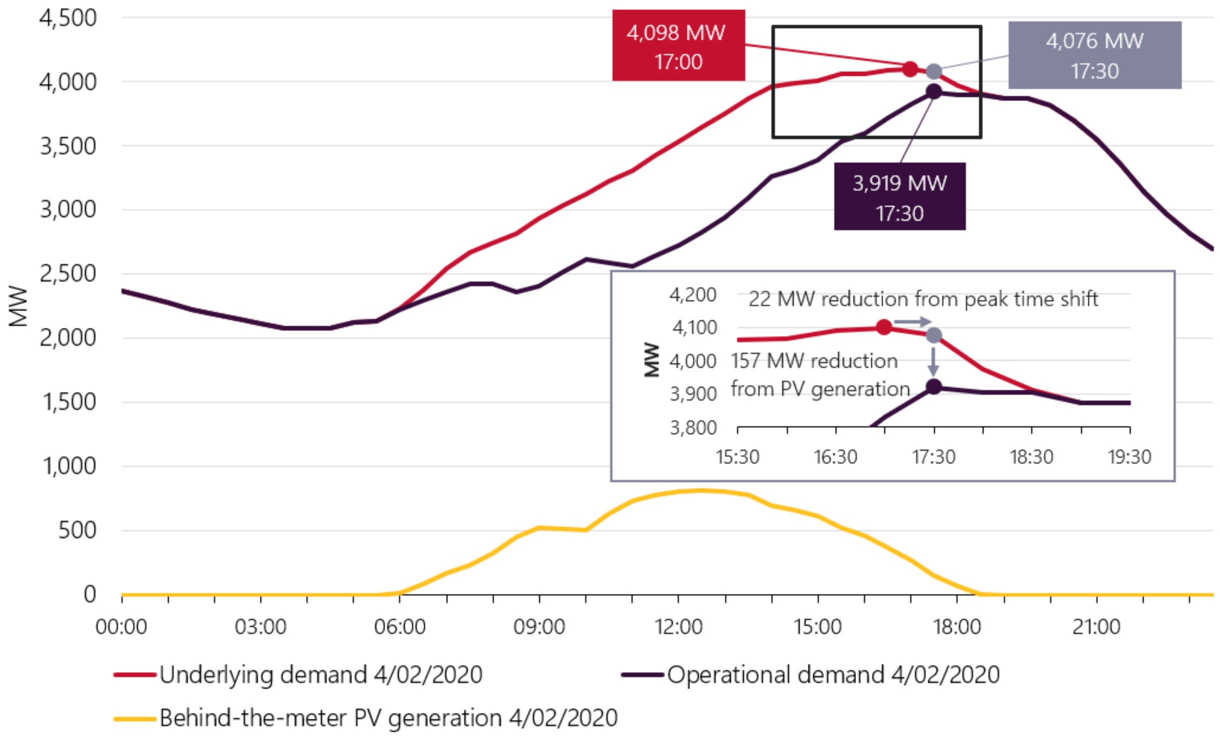
Peak demand in the SWIS has been volatile in the past five years, primarily due to weather conditions.

The 2019-20 summer observed the second-highest annual peak since energy market start in 2006, at 3,919 MW[21] on 4 February 2020. This peak was primarily driven by very hot temperature conditions (43.3°C)[22] on the day, after two consecutive hot days of over 35°C. This contrasted with summer 2018-19, when the lowest summer peak since 2006 (3,256 MW) was recorded.

It is expected that long-term temperature trends will continue to have significant impacts on peak demand. In this WEM ESOO, AEMO incorporated climate change into the demand and operational consumption forecasts. As ongoing evidence from the Bureau of Meteorology suggests continued changes in Australia's climate conditions[23], AEMO will continue to monitor the effects of climate on peak demand and capture those in the forecasts.

Behind-the-meter PV generation is estimated to have reduced the 2019-20 summer peak demand by 179 MW, representing 4.4% of the underlying peak demand[24] (4,098 MW) which occurred during the 17:00 to 17:30 Trading Interval on 4 February 2020, as shown in Figure 2.

Figure 2 Underlying and observed demand profiles on underlying and observed peak demand day, 4 February 2020



[21] Total Sent Out Generation (TSOG) over a 30-minute Trading Interval. This was the third-highest daily peak demand on record; the highest and second-highest daily peak demands on record occurred on 8 February 2016 and 14 March 2016 respectively.

[22] The hottest day observed over the 2019-20 Hot Season. The Hot Season is defined in the WEM Rules as the period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April.

[23] Bureau of Meteorology 2018, *State of the Climate 2018*, Australian Government, at http://www.bom.gov.au/state-of-the-climate/State-of-the-Climate-2018.pdf.

[24] Underlying demand refers to operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage. Due to the small uptake of behind-the-meter battery storage in the SWIS, its impact on historical underlying demand is negligible and not calculated.

Strong uptake of behind-the-meter PV has continuously reduced the daytime minimum demand in the SWIS over the last three years. As early as 2023-24, minimum demand is forecast to fall below the 700 MW security threshold under the expected demand growth scenario. The associated operational challenges will be addressed through the Delivering the Future Power System and the DER workstreams being developed as part of the WA Government's ETS[25].

AEMO expects the strong growth of behind-the-meter PV capacity in the SWIS to continue, with an expected 2,612 MW[26] of total installed capacity by the end of the outlook period. Technological, commercial, and regulatory factors, as well as increasing environmental awareness, continue to drive this strong uptake.

Reserve Capacity Price amendments and other market changes

The Minister for Energy amended the WEM Rules on 11 February 2020 to implement changes to the RCP from the 2021-22 Capacity Year[27]. As one element of the WA Government's ETS, the Reserve Capacity pricing amendments ensure the RCP is more responsive to the level of excess capacity and better reflects the economic value of incremental capacity. The changes included a sharper pricing curve, transitional pricing arrangements, and equivalent pricing for DSM and generation Facilities.

There are several other workstreams of the ETS that may impact the RCM, including:

- The constrained network access framework is being developed to improve generator access to the Western Power network. This will deliver changes to the RCM to allow Capacity Credits to be allocated in a constrained network[28].
- The DER Roadmap (released in April 2020), outlines a five-year plan to implement changes to standards, rules, and regulation that support active DER[29]. Integration of DER into the SWIS will most likely impact the timing and magnitude of the operational peak demand.
- A Whole of System Plan (WoSP) is being developed by the WA Government (supported by AEMO and Western Power). The WoSP aims to present a unified system plan by identifying the generation capacity mix and network investment required to meet demand at the lowest sustainable system cost over a 20-year outlook period. The purpose and the modelling methodology and scenarios of the WoSP are different to those of the WEM ESOO. As such, the outcomes of the WoSP and the WEM ESOO are not comparable.

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[25] See https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.
[26] Forecast installed capacity of behind-the-meter PV as at June 2030.
[27] See https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals.
[28] See https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.
[29] Active DER systems incorporate smart controllers that can respond to parameters such as price, or directly to control signals for system security purposes.

Contents

Tables

Figures

1. Year in review – Reserve Capacity Mechanism

This chapter provides a summary of key outcomes and events associated with the Reserve Capacity Mechanism (RCM) in the Wholesale Electricity Market (WEM) in Western Australia (WA), since the publication of the *2019 Electricity Statement of Opportunities* (ESOO)[30].

- In September 2019, a total of 4,924.8 megawatts (MW) of Capacity Credits was assigned to meet the Reserve Capacity Requirement (RCR) of 4,482 MW for the 2019 Reserve Capacity Cycle in relation to the 2021-22 Capacity Year[31], representing a 9.9% excess capacity level.
  - For more information on Facilities assigned Capacity Credits for the 2021-22 Capacity Year, please refer to Chapter 2 of this WEM ESOO.
  - For the RCR determination for the 2020 Reserve Capacity Cycle in relation to the 2022-23 Capacity Year, please refer to Chapter 7 of this WEM ESOO.
- In December 2019, the Benchmark Reserve Capacity Price (BRCP) was determined as $141,900 per MW per year for the 2020 Reserve Capacity Cycle. This determination is the lowest since the 2009-10 Capacity Year and 8.0% lower than the BRCP determined for the 2019 Reserve Capacity Cycle[32], primarily as a result of declining bond yields.
  - For more information on the 2020 BRCP, please refer to AEMO's *Benchmark Reserve Capacity Price for the 2022-23 Capacity Year Final Report*[33] and the ERA's *Decision on the Benchmark Reserve Capacity Price to apply in the 2022/23 Capacity Year*[34].
- In January 2020, the *Request for Expressions of Interest (EOI) for the 2020 Reserve Capacity Cycle*[35] was published, which invited new generation or Demand Side Management (DSM) projects to express their interest in providing capacity for the 2022-23 Capacity Year. In May 2020, the *2020 Expressions of Interest summary report*[36] was published. Three EOIs were received with a total of 62 MW of potential capacity, including one proposed non-intermittent generator and two intermittent generators.

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30 See https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2019/2019-wem-esoo-report.pdf?la=en.

31 For Capacity Credits assigned for the 2021-22 Capacity Year, see https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/assignment/2019/capacity-credits-assigned-for-the-2021-22-capacity-year.pdf?la=en&hash=A50EB426A214BB872C8250513F92EEA2.

32 AEMO. 2019 Benchmark Reserve Capacity Price for the 2021-22 Capacity Year Final Report. January 2019, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/brcp/2019/final-report/final-report---2019-brcp-for-2021-22-capacity-year.pdf?la=en&hash=1C873E58590B61BB492C7F210FD01D9F.

33 See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/brcp/2020/final-report/final-report---benchmark-reserve-capacity-price-for-the-2022-23-capacity-year.pdf?la=en&hash=01DBBEC4291877CDA51EC016432D181A.

34 See https://www.erawa.com.au/cproot/20891/2/Benchmark-Reserve-Capacity-Price-2020---Decision-paper.pdf.

35 See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2020/2020-request-for-expressions-of-interest.pdf?la=en.

36 See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2020/2020-eoi-summary-report.pdf?la=en.

   - For more information on the forecast capacity supply and demand balance for the 2022-23 to 2029-30 Capacity Years, please see Chapter 7 of this WEM ESOO.
- On 4 February 2020, peak demand for the 2019-20 summer was recorded as 3,919 MW[37]. This was the second-highest annual peak in the South West interconnected system (SWIS) since energy market start in 2006[38]. The estimated impact of behind-the-meter photovoltaics (PV) at the time of peak was 157 MW, the highest behind-the-meter PV[39] effect on peak reduction historically observed.
   - For more information on the historical peak demand and impact of behind-the-meter PV, please refer to Chapter 3 of this WEM ESOO.
   - For more information on the distributed energy resources (DER)[40] forecasts, please refer to Chapter 4 of this WEM ESOO.
   - For more information on the peak demand forecasts, please refer to Chapter 5 of this WEM ESOO.
- In February 2020, the Minister for Energy amended the Wholesale Electricity Market Rules (WEM Rules) to implement changes to the Reserve Capacity Pricing from the 2021-22 Capacity Year[41]. The floating Reserve Capacity Price (RCP) of $78,573 per MW per year and the RCP for Transitional Facilities of $114,000 per MW per year were determined for the 2021-22 Capacity Year[42].
   - For more information on the Reserve Capacity pricing changes, please refer to Chapter 8 of this WEM ESOO.
- On 9 April 2020, AEMO published the *COVID-19 – Potential Impacts to the 2020 Reserve Capacity Cycle issues paper*[43], requesting stakeholder feedback on a deferral of the 2020 Reserve Capacity Cycle. Based on the 12 submissions received, AEMO has deferred key dates associated with the Certified Reserve Capacity process for the 2020 Reserve Capacity Cycle for two months.
   - For more information on the extended 2020 Reserve Capacity timetable, please refer to the Reserve Capacity timetable on AEMO's website[44].
- AEMO expects the impact of the COVID-19 pandemic on the WA economy will be relatively short-term[45], with the WA economy expected to largely recover from the 2022-23 financial year. As such, AEMO retained the 2020 WEM ESOO publication timeline[46] and incorporated COVID-19 impacts into the peak demand and operational consumption forecasts.
   - For more information on COVID-19 impacts on the peak demand and operational consumption forecasts, please refer to Chapter 4 of this WEM ESOO.

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[37] Measured as the Total Sent Out Generation (TSOG) over a 30-minute Trading Interval. The maximum temperature for the peak demand day was the highest observed for any peak demand day since 2015, reaching 43.3°C and was the hottest day observed during the 2019-20 summer.

[38] This was the third-highest daily peak demand on record; the highest and second-highest daily peak demand values on record were 4,004 MW and 3,994 MW and occurred on 8 February 2016 and 14 March 2016 respectively.

[39] Behind-the-meter PV includes both residential and commercial behind-the-meter PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 10 MW in the SWIS. Further details have been provided in Chapter 3.

[40] DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter. Any generators that are connected to the distribution network that are assigned Capacity Credits are not included in the definition of DER technologies, for example Northam Solar Farm.

[41] Energy Policy WA. Improving Reserve Capacity Pricing Signals (page reviewed 25 February 2020), at https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals.

[42] For the RCPs determined for the 2019 Reserve Capacity Cycle, see https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price.

[43] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/wa_wem_consultation_documents/2020/covid19/covid-19-potential-impacts-to-the-2020-reserve-capacity-cycle.pdf?la=en. Coronavirus disease 2019 (COVID-19) is an infectious disease caused by severe acute respiratory syndrome coronavirus. The World Health Organization declared the outbreak to be a Public Health Emergency of International Concern on 30 January 2020, and recognised it as a pandemic on 11 March 2020. See https://www.who.int/dg/speeches/detail/who-director-general-s-opening-remarks-at-the-media-briefing-on-covid-19---11-march-2020.

[44] See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-timetable.

[45] AEMO engaged the economic forecasting consultant BIS Oxford Economics (BIS Oxford) to assess the COVID-19 impact and adjusted the economic forecasts accordingly.

[46] The 2020 WEM ESOO is required to be published by 17 June 2020 in accordance with clause 4.1.8 of the WEM Rules.

2. Changes in supply

This chapter focuses on generation and DSM capacity of Facilities in the WEM that have been allocated Capacity Credits through the RCM.

2.1 Certified Facilities

For the 2021-22 Capacity Year, 33 Market Participants operating 66 Facilities were assigned a total of 4,924.8 MW of Capacity Credits[47]. These Facilities comprise:

- 39 Scheduled Generators (4,639.3 MW).
- 24 Non-Scheduled Generators (NSGs) (201.1 MW).
- Three Demand Side Programmes (DSPs) (84.5 MW).

Total Capacity Credits assigned for the 2021-22 Capacity Year decreased by 0.8% from 4,965.6 MW in the 2020-21 Capacity Year. This decrease is primarily due to the Relevant Level calculation that has resulted in a reduction in assigned Capacity Credits of a number of NSGs (see Section 2.2.3).

There were two new RCM entrants for the 2021-22 Capacity Year:

- Kwinana Waste-to-Energy (WTE) Facility (36.0 MW), being developed by Avertas Energy. This is the first Facility participating in the RCM that has a renewable fuel type (waste) and has been classified as a Scheduled Generator.
- Griffin DSP (20.0 MW).

Figure 3 summarises the market share of Capacity Credits assigned for the 2021-22 Capacity Year by fuel type.

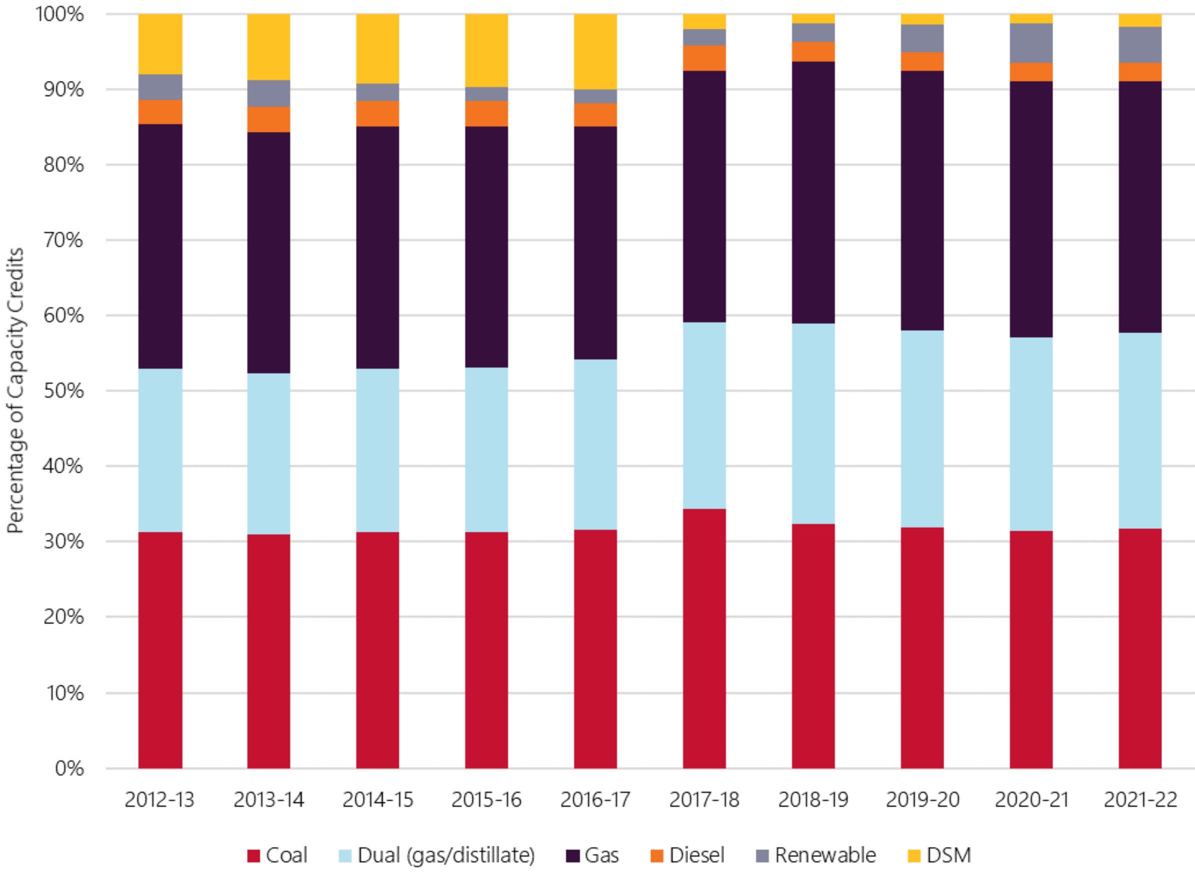
The differences in the assignment of Capacity Credits by fuel type between the 2020-21 Capacity Year and 2021-22 Capacity Year include:

- A decrease of 2% in gas, as the Tiwest Cogeneration Facility does not hold Capacity Credits for the 2021-22 Capacity Year.
- A decrease of 9% in renewables[48] (wind, solar, waste, and biogas), as a result of the Relevant Level calculation.
- An increase of 28% in DSM, due to the entry of Griffin DSP.
- Negligible changes in distillate, coal, and dual-fuel Facilities.

[47] Behind-the-meter PV does not receive Capacity Credits. For further information about behind-the-meter PV, see Chapter 3 and Chapter 4.

[48] Includes all NSGs and the Kwinana WTE Facility.

Figure 3 Proportion of Capacity Credits by fuel type, 2012-13 to 2021-22 Capacity Years



2.2 Capacity Credits by Facility class

The Capacity Credits assigned to a Facility indicate the level of capacity expected to be available during peak demand periods. This is independent of the total energy generation each year, which is affected by factors including operating cost per megawatt hour (MWh), age, system demand, classification, scheduled outages[49], commercial arrangements, and bidding strategies.

Newer generators are generally more fuel-efficient and can operate for longer periods without scheduled outages, so have a higher energy output. Facilities that provide baseload generation, such as coal-fired generators, are designed to operate continuously and have high start-up costs. Consequently, it may be more economically viable for these Facilities to continue to operate when Balancing Market prices are low or even negative.

The total maximum capacity[50] of Facilities assigned Capacity Credits for the 2021-22 Capacity Year is 5,946.8 MW, comprising:

- **Scheduled Generators** – these make up 4,776.2 MW (80.3%) of the maximum capacity. This category consists of 1,713.8 MW (35.9%) gas, 1,566.9 MW (32.8%) coal, 1,326.0 MW (27.8%) dual (gas/distillate), 133.5 MW (2.8%) distillate, and 36.0 MW (0.8%) renewable fuel (waste) capabilities.
- **NSGs** – these make up 1,170.6 MW (19.7%) of the maximum capacity. This consists of 788.3 MW (67.3%) wind, 209.9 MW (17.9%) wind and solar, 150.8 MW (12.9%) solar, and 21.6 MW (1.8%) biogas.

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[49] Outage data can be sourced from AEMO's Market Data website, at http://data.wa.aemo.com.au/#outages.

[50] Maximum Capacity data is based on the net sent out generation or installed capacity and can be found on AEMO's Market Data website, at http://data.wa.aemo.com.au/#facilities.

For comparison, behind-the-meter PV generation (which does not receive Capacity Credits) had an installed capacity of approximately 1,329 MW as of February 2020. This is larger than Muja CD – the largest power station in the SWIS – which has an installed capacity of 854 MW.

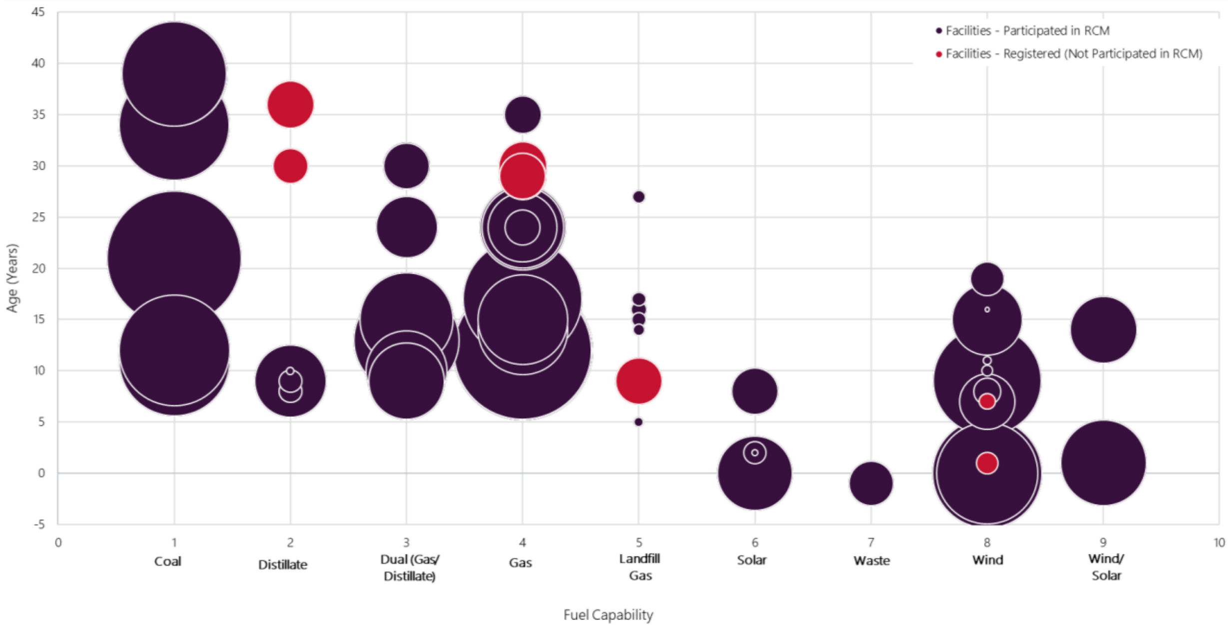
The following section details the performance of each Facility class that has been assigned Capacity Credits for the 2021-22 Capacity Year.

2.2.1 Age of Facilities assigned Capacity Credits

Figure 4 compares Facilities assigned Capacity Credits for the 2021-22 Capacity Year based on age, maximum capacity, and fuel type. The key trends identified are:

- Based on the total maximum capacity (5,946.8 MW), the majority of the capacity (38%) comprises Facilities that are 11-15 years old, followed by 21-25 years old (14%), more than 30 years old (14%), and 6-10 years old (13%). The lowest capacity Facilities are 1-5 years old (2%), 26-30 years old (4%), 16-20 years old (5%), or under construction (9%).
- Based on the Facility class, 42% of the NSG maximum capacity (1,170.6 MW) is Facilities still under construction, and 44% of the Scheduled Generators' maximum capacity (4,776.2 MW) is Facilities that are 11-15 years old.
- There are no Scheduled Generators that are 1-5 years old, or NSGs older than 20 years, participating in the RCM.

Figure 4 Facilities by age, fuel capability, and maximum capacity[A,B]



A. Bubble sizes represents the maximum capacity in MW.
B. Facilities that are under construction or less than a year old are represented by zero or negative values for age.

2.2.2 Scheduled Generators

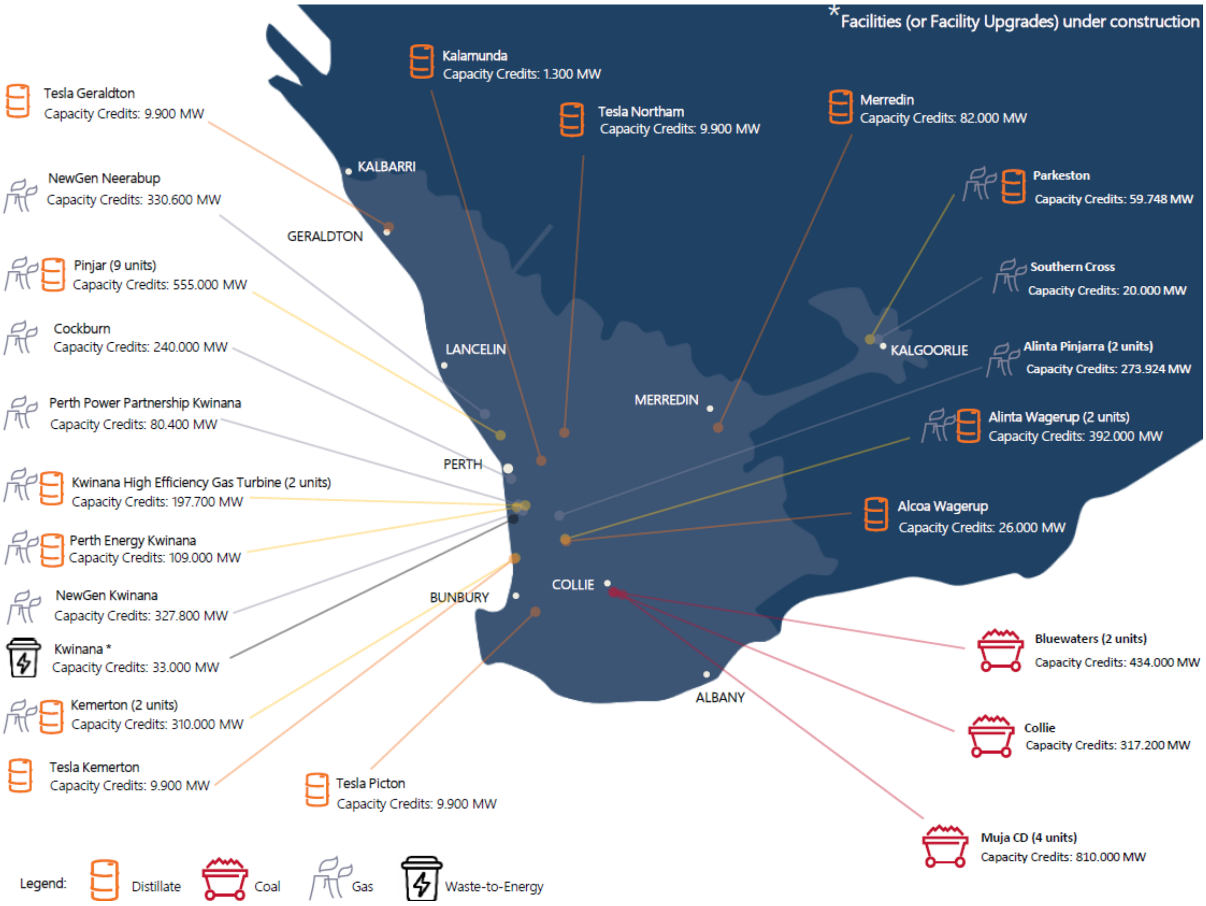
The locations and Capacity Credit assignments for Scheduled Generators certified for the 2021-22 Capacity Year are shown in Figure 5.

There have been no significant changes to the fleet of Scheduled Generators compared to the previous Capacity Year:

- Assigned Capacity Credits for Scheduled Generators decreased marginally by 0.1% from 4,641.9 MW in the 2020-21 Capacity Year, compared to 4,639.3 MW in the 2021-22 Capacity Year.

- The Kwinana WTE Facility was the only new Scheduled Generator to be assigned Capacity Credits (33.0 MW) for the 2021-22 Capacity Year.
- While the Tiwest Cogeneration Facility held 36.0 MW of Capacity Credits for the 2020-21 Capacity Year, it was not assigned Capacity Credits for the 2021-22 Capacity Year.
- Muja CD remains the largest power station, with four units[51] accounting for 16.5% of the total Capacity Credits assigned for the 2021-22 Capacity Year.

Figure 5 Scheduled Generators map for the SWIS, 2021-22



Scheduled Generators' operating characteristics

AEMO defines the classification of baseload, mid-merit, peaking Facilities as follows[52]:

- **Baseload capacity** relates to Scheduled Generators that operate more than 70% of the time.
- **Mid-merit capacity** relates to Scheduled Generators that operate between 10% and 70% of the time.
- **Peaking capacity** relates to Scheduled Generators that operate less than 10% of the time.

Scheduled Generators are typically assigned Capacity Credits equal or close to their maximum capacity. Figure 6 shows the maximum capacities, Capacity Credit assignments, and operating characteristics of existing Scheduled Generators in the 2021-22 Capacity Year[53].

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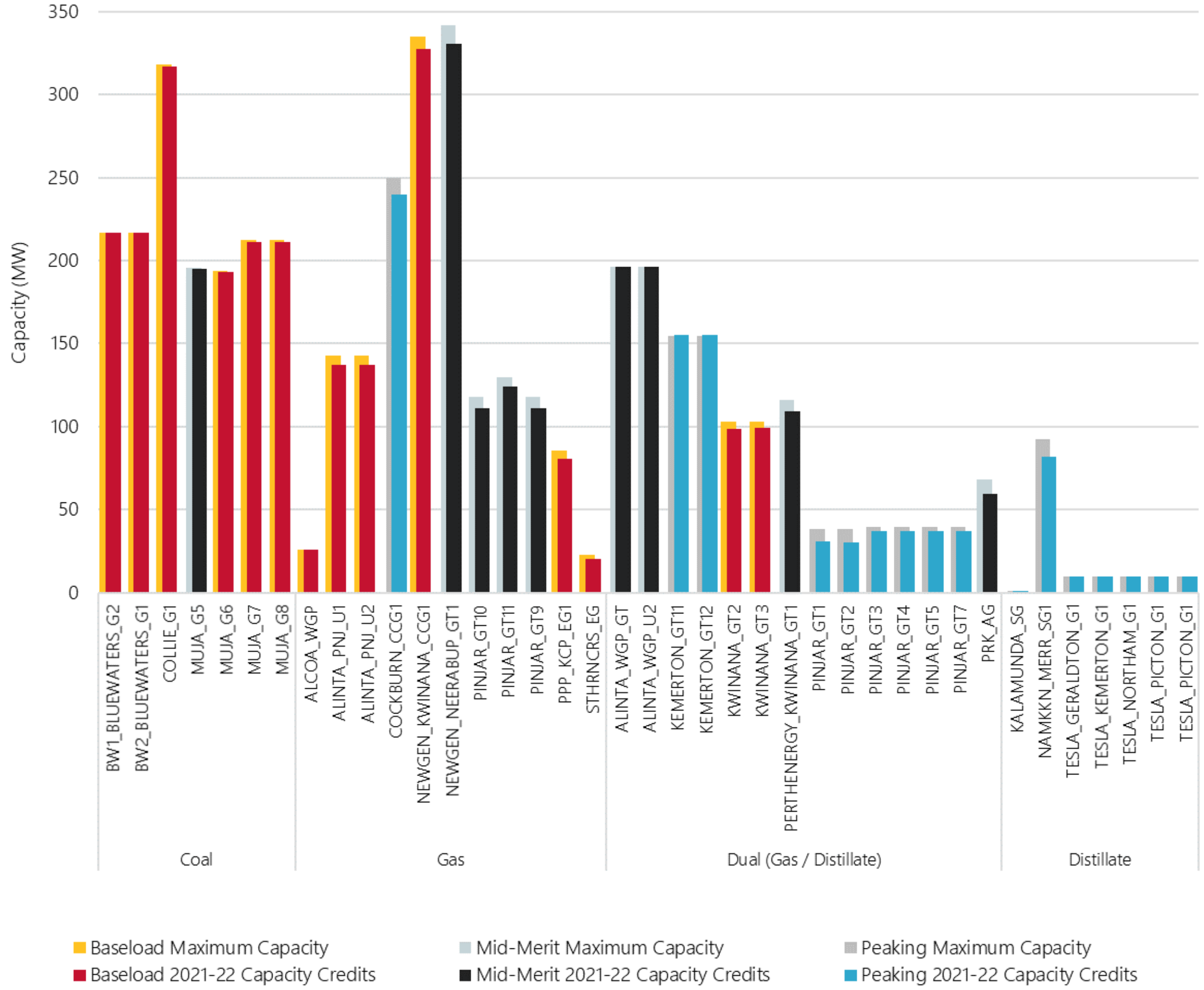
[51] Muja CD comprises of Muja units G5, G6, G7, and G8, with 195 MW, 193 MW, 211 MW, and 211 MW of Capacity Credits respectively in the 2021-22 Capacity Year.

[52] The classification of baseload, mid-merit, and peaking Facilities is based on the percentage of Trading Intervals in the 2018-19 Capacity Year that the Facility operated, adjusted for full outages. A full outage has been defined as a Trading Interval where a Facility has gone on an outage equal to its Capacity Credits assigned for the 2018-19 Capacity Year.

[53] This does not include the Kwinana WTE Facility which is scheduled to commence operation in October 2021.

Figure 6 Capacity Credit assignments, operating classification, and age of Scheduled Generators



Summary of trends for Scheduled Generators

In summary:

- 49.4% (2,292.0 MW) of assigned Capacity Credits have been classified as baseload capacity, 30.9% (1,432.3 MW) as mid-merit capacity, and 19.0% (881.9 MW) as peaking capacity, while 0.7% (33.0 MW)[54] remains to be classified.
- Baseload capacity (totalling 2,292.0 MW of Capacity Credits) consists of 59.6% coal, 31.8% gas, and 8.6% dual-fuel Facilities.
- Mid-merit capacity (totalling 1,432.3 MW of Capacity Credits) consists of 13.6% coal, 47.2% gas, and 39.1% dual-fuel Facilities.
- Peaking capacity (totalling 881.9 MW of Capacity Credits) consists of 27.2% gas, 13.9% distillate, and 58.9% of dual-fuel Facilities.

[54] Kwinana WTE has the capacity to generate 36 MW (for more information, see https://avertas.com.au/).

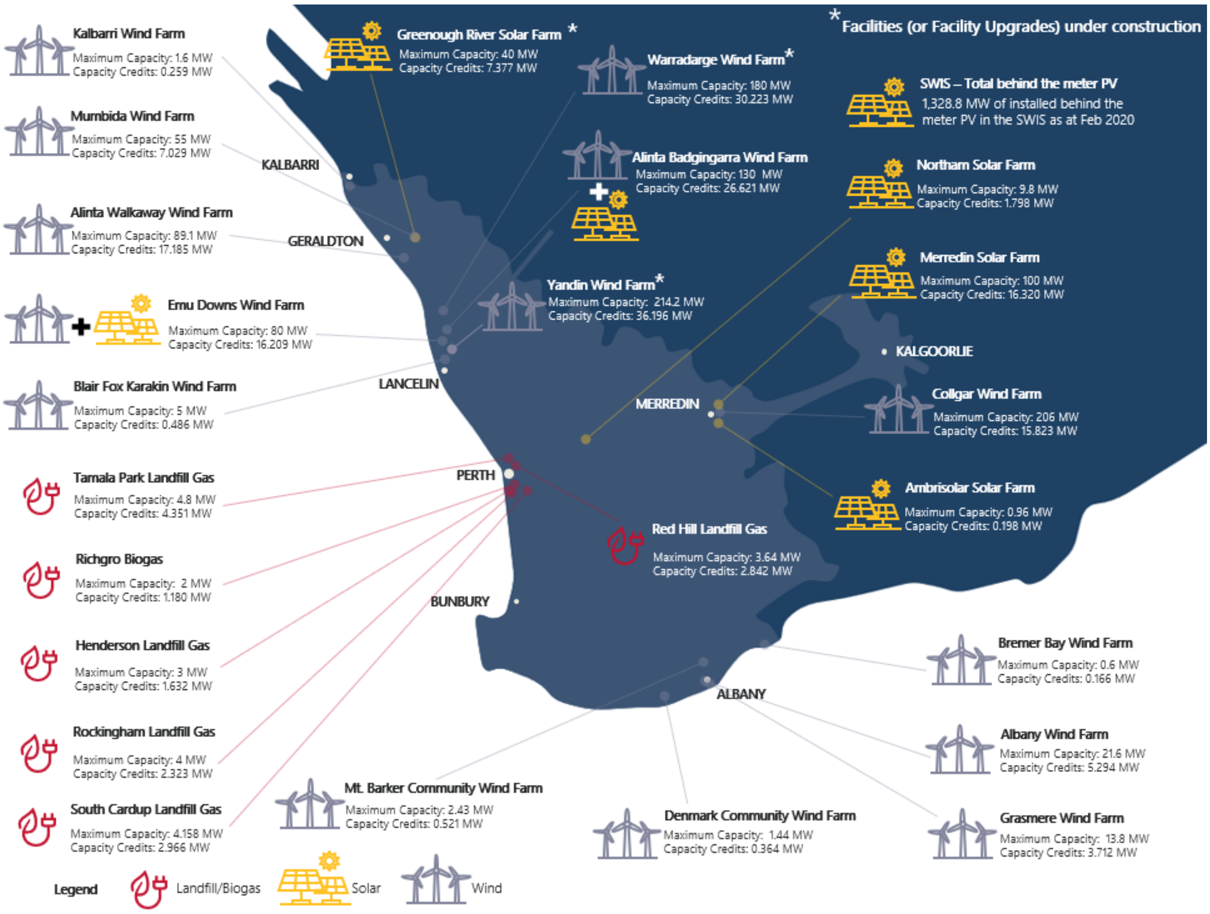
2.2.3 Non-Scheduled Generators

NSGs are typically assigned a lower quantity of Capacity Credits relative to their maximum generation capacity, to reflect their generation during peak demand periods in the previous five years[55]. In comparison, Scheduled Generators are assigned Capacity Credits based on their maximum generation capacity at 41°C.

The quantity of Capacity Credits assigned to NSGs decreased by 22.0% from 257.7 MW in the 2020-21 Capacity Year to 201.1 MW in the 2021-22 Capacity Year. The maximum capacity of NSGs assigned Capacity Credits for the 2021-22 Capacity Year is 1,170.6 MW (19.7% of total maximum capacity).

The Capacity Credit assignment, maximum capacity, and location of each NSG Facility for the 2021-22 Capacity Year is shown in Figure 7.

Figure 7 Non-Scheduled Generators map for the SWIS, 2021-22[A,B]



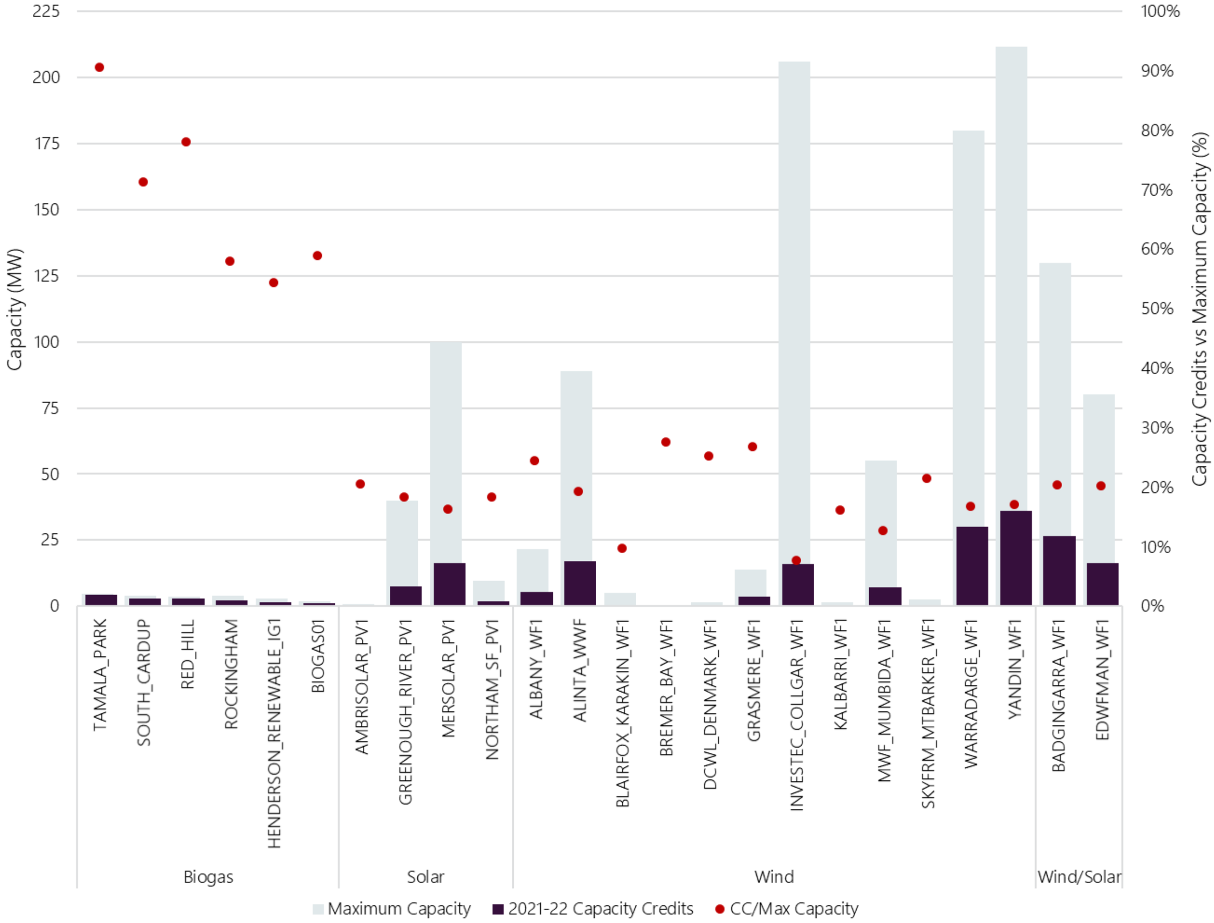
A. Maximum Capacity installed for each Facility has been sourced from AEMO Market Data, at http://data.wa.aemo.com.au/#facilities. Installed capacities are used for Facilities under construction.
B. Greenough River Solar Farm is currently upgrading the Facility to increase the maximum capacity from 10 MW to 40 MW by the end of 2020 (https://www.brightenergyinvestments.com.au/greenough-river-solar-farm).

NSG operating characteristics

NSG Facilities cannot be scheduled, because the level of output is dependent on factors beyond the control of the operator (such as wind speed). The maximum generation capacities of NSGs compared to the quantity of Capacity Credit assigned to each NSG Facility in the 2021-22 Capacity Year are shown in Figure 8.

55 Capacity Credits assigned to many existing NSGs have decreased due to decreasing Relevant Levels (the MW quantity determined by AEMO in accordance with the Relevant Level Methodology specified in Appendix 9 of the WEM Rules).

Figure 8 Capacity Credit assignments and maximum capacity of Non-Scheduled Generators



Summary of trends for NSGs

In summary:

- The three NSG Facilities with the greatest number of Capacity Credits for the 2021-22 Capacity Year are Yandin Wind Farm (18.0%), Warradarge Wind Farm (15.0%)[56], and Badgingarra Wind and Solar Farm (13.2%)[57].
- When comparing maximum capacity to Capacity Credits assigned, all biogas Facilities have the highest ratios (91% to 54%). Mumbida Wind Farm, Blairfox Karakin Wind Farm, and Collgar Wind Farm have the lowest ratios, of 13%, 10%, and 8% respectively.

2.2.4 Demand Side Programmes

DSPs were allocated 1.7% of the total Capacity Credits assigned for the 2021-22 Capacity Year. The assigned Capacity Credits for DSPs increased by 28.0% from 66.0 MW in the 2020-21 Capacity Year to 84.5 MW in the 2021-22 Capacity Year. The increase in Capacity Credits was attributed to the entry of the Griffin DSP Facility (20.0 MW).

[56] Yandin and Warradarge Facilities are under construction.

[57] Badgingarra Wind and Solar Farm Facility commenced operation in 2019.

3. Changes in demand

The 2019-20 peak summer demand was the second-highest annual peak observed since the energy market commenced in 2006. Minimum demand reached two new record lows since the 2019 WEM ESOO publication. Operational consumption during the 2018-19 financial year decreased from the previous year, while consumption from behind-the-meter PV increased.

3.1 Historical peak demand

This section discusses historical trends in operational and underlying peak demand (in MW) in the SWIS:

- Section 3.1.1 examines the 2019-20 operational peak demand in the context of previously observed trends.
- Section 3.1.2 analyses the 2019-20 underlying peak demand in the context of previously observed trends.
- Section 3.1.3 investigates seasonal trends in peak demand and includes a discussion of the 2018-19 winter peak demand.

Throughout this section and Section 3.2:

- The reported temperature data is measured at the Perth Airport weather station (station identification number 9021), unless otherwise specified[58].
- Demand refers to operational demand[59] unless otherwise specified.
- Underlying demand refers to operational demand plus an estimation of behind-the-meter PV generation and the impacts of behind-the-meter battery storage[60].
- Summer refers to the Hot Season[61] as defined by the WEM Rules, winter includes June to August, and the shoulder season includes all other months.
- All data in this section is presented in Capacity Years unless otherwise specified[62].

3.1.1 Operational peak demand

In this section, the 2019-20 summer peak is discussed in the context of historical trends.

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[58] All temperature data is sourced from the Bureau of Meteorology (BOM).

[59] For historical values, operational demand refers to network demand met by utility-scale generation and excludes demand met by behind-the-meter PV generation. Operational demand is measured in MW and averaged over a 30-minute period. It is reported on a "sent-out" basis and calculated as the TSOG x 2 to convert non-loss adjusted MWh to MW for a Trading Interval. The operational peak demand is identified as the highest operational demand calculated for a Capacity Year.

[60] Behind-the-meter PV generation estimates are based on solar capacity factor traces sourced from SolCast. Due to the small uptake of behind-the-meter battery storage in the SWIS, its impact on historical underlying demand is negligible and not calculated.

[61] The period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April.

[62] Data for the 2019-20 Capacity Year includes up until 29 February 2020. Metered values for TSOG beyond this date were not available at the time of undertaking analysis for this WEM ESOO publication, as it can take up to two months for settlement cycles to complete..

AEMO will publish a separate piece of analysis on customers' response to the Individual Reserve Capacity Requirement[63] mechanism and the resulting impact on load reduction on the peak demand day following the 2020 WEM ESOO publication.

The 2019-20 summer peak

The 2019-20 summer peak of 3,919 MW was observed on Tuesday 4 February 2020 during the 17:30 to 18:00 Trading Interval[64]. The following observations can be made, comparing this peak with historical peaks (see Table 4):

- This recent summer peak was the second-highest annual peak and the third-highest daily peak[65] observed since the energy market commenced in 2006. This is in contrast to last year with the lowest summer peak (3,256 MW).
- The maximum temperature for the peak demand day was the highest observed for any peak demand day since 2015, reaching 43.3°C. This was also the hottest day observed during the 2019-20 summer.

Table 4 Comparison of annual peak demand days, 2012-13 to 2019-20

Capacity Year	Date	Trading Interval of peak demand	Peak demand (MW)	Daily maximum temperature (°C)	Time of temperature peak	Rank of day[A]
2019-20	4 February 2020	17:30	3,919	43.3	14:30	1
2018-19	7 February 2019	17:30	3,256	35.8	15:00	21
2017-18	13 March 2018	17:30	3,616	38.5	14:00	2
2016-17	21 December 2016	17:00	3,543	42.8	14:30	2
2015-16	8 February 2016	17:30	4,004	42.6	15:00	3
2014-15	5 January 2015	15:30	3,744	44.2	13:30	1
2013-14	20 January 2014	17:30	3,702	38.7	15:00	7
2012-13	12 February 2013	16:30	3,739	41.1	13:00	2

A. A rank of 1 indicates the hottest day in the Capacity Year, 2 indicates the second hottest day, and so on.
Source: AEMO, Solcast and BOM.

Temperature patterns have a significant influence on peak demand values. For example, consecutive days of warm temperatures are likely to drive high demand, as retention of heat in buildings can increase cooling load requirements. Demand is also correlated with the day-of-week, and lower demand is generally observed on holidays and weekends, as commercial energy demand historically drives higher demands on working days.

In Figure 9, day-of-week and temperature patterns have been compared between three summers (2019-20, 2018-19, and 2015-16), to illustrate the effect of these variables and explain the drivers behind the most recent peak demand.

[63] The Individual Reserve Capacity Requirement financially incentivises Market Customers to reduce consumption during peak demand periods and consequently reduce their exposure to capacity payments.

[64] References to Trading Intervals refer to the interval start time; for example, the 17:30 Trading Interval refers to the interval that commences at 17:30 and ends at 18:00.

[65] In the 2015-16 Capacity Year there were two daily peaks observed that exceed the recent peak, on 8 February 2016 (4,004 MW) and 14 March 2016 (3,994 MW).

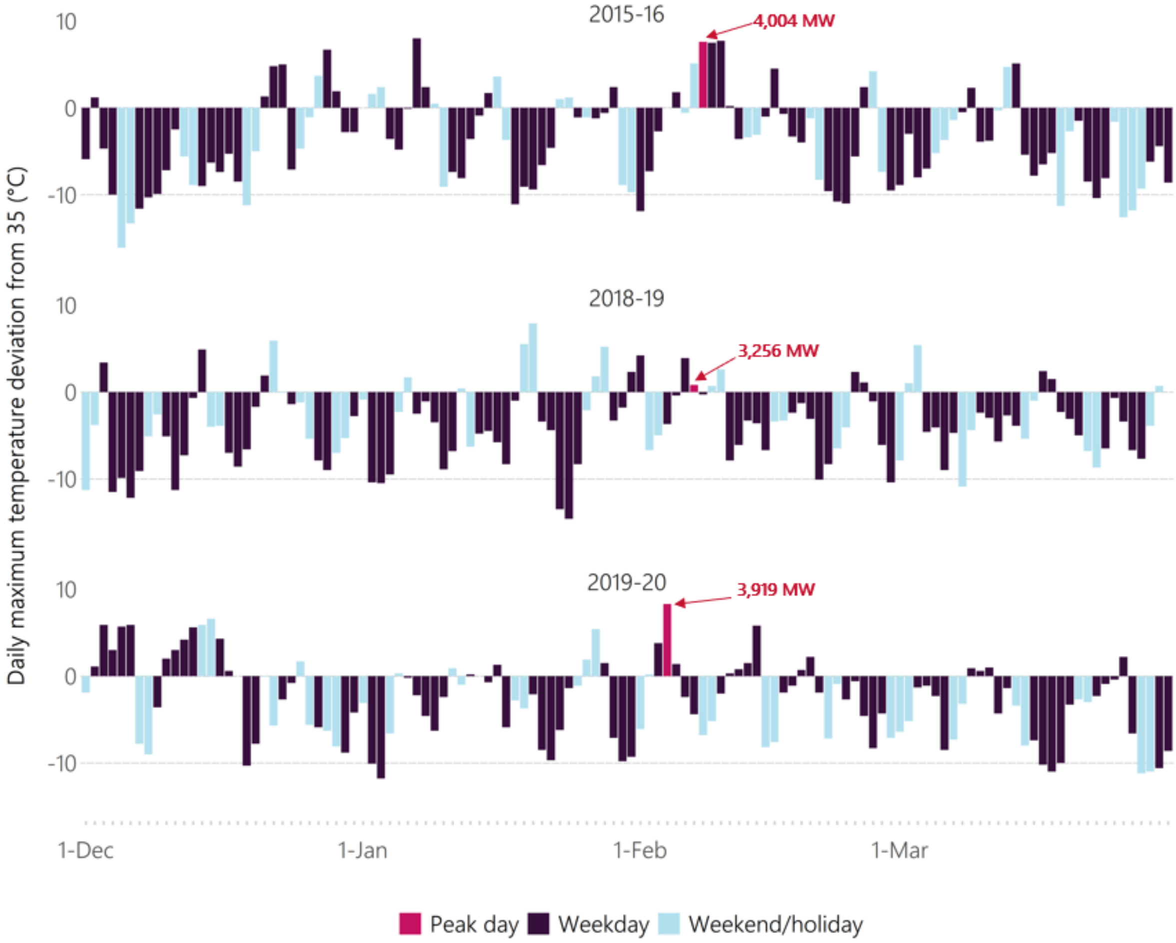
Figure 9 illustrates daily maximum temperatures as a deviation from 35°C[66] and indicates which days are weekends and holidays. The following can be observed:

- During 2015-16 and 2019-20, more hot days occurred during weekday periods and had higher temperatures, than during 2018-19.
- These summers also saw more and longer strings of consecutive hot days than 2018-19; there were no more than two consecutive days of over 35°C during 2018-19.

The impacts of these patterns on the demands observed during the summers are as follows:

- Higher temperatures on working days drove higher peak demand for both 2019-20 (3,919 MW) and 2015-16 (4,004 MW) peak days; in both years, maximum temperatures exceeded 40°C.
- The disparity between the 2019-20 peak (3,919 MW) and the 2018-19 peak (3,256 MW) can be largely explained by temperature differences; daily maximums for the peak days were 43.3°C and 35.8°C respectively.
- In addition to the annual peak days highlighted in the figure, the 2019-20 and 2015-16 summer periods experienced more high demand days than the 2018-19 summer; there were 28 daily demand peaks in 2019-20 (and 16 in 2015-16) that exceeded the 2018-19 annual peak demand[67].

Figure 9 Daily maximum temperature deviation from 35°C[A], during summer periods, 2015-16, 2018-19 and 2019-20



A. Summer season temperature deviation from 35°C, temperatures exceeding this threshold are defined as hot days.
Source: BOM.

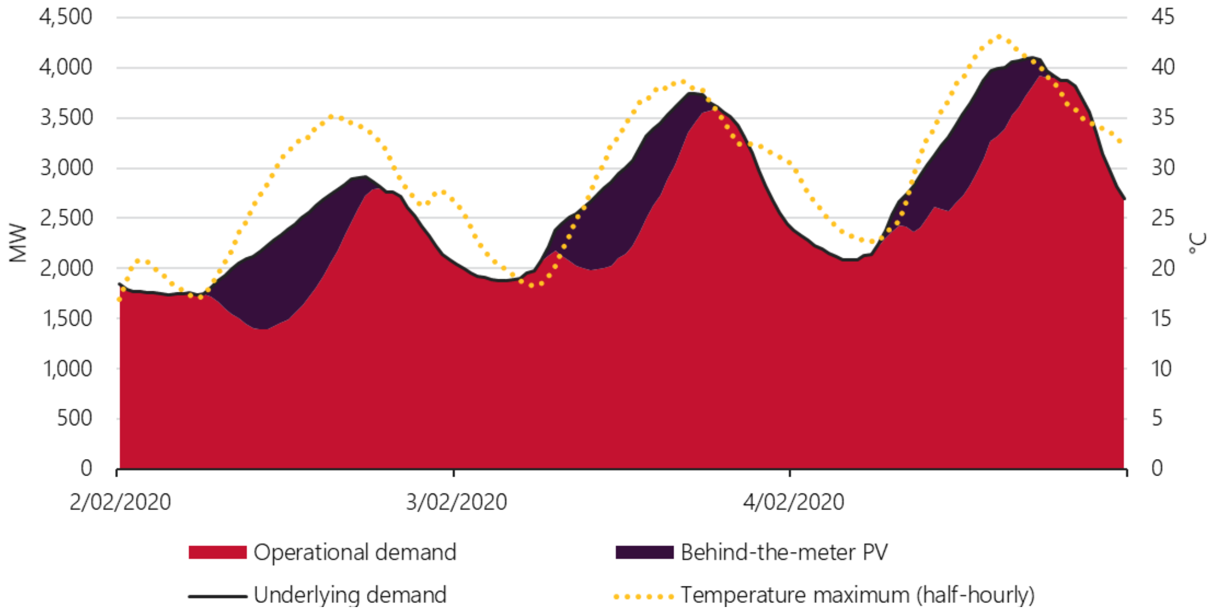
[66] The BOM information on climate extremes defines >35°C as the 'hot day' benchmark.

[67] Metered demand values for 2019-20 summer are incomplete and include up to 29 February 2020.

To further illustrate the impacts of lead-up days on peak demand, Figure 10 shows the days preceding the 2019-20 summer peak day, displaying the temperature and demand profiles from 2-4 February 2020:

- The 2019-20 peak demand day was the third day in a row of temperatures exceeding 35°C; daily maximum temperatures rose from 35.1°C to 43.3°C across the three days, resulting in higher demand with subdued overnight lows[68].
- The 2019-20 peak on 4 February is 322 MW higher than the next highest peak, which occurred one day prior, on 3 February 2020.
- In Figure 10, underlying demand is denoted as the sum of operational demand and behind-the-meter PV generation. The underlying peak on 4 February was 4,098 MW observed during the 17:00 to 17:30 Trading Interval, discussed further in Section 3.1.2.

Figure 10 Demand and temperature profiles for the peak demand day and preceding two days (2, 3, and 4 February 2020)



3.1.2 Underlying peak demand

Underlying peak is the maximum that would have occurred if there was no generation from behind-the-meter PV.

In the 2019-20 summer the underlying peak occurred on the same day as the peak demand day (4 February 2020).

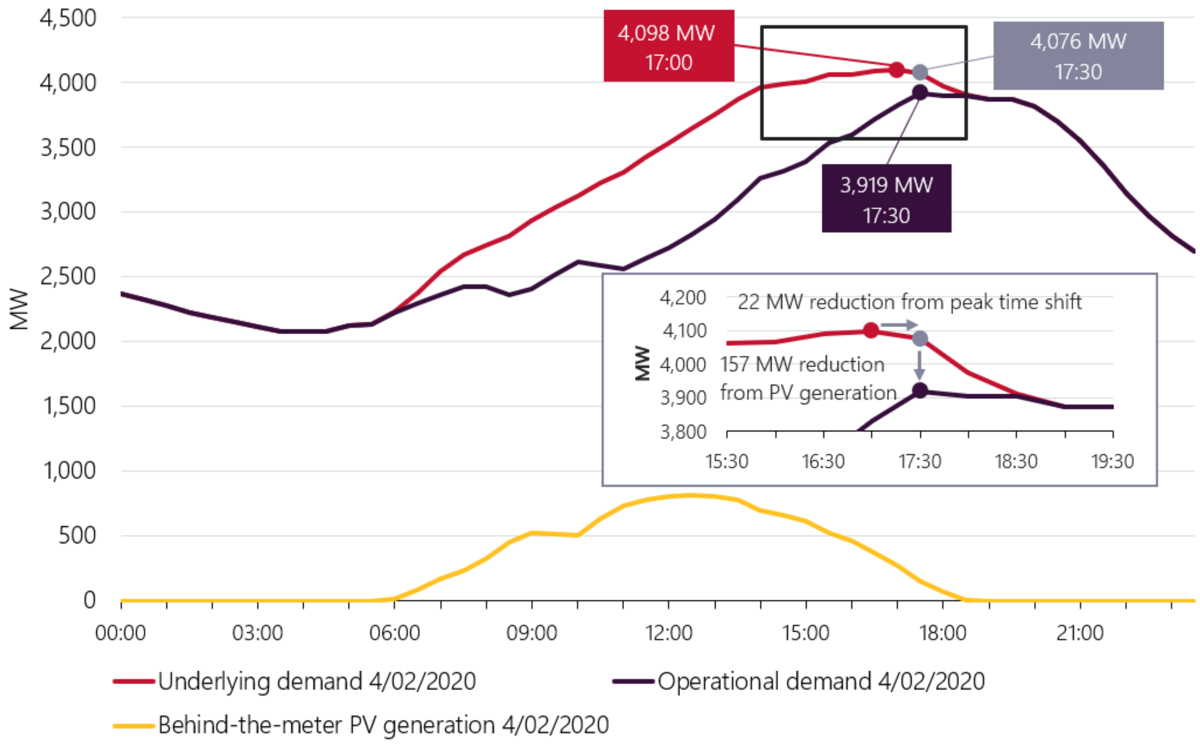
Figure 11 compares the demand profile between underlying and operational demand on this day, illustrating that:

- The underlying peak is estimated at 4,098 MW and occurred during the 17:00 to 17:30 Trading Interval, one interval before the occurrence of operational peak.
- The difference between the underlying peak and the operational peak is approximately 179 MW; 22 MW of the difference is caused by the peak time shift effect, and 157 MW is caused by the direct reduction in demand as a result of behind-the-meter PV generation. The time shift effect is comparatively smaller than the 2018-19 underlying peak, because the underlying peak occurred later in the day. Last year saw an

[68] Night-time minimums on 3 and 4 of February were among the highest (top seven of 91 days) observed in the Hot Season.

underlying peak during the 14:00 to 14:30 Trading Interval and a 193 MW reduction from the peak time shift effect.

Figure 11 Operational and underlying demand profiles on underlying and observed peak demand day, 4 February 2020



Historically, underlying peak demand has commonly occurred on the same day as peak demand. This can be noted in Table 5, which compares estimated underlying peak demand with operational peak demand for the past eight years.

In this comparison:

- The 2019-20 summer underlying peak is:
  - The highest observed underlying peak since 2015-16.
  - The latest occurring annual underlying peak in the observation period, occuring in the 17:00 to 17:30 Trading Interval.
- Underlying peak demand has occurred on the same day as peak demand since 2012-13 in all but two cases.
- With the exception of 2013-14, underlying peak has consistently occurred among the three hottest days in the Capacity Year.

Table 5 Comparison of underlying peak demand days, 2012-13 to 2019-20

Capacity Year	Date of underlying peak	Estimated underlying peak Trading Interval	Estimated underlying peak demand (MW)	Peak demand Trading Interval	Peak demand (MW)	Reduction in peak from PV generation (MW)[A]	Reduction in peak demand from peak time shift (MW)[A]	Rank of day[B]
2019-20	4 February 2020	17:00	4,098	17:30	3,919	157	22	1
2018-19	20 January 2019 [C]	14:00	3,543	17:30	3,256	149	139	1
2017-18	13 March 2018	16:30	3,750	17:30	3,616	65	68	2
2016-17	21 December 2016	15:30	3,725	17:00	3,543	115	67	2
2015-16	8 February 2016	16:30	4,146	17:30	4,004	75	67	3
2014-15	5 January 2015	15:30	3,862	15:30	3,744	118	0	1
2013-14	21 January 2014[C]	16:30	3,784	17:30	3,702	48	34	11
2012-13	12 February 2013	16:00	3,797	16:30	3,739	52	6	2

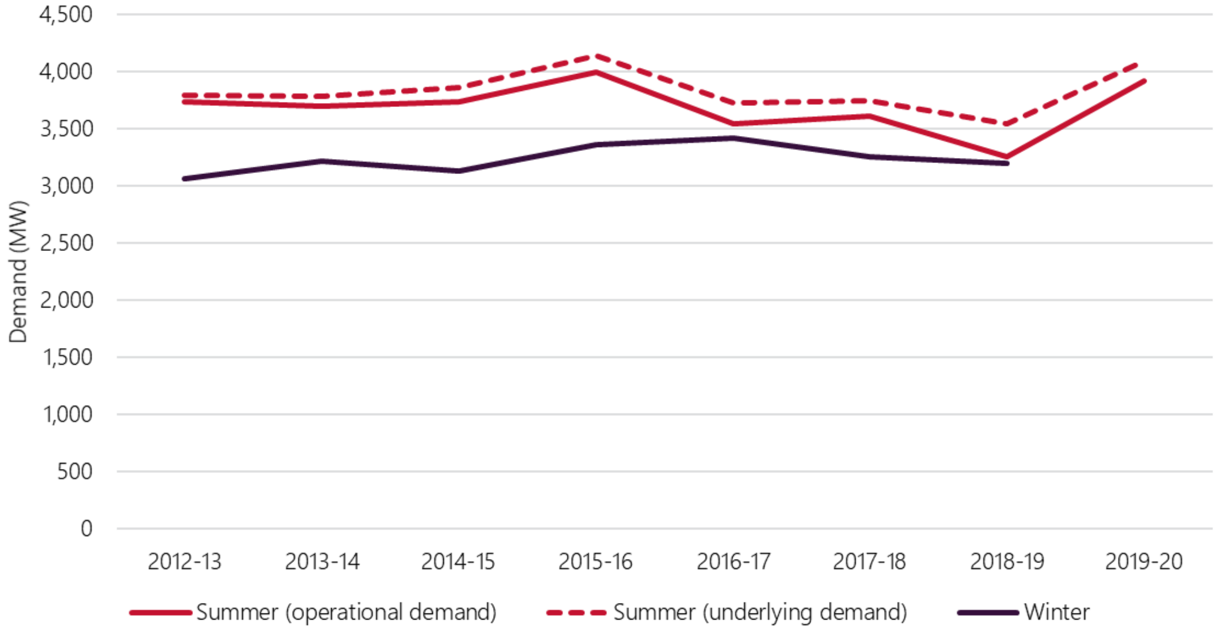
A. Estimated behind-the-meter PV generation differs from estimations shown in previous ESOOs due to methodology improvements in estimating the solar capacity factor traces. These traces are now sourced from Solcast.
B. A rank of 1 indicates it was the hottest day in the Capacity Year, 2 indicates the second hottest day, and so on.
C. Underlying peak occurred on a different day to peak demand.
Source: AEMO, Solcast and BOM.

3.1.3 Seasonal trends and winter peak demand

Summer and winter peak demands have shown different growth trends over the past eight years, as shown in Figure 12. The following observations can be made:

- Between 2012-13 and 2015-16, operational peaks during both seasons were steadily increasing, at an average annual rate of 2.3% and 3.1% for summer and winter respectively.
- Between 2015-16 and 2018-19, the summer peak has trended downward at a faster rate than the winter peak; an annual average reduction of 6.7% in summer peak was observed, compared with a 1.7% reduction for the winter peak during this period.
  - This trend resulted in a convergence of summer and winter peak demand in 2018-19, with a difference of only 56 MW between summer and winter peaks in that Capacity Year. In comparison with historical trends, this represents an unusually low disparity between seasonal peaks.
  - While the downward trend in summer peaks has been accelerated by the impacts of behind-the-meter PV, as indicated by the slower decline in underlying peak demand (5.1% annual average reduction between the same years), peaks in underlying demand are still trending downward during this period.
- The 2019-20 summer peak marks a deviation from the recent downward trend; this comparatively high summer peak has been discussed in detail in the previous sections.
- Winter operational and underlying peak demand values are identical for the observed period. This is because winter peak has historically occurred during night-time hours when there is no effect from behind-the-meter PV generation.

Figure 12 Summer and winter peak demand, 2012-13 to 2019-20[A]



A. At the time of publication, values for winter 2020 were not available. No distinction has been made between winter peaks for operational demand and underlying demand, as the values are identical for the observed period.

Peak demand for the 2019 winter period was 3,199 MW and occurred on 10 June 2019 during the 18:00 to 18:30 Trading Interval. Table 6 compares this winter peak with previous winter peaks to 2012-13. Table 6 illustrates that winter peaks have progressively occurred on warmer days, denoted by upward trends in daily minimum and daily median temperatures on winter peak days.

Table 6 Comparison of winter peak demand days, 2012-13 to 2018-19

Capacity Year	Date	Trading Interval of winter peak demand	Peak demand (MW)	Daily minimum temperature (°C)	Daily median temperature (°C)	Daily maximum temperature (°C)
2018-19	10 June 2018	18:00	3,199	8.5	14.7	19.1
2017-18	9 August 2018	18:30	3,256	7.0	12.8	16.8
2016-17	31 July 2017	18:00	3,419	7.5	11.2	15.7
2015-16	7 June 2016	18:00	3,366	6.5	11.3	14.9
2014-15	23 June 2015	18:00	3,135	1.8	7.5	16.8
2013-14	23 June 2014	18:00	3,217	1.3	7.0	16.0
2012-13	8 July 2013	18:00	3,071	2.5	7.8	18.5

Source: AEMO and BOM.

3.2 System minimum demand

Minimum demand in recent years has become prevalent during daytime periods. Increasing uptake of behind-the-meter PV systems is expected to continuously reduce system daytime minimum demand. This poses operational challenges and increases system security risks[69] (see Section 5.2 and Chapter 8 for further discussion). AEMO conducted analysis of historical minimum demand in this section to identify historical and seasonal trends in minimum demand[70].

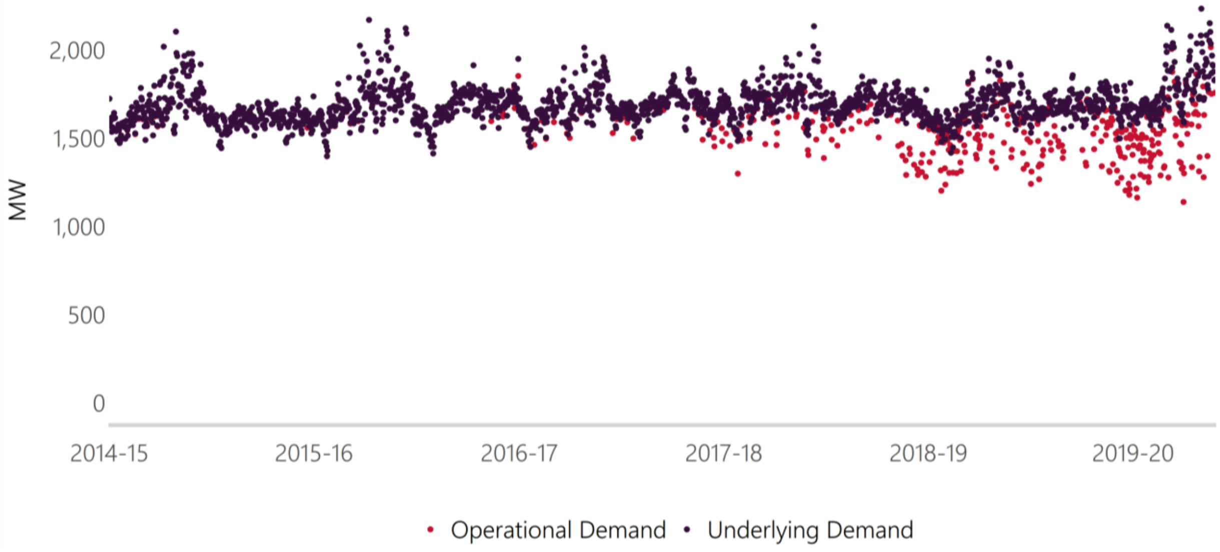
3.2.1 Historical trends

Historically, daily minimum demand occurred during overnight periods when residential and commercial energy use was typically low. However, the rapid uptake of behind-the-meter PV is now contributing to increasingly low mid-day system demand, despite there being no equivalent reduction in underlying demand during these periods.

Figure 13 illustrates the impact of behind-the-meter PV on reducing system minimum demand. It compares historical daily minimums between operational demand and underlying demand over the period 2014-15 to 2019-20, showing that:

- Annual minimums in underlying demand have grown marginally, at an average annual rate of 1.7% between 2014-15 to 2019-20. This is driven by relatively consistent energy use patterns during low demand (typically overnight) periods[71].
- Annual minimum values in operational demand have reduced at an average annual rate of 4.6% between 2014-15 to 2019-20[72]. This is most notable from 2017-18 onwards, where the frequency of daily minimums for operational demand below those of underlying demand can be seen to increase. This was solely the effect of behind-the-meter PV generation offsetting demand that would otherwise be met by the grid. In the period October 2019 to February 2020, behind-the-meter PV was estimated to have reduced demand during daytime minimums by an average of 595 MW[73].

Figure 13 Daily minimum load, 2014-15 to 2019-20[A]



A. 2019-20 Capacity Year data includes up to 29 February 2020.

[69] AEMO 2019. *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS*, at https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf?la=en&hash=3A7FEBC1F00F0FDE97DB8213AD58D488.

[70] Throughout this section, temperature data, season, and demand definitions are the same as Section 3.1. Data is presented in Capacity Year unless otherwise specified.

[71] During the observed period, approximately 94.5% of daily minimums in underlying demand occurred during night-time hours.

[72] Metered demand values for the 2019-20 Capacity Year are incomplete and include up to 29 February 2020.

[73] This value is the average of behind-the-meter PV generation at the time of daily minimum operational demand, during daytime hours only. In summer and shoulder seasons, earlier sunrises mean that daily minimums that occur during early morning hours (5:30 to 6:30) are captured in this average, when behind-the-meter PV generation is typically negligible (less than 20 MW). The impact of behind-the-meter PV generation is highest between the hours of 11:00 to 14:00 (ranging from 470 MW to 918 MW).

To further demonstrate these trends, Table 7 shows record minimums in operational demand for 2014-15 to 2019-20.

The following observations can be made:

- Before 2017-18, all record minimums occurred during overnight/early morning periods, which are typically characterised by low electricity demand.
- In the most recent three years (2017-18 onwards):
  - All record daily minimums have occurred during daytime hours that corresponded with periods of high behind-the-meter PV generation.
  - Behind-the-meter PV generation during these Trading Intervals was estimated to account for 39%, on average, of total underlying demand.
  - The most recent three minimum demands values were the lowest observed.
- These trends can primarily be explained by increasing behind-the-meter PV installations; between 2016-17 and 2019-20, installed capacity of behind-the-meter PV more than doubled.

Table 7 Comparison of minimum demand days, 2014-15 to 2019-20

Capacity Year	Date	Trading Interval of minimum demand	Minimum demand (MW)	Estimated impact of PV at time of minimum (MW)	Estimated PV installed capacity (MW)	Estimated PV capacity factor at time of minimum (%)
2019-20[A]	4 January 2020	11:00	1,138	896	1,305	69
2018-19	29 September 2019	11:30	1,179	814	1,224	66
2017-18	30 September 2018	12:30	1,282	612	989	62
2016-17	23 October 2016	03:30	1,451	-	622	0
2015-16	25 October 2015	05:30	1,397	-	506	0
2014-15	19 April 2015	03:30	1,444	-	455	0

A. 2019-20 Capacity Year includes up to 29 February 2020 (maximum data available at time of publication).
Source: AEMO, Solcast and BOM.

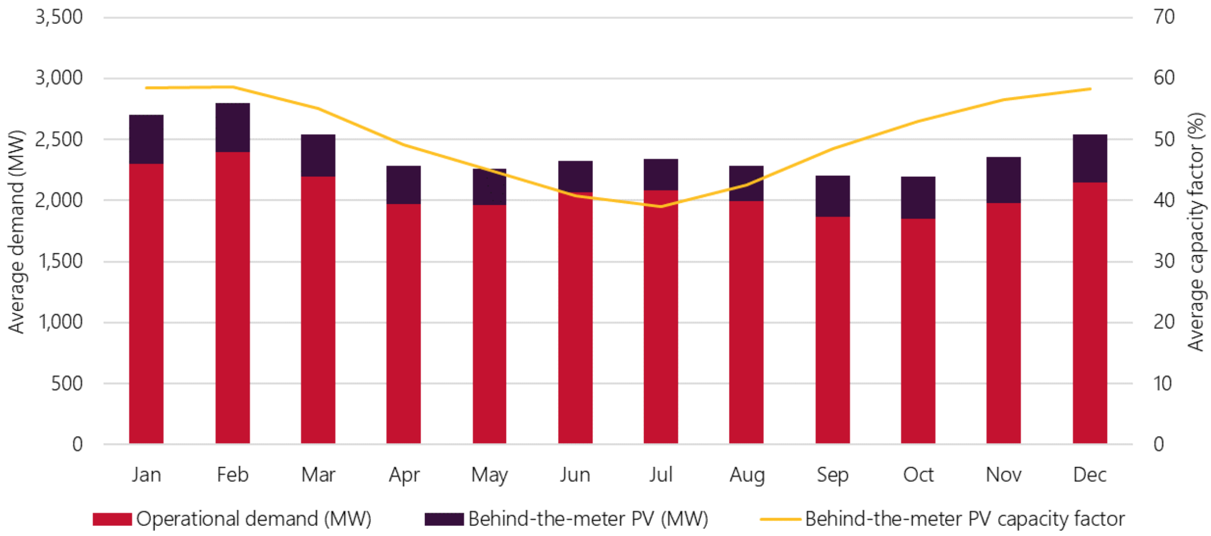
3.2.2 Seasonal trends

Concurrent with the appearance of daytime minimum demand in recent years, new seasonal trends in minimum demand emerged.

Low overnight demand is driven mostly by mild temperatures and has historically occurred during the shoulder seasons. However, yearly daytime minimums often occur in late spring (October and November), when mild temperatures and sunny weather conditions lead to a combination of low electricity demand and high behind-the-meter PV generation.

Figure 14 highlights contributing factors to seasonal trends in low demand. It shows monthly averages in underlying demand and behind-the-meter PV capacity factor, during midday hours when low demands are prevalent. The latter half of the year represents a concurrence of high behind-the-meter PV generation and relatively low underlying demand. With increasing installations in behind-the-meter PV, these conditions are expected to lead to an increasing number of extreme lows in operational demand during the daytime.

Figure 14 Monthly averages for underlying demand and behind-the-meter PV capacity factors, during the hours of 10:00 and 14:00[A]



A. All figure values are calculated using the data pertaining to 2012-13 to 2019-20 inclusive. The 2019-20 Capacity Year includes up to 29 February 2020.

Further illustration of the seasonal effect of behind-the-meter PV is shown in Figure 15, which compares the distribution density between underlying and operational demand to infer the effect of behind-the-meter PV. Figure 15 depicts the distribution of demand, where a given level of demand corresponds with a density (indicating frequency of occurrence). The figure was generated using half-hourly data for the 2018-19 Capacity Year, filtered for Trading Intervals that occurred during daylight hours[74].

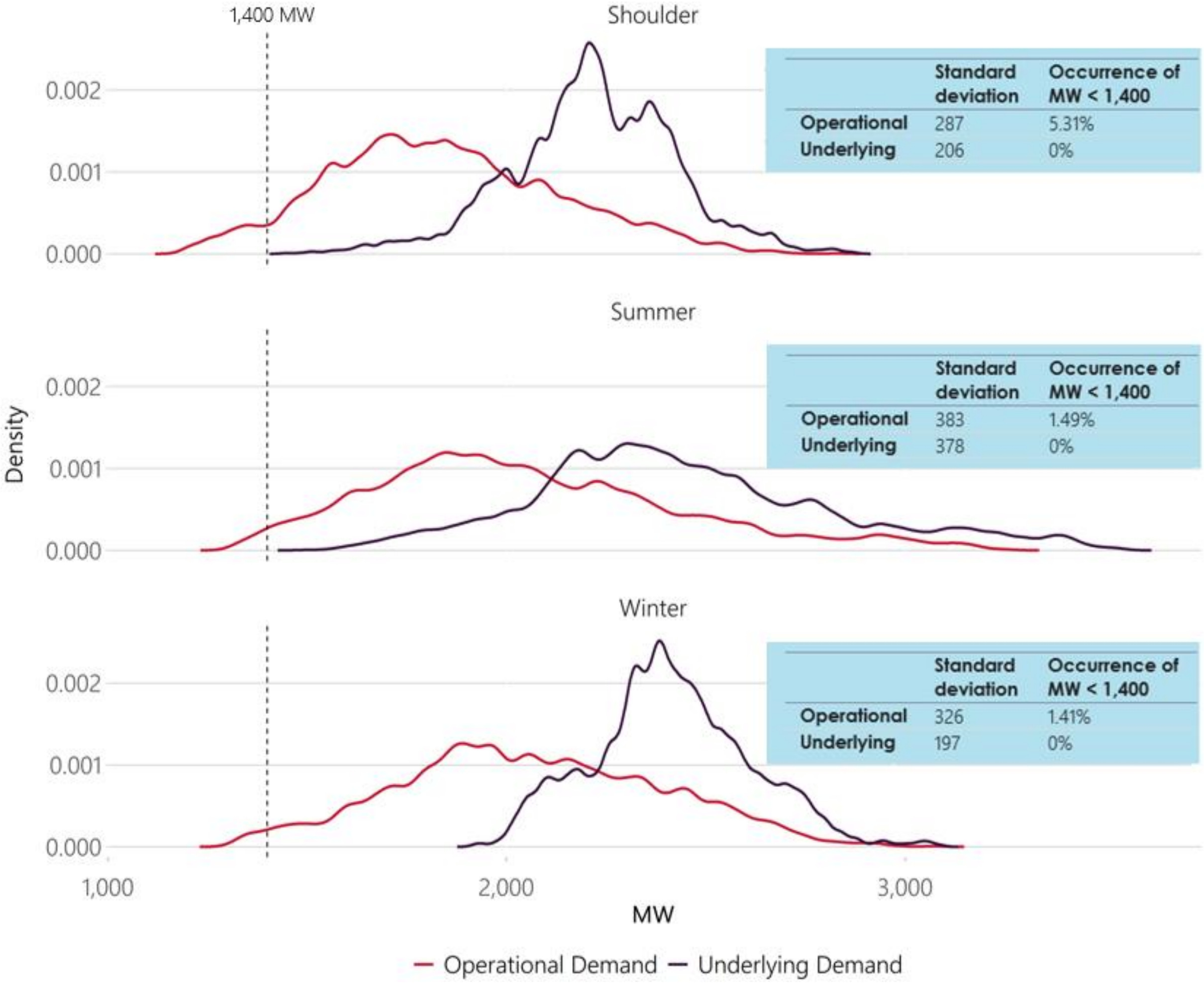
Figure 15 highlights that:

- In all seasons:
  - Behind-the-meter PV has a proportionally larger effect during periods of low demand, denoted by the leftward slant in the curves representing operational demand. During low demand periods, the differences between operational and underlying demand are larger than during times of high demand, because high demand usually occurs during late afternoon/evening when behind-the-meter PV output is relatively low.
  - Operational demand is more widely distributed than underlying demand, meaning behind-the-meter PV is leading to increased variability in operational demand. In Figure 15, standard deviation has been included to demonstrate this increased variability. Variability is occurring in practice on both intra-day and inter-day timescales.
- In the shoulder season, operational demand occurs at lower levels more frequently than other seasons. This can be noted in the figure by the higher number of intervals occurring below 1,400 MW[75] in the shoulder seasons; 5.31% compared with 1.49% and 1.41% for summer and winter respectively.
- In summer, both operational and underlying demand are more widely distributed, indicating high variability during this season (see the higher standard deviation). This can be explained by temperature patterns during the summer season, which range from typical comfortable temperatures (~22°C) that are known to drive mild demand days, to high temperatures corresponding with peak demand.

[74] Daylight intervals were determined based on historical sunrise and sunset times for the Perth area, to the nearest half-hour.

[75] 1,400 MW has been chosen as a benchmark value to demonstrate the seasonal patterns in demand.

Figure 15 Distribution density of daytime operational and underlying demand, 2018-19A



A. The operational demand minimums for the 2018-19 Capacity Year are as follows: shoulder 1,179 MW, summer 1,313 MW, winter 1,308 MW.

3.2.3 Minimum demand in 2019-20

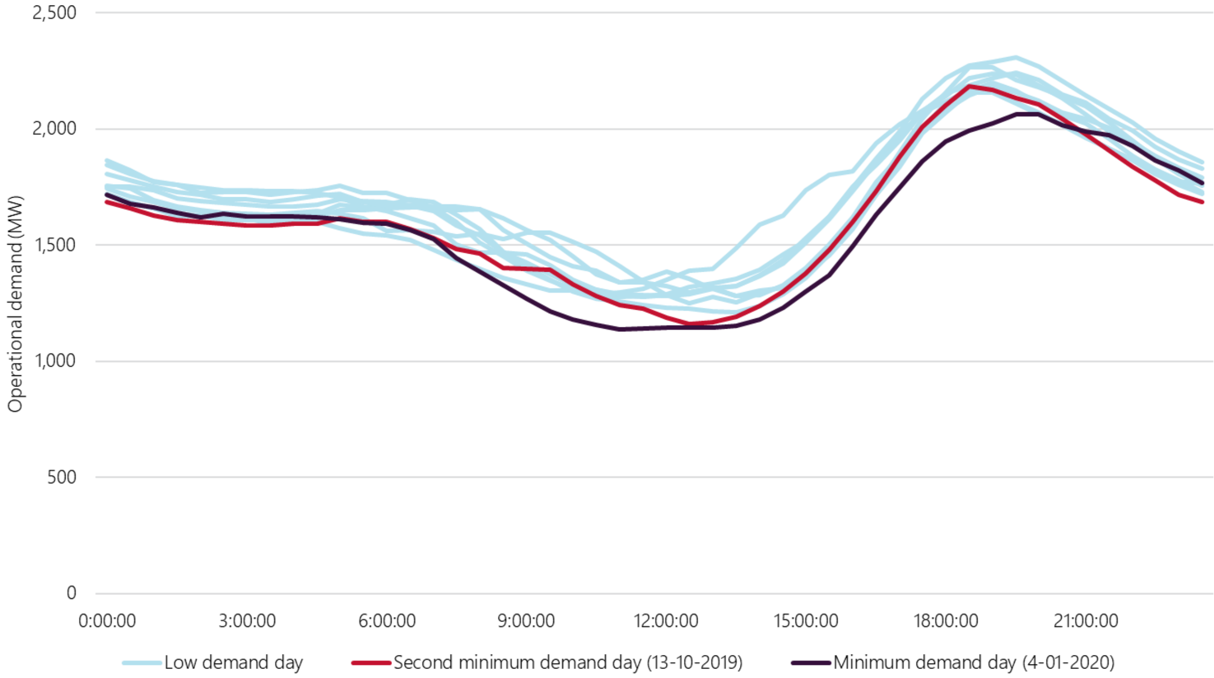
The previous minimum demand record of 1,179 MW (set 29 September 2019) was broken on two occasions during 2019-20. These occurred on 13 October 2019 when demand reached 1,162 MW during the 12:30 to 01:00 Trading Interval and on 4 January 2020 when the current record was set at 1,138 MW, observed in the 11:00 to 11:30 Trading Interval.

Observations regarding 4 January 2020 include:

- The record demand low occurring during summer is a break from typical seasonal trends. However, temperatures were mild and comparable to a typical shoulder season, ranging from 12°C to 27°C. Effects of mild temperatures on this day may have been compounded by early January timing, as periods surrounding Christmas and New Year have the potential to experience lower demands through an increase in observed non-working days.
- Behind-the-meter PV generation reached a peak of 924 MW during the 12:00 Trading Interval, which is estimated to be the second-highest MW level of PV output recorded.

Figure 16 shows demand on the 10 lowest demand days for 2019-20. On two of these days, demand reached minimums lower than any experienced since market start in 2006.

Figure 16 Demand on the 10 low demand days for 2019-20[A]



A. The 2019-20 Capacity Year includes up to 29 February 2020 (maximum data available at time of publication).

As minimum demand records continue to be broken year-on-year due to increasing behind-the-meter PV generation, there are growing challenges for system operation. These include increased requirements on fleet ramping capability to facilitate the transition between daily troughs and evening peaks, and challenges associated with reduced proportions of synchronous generation online during midday periods[76] (see Chapter 8 for further discussion).

3.3 Historical energy consumption

Historical energy consumption investigates total operational and underlying consumption, including behind-the-meter PV generation and residential consumption, for the period 2011-12 to 2018-19 in the SWIS.

Data in all figures is presented in financial years unless otherwise specified.

3.3.1 Operational consumption

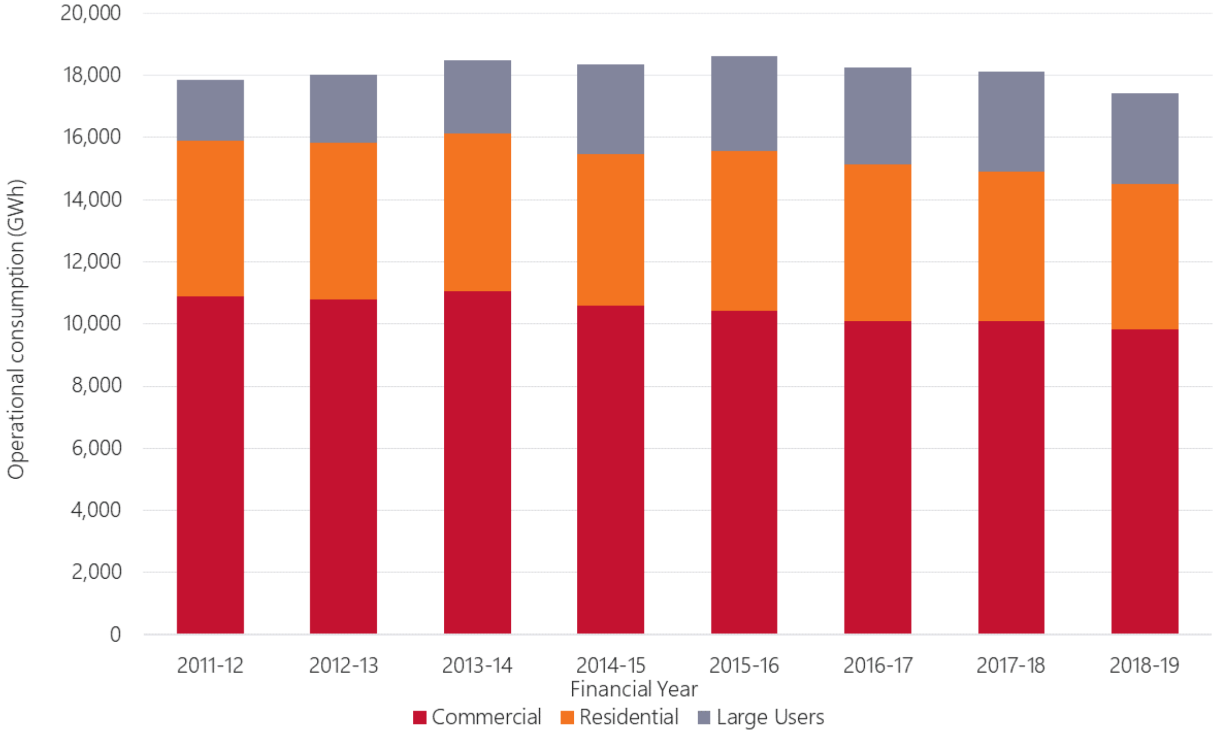
Figure 17 shows the breakdown of total operational consumption[77] into commercial, residential, and large users[78].

[76] As output from behind-the-meter PV offsets operational demand, it results in less demand being provided for by synchronous generators. This can have implications for power system operation, including system stability, inertia, frequency management, and voltage management.

[77] Electricity consumption that is met by all utility-scale generation. Consumption met by behind-the-meter PV generation is not included in this value. Operational consumption includes consumption from electric vehicles (EVs).

[78] Large users are defined as customers using more than 20 MW. They are not the same as Large Industrial Loads, or LILs (see Chapter 4).

Figure 17 Total operational consumption, 2011-12 to 2018-19



Source: AEMO and Synergy.

Total operational consumption increased by 3.6% over the period 2011-12 to 2013-14, as a result of a 19.8% growth in consumption from large users (including desalination plants and large mines). For the period 2013-14 to 2018-19, total operational consumption declined at an average annual rate of 1.2%, despite large user consumption increasing over this period. The decline was mostly driven by behind-the-meter PV generation reducing residential and commercial operational consumption.

Operational residential and commercial consumption decreased at an average annual rate of 1.0% and 1.4% respectively between 2011-12 and 2018-19. In 2018-19, commercial and residential consumption accounted for 83% of total operational consumption, compared to 89% in 2011-12.

Large user consumption grew over the period 2011-12 to 2017-18 but declined by 8.8% between 2017-18 and 2018-19. This decline is partially due to a significant reduction in consumption by large loads during last year's rainy season, and maintenance outages for large mines.

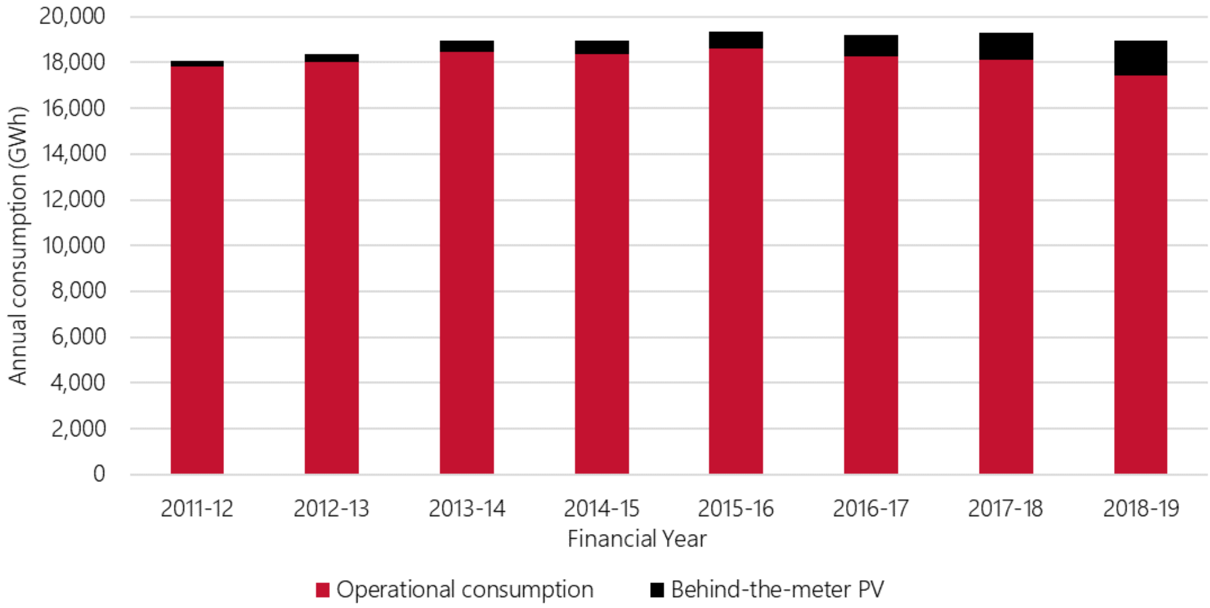
3.3.2 Underlying consumption

AEMO's estimates of historical underlying consumption, representing both electricity consumed from the SWIS and residential and commercial consumption met by behind-the-meter PV, are shown in Figure 18.

Total underlying consumption increased by 5% over the period 2011-12 to 2013-14 due to growth in large user consumption. Since 2013-14, total underlying consumption has remained relatively consistent.

The reduction in operational consumption in the same period is largely attributed to behind-the-meter PV generation, which has increased by 235%, from 459 GWh in 2013-14 to 1,537 GWh in 2018-19.

Figure 18 Operational consumption and behind-the-meter PV generation, 2011-12 and 2018-19

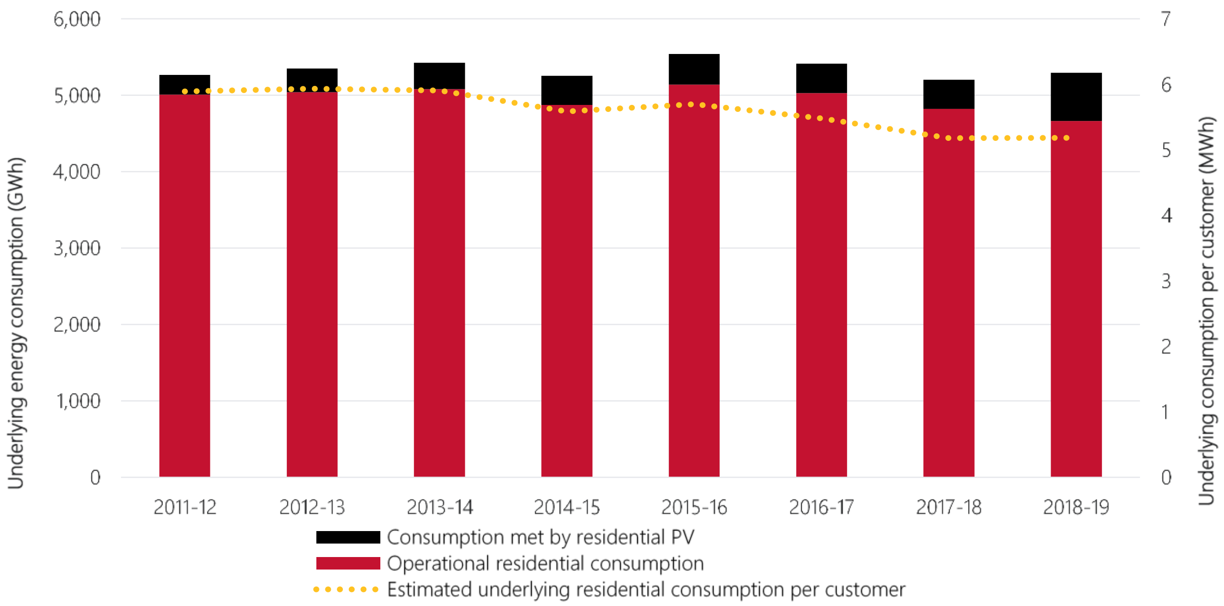


Source: AEMO calculations based on Synergy data.

3.3.3 Underlying and operational residential consumption

AEMO calculated underlying residential consumption over the period 2011-12 to 2018-19, as shown in Figure 19. This includes energy supplied by the SWIS grid plus energy supplied by residential behind-the-meter PV generation[79].

Figure 19 Underlying residential consumption, 2011-12 to 2018-19



Source: AEMO calculations based on Synergy data.

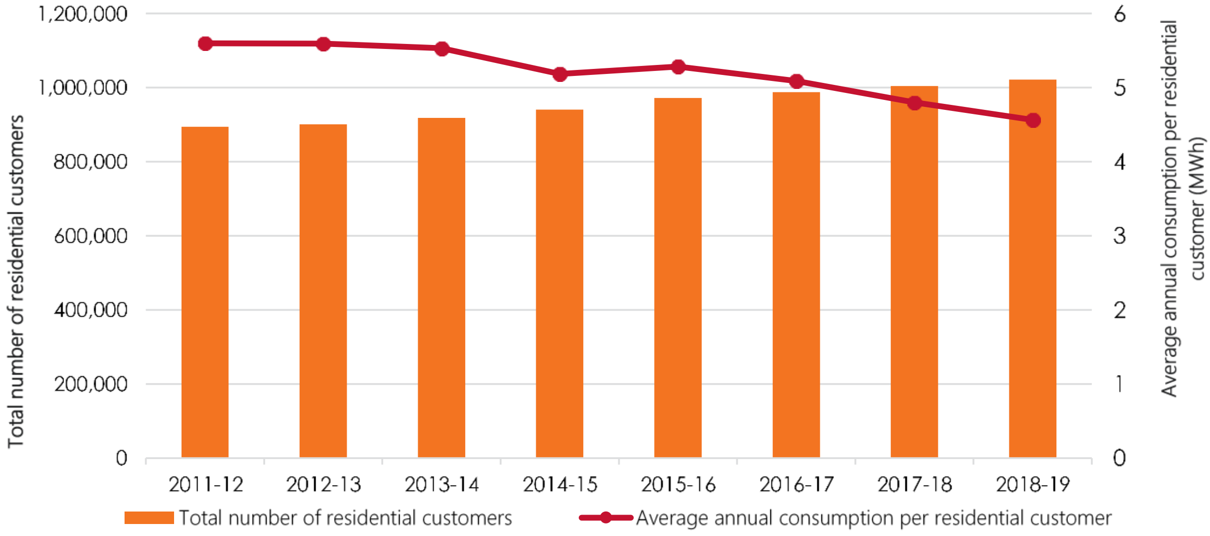
Underlying residential consumption has remained relatively stable over the past eight years, despite continued growth in residential customer numbers (see Figure 20). This is due to the reduction in average underlying residential consumption per customer over time.

[79] Values for residential behind-the-meter PV in this section are based on Synergy data.

Figure 20 shows that average annual underlying residential consumption per customer has reduced at an average annual rate of 1.8% from 5.9 MWh in 2011-12 to 5.2 MWh in 2018-19. This can be largely explained by improved energy efficiencies in both residential buildings (such as improvements in insulation and ventilation) and home appliances (for example, LED lighting and Energy Star certified appliances such as televisions, refrigerators, and dishwashers).

The share of underlying residential consumption met by residential behind-the-meter PV generation has doubled, from 6% in 2011-12 to 12% in 2018-19. This has further reduced average annual operation residential consumption per customer, from 5.6 MWh in 2011-12 to 4.6 MWh in 2018-19, at an annual average rate of 2.9%.

Figure 20 Annual average consumption per residential customer, 2011-12 to 2018-19



Source: AEMO calculations based on Synergy data.

Residential behind-the-meter PV generation, combined with energy efficiency improvement, has reduced average operational residential consumption per customer at a faster rate than growth in new customer connections, placing downward pressure on total operational residential consumption. AEMO expects these trends to continue and that this will continue to decrease operational residential consumption over the outlook period.

4. Forecast methodology and assumptions

This chapter describes the methodology and assumptions used to develop operational peak demand[80] and operational consumption forecasts for the 2020-21 to 2029-30 Capacity Years. It discusses the main drivers affecting the forecasts, including:

- Uptake of DER technologies[81] (behind-the-meter PV, battery storage systems, and electric vehicles [EVs]).
- Economic growth.
- Large Industrial Loads (LILs)[82].

4.1 Forecast methodology

4.1.1 Overview

For the first time, the peak demand and operational consumption forecasts for this WEM ESOO have been developed in-house by AEMO[83].

The forecasting methodologies[84] applied are consistent with those used for the 2019 National Electricity Market (NEM) ESOO while taking into consideration WEM-specific features. This consistent approach allows the WEM to be compared against other regions in Australia.

AEMO continues to evolve its forecasting methodologies to suit new market developments, based on its observations and consultation with stakeholders.

Development of the peak demand and operational consumption forecasts for this 2020 WEM ESOO was based on the forecasting methodologies outlined in the *2019 Electricity Demand Forecasting Methodology Information Paper (Methodology Information Paper)*[85]. This section summarises the methodologies, focusing on the WEM-specific features and improvements compared to the 2019 WEM ESOO.

Key definitions

Table 8 lists definitions for demand and energy consumption terms used in this WEM ESOO.

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[80] Peak demand refers to operational peak demand unless otherwise specified.

[81] DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter. Any generators that are connected to the distribution network that are assigned Capacity Credits are not included in the definition of DER technologies, for example Northam Solar Farm.

[82] LILs are identified based on their demand over the previous financial year and use more than 10 MW for at least 10% of the year. This threshold aims to capture the most energy intensive consumers.

[83] AEMO has historically engaged consultants to provide annual peak demand and operational consumption forecasts for use in the WEM ESOOs.

[84] The minimum demand forecasts followed a similar approach to the peak demand forecasts.

[85] AEMO, 2019. Electricity Demand Forecasting Methodology Information paper, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2019/electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

Table 8 Definitions for key demand and consumption terms in the forecast methodology

Term	Definition
Demand	The amount of power (in MW) that is consumed on a 'sent-out' basis (excluding electricity used by a generator[A]) and averaged over a 30-minute period.
Operational demand[B]	Demand that is met by all utility-scale generation, excluding the impacts of behind-the-meter PV generation and battery storage. Operational demand includes demand from EVs.
Underlying demand	Operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage.
Consumption	The amount of electricity (in MWh or gigawatt hours [GWh]) that is used over a period of time, reported on a "sent-out" basis (excluding electricity used by a generator).
Operational consumption[C]	Electricity consumption that is met by all utility-scale generation. Consumption met by behind-the-meter PV generation is not included in this value. Operational consumption includes consumption from EVs.
Underlying consumption	Operational consumption plus an estimation of behind-the-meter PV generation.

A. This may be called 'auxiliary load', 'parasitic load', or 'self-load', referring to energy generated for use within power stations.
B. Historical operational demand is calculated as the TSOG multiplied by two, to convert non-network-loss-adjusted MWh to MW for a 30-minute Trading Interval. The historical operational peak demand and minimum demand are identified as the highest and lowest operational demand calculated for a Trading Interval in a Capacity Year, respectively.
C. Historical operational consumption is equal to the TSOG data.

Scenarios

Operational peak demand and consumption forecasts were developed based on three demand growth scenarios – low, expected, and high – for the 10-year outlook period from the 2020-21 to 2029-30 Capacity Years[86].

These scenarios stemmed from different levels of economic growth and were developed to capture uncertainties in structural drivers, such as population and gross state product (GSP) growth. A summary of the key assumptions of structural drivers for each demand growth scenario is outlined in Table 9.

For the peak demand forecasts, AEMO modelled uncertainties due to random effects including weather conditions (primarily temperature[87]), seasonal effects, and random volatility. These uncertainties were modelled using a probability distribution, where peak demand forecasts were expressed as three probability of exceedance (POE) values from the probability distribution for each scenario, including[88]:

- A 10% POE value is expected to be exceeded, on average, one year in 10, reflecting hot weather conditions.
- A 50% POE value is expected to be exceeded, on average, one year in two, reflecting average weather conditions.
- A 90% POE value is expected to be exceeded, on average, nine years in 10, reflecting mild weather conditions.

Applying a similar methodology as the 2019 WEM ESOO, the expected scenario for behind-the-meter PV uptake was used for the three demand growth scenarios. This approach was adopted because behind-the-meter PV uptake appeared to be strongly driven by the payback period (calculated based on factors such as installation cost, electricity prices and customer load sizes) and customers' adoption preferences in WA, rather than macroeconomic drivers like GSP growth. As current observed trends suggest

[86] Minimum demand forecasts are developed under the low, expected, and high scenarios for a five-year outlook period from 2020-21 to 2024-25 Capacity Years.

[87] For this WEM ESOO forecasting, temperatures are based on the Perth Airport weather station records sourced from BOM.

[88] Contrary to peak demand forecasts, for minimum demand forecasts, a 10% POE forecast represents nine years in ten on average, demand would be expected to fall below this forecast, and a 90% POE forecast represents one year in ten on average, demand would be expected to fall below this forecast.

behind-the-meter battery storage uptake is likely to follow the same pattern, the expected scenario for behind-the-meter battery storage uptake was similarly applied across the three demand growth scenarios in this 2020 WEM ESOO.

In addition to these factors, application of the expected scenarios for behind-the-meter PV and battery storage to the high and low demand growth scenarios allows the forecasts to capture a wider range of peak demand growth outcomes[89]. For example, as behind-the-meter PV acts to reduce demand; expected behind-the-meter PV uptake applied to a high demand growth scenario allows for higher demand growth than would be captured when applying the high behind-the-meter PV scenario.

Table 9 Key assumptions for low, expected and high demand forecasts

	Expected	Low	High
Demand drivers			
Economic and population growth forecasts Developed by BIS Oxford – see Section 4.3.1	Expected	Low	High
New LILs forecast Determined by AEMO – see Section 4.3.3	Expected	Low	High
Residential connections	Expected	Low	High
Energy efficiency	Expected	Low	High
DER uptake			
Behind-the-meter PV systems[A]	Expected	Expected	Expected
Behind-the-meter battery storage systems[A]	Expected	Expected	Expected
EVs[B]	Expected	Low	High

A. The behind-the-meter PV and batteries forecasts were developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO)[90] and Green Energy Markets (GEM)[91]. See Sections 4.2.1 and 4.2.2 for further information.
B. The EV forecasts were developed by CSIRO. See Section 4.2.3 for further information.

AEMO will continue to monitor trends and data availability in uptake of behind-the-meter PV and battery storage, consult with stakeholders, and update the scenario assumptions in future WEM ESOOs if required.

An additional challenge to this year's demand forecasting was incorporating the impacts of the COVID-19 pandemic. AEMO endeavoured to adjust the demand forecasts to account for COVID-19 impacts, based on external consultants' best estimates of the economic growth outlook (see Section 4.3.1) and DER uptake projections (see Section 4.2).

4.1.2 Peak demand forecasts

AEMO developed two models for the peak demand forecasts:

- A maximum Generalised Extreme Value (GEV) model.
- A half-hourly model.

The GEV model focuses on capturing and understanding the distribution of the extreme values. Comparatively, the half-hourly model is more reliant on weather, which is used to simulate half-hourly

[89] Low, expected, and high demand growth scenarios are defined in accordance with clause 4.5.10(a) of the WEM Rules.
[90] See http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report.
[91] See http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/Green-Energy-Markets-DER-Forecast-Report.

demand and model the impact of DER. AEMO applied the GEV model to estimate the peak demand in the 2019-20 summer, the base year of the forecast[92]. This estimate was used to benchmark the peak demand forecasts developed by the half-hourly model for the base year and to rebase the half-hourly model, if required. AEMO then applied the half-hourly model to grow demand out to 2029-30.

Generalised Extreme Value model

The GEV model was fitted by applying weekly operational maximums as a function of behind-the-meter PV capacity (MW), customer connections, calendar effect, average weather, and average solar irradiance. The GEV models were applied to simulate peak demand for each week, which were then aggregated to the seasonal peak demand (summer and winter). The peak demand forecasts developed by the GEV were used for the base year, and the half-hourly model then forecast the year-on-year change in demand accounting for shifts in time of day for peak demand.

Half-hourly forecasting model

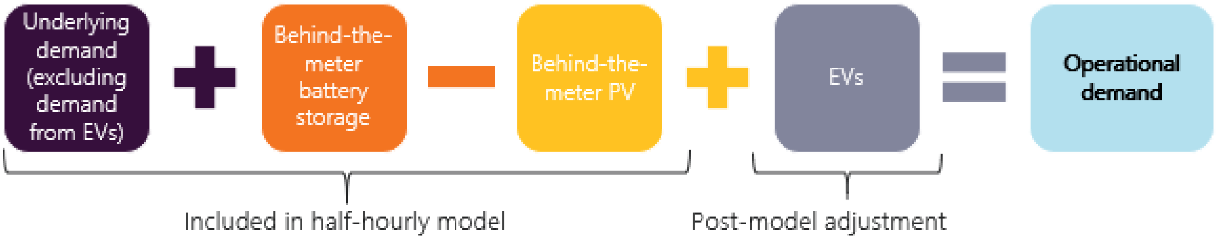
AEMO developed a half-hourly regression model for the peak demand forecasts for the 2020 WEM ESOO. This model forecasts half-hourly demand by simulating the relationship between underlying demand and key explanatory variables (including weather effects) and calendar effects (such as public holidays, the day of the week, and the month).

The forecasting process split forecast demand for each half-hour into heating load, cooling load, and base load elements[93]. Half-hourly heating load, cooling load, and base load were then increased by annual or seasonal growth indices. These indices were derived from, and on the same basis as the operational energy consumption forecasts. These projections include structural drivers including economic conditions (such as electricity price, GSP growth, and industrial activity) and demographic conditions (such as connections growth).

The resulting underlying demand forecasts (excluding demand from EVs), along with forecasts of uptake of behind-the-meter PV and battery storage, were then modelled on a half-hourly basis to capture variation in these components as a result of weather effects. The resulting demand value was adjusted to reflect the impact of the modelled behind-the-meter PV and battery storage components. This result was then adjusted post-modelling by the impact of EV operation.

This process (depicted in Figure 21) derived the operational demand forecasts by accounting for the impact of generation of behind-the-meter PV and operation of behind-the-meter battery storage and EVs on underlying demand.

Figure 21 Adjustment process for half-hourly modelled demand[A]



A. The impact of behind-the-meter battery storage in this context is either positive (increasing demand due to charging) or negative (decreasing demand due to discharging).

[92] Actual demand data for the 2019-20 summer was available at the time of forecasting, however the base year is re-estimated by the GEV model to establish a probability distribution of operational peak demand to calculate the POE operational peak demand values.

[93] Heating/cooling load is defined as temperature dependent consumption (e.g. electricity used for heating/cooling). Load that is independent of temperature (e.g. electricity used in cooking) is called base load or non-heating load.

For each year of the outlook period, the half-hourly model was run for 1,000 simulated weather years. From the 1,000 simulated annual peak demand values, AEMO then extracted the necessary 10% POE, 50% POE, and 90% POE peak values and associated peak timing.

The half-hourly model better accounted for the impact of DER on demand, including shifts in peak demand timing, compared to the annual peak demand forecasting model applied in the 2019 WEM ESOO. This is primarily because the previous model assumed static timing of peak demand throughout the outlook period for assessing the effect on peak of behind-the-meter PV and battery storage. Since uptake of behind-the-meter PV was expected to grow strongly, the subsequent peak shifting effects were not captured.

Due to this modelling improvement, compared with the 2019 WEM ESOO forecasts, this year's modelling results observed more variation in peak demand levels as a result of behind-the-meter PV and battery storage impacts. This variation affected the tail ends of the distributions (10% POE and 90% POE) in particular, which become increasingly difficult to estimate. In the peak demand forecasts, higher variation in the 10% POE and 90% POE is observed when compared with the 50% POE (discussed further in Chapter 5).

An average annual temperature increase of 0.031°C per year adjustment, based on AEMO's analysis of climate projections, was applied for the half-hourly modelling over the outlook period. This process recognised that climate change is impacting future weather outcomes. AEMO is working with the BOM and CSIRO on improving future climate data, including forecast temperature changes (versus today's climate) on extreme days and growth in the number of consecutive hot days. This will be incorporated into AEMO's forecasts as data becomes available[94].

Further information about the peak demand forecasts applying the GEV model and the half-hourly model is provided in Chapter 5 of the *Methodology Information Paper*.

4.1.3 Minimum demand forecasts

For the first time, AEMO developed forecasts of minimum demand in the SWIS. The methodology applied for minimum demand forecasts was similar to that applied for the peak demand forecasts, in that AEMO applied a minimum GEV model and a half-hourly model. Key differences in the methodology applied are outlined below:

- Minimum demand forecasts produced by the half-hourly model were re-based using results from the minimum GEV model, because the GEV model was seen to be comparatively more accurate at modelling minimum demand levels than the half-hourly model.
- Minimum demand forecasts are presented for a five-year outlook period, from 2020-21 to 2024-25 Capacity Years. Reasons for this are explained in Section 5.2.

4.1.4 Operational consumption forecasts

AEMO developed the annual operational consumption forecasts for the low, expected, and high demand growth scenarios based on the scenario assumptions outlined in Table 10. These forecasts were segmented into two broad customer sectors, business and residential.

Business consumption forecasts

In forecasting business consumption, AEMO modelled LILs separately from the broader small to medium enterprises (SME) business sector, based on the observation that they have historically been subject to different underlying energy consumption drivers.

Large industrial loads consumption forecast

LILs are defined as loads which use more than 10 MW for at least 10% of the year and were identified based on their demand over the previous financial year. This definition captures the most energy-intensive

[94] The project outcomes can be followed at https://aemo.com.au/initiatives/strategic-partnerships/planning-initiatives.

transmission- and distribution-connected consumers in the SWIS, including mining and mineral processing loads.

For existing LILs, AEMO adopted a survey-based approach to forecast electricity consumption, which was supplemented by obtaining additional information through interviews. The survey collected information on forecast electricity consumption (MWh) and maximum demand (MW) for each demand growth scenario.

AEMO engaged with industry stakeholders including Western Power and the WA Department of Jobs, Tourism, Science and Innovation to identify new LILs and the appropriate demand growth scenario. AEMO developed demand and energy consumption forecasts for new LILs based on their contracted maximum demand, adjusted by diversity factors[95]. Forecasts of these new LILs are detailed in Section 4.3.3.

For more information on the LIL forecasting process, see Section 2.2.1 of the *Methodology Information Paper*.

Small to medium enterprise underlying consumption forecast

SME consumption forecasts[96] were developed using short-term and long-term models. The short-term model was used to forecast consumption in the base year (2019-20), accounting for weather-sensitive loads. The long-term model grew the short-term forecasts from the base year by applying economic drivers, including GSP and commercial electricity prices[97].

The short-term model applied a linear regression to forecast the SME underlying consumption by considering heating degree days (HDD)[98], cooling degree days (CDD)[99], and a dummy variable for weekends and public holidays. A heating benchmark temperature of 18°C and a cooling benchmark temperature of 21°C were used to calculate HDD and CDD. The short-term model predicted the weather normalised[100] starting year forecast in the absence of behavioural changes to economic drivers. This provided a starting point (to reflect current consumption patterns) that considered intra-year seasonality and holiday and weather variations.

Based on the coefficients estimated in the short-term model, the heating load, cooling load, and base load segments were then estimated for the long-term model. The long-term model also applied linear regression, with coefficients representing elasticity response of the independent variables (GSP and business electricity prices). For each forecast year:

- The heating/cooling load for each forecast period was estimated by applying the short-term model's heating/cooling load coefficients to the GSP and price projections (after adjusting for climate change and energy efficiency impacts).
- The base load for each forecast period was estimated by applying the SME base load coefficient to the GSP and price projections (after adjusting for climate change and energy efficiency impacts).

A climate change index was applied by adjusting the heating and cooling load forecasts, where average temperature was adjusted by an increase of 0.031°C per year.

AEMO developed energy efficiency estimates for the WEM by applying a similar approach as the energy efficiency savings forecast developed by a consultant (Strategy. Policy. Research. Pty Ltd) in 2019 for the residential and commercial sectors[101].

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[95] Diversity factors are weightings applied to a new LIL's contracted maximum demand to account for different consumption levels during the load's operation.

[96] This covers any distribution connected loads excluded from the LIL category.

[97] Future commercial electricity prices estimated using projections of the cost of future generation in the SWIS.

[98] The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.

[99] The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.

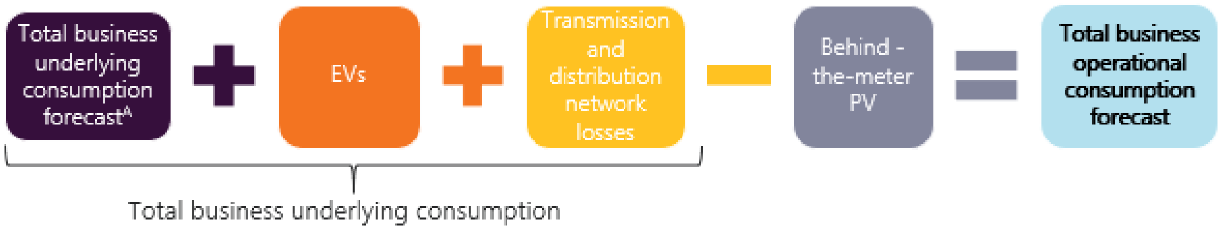
[100] See Appendix A2 of the *Methodology Information Paper*.

[101] Strategy. Policy. Research. Pty Ltd. Energy Efficiency Forecasts: 2019 - 2041. July 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/StrategyPolicyResearch_2019_Energy_Efficiency_Forecasts_Final_Report.pdf.

Total business operational consumption forecasts

The total business underlying consumption forecasts are the aggregate of the LIL forecasts and the SME underlying consumption forecasts (excluding consumption from EVs). The total business operational consumption forecasts were developed by applying the adjustments to the total business underlying consumption forecasts to account for the impact of electricity consumption of EVs and generation of behind-the-meter PV, as shown in Figure 22[102].

Figure 22 Adjustment process for final business operational consumption forecasts[A]



A. Excluding network losses and consumption from EVs.

Further information on business consumption forecasts is in Chapter 2 of the *Methodology Information Paper*.

Residential consumption forecasts

AEMO applied a "growth" model to develop 10-year annual residential electricity consumption forecasts based on historical residential connections[103] and monthly consumption data that was supplied by Synergy.

The residential operational consumption forecast was generated by applying the following steps:

1. The monthly average underlying consumption per residential connection was estimated for a five-year period (2014-15 to 2018-19 financial years). The five-year period was chosen to capture the most recent residential consumption patterns and seasonality.
2. A regression model was applied to the monthly data for the five-year period from step 1, using average monthly underlying consumption per connection, CDD, and HDD. The monthly average underlying consumption per connection was split between base load, cooling load, and heating load elements based on the estimated coefficients of CDD and HDD[104].
3. The average annual base load, heating load, and cooling load at a per-connection level were estimated on projected annual HDD and CDD under 'standard' weather conditions[105].
4. The forecast was then adjusted by considering the impact of other modelled consumption drivers, including electric appliance uptake, energy efficiency savings, changes in retail prices, climate change impacts, gas-to-electricity switching, and the behind-the-meter PV rebound effect[106].
5. The forecasts were then scaled up with the connection growth forecast to project future base, heating, and cooling consumption over the forecast period[107].
6. The forecast of residential underlying consumption was estimated as the sum of base, heating, and cooling load as well as the consumption from EVs.

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[102] The impact of battery storage on consumption is assumed to be negligible, aside from minor efficiency losses, and therefore not included.

[103] In the SWIS, Synergy supplies electricity to non-contestable customers whose annual electricity consumption is less than 50 MWh. See https://www.erawa.com.au/gas/switched-on-energy-consumers-guide/can-i-choose-my-retailer.

[104] The coefficients represented the sensitivities of residential loads per connection to cool and warm weather respectively.

[105] See Appendix A2 of the 2019 Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2019/electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

[106] The PV rebound effect refers to the notion that households with installed behind-the-meter PV are likely to increase consumption due to lower electricity bills.

[107] The connection forecast methodology has been refined with a split of residential and non-residential connections. Only the residential connections are used. For further information, see Appendix A5.

7. The residential operational consumption forecast was calculated by subtracting the behind-the-meter PV generation from the underlying residential consumption forecasts and adding the network losses.

Further information on residential consumption forecasts is in Chapter 3 of the *Methodology Information Paper*.

Methodology improvements

AEMO developed peak demand and operational consumption forecasts using in-house forecasting models. This has resulted in improvements compared to the 2019 WEM ESOO, including:

- The half-hourly model simulated half-hourly demand and better accounted for the impact of DER on demand, including shifts in peak demand timing.
- Energy efficiency savings were projected[108] for the residential and commercial sectors respectively and applied as adjustments to the forecasts.
- The impact of climate change was estimated and applied to the forecasts to adjust for the effect of increasing temperatures.
- Surveys and interviews were conducted for key LILs to identify broad market dynamics affecting these loads, as well as industry-specific opportunities and threats.

4.2 Distributed energy resources forecasts

AEMO commissioned two external consultants to develop DER forecasts:

- CSIRO developed the uptake forecasts for behind-the-meter PV, battery storage, and EV[109].
- GEM's forecasts covered behind-the-meter PV and battery storage[110].

The forecasting models developed by each consultant are different, providing AEMO a broader spectrum of expected behind-the-meter PV and battery storage uptake to consider across the forecast scenarios.

DER forecasts were developed for Australia for the three scenarios: low, expected and high[111]. Table 10 shows the allocation of the two consultants' forecasts to the low, expected, and high scenarios of behind-the-meter PV and battery storage uptake forecasts.

Table 10 Consultant DER forecast to scenario mapping

	Expected	Low	High
Behind-the-meter PV	Average of CSIRO and GEM expected	CSIRO low	GEM high
Behind-the-meter battery storage	Average of CSIRO and GEM expected	CSIRO low	GEM high
EVs	CSIRO expected	CSIRO low	CSIRO high

108 By an external consultant.

109 2020 CSIRO DER report, at http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report.

110 2020 GEM DER report, at http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/Green-Energy-Markets-DER-Forecast-Report.

111 Low, expected and high scenarios are named slow change, central, and step change respectively in the CSIRO report. In addition to these scenarios, CSIRO and GEM developed forecasts for fast change and high DER scenarios. These scenarios were not used in this 2020 WEM ESOO. See CSIRO and GEM's reports for further information.

A summary of the DER forecast results and the impact on the peak demand and energy consumption forecasts is presented below. Further details on the methodology and assumptions for the DER forecasts are in the CSIRO and GEM reports[112].

4.2.1 Behind-the-meter PV forecast

CSIRO and GEM developed behind-the-meter PV installed capacity forecasts on a monthly basis for residential (≤10 kilowatts [kW]), small commercial (10 kW to 100 kW), and large commercial (100 kW to 10 MW) PV installations.

The assumptions and methodologies used to forecast behind-the-meter PV installed capacity are outlined in the CSIRO and GEM reports. At a high level, the methodologies were:

- For all PV forecasts, CSIRO used a combination of techniques across the outlook period. In the near term (until June 2021-22), CSIRO used trend-based modelling to capture recent growth trajectories. For PV systems less than 100 kW, CSIRO then applied a consumer adoption curve model for the remainder of the outlook period, aimed at capturing price and non-price drivers. For larger systems (>100 kW), CSIRO applied return-on-investment modelling for the remainder of the outlook period, with a focus on capturing financial factors.
- GEM applied a consumer payback model for all PV systems, aimed at capturing revenue and cost factors. The model was moderated to account for factors such as market saturation, new dwelling construction, and system replacement, as well as non-price factors such as consumer awareness and industry competition.

Both consultants incorporated the impact of the COVID-19 pandemic to the forecasts:

- CSIRO expected major impacts to be limited to the short term. Slower rates of new DER installations (relative to the trend that would otherwise have been projected) were assumed for the 2020-21 and 2021-22 financial years, based on observed societal responses to the pandemic. After 2021-22, the impact was largely assumed to have dissipated.
- GEM adjusted its short-term forecasts until 2022-23 based on the results of a survey conducted in partnership with PV Magazine[113], and developed low, high, and most probable impact assumptions on solar installation levels. GEM assumed the impacts would dissipate after June 2022.

The expected scenario for behind-the-meter PV uptake was applied across the low, expected, and high peak demand and energy forecasts. Behind-the-meter PV uptake forecasts under all three scenarios are presented in the 2020 WEM ESOO Data Register[114], so stakeholders can apply alternative DER uptake scenarios.

Installed capacity forecasts

Figure 23 shows the forecast uptake of total behind-the-meter PV in the SWIS under the low, expected, and high PV scenarios.

Installed behind-the-meter PV capacity is forecast to grow:

- Under the expected PV scenario, at an average annual rate of 6.5% (126 MW per year) to reach 2,612 MW by June 2030 from 1,481 MW in June 2021.
- Under the low growth PV scenario, at an average annual rate of 3.2% to reach 1,862 MW by June 2030.
- Under the high growth PV scenario, at an average annual rate of 9.5% to reach 3,687 MW by June 2030.

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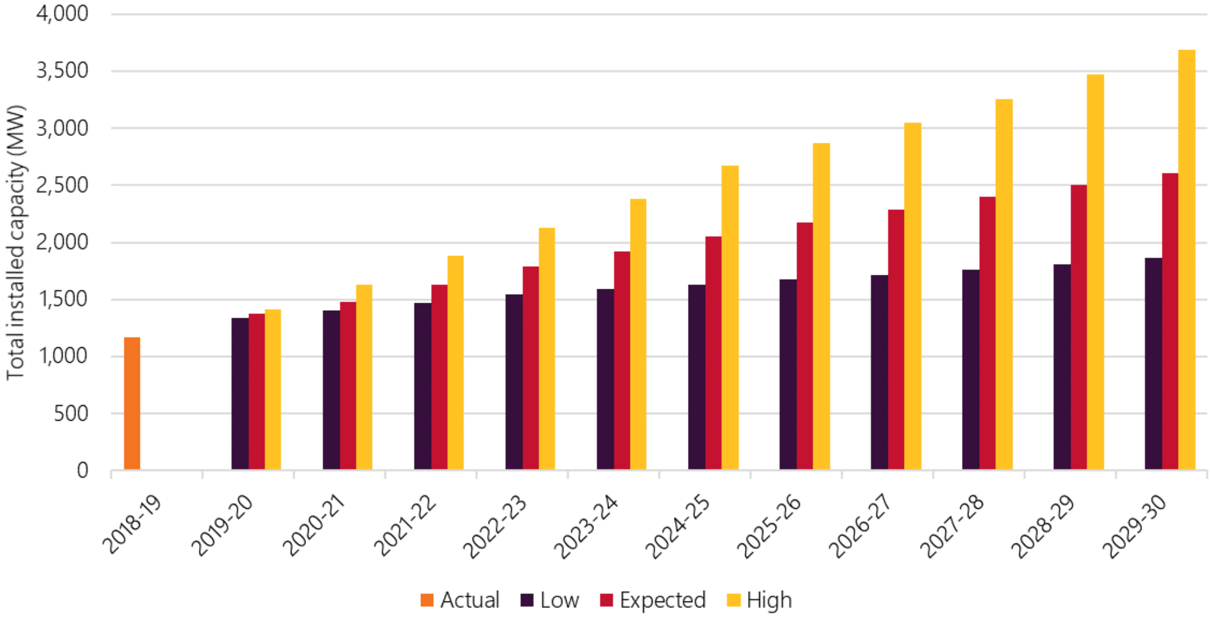
112 At https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

113 See https://www.pv-magazine-australia.com/2020/04/09/survey-covid-19-to-cause-50-decline-in-rooftop-solar-segment/.

114 At https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

Figure 23 Installed behind-the-meter PV capacity, 2018-19 to 2029-30 financial years[A,B]



A. Cumulative installed capacity forecasts account for degradation of solar panel output over time. CSIRO applied a degradation rate of 0.5% per annum and GEM applied a degradation rate of 0.7% per annum.
B. Historical monthly behind-the-meter PV capacity data is provided in the 2020 WEM ESOO Data Register.
Source: CSIRO and GEM

While the 10-year average annual growth rates for the expected and high PV scenarios are lower than the 2019 WEM ESOO forecast, growth in this year's low PV scenario is forecast to be the same.

The forecast growth in behind-the-meter PV uptake is expected to have a diminishing impact on peak demand into the future, as the peak time shifts to later in the day when solar irradiance is minimal.

However, it will continue to reduce system minimum demand, which is expected to remain during the day over the outlook period[115]. Consumption will also continue to reduce.

Historical and averaged daily capacity factor traces

For the 2020 WEM ESOO, AEMO has updated the method for calculating behind-the-meter PV capacity factors in the SWIS, by engaging SolCast[116] to provide estimated capacity factors at a half-hourly resolution.

Figure 24 shows the historical solar capacity factor traces for the period from 2012 to 2019 (calendar years), averaged by month.

Solar traces are based on modelling of behind-the-meter PV output paired with solar irradiance satellite data. Modelled PV output has been validated against actual sample data and corrected for various factors.

The sample size of actual PV systems used for validation is greater than the sample size used in the 2019 WEM ESOO capacity factor estimations[117], improving the accuracy.

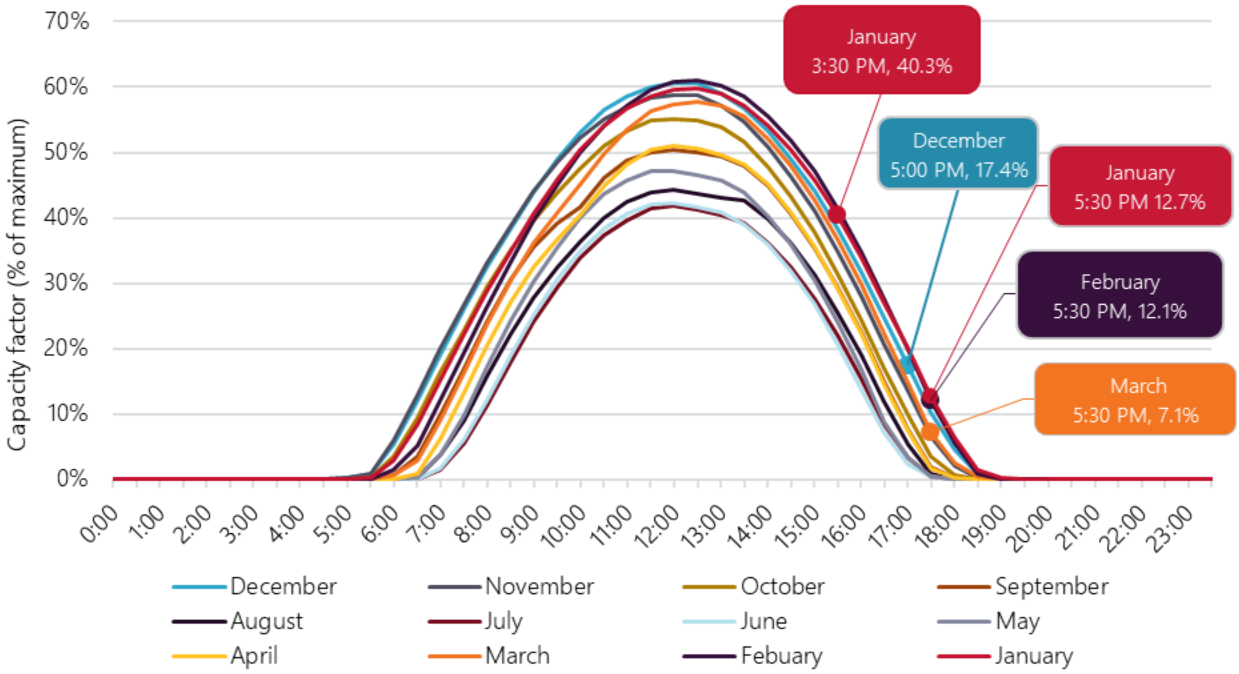
The average yearly capacity factor calculated from the traces for the 2012 to 2019 calendar years is 16.1%.

[115] Minimum demand forecasts are presented for a five-year outlook period.

[116] See https://solcast.com/solar-radiation-data/inputs-and-algorithms/.

[117] The sample used for developing the capacity factor traces used in the 2019 WEM ESOO comprised SolarCity rooftop PV units with gross interval metering installed.

Figure 24 Solar capacity factor traces, averaged by month, for behind-the-meter PV in the SWIS, 2012 to 2019 calendar years[A,B]



A. All capacity factor values are half-hourly averages and all times are half-hour interval start times (for example, the average capacity factor in January between 13:30 and 14:00 is 40.3%).
B. The coloured boxes indicate the months and Trading Intervals of historical peak demand over the last six Capacity Years. For further information on peak demand Trading Intervals, refer to Chapter 5.
Source: AEMO calculations based on Solcast data.

Impact on peak demand

Behind-the-meter PV reduces peak demand by shifting the peak to a later Trading Interval in the day and displacing demand from the SWIS.

As an improvement to the 2020 WEM ESOO, AEMO modelled the expected effect of behind-the-meter PV on peak demand by incorporating PV generation[118] as a dependent variable in the half-hourly modelling of weather conditions, seasonal effects and stochastic volatility (see Section 4.1). By including underlying demand and behind-the-meter PV in the same half-hourly model, the simulated outcomes of each component aligned. After simulation, the effect of behind-the-meter PV was then subtracted from underlying demand to determine the net demand value (further adjustments for battery storage and EVs are discussed in Sections 4.2.2 and 4.2.3).

As forecast installed capacity of behind-the-meter PV increases throughout the outlook period, the following effects were captured by the half-hourly model:

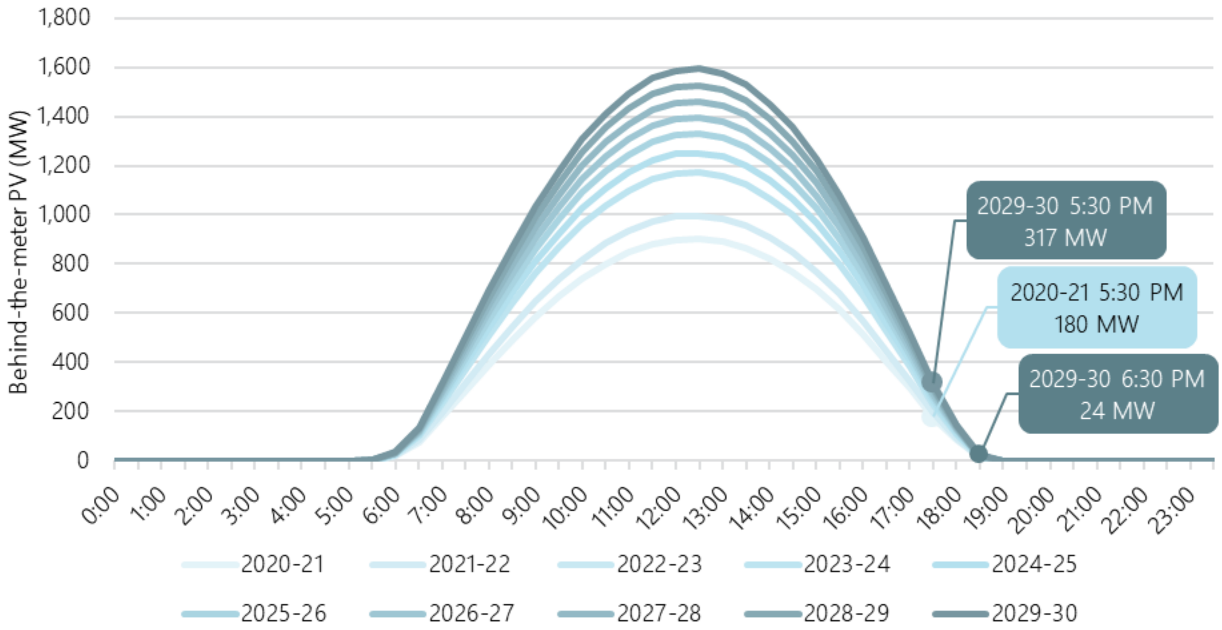
- The peak demand time is shifted to Trading Intervals later in the day, as increasing behind-the-meter PV generation offsets demand that would otherwise be consumed from the SWIS. By 2023-24, the likely peak demand time is forecast to shift from the period between 17:00 to 18:00 to after 18:30.
- Toward the second half of the outlook period, behind-the-meter PV generation observed during the peak demand Trading Interval is forecast to reduce as peak demand will be more likely to occur during Trading Intervals when PV is generating at low or nil amounts.

Introduction of half-hourly modelling for the 2020 WEM ESOO has resulted in a more accurate reflection of the time shifting and reduction effect of behind-the-meter PV on peak demand throughout the outlook period, compared to the method applied in the 2019 WEM ESOO.

[118] Forecast generation of behind-the-meter PV (half-hourly) is calculated by combining forecast installed capacity (MW) and a historical averaged capacity factor (%), as shown in the previous sections.

Figure 25 illustrates an example of behind-the-meter PV generation profiles, which shows the average historical February capacity factor applied to forecast values of installed PV capacity for each financial year in the outlook horizon.

Figure 25 Average February behind-the-meter PV profile, 2020-21 to 2029-30 financial years[A]



A. Example profiles used to illustrate the growing magnitude of behind-the-meter PV generation, not generation profiles developed by the half-hourly forecast model.

Effect on operational consumption

To estimate future reductions to operational consumption due to behind-the-meter PV, the expected behind-the-meter PV scenario was applied across the low, expected, and high operational consumption forecasts.

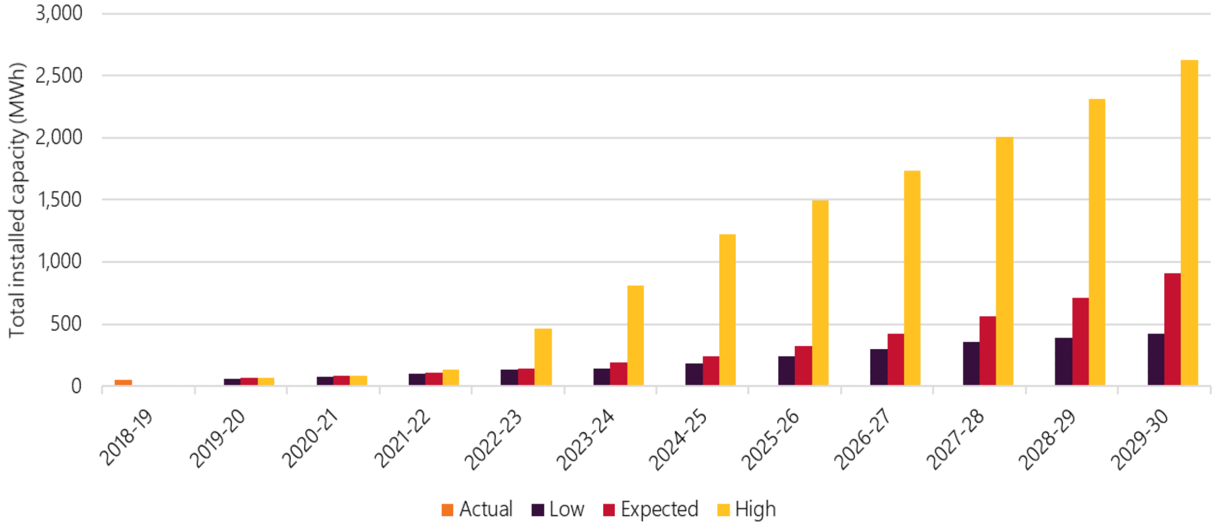
The effect on operational consumption was forecast by multiplying the expected behind-the-meter PV system installation forecasts by the average behind-the-meter PV capacity factor from the solar traces. The forecast reduction in operational consumption from behind-the-meter PV is 3,772 GWh for the 2029-30 financial year, or 19% of the total underlying forecast energy consumption.

4.2.2 Behind-the-meter storage forecasts

Behind-the-meter battery storage forecasts assumed that each residential battery storage installation was paired with a behind-the-meter PV system to minimise electricity import from the grid. The assumptions and methodologies used to forecast battery storage installed capacity are outlined in the CSIRO and GEM reports. At a high level these are similar to the methodologies adopted for forecasting behind-the-meter PV uptake (see Section 4.2.1).

The battery installed capacity forecasts for the low, expected, and high battery scenarios are shown in Figure 26. Under the expected growth battery scenario, the installed capacity of battery systems in the SWIS is projected to increase at an annual average growth rate of 30.5% from 65 MWh in June 2021 to 908 MWh in June 2030. The high growth rate is primarily attributed to the expected reduction in the cost of battery systems over the forecast period.

Figure 26 Installed capacity of battery storage systems (behind-the-meter)A, 2018-19 to 2029-30 financial years



A. Cumulative installed capacity forecasts account for degradation of battery performance over time. For more information see CSIRO and GEM reports.
Source: CSIRO and GEM.

Impact on peak demand

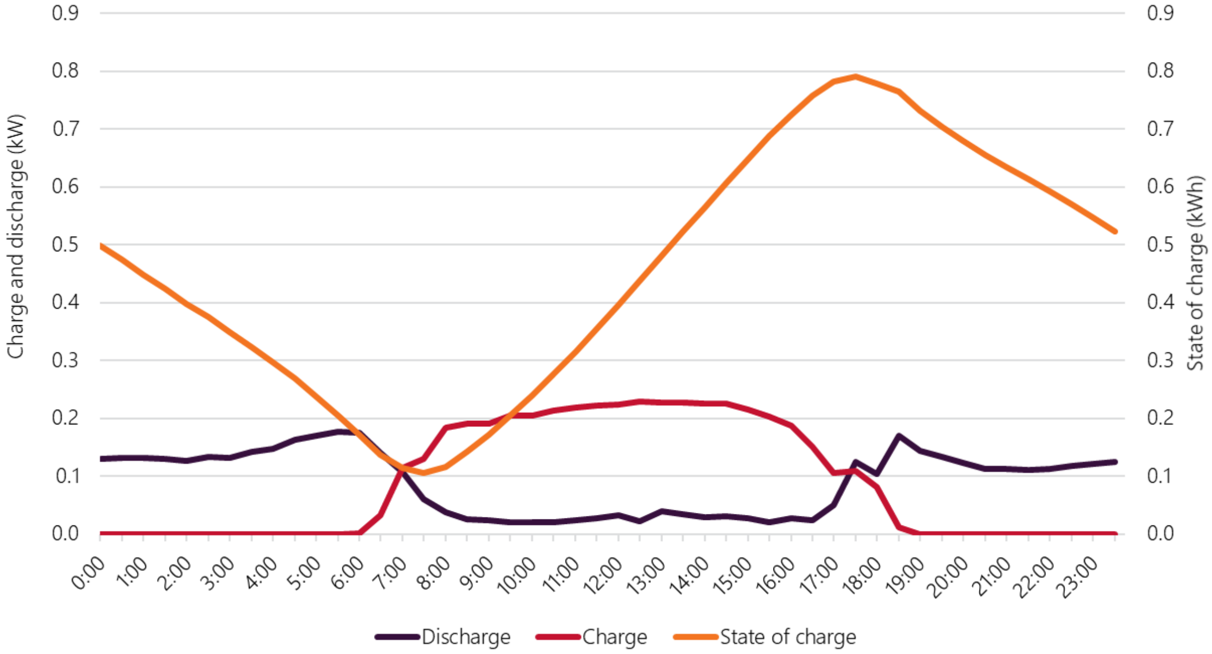
CSIRO developed the daily charge and discharge profile for behind-the-meter batteries. The profiles were based on historical solar irradiance assuming batteries primarily charge from excess behind-the-meter PV generation. As an improvement to the 2020 WEM ESOO, AEMO modelled the contribution of batteries to peak demand by including batteries as a dependent variable in the half-hourly modelling of weather conditions, seasonal effects and random volatility in a similar manner to behind-the-meter PV (see Section 4.1).

The peak demand forecasts consider operation of behind-the-meter batteries under flat tariffs. Batteries are assumed to operate to minimise household/commercial business bills without any concern for whether the aggregate outcome is optimised for the electricity system. Under flat tariffs, customers will set their battery to do one of two things:

- Charge if solar exports are detected when the battery is not full.
- Discharge if electricity imports are detected when the battery is not empty.

This operation shifts energy from daytime periods to be consumed during the evening household peak, offsetting peak consumption for that customer. An example profile has been provided in Figure 27, which shows the average February daily charging and discharging pattern for residential customers.

Figure 27 Average February residential battery charge, discharge, and state of charge profiles[A]



A. Normalised battery charge, discharge, state of charge under a flat tariff and no aggregated response.

Battery efficiency loss

In this 2020 WEM ESOO, it has been assumed that behind-the-meter battery storage will have a negligible impact on operational consumption over the forecast period because behind-the-meter battery storage simply stores energy to use later and has relatively small efficiency losses[119], particularly for the first five years of the outlook period.

AEMO continues to monitor trends in battery uptake and usage. The forecast methodology for the effect of behind-the-meter batteries on operational consumption will be updated as further units are installed and will be included in future WEM ESOOs.

4.2.3 Electric vehicle uptake forecasts

CSIRO developed the forecasts for battery EVs and plug-in hybrid EVs. For each type, CSIRO projected EV uptake for vehicle classes including residential, light commercial, and heavy commercial such as buses and trucks. Forecast EV numbers in the SWIS are shown in Table 11 below.

Projections for EV uptake assume a slow start, due to limited public charging infrastructure, the narrow range of models currently available, and the cost relative to vehicles with internal combustion engines.

The range between the high and low forecasts is relatively wide, due to:

- Different cost projections, including the time to reach cost parity with internal combustion engine vehicles.
- Uncertainty regarding decisions on industry and emissions reduction policies.
- Differences in assumptions regarding infrastructure limitations and new business models.
- In the high EV scenario, forecasts are comparatively higher due to the assumptions of a zero-emission road transport sector by 2050 and allowing the EV sales share to grow to 100% by 2040 in most vehicle classes.

[119] Depending on the technology type of the battery storage system, the typical round-trip efficiency of energy storage in batteries can be in the range between 70% and 95%.

Table 11 Forecast total number of EVs, 2020-21 to 2029-30 financial years

Scenario	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Expected	1,022	1,168	1,373	1,671	3,416	8,002	18,474	36,618	63,382	99,125
Low	988	1,003	1,021	1,043	1,200	1,548	2,281	3,700	6,378	11,261
High	1,044	2,741	8,754	31,105	63,311	111,869	177,593	258,399	367,650	506,933

Source: CSIRO.

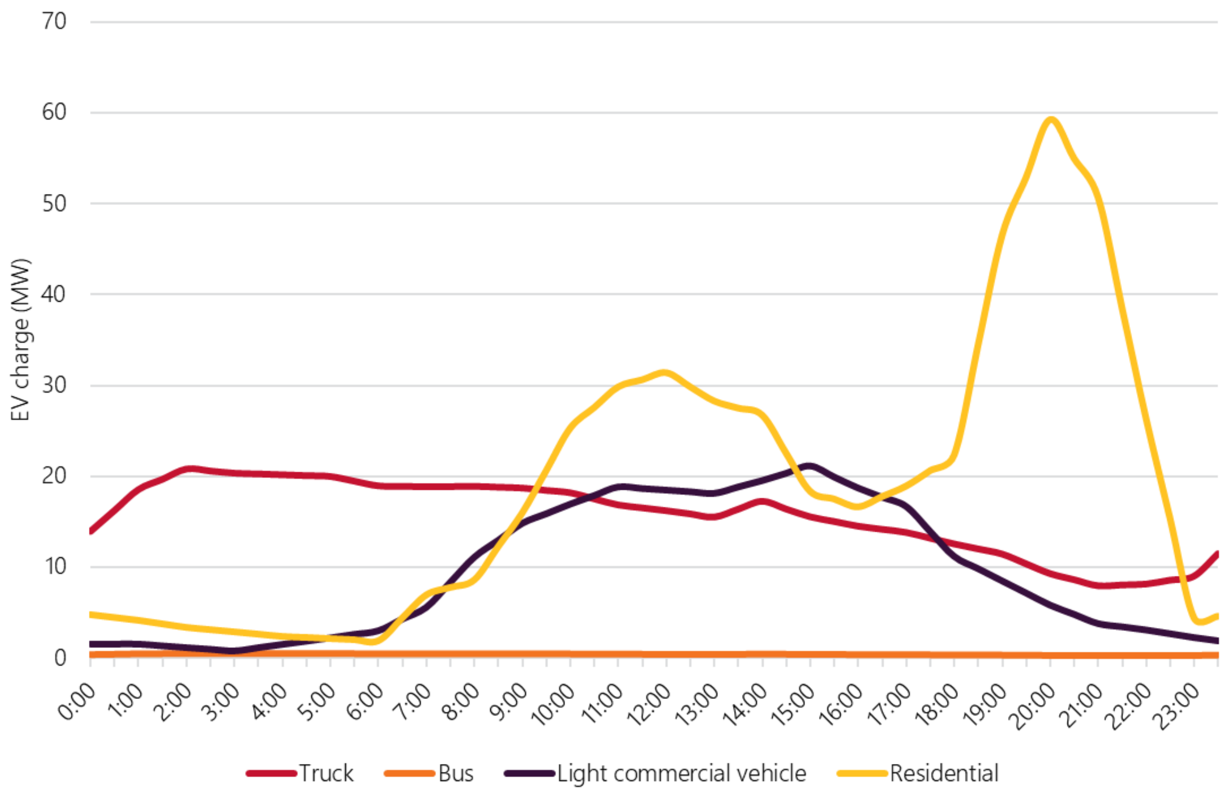
EV impact on peak demand

The impact of EVs on peak demand depends on the number of EVs charging at the peak demand time and was calculated as the projected number of EVs multiplied by a specific charge profile for the EV type. EV charge profiles were applied as a post-model adjustment to results of the half-hourly modelling of underlying demand, behind-the-meter PV and battery storage.

CSIRO developed four types of EV charge profiles: convenience, night, day, and fast charging or highway charging. These are defined as follows:

- Convenience charging does not impose any specific constraints on charging.
- Fast charging or highway charging is based on studies from China, where deployment is large and utilisation of fast charging or highway charging has been observed.
- Day and night charging accounts for future incentives that encourages night charging in the short term and day charging in the longer term when solar generation is expected to strongly reduce daytime load.

Figure 28 Expected scenario, average daily weekday EV charging profiles, June 2030



Source: CSIRO.

As EV uptake increases, effective management of the impact of EVs on peak demand will require a more detailed understanding of consumer driving and charging behaviour, how controlled charging incentives may affect that behaviour, and opportunities for consumers to participate in demand response management or provide grid services.

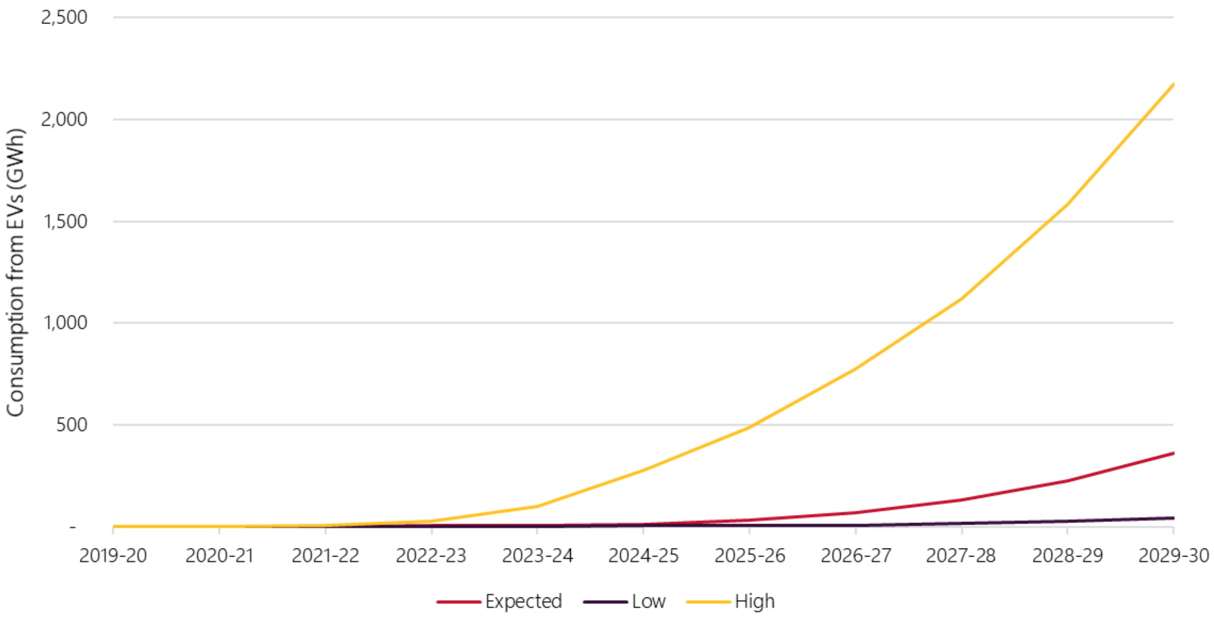
AEMO will continue to monitor trends in EV uptake and charging patterns. Assumptions regarding EV impact on peak demand will be updated in future WEM ESOOs as the market penetration level changes.

EV impact on operational consumption

The forecast effect of EVs on operational consumption in the SWIS is shown in Figure 29. By the end of the 2029-30 financial year:

- Under the expected EV scenario, EV energy consumption is forecast to be 362 GWh, accounting for approximately 2.1% of total operational consumption.
- Under the low EV scenario, EV energy consumption is forecast to reach 46 GWh (0.3%).
- Under the high EV scenario, EV energy consumption is forecast to reach 2,178 GWh (11.0%).

Figure 29 EV contribution to operational consumption, 2019-20 to 2029-30 financial years



Source: CSIRO.

4.3 Supporting forecasts

AEMO engaged BIS Oxford to provide forecasts for WA GSP[120]. AEMO developed the LIL forecasts in consultation with specific LILs in the WEM.

The following sections provide an overview of these supporting forecasts and assumptions applied.

[120] Refer to: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/BIS-Oxford-Economics-Macroeconomic-Projections for detailed information on BIS Oxford's macroeconomic forecasting approach (pre-COVID-19) and outcomes. BIS Oxford refined their Central Scenario (expected scenario) forecast to account for expected bookend impacts of the COVID-19 pandemic, defining a "Baseline" and a "Downside" range considering newer information available after the initial report's finalisation. Further information on this refinement is available at http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/BIS-Oxford-Economics-Macroeconomic-Central-Scenario-and-Downside-Scenario-Forecast.

4.3.1 Economic growth outlook

BIS Oxford applied a suite of in-house models that includes the Oxford Global Economic Model, the Global Industry Model, and the Australian Regional Model to develop the economic forecasts for Australia and for each Australian state:

- At the international level, countries are linked through trade (for example, imports and exports), financial variables (for example, the US Federal Reserve rates and exchange rates), and commodity prices.
- At the country level, the model is Keynesian in the short run, with output driven by shifts in demand. In the long run the model is neo-classical and gross domestic product is determined by the economy's supply side potential (for example, labour supply, capital stock, and productivity).
- At the state level, the model is built on an industry basis to incorporate state characteristics, including state-specific short run cycles, particularly around investment activity in the mining and construction sectors.

BIS Oxford expected the COVID-19 pandemic to have direct impacts on economic aspects in Australia including services trade (tourism and education), supply chain disruptions (production and distribution), energy and fuel markets (uncertainty in global demand), and equity market (sharp corrections due to uncertainty in the economic outlook).

The low, expected, and high projections for GSP, which incorporate BIS Oxford's assessment of the COVID-19 impacts, are presented in Table 12. These projections were applied to low, expected, and high demand growth scenarios respectively.

Table 12 WA GSP (%) forecasts for different economic growth scenarios, 2020-21 to 2029-30 financial years

Scenario	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
High	-0.2	9.2	4.4	2.4	2.2	2.7	2.8	2.8	2.9	3.0
Expected	-1.1	8.1	3.0	2.7	2.4	2.6	2.6	2.7	2.7	2.8
Low	-1.8	6.8	2.6	2.5	2.1	2.4	2.4	2.4	2.4	2.4

Source: BIS Oxford.

WA is expected to face a more modest downturn in GSP than other Australian states. While construction and services are expected to dampen the economy in the near to short term, this is forecast to be partially offset by the relatively resilient mining sector.

Under the expected economic scenario:

- GSP is forecast to contract at a rate of 1.1% in both 2019-20 and 2020-21 due to the impacts of the COVID-19 pandemic.
- The state economy is projected to experience a strong recovery in 2021-22 and 2022-23 with a GSP growth rate of 8.1% and 3.0% respectively. This is largely driven by improvements in the international economy, recovering consumer confidence, and expected state and federal fiscal and monetary stimulus packages[121].
- After 2022-23, the economy is expected to return to normal with state GSP forecast to grow at around 2.5%.

AEMO recognises the significance that COVID-19 restrictions may have on the economic outlook for WA, and the potential flow-on impact on electricity consumption. BIS Oxford forecast a downside sensitivity on the

[121] State Government business and industry advice is updated regularly, at https://www.wa.gov.au/organisation/department-of-the-premier-and-cabinet/covid-19-coronavirus-business-and-industry-advice. Federal Government national COVID-19 advice is updated regularly, at https://www.australia.gov.au/.

expected scenario to identify the relatively severe economic impacts of COVID-19 restrictions until June 2021. These restrictions would continue to limit the opportunity for SME in some industries from operating as normal. Given the relatively high uncertainty of COVID-19 impacts on electricity consumption, AEMO's low and expected forecasts provide a sufficiently wide range such that extended COVID-19 restrictions would lead to estimated consumption outcomes that fall within these scenarios.

Further details on the methodology and assumptions for the WA GSP forecasts can be found in BIS Oxford's report.

4.3.2 Residential electricity connection forecasts

Residential connections were applied to forecast the residential electricity consumption described in Section 4.1.4. AEMO developed the residential connections forecast under the low, expected, and high scenarios for the SWIS. These were applied to low, expected, and high demand growth scenarios respectively. The forecast annual growth rates for the three connections growth scenarios are outlined in Table 13 below.

The forecast was developed by applying a mix of the SWIS residential National Meter Identifier (NMI) growth rate to historical NMI numbers for the first four years with the high growth connections scenario applying the highest historical NMI growth rate and vice versa for the low scenario. In previous WEM ESOOs, only the Australian Bureau of Statistics (ABS) 2019 household growth rate projections were applied[122]. The residential connections growth was smoothed to the ABS 2019 long-term household forecast growth for the first four years by transitioning from one rate to the other.

Table 13 Forecast residential connections growth (%) scenarios, 2020-21 to 2029-30 financial years

Scenario	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
High	1.6	1.6	2.0	1.9	1.9	2.0	2.1	2.0	2.0	2.0
Expected	1.3	1.3	1.4	1.5	1.5	1.6	1.8	1.7	1.7	1.7
Low	1.1	1.1	0.9	1.1	1.2	1.3	1.3	1.3	1.3	1.2

4.3.3 New large industrial loads

AEMO engaged with a range of stakeholders, including Western Power, in deciding to include prospective and committed LILs in the 2020 WEM ESOO.

A new LIL[123] project is only included in the expected demand growth scenario when all the following criteria are met:

- The project has obtained the required environmental approvals.
- The project has obtained approvals from Western Power to connect to the SWIS.
- The project proponent has publicly announced that it has taken a positive final investment decision and/or the project has commenced construction.

A LIL that only meets the first two of these criteria is included in the high demand growth scenario. New projects included in the expected scenario are included in the low demand growth scenario, but the increase in demand from the project is adjusted downward to reflect slower development (for example, a project with multiple development stages may only complete the first stage in the low scenario).

[122] ABS Cat. No. 3236.0 - Household and Family Projections, Australia, 2016 to 2041, 14 March 2019. ABS Cat, at https://www.abs.gov.au/AUSSTATS/abs@.nsf/mediareleasesbyReleaseDate/8F87B47A8FAB2D5CCA256EB700004FF9?OpenDocument.

[123] Consistent with the definition of existing LILs, new LILs are expected to consume more than 10 MW for at least 10% of the time in the future.

Five projects were identified as new LILs[124] and included in the expected demand and operational consumption forecasts for the 2020 WEM ESOO. These were an expansion to an existing mine site, three new mineral processing plants, and one industrial load. Three[125] of these projects have multiple development stages, with the stages being allocated to the three scenarios based on the assessment criteria.

While LILs were modelled explicitly in the operational consumption forecasts, their impact on maximum demand is indirect, and is therefore indicative only. The scenario implications are as follows:

- The new LILs were estimated to add approximately 375 GWh, 445 GWh, and 850 GWh of electricity consumption annually against the 2018-19 base year, under the low, expected, high demand growth scenarios, respectively.
- The low demand growth scenario includes only stage one development of the three multiple-stage projects, which are expected to add approximately 54 MW to peak demand by 2021 than would otherwise have been the case.
- The expected growth scenario includes all stage one development of the three projects included in the low demand growth with the addition of stage two development of one project. These loads add approximately 64 MW to peak demand by 2022.
- All stages of all five projects were added to the high demand growth scenario, adding approximately 126 MW to peak demand by 2028.

[124] AEMO calculated demand and energy consumption for new LILs based on their contracted maximum demand, adjusted by diversity factors.

[125] All three projects were included in the expected and high growth scenario forecasts in the 2019 WEM ESOO.

5. Forecast results

Expected peak demand is forecast to decline slightly in the near term (from 4,008 MW in 2020-21 to 3,913 MW in the 2023-24 Capacity Year), returning to a relatively stable 10-year outlook.

Minimum demand is forecast to decline in all scenarios, primarily driven by increasing behind-the-meter PV generation during mid-day periods.

Growth in operational consumption is forecast to be slow or declining in all sectors, primarily due to increased consumption from behind-the-meter PV.

Forecasts are presented for three demand growth scenarios: low, expected, and high demand growth.

These scenarios reflect different projections of levels of economic and population growth, LILs, energy efficiency gains, and uptake of EVs[126]. The same projections for behind-the-meter PV and battery have been applied for all scenarios[127].

For each demand growth scenario, the peak and minimum demand forecasts have been modelled under three probabilistic outcomes; 10% POE, 50% POE, and 90% POE[128]. These outcomes capture variation due to random drivers such as weather (See Section 4.1).

In the following sections:

- All data in the peak demand and minimum demand forecasts is presented in Capacity Year unless otherwise specified.
- All data in the consumption forecasts is presented in Financial Year unless otherwise specified.
- Demand refers to operational demand unless otherwise stated.
- Forecasts assume no limitations to system capacity of behind-the-meter PV (further discussed in Section 5.2.1).

5.1 Peak demand forecasts

Peak demand forecasts have been modelled for the outlook period 2020-21 to 2029-30.

5.1.1 Annual peak demand forecasts

All annual peaks are forecast to occur in summer. Figure 30 shows the 10% POE peak demand forecasts under the three demand growth scenarios, alongside actual peak demand from 2012-13 onwards.

In the expected growth scenario, 10% POE peak demand is forecast to decline slightly from 4,008 MW in 2020-21 to 3,913 MW in 2023-24. The forecast remains relatively flat for the remainder of the outlook period

[126] Detailed assumptions for each scenario can be found in Chapter 4 of this WEM ESOO.

[127] See Chapter 3 of this WEM ESOO for further information.

[128] For peak demand forecasts, 10% POE represents a 1-in-10-year chance of exceedance and the 90% POE represents a 9-in-10-year chance of exceedance. For the minimum demand forecasts, these are best interpreted as 10% POE representing a 9-in-10-year chance of demand being below the forecast value and a 90% POE forecast representing a 1-in-10-year chance demand will fall below the forecast value.

and reaches 3,937 MW in 2029-30, with a 10-year average annual growth rate of -0.2%. Lack of growth in the expected and low growth scenarios is predominantly driven by forecast reductions in residential and SME demand and increases in installations of behind-the-meter PV and battery storage systems.

In the high demand growth scenario, peak demand is forecast to fall slightly from 4,053 MW in 2020-21 to 3,983 MW in 2024-25, before increasing to 4,138 MW in 2029-30, at a 10-year annual average growth rate of 0.2%. Demand increases in this scenario are largely driven by forecast rapid EV uptake in the latter half of the outlook period[129].

The modelled effects of the COVID-19 pandemic for all scenarios contributed to a slightly lower GSP until 2023-24 than would otherwise have been forecast (see Chapter 4 for more details). This is projected to impact demand growth, mainly in the SME sector, between 2020-21 and 2023-24, after which the effects of COVID-19 are forecast to largely dissipate.

Figure 30 10% POE forecast peak demand and actuals under different demand growth scenarios, 2012-13 to 2029-30

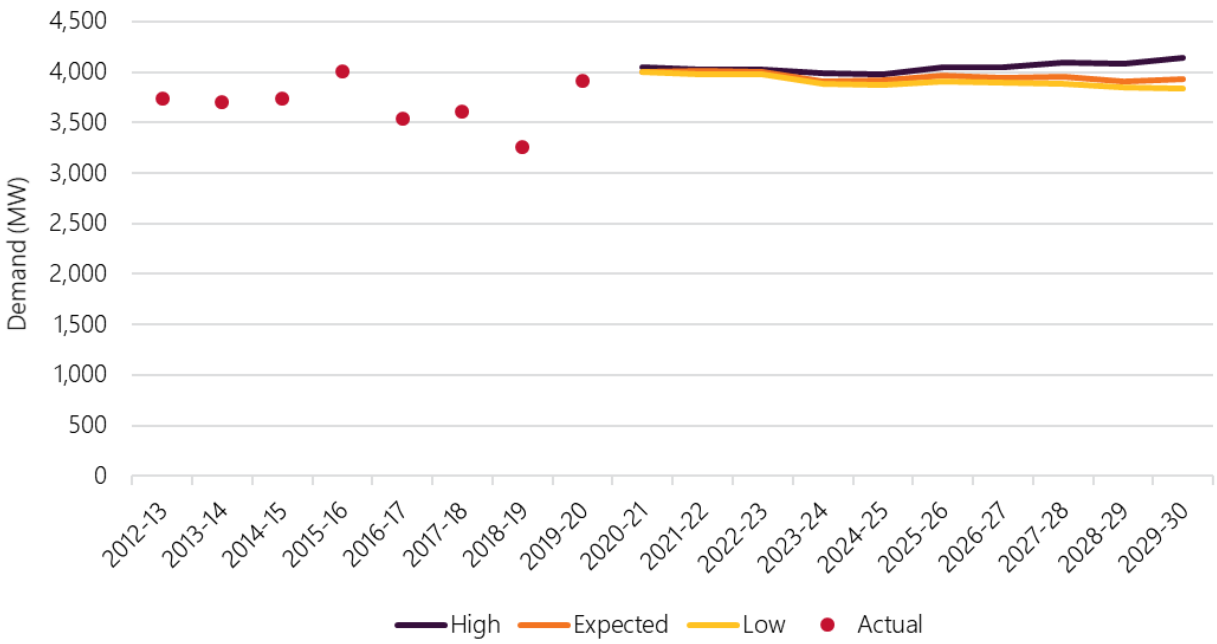


Figure 31 shows 10% POE, 50% POE and 90% POE forecasts for the expected demand growth scenario.

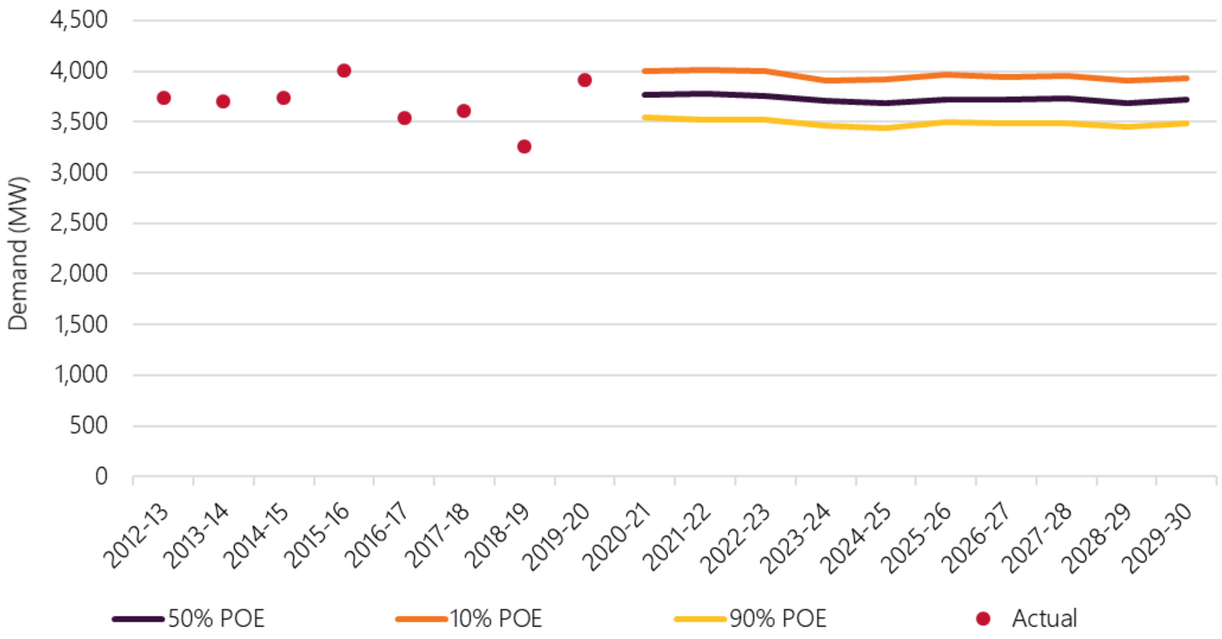
It can be seen that, in comparison with the 50% POE, the 10% POE and 90% POE forecasts show slightly more variation from year to year, such as the 89 MW reduction in the 10% POE observed between 2022-23 and 2023-24, from 4,002 MW to 3,913 MW (see Section 4.1.2 for an explanation of the variations).

The figure also highlights relatively similar growth trajectories to 10% POE forecast under the expected scenario discussed above, noting that:

- In the 50% POE forecast, peak demand is projected to be the most stable across the outlook period, with a 10-year average annual growth rate of -0.2%. Peak demand is forecast to reduce slightly from 3,744 MW in 2020-21 to 3,684 MW in 2024-25, before increasing again to 3,720 MW by 2029-30.
- Under the 90% POE forecast, peak demand is projected to reduce slightly from 3,544 MW in 2020-21 to 3,438 MW in 2024-25, before remaining relatively stable for the remainder of the outlook period, at a 10-year average annual growth rate of -0.2%, reaching 3,451 MW in 2029-30.

[129] High EV uptake in this scenario is driven by the assumption a zero emissions fleet will exist by 2050 (see Section 4.1).

Figure 31 10% POE, 50% POE, and 90% POE peak demand forecasts under the expected demand growth scenario, 2012-13 to 2029-30



Change in timing of peak demand

In response to rapid uptake of behind-the-meter PV and the subsequent impacts on peak demand (see Section 3.1.2 for analysis), AEMO has applied a half-hourly demand forecasting model to better account for the impact of behind-the-meter PV and other forms of DER on demand, including shifts in peak demand timing.

In all scenarios, the likely timing of peak demand is expected to shift from between 17:00 and 18:00 to later in the day, due to the combined impacts of behind-the-meter PV generation and battery storage operation. By 2023-24, peak demand is more likely to occur after 18:30.

This trend is observed in all POE outcomes, although the 10% and 90% POE forecasts show slightly more variability in the timing of peak demand than the 50% POE forecast.

This time-shifting effect is expected to result in a diminishing impact of behind-the-meter PV generation on reduction of peak demand throughout the outlook period, as peak demand is likely to occur during times when behind-the-meter PV generation is negligible.

Seasonal peaks

Winter peak demands are expected to remain lower than summer peaks throughout the outlook period, despite winter peaks being forecast to have a higher average growth rate than summer peaks. This is largely due to the impact of behind-the-meter PV generation on winter peak being zero, as the peak always occurs after sunset.

The forecast trends in the 10% POE winter peak demand are:

- In the expected and low growth scenarios, winter peaks are projected to reduce marginally in the near term, with five-year annual average growth rates of -0.3% and -0.6% respectively. By the end of the outlook period, growth in the expected scenario is forecast to reach a 10-year average annual growth rate of 0.1%, and the low scenario to reach -0.1%.
- In the high demand growth scenario, winter peaks are forecast to increase from 3,106 MW in 2020-21 to 3,411 MW by 2029-30, at a 10-year average annual growth rate of 1.0%. Demand growth in this scenario is largely driven by a projected increase in EV uptake in the latter half of the outlook period.

Similar to the summer peak demand, the key driver reducing winter peak demand in the near term is lower residential and SME consumption, largely due to the impacts of the COVID-19 pandemic. Improved energy efficiency drives reductions later in the outlook period, while forecast EV uptake is expected to increase winter peak at various levels under the three scenarios.

Winter peak forecasts are shown in Appendix A5.

5.1.2 Reconciliation with previous forecasts

The summer peak demand for 2019-20 was 3,919 MW, observed on 4 February 2020 during the 17:30 to 18:00 Trading Interval. This falls between the 10% POE and the 50% POE peak demand forecasts published in the 2019 WEM ESOO. As a result, AEMO has reconciled the actual peak against both the 10% POE and 50% POE.

The variance between the 2019-20 summer peak demand and the forecast is characterised as the sum of effects resulting from different forecast components (summarised in Table 14). These components can be attributed to different steps in the forecasting process:

- Temperature effects are attributed to the modelling component aimed at capturing both deterministic (such as temperature) and unexplained random factors.
- Economic effects are attributed to the modelling of structural drivers.
- The effects of behind-the-meter PV were captured in post modelling adjustments.

The effects of each component on the forecasting inaccuracies are explained below.

The largest effect was from the temperature component:

- The temperature conditions used to develop the forecasts included daily maximum, daily overnight minimum, and the previous two daily maximums. For the 2019-20 peak, observed temperature conditions were higher than expected by the forecast model, for the 50% POE and 10% POE.
- Table 14 shows that if the forecasts were developed using the observed temperature conditions (with all other factors equal), the results would be 4,080 MW for the 50% POE forecast and 4,179 MW for the 10% POE forecast. These represent 322 MW and 172 MW higher than the 50% POE and 10% POE forecasts respectively. Section 3.1.1 has more detail on the impacts of weather conditions on 2019-20 summer peak demand.
- The temperature component effects described above are captured in the regression modelling portion of AEMO's 2019 WEM ESOO peak demand forecasts[130]. The regression model aims to capture deterministic drivers of demand, such as temperature and day of the week, as well as random drivers that are not explained by the model. In order to do this, an uncertainty term[131] is added to the demand that is estimated from the deterministic modelling. The resulting values are used to create the probability distribution, from which the 10% POE and 50% POE values are selected. Due to the shape of the probability distribution, the 10% POE generally captures higher uncertainty in random drivers of demand than the 50% POE. As a result, the difference between the 50% POE and 10% POE values after accounting for weather effects (4,080 MW and 4,179 MW respectively) is due to the uncertainty term of the regression.

Components that resulted in forecast values being higher than actual demand are:

- Behind-the-meter PV (-62 MW).

[130] See Chapter 5 of ACIL Allen's 2019 peak demand and energy forecasts for the South West interconnected system report, at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2019/2019-WEM-ESOO-report.pdf.

[131] Each simulated peak included an uncertainty term, drawn from a normal distribution with a mean of zero and the standard deviation equal to the standard error of the 2019 peak demand regression model.

– The 2019 WEM ESOO forecast the estimated effect of behind-the-meter PV generation at the time of peak demand as 96 MW[132]. This was based on a forecast of 1,243 MW of behind-the-meter PV installed capacity, assumed to be generating at a capacity factor of 7.7% at the time of peak.

– The actual installed capacity is estimated to be 1,322 MW as of 4 February 2020, and the estimated capacity factor for 17:30 on this day is 11.9%[133]. Therefore, the actual effect of behind-the-meter PV at the time of peak demand is estimated at 157 MW (an additional 61 MW), resulting in greater reduction effect on peak demand than was anticipated in the forecasts.

- Economic effects (-6.2 MW) – actual GSP growth during the 2018-19 financial year was 1.0%[134], compared with a forecast growth rate of 2.4%, resulting in a forecast inaccuracy of -6.2 MW.
- Residual (-94 MW [50% POE] and -193 MW [10% POE]) – this is used to account for any factors that were excluded from the model or where there are more complex inter-relationships between variables compared to the model specification that cannot be individually quantified or captured by the regression uncertainty term.

Table 14 Reconciliation between actual and forecast 2019-20 summer peak demand (MW)

	Forecast peak	Temperature effects	Behind-the-meter PV	Economic/GSP effects	Residuals	Actual peak
50% POE	3,758	322	-61	-6.2	-94	3,919
10% POE	4,007	172	-61	-6.2	-193	3,919

Source: ACIL Allen and AEMO.

5.1.3 Changes from previous forecasts

The peak demand forecasts presented in the 2020 WEM ESOO are lower than the forecasts in the 2019 WEM ESOO, and this difference increases throughout the outlook period. A comparison is shown in Table 15, where the 2020 WEM ESOO forecasts are lower than the 2019 WEM ESOO forecasts by an average of 135 MW across the outlook period.

Table 15 Difference between 10% POE expected scenario forecasts, 2019 WEM ESOO and 2020 WEM ESOO (MW)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
2020 WEM ESOO forecast	4,008	4,018	4,002	3,913	3,923	3,964	3,942	3,959	3,908
2019 WEM ESOO forecast	4,063	4,075	4,074	4,078	4,079	4,092	4,117	4,128	4,152
Difference	-55	-57	-72	-165	-155	-127	-175	-169	-243

Key drivers for this change include:

- The impacts of the COVID-19 pandemic between now and 2023-24 (discussed in Section 4.1).
- Modelling of energy efficiency improvements, which are likely to reduce peak demand throughout the outlook period.

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132 In the 2019 WEM ESOO, this was assumed to occur during the 17:30 to 18:00 Trading Interval in February.

133 Estimated capacity factors were provided by SolCast (see Section 4.2 for more information).

134 This 0.98% is the most recent (2018-19 FY) GSP growth rate obtained from the Australian Bureau of Statistics (ABS) Australian National Accounts: State accounts.

- A combination of impacts from DER, which act to both reduce and increase peak. Compared with previous years, these DER impacts, including timing shifts in peak demand, have been better captured in the current WEM ESOO through the application of half-hourly demand modelling.

5.2 Minimum demand forecasts

Minimum demand forecasts have been developed for the 2020 WEM ESOO for the first time.

Current challenges associated with minimum demand are being addressed as part of the DER workstreams within the WA Government's Energy Transformation Strategy (ETS). These workstreams are expected to impact system thresholds that have the potential to limit capacity of behind-the-meter PV and are likely to impact future levels of minimum demand, for example through investment in storage and other grid support technologies (discussed later in this section).

As these workstreams are currently in development, the details are not known to the point where they can be accurately incorporated in long term demand forecasts[135]. Given this may have a high relevance to minimum demand, the following forecasts have been presented for a five-year outlook period.

In all scenarios, decreasing demand minimums are primarily driven by projected growth in behind-the-meter PV installations. In the expected growth scenario, installed behind-the-meter PV capacity is forecast to increase from 1,372 MW to 2,051 MW between 2020-21 and 2024-25.

As a result of continued uptake in behind-the-meter PV, minimum demand is expected to remain between 11:00 and 14:00, in line with historical trends.

All annual minimums are forecast to occur in the shoulder season, which is driven by the combination of high behind-the-meter PV generation and lower underlying demand due to milder temperatures (discussed in Section 3.2).

5.2.1 Annual minimum demand forecasts

The 50% POE forecast is presented for all demand growth scenarios, representing a 1-in-2 chance that a minimum will fall below the reported value. The complete set of 10% POE and 90% POE forecasts are available in Appendix A6. All levels of POE are presented for the expected scenario.

Figure 32 shows the 50% POE minimum demand forecasts under the three demand growth scenarios, and actual minimum demand values for the period 2012-13 to the present:

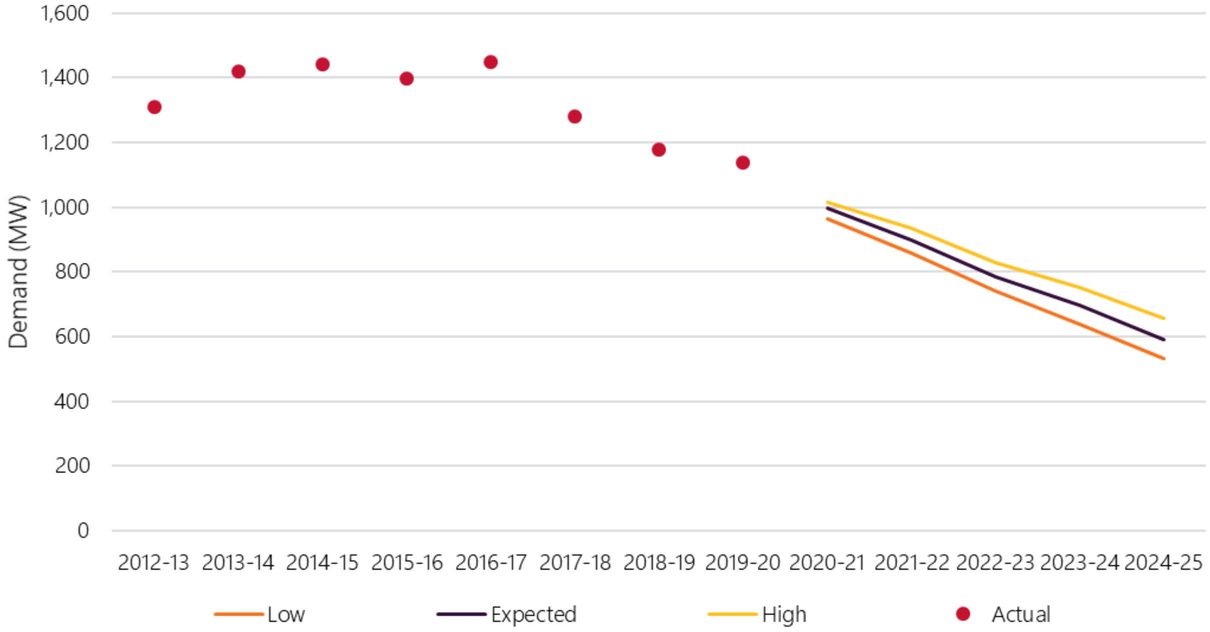
- In the expected growth scenario, minimum demand is forecast to reduce from 997 MW in 2020-21 to 591 MW in 2024-25, declining at a five-year average annual rate of 12.3%.
- In the low growth scenario, minimum demand is forecast to decline from 965 MW in 2020-21 to 533 MW in 2024-25, declining at a five-year average annual rate of 13.8%.
- In the high growth scenario, minimum demand is forecast to reduce from 1,016 MW in 2020-21 to 658 MW in 2024-25, decreasing at a five-year average annual rate of 10.3%.

The spread of the minimum demand forecasts for the three scenarios is relatively narrow, primarily because the largest driver, behind-the-meter PV forecasts, is the same in each scenario.

Declining daytime minimums are compounded by overall dampened growth in energy demand in the low and expected scenarios, driven by reduced business and commercial consumption across the forecast period. The modelled effects of COVID-19 are expected to have a negligible impact on minimum demands.

[135] Forecasts assume no limit to system capacity of behind-the-meter PV.

Figure 32 50% POE forecast minimum demand and actuals[A] under different growth scenarios, 2012-13 to 2024-25

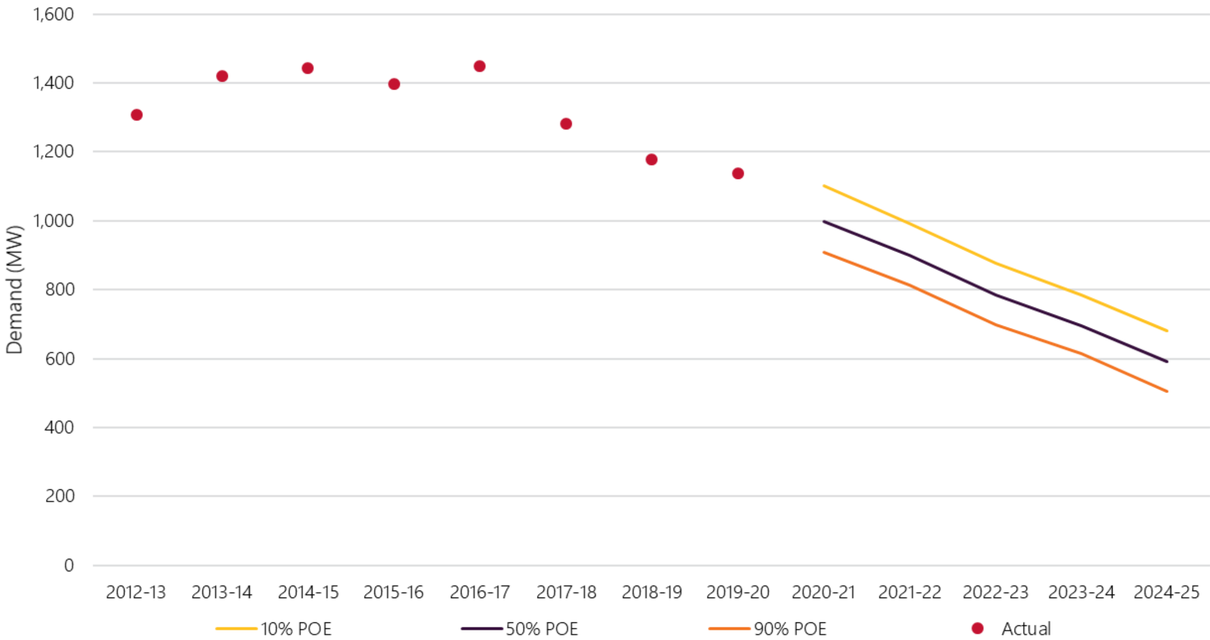


A. Actual minimum demand for the 2019-20 Capacity Year is a year-to-date value, based on data up until 29 February 2020.

Figure 33 shows 10% POE, 50% POE and 90% POE forecasts under the expected demand growth scenario. These probabilistic outcomes represent variation in the minimum demand forecasts primarily driven by weather:

- Negative growth is forecast during the entire five-year outlook period. The forecast five-year average annual growth rates are -11.4%, -12.3%, and -13.6% for the 10%, 50%, and 90% POE forecasts respectively. In the 90% POE forecast, minimum demand is projected to reach 507 MW by the end of the outlook period in 2024-25.

Figure 33 10% POE, 50% POE, and 90% POE minimum demand forecasts and actuals under the expected demand growth scenario, 2012-13 to 2024-25



System security threshold

AEMO has defined a system security threshold in the order of 700 MW[136] for operational demand[137]. Below this point, the available synchronous generation and associated inertia and voltage control may not be sufficient to maintain reactive power balance and the SWIS may be exposed to unacceptable power system risks.

This threshold analysis considered various combinations of synchronous generation connected to the network (online and offline), ramp rate considerations, transmission equipment in service, and the minimum generating thresholds of the generation fleet in the SWIS, and is subject to change depending on the on-line equipment and as the power system evolves.

The 2020 WEM ESOO modelling indicates that:

- In the expected and low demand growth scenarios, the 700 MW threshold is forecast to be reached between 2022-23 and 2024-25.
- In the high demand growth scenario, this threshold is forecast to be reached slightly later; sometime after 2023-24.

The operational challenges associated with declining minimum demand will be addressed through the Delivering the Future Power System and the DER workstreams being developed as part of the WA Government's ETS (see Chapter 8 for further detail).

Current ETS initiatives to lower this threshold include:

- New inverter standards for power ramp rate limits:
  - Mandatory enablement of voltage-var and voltage-watt parameters.
  - Improving inverter autonomous functions.
  - Developing standards for communication functionality.
- Investment in grid support technologies such as:
  - Reactors.
  - Storage (such as batteries).
  - Voltage and frequency control equipment.
  - Dynamic Under Frequency Load Shedding.

Initiatives that reduce behind-the-meter PV generation or increase demand during times of reduced load, and the introduction of synchronous condensers, will further reduce the risk to the power system.

5.3 Consumption forecasts

Figure 34 shows operational consumption forecasts to 2029-30 for the low, expected, and high demand growth scenarios. Operational consumption is forecast to decrease over the outlook period in the low and expected growth scenarios, at an average annual rate of:

- 0.8% in the low growth scenario, from 17,082 GWh in 2020-21 to 15,846 GWh in 2029-30.
- 0.4% in the expected growth scenario, from 17,589 GWh in 2020-21 to 17,029 GWh in 2029-30.

Under the high growth scenario, operational consumption is forecast to grow at an average annual rate of:

- 1.1%, from 18,000 GWh in 2020-21 to 19,778 GWh in 2029-30.

A full set of operational consumption forecasts is provided in Appendix A7.

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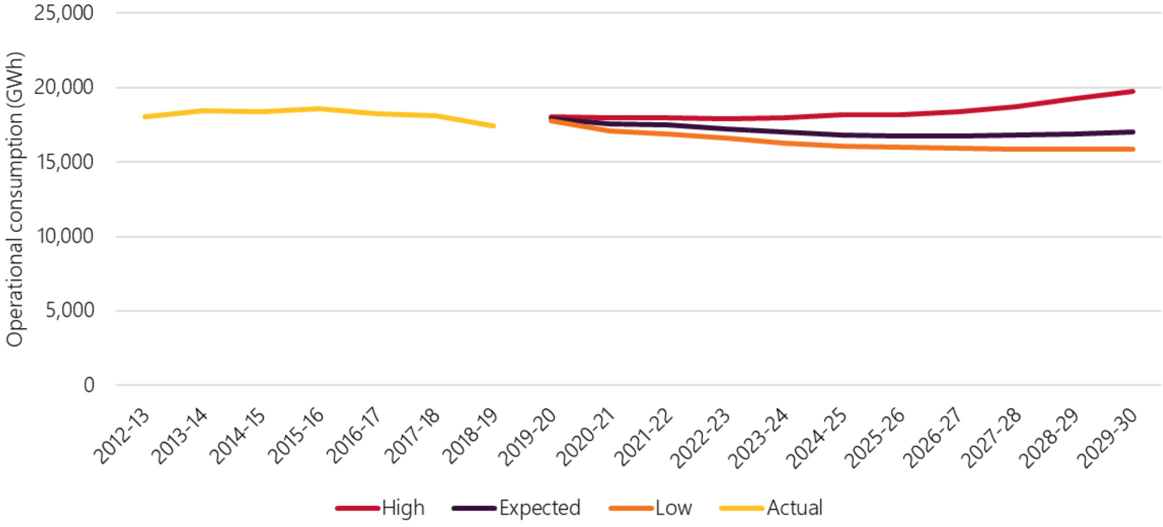
[136] The system security threshold is dynamic as it is subject to the condition of the network including on-line equipment and changes to the power system.

[137] For further information on the system security threshold, see AEMO, *Integrating Utility-scale Renewables and DER in the SWIS*, March 2019, at http://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf.

Figure 34 Operational consumption, actual and forecast under different growth scenarios, 2012-13 to 2029-30



The forecast decline in operational consumption in the low and expected growth scenarios is because:

- The proportion of consumption met by behind-the-meter PV installations is forecast to grow for both residential and commercial customers at an average annual rate of 6% (in the expected scenario), due to increasing installations of behind-the-meter PV. This will continue to offset operational consumption (see Section 3.3 for further information).
- Residential consumption is projected to fall, and business sector consumption is forecast to have weak growth. This is largely driven by energy efficiency improvements, and by continued growth in behind-the-meter PV generation in the longer term.

In the expected scenario, these declines are forecast to be partly offset by:

- Energy use by EVs growing at an average annual rate of 67%. EVs are forecast to contribute 377 GWh (2.9% of total operational consumption) by 2029-30 (see Chapter 4 for more information on EVs).
- LILs energy consumption is forecast to grow at 0.7% over the outlook period to reach 4,212 GWh (32.3% of total operational consumption) by 2029-30 (see Chapter 4 for more information on LILs).

Operational consumption is forecast to grow in the high growth scenario, driven by expected strong uptake of EVs, strong economic growth, and steady connections growth over the outlook period.

As part of its continuous improvement in forecasting, AEMO has provided separate forecasts for the residential and business sectors for the first time in this WEM ESOO.

5.3.1 Residential sector forecasts

Table 16 summarises annual residential operational consumption forecasts for the expected, low, and high demand growth scenarios.

Table 16 Residential annual operational consumption forecasts under different growth scenarios, 2020-21 to 2029-30 (GWh)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Expected	4,620	4,515	4,364	4,233	4,114	4,031	3,980	3,972	3,976	3,999
Low	4,609	4,498	4,335	4,185	4,048	3,943	3,855	3,791	3,723	3,661
High	4,651	4,561	4,438	4,383	4,354	4,392	4,485	4,633	4,838	5,110

In summary, residential operational consumption is forecast to:

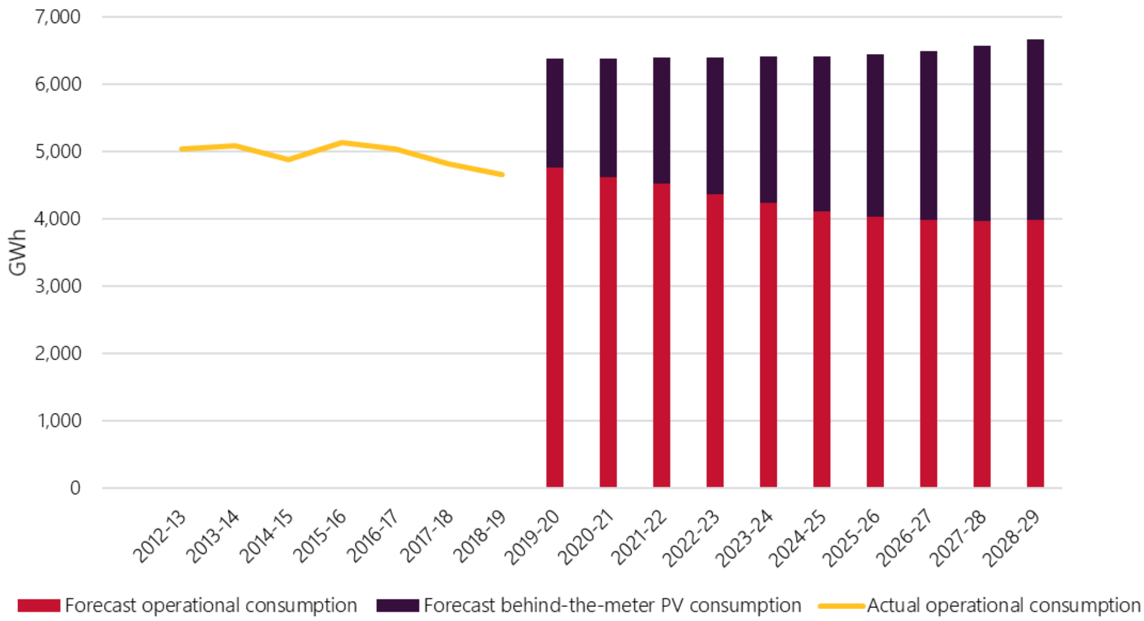
- Decline in the expected scenario, at an average annual rate of 1.6%, from 4,620 GWh in 2020-21 to 3,999 GWh in 2029-30.
- Decline in the low growth scenario, at an average annual rate of 2.5%, from 4,609 GWh in 2020-21 to 3,661 GWh in 2029-30.
- Grow in the high growth scenario, at an average annual growth rate of 1.1%, from 4,651 GWh in 2020-21 to 5,110 GWh in 2029-30.

Figure 35 shows residential operational consumption forecasts under the expected scenario, with forecasts of residential consumption from behind-the-meter PV. The combined operational consumption and behind-the-meter PV forecasts represent forecast underlying residential consumption (total consumption by residential consumers, from all sources).

As Figure 35 shows, underlying residential consumption is forecast to continue growing in the next ten years under this scenario, from 6,380 GWh in 2020-21 to 6,764 GWh in 2029-30. While ongoing improvements in energy efficiency are forecast to offset some growth in consumption, net growth is positive and largely driven by increases in residential connections and uptake of EVs. Consumption from EVs is forecast to increase from 1 GWh to 205 GWh by the end of the outlook period.

Meanwhile, operational residential consumption is forecast to fall at an annual average rate of 1.6%, declining from 4,620 GWh in 2020-21 to 3,999 GWh in 2029-30, due to continued uptake in behind-the-meter PV and energy efficiency improvements.

Figure 35 Residential annual consumption actual and forecast for the expected scenario, 2012-13 to 2029-30



5.3.2 Business sector forecasts

Table 17 shows the business sector annual operational consumption forecasts for the expected, low and high demand growth scenarios.

Table 17 Business annual operational consumption forecasts under different growth scenarios, 2020-21 to 2029-30 (GWh)

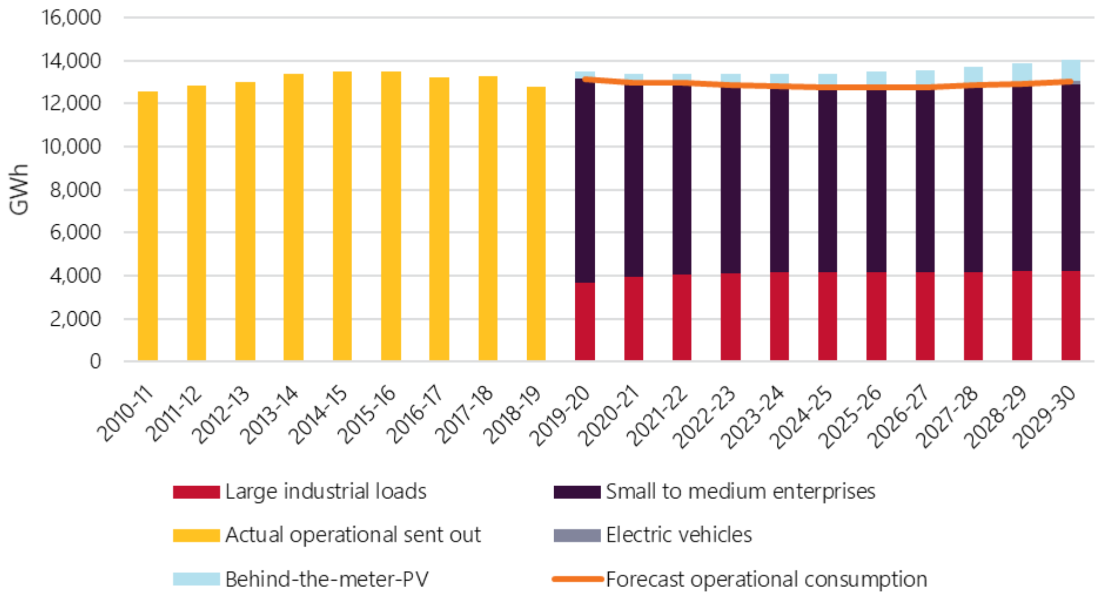
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Expected	12,969	12,952	12,845	12,776	12,727	12,741	12,769	12,830	12,918	13,030
Low	12,473	12,370	12,246	12,105	12,031	12,049	12,059	12,089	12,134	12,185
High	13,349	13,426	13,450	13,583	13,790	13,819	13,895	14,065	14,396	14,668

In summary, business operational consumption is forecast to:

- Grow in the expected scenario, at an average annual rate of 0.1%, from 12,969 GWh in 2020-21 to 13,030 GWh in 2029-30.
- Decline in the low growth scenario, at an average annual rate of 0.3%, from 12,473 GWh in 2020-21 to 12,185 GWh in 2029-30.
- Grow in the high growth scenario, at an average annual rate of 1.1%, from 13,349 GWh in 2020-21 to 14,668 GWh in 2029-30.

Figure 36 shows business operational consumption forecasts under the expected scenario, with forecasts of business consumption from behind-the-meter PV. The combined operational consumption and behind-the-meter PV forecasts represent forecast underlying business consumption (total consumption by business consumers, from all sources).

Figure 36 Business sector annual consumption actuals and forecasts under the expected scenario, 2010-11 to 2029-30



As Figure 36 shows, in the expected scenario, underlying business consumption (including operational consumption and behind-the-meter PV) is forecast to increase marginally, at an annual average growth rate of 0.5%, between 2020-21 and 2029-30.

Consumption from LILs is forecast to grow at an average annual rate of 0.7% throughout the outlook period, increasing from 3,972 GWh in 2020-21 to 4,212 GWh in 2029-30. Consumption from SMEs is forecast to fall at an annual average rate of 0.4% throughout the forecast period, declining from 9,441 GWh in 2020-21 to 8,645 GWh in 2029-30.

Business operational consumption (including SMEs, LILs, and EVs consumption from the business sector) is expected to be predominantly flat, with an annual average growth rate of 0.1%; it is forecast to increase marginally from 12,969 GWh in 2020-21 to 13,030 GWh by 2029-30. These trends are largely driven by projected increases in consumption from EVs, partially offset by decreases in consumption due to efficiency improvements and continued growth in behind-the-meter PV.

Business consumption from behind-the-meter PV is forecast to increase from 402 GWh to 1,007 GWh between 2020-21 and 2029-30, at an annual average growth rate of 10.7%.

5.3.3 Changes from previous forecasts

The 2020 WEM ESOO is forecasting operational consumption to be an average 799 GWh lower than the forecasts presented in the 2019 WEM ESOO when comparing expected scenarios over the outlook period. However, forecast growth trends are similar, with both forecasts projecting operational consumption to decline at an annual average rate of 0.4%. Table 18 summarises the difference in forecasts.

Table 18 Difference between operational consumption expected scenario forecasts, 2019 WEM ESOO and 2020 WEM ESOO (GWh)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
2019 WEM ESOO forecast	18,289	18,151	18,008	17,864	17,775	17,694	17,629	17,569	17,543
2020 WEM ESOO forecast	17,589	17,467	17,208	17,009	16,841	16,773	16,749	16,803	16,894
Difference	-700	-684	-800	-855	-934	-921	-880	-766	-649

Source: ACIL Allen and AEMO.

The lower consumption forecast in the 2020 WEM ESOO can largely be attributed to:

- Improvements in AEMO's methodology for estimating behind-the-meter PV compared to previous years (see Section 4.2 for more information about the forecast methodology for behind-the-meter PV).
- Flat growth in business sector consumption forecasts, primarily due to COVID-19 impacts slowing previously expected economic growth.
- Continued improvements in energy efficiency in both residential and business sectors.

6. Reliability assessment methodology

The Planning Criterion is used to set the Reserve Capacity Target (RCT) for each Capacity Year in the Long Term PASA Study Horizon. This chapter explains the purpose of the Planning Criterion in ensuring power system reliability and the methodologies used to determine the RCT.

6.1 Planning Criterion

Reliability standards are used in power systems to ensure the risk of failing to meet demand falls within acceptable limits.

Involuntary load shedding caused by insufficient capacity can be costly to the economy and community, especially when there are frequent long-duration supply disruptions. However, the marginal cost of capacity increases as the difference between available capacity and peak demand increases, while the marginal benefit to reliability declines. Therefore, setting a reliability standard requires a trade-off between the economic effects of involuntary load shedding and the cost of acquiring more capacity than required to meet demand at all times[138].

Globally, different reliability standards are used in power systems depending on the specific reliability risks, which vary according to the system's size, demand profiles, generator characteristics and outages, and level of interconnection. In the WEM, the reliability standard is called the Planning Criterion and is defined in clause 4.5.9 of the WEM Rules[139]. AEMO uses the Planning Criterion to set the Reserve Capacity Target (RCT) for each Capacity Year in the Long Term PASA Study Horizon.

The Planning Criterion requires sufficient capacity to be available in the SWIS in each Capacity Year to meet both of the following requirements:

- The 10% POE peak demand forecast[140] under the expected demand growth scenario plus allowances for Intermittent Loads[141], frequency control, and a reserve margin ("defined scenario").
- Limit expected unserved energy (EUE) to 0.002% of annual forecast expected energy consumption[142].

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138 The value of customer reliability (VCR) and the cost of supply are two factors to consider in setting the level of the reliability standard. The VCR represents value customers place on having reliable supply and avoiding most types of reliability events. VCRs seek to reflect the value different types of customers place on a reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour ($/kWh) of unserved energy. In general, the more conservative the reliability standard, the higher the cost for consumers.

139 The Economic Regulation Authority (ERA) is required to conduct a review of the Planning Criterion, including a review of the technical analysis in accordance with clause 4.5.15 of the WEM Rules. For the WEM Reviews scheduled by the ERA, see https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews.

140 The peak demand forecast is based on sent out demand (MW) averaged over a 30-minute period. It is calculated as the TSOG x 2 to convert non-loss adjusted megawatt hour (MWh) to MW for a Trading Interval.

141 An Intermittent Load is a load that is normally fully served by embedded generation. It only requires electricity from the network when its embedded generator is not fully operational. It must reasonably be expected to have net energy consumption for not more than 4,320 Trading Intervals in any Capacity Year (approximately 25% of time), as specified in clause 2.30B.2 of the WEM Rules.

142 A normalised metric, which does not have a unit (e.g. MWh or MW) is used for EUE. The energy consumption forecast is based on the TSOG (MWh) data.

AEMO engaged Robinson Bowmaker Paul (RBP) to conduct the Long Term PASA analysis, including the assessment of EUE and determination of the Availability Classes capacity requirements and Availability Curves as required under clauses 4.5.12 and 4.5.10(e) of the WEM Rules respectively. Further information about the methodology can be found in RBP's report[143].

6.2 The defined scenario

Since the RCM commenced in 2005, the defined scenario has always set the RCTs, because it has exceeded the capacity required to satisfy the EUE component of the Planning Criterion. The defined scenario is calculated as shown in Figure 37, and its components are explained in further detail in Table 19.

Figure 37 Defined scenario calculation

Table 19 Descriptions and methodology for the defined scenario components

Component	Description	Methodology
10% POE expected peak demand forecast	The level of electricity demand expected to be exceeded once in every 10 years under the expected demand growth scenario.	Described in Chapter 4.
Reserve margin	Accounts for both of the following: • Annual variability of peak demand in the SWIS. • The failure of the largest generating unit.	Calculated as the greater of: • 7.6% of the sum of the 10% POE forecast peak demand and the Intermittent Load allowance. • The maximum sent out capacity (measured at 41°C) of the largest generating unit[A].
Intermittent Load allowance	An estimation of the capacity required to cover the forecast cumulative needs of Intermittent Loads, which are excluded from the 10% POE expected peak demand forecast.	An iterative process is used to calculate the forecast maximum possible Intermittent Load levels, which is then adjusted based on the ratio of the RCT to the 10% POE expected peak demand forecast.
Frequency control allowance	Additional capacity required to provide Minimum Frequency Keeping Capacity and ensure that load following ancillary services (LFAS) are maintained.	LFAS requirements[B] are set for the 2019-20 financial year as follows[C]: • 85 MW between 5:30 and 19:30. • 50 MW between 19:30 and 5:30. AEMO has used 85 MW for the frequency control allowance, since peak demand is expected to fall in the 5:30 to 19:30 period.

A. AEMO considers NewGen Neerabup (330.6 MW, calculated on a sent out basis at 41°C) to be the largest generating unit in the SWIS.
B. With increasing levels of behind-the-meter PV, and large and small scale renewable generation connecting to the SWIS, AEMO expects the LFAS requirement to increase. Any changes will be reflected in future WEM ESOOs. The new Essential System Services framework (which is part of the WA Government's ETS) is underway, and this may also change the LFAS requirement.
C. LFAS requirements are set annually in the Ancillary Services Report for the WEM. The 2019 Ancillary Services Report for the WEM is available at https://aemo.com.au/-/media/files/electricity/wem/data/system-management-reports/2019-ancillary-services-report.pdf?la=en&hash=8C5E02BDCDA8A0D54B61762700E79AF2.

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[143] RBP 2020. 2020 assessment of system reliability, development of Availability Curves, and DSM Dispatch Quantity forecasts for the South West interconnected system, at https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

6.3 Expected unserved energy assessment

Unserved energy specified in the Planning Criterion refers to electricity that is required by consumers but not supplied because of insufficient generation or Demand Side Management capacity[144]. Involuntary load shedding caused by a Forced Outage at a large generation unit on a low capacity margin day[145] is an example of unserved energy. The EUE component of the Planning Criterion accounts for unreliable or intermittent generation by ensuring that energy requirements can be met throughout the relevant Capacity Year. It provides an indication of the magnitude of supply shortfall events.

Without this requirement, it may be possible for the SWIS to have enough capacity to meet the defined scenario but with high levels of unserved energy as a result of generation forced outages or intermittency.

RBP completed the assessment of EUE in three phases, and applied a combination of time sequential capacity availability simulation and Monte Carlo analysis for each Capacity Year in the Long Term PASA Study Horizon. Compared to the EUE assessment conducted for the 2019 WEM ESOO[146], the approach adopted for this WEM ESOO allows the EUE assessment to account for shifting peak demand time due to behind-the-meter PV and battery storage uptake. The three phases were:

1. Undertake hourly load forecasting to develop a reference load duration curve (LDC).
   - Historical sent out generation was used to develop an average underlying load shape[147], which was then applied to the 2018-19 Capacity Year's load chronology to produce the underlying reference load profile.
   - The underlying reference load profile was scaled to match the 50% POE underlying peak demand and underlying operational consumption[148] forecast under the expected demand growth scenario to develop hourly underlying load forecasts.
   - An average of five simulations of behind-the-meter PV generation profiles (accounting for cloud cover[149]) was calculated and applied to the behind-the-meter PV uptake forecasts to determine hourly behind-the-meter PV contributions to offset underlying load requirements.
   - The operational load profiles for each Capacity Year were developed by combining the hourly underlying load forecasts and the hourly behind-the-meter PV and battery storage[150] contributions, with an adjustment for network losses.
   - The operational load profiles were scaled to the forecast operational consumption and 50% POE peak demand values under the expected demand growth scenario.
2. Run simulation to calculate the average EUE using the operational load profiles developed in Phase 1.
   - Time sequential capacity availability simulation was used to compare the total available capacity to the corresponding load in an hour. This considered planned outages, intermittent generation, an application of the network constraints to Constrained Access Facilities[151], and randomly sampled Forced Outages. EUE occurs whenever the total available capacity is less than the load in an hour.

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144 This excludes unserved energy associated with power system security incidents that result from multiple concurrent contingency events and outages of distribution network elements.

145 A capacity margin level is an amount of available capacity over demand. A low capacity margin can be attributed to high demand and/or low supply.

146 RBP 2019. 2019 assessment of system reliability, development of Availability Curves, and DSM Dispatch Quantity forecasts for the South West interconnected system, at http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-ElectricityStatement-of-Opportunities.

147 Historical sent out generation included the last five full Capacity Years from 2014-15 to 2018-19.

148 The forecast LDC based on the 50% POE peak and expected operational consumption represents an expected scenario for the reliability assessment in accordance with clause 4.5.9(b) of the WEM Rules.

149 AEMO provided historical capacity factor data for the period 1 January 2010 to 23 February 2020, sourced from Solcast, for the calculation. The PV generation outage simulation accounting for cloud cover probability considered dependencies of cloud cover in the previous hour and season of the year.

150 Behind-the-meter battery storage contribution was calculated as the result of multiplying the normalised residential and commercial batteries' charge/discharge profiles by the residential and commercial battery uptake forecasts, respectively.

151 As defined in the WEM Rules.

- Monte Carlo analysis was applied to run the EUE simulation over many iterations with probabilistically simulated Forced Outages. EUE was calculated as the average of the total estimates of unserved energy from the Monte Carlo runs.

3. Determine the amount of Reserve Capacity required to limit the EUE to 0.002% of the annual expected operational consumption forecast.
   - The average EUE was calculated as a percentage of the annual expected operational consumption forecast for a given Capacity Year.
   - If the percentage of EUE is greater than 0.002%, the RCT is incrementally increased to reassess the average EUE until the EUE is less than or equal to 0.002%. The RCT will then be set by part (b) of the Planning Criterion.

6.4 Minimum capacity requirements (Availability Classes)

Certified Reserve Capacity is allocated to two classes based on capacity availability:

- Availability Class 1 relates to generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages or other restrictions.
- Availability Class 2 relates to capacity that is not expected to be available for dispatch for all Trading Intervals.

DSM capacity is required to satisfy the minimum availability requirements[152] including being available to provide capacity for at least 200 hours in a Capacity Year to participate in the RCM and generally relates to Availability Class 2 capacity.

RBP determined the minimum quantity of capacity required to be provided by Availability Class 1 for the 2021-22 and 2022-23 Capacity Years (the second and third years of the Long Term PASA Study Horizon) using the same simulation approach as for EUE, but with the following differences:

1. DSM was modelled to be dispatched optimally to reduce peak demand, subject to availability and scheduling constraints.
2. A reserve requirement was modelled to represent the criteria for evaluating Outage Plans (the Ready Reserve Standard and Ancillary Service Requirements under clause 3.18.11 of the WEM Rules).
3. Forced Outages were removed from the model to avoid double-counting, since the reserve requirement already accounts for Forced Outages.
4. The model was iterated, reallocating the amount of generation and DSM capacity each time, until the 0.002% EUE limit was violated.

The quantity of capacity where the EUE equals 0.002% of operational consumption, determined in step 4, sets the minimum Availability Class 1 requirement.

The Availability Class 2 requirement is calculated by subtracting the Availability Class 1 requirement from the RCT.

6.5 Availability Curves

The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year[153]. The minimum capacity requirement for each Trading Interval is

[152] As specified in clause 4.10.1(f) of the WEM Rules.

[153] The Availability Curve (defined in clause 4.5.10(e) of the WEM Rules) shows how demand changes over a Capacity Year, with demand on the vertical axis and time on the horizontal axis. It can be used to determine the number of hours when the capacity requirement exceeds a given level of demand.

calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads and LFAS.

For the 2020 WEM ESOO, the Availability Curve has been determined for the 2021-22 and 2022-23 Capacity Years (the second and third Capacity Years in the Long Term PASA Study Horizon). The determined Availability Curves are provided in Chapter 7.

RBP determined the Availability Curves by:

1. Using the operational load profiles for the 2021-22 and 2022-23 Capacity Years developed in Phase 1 of the EUE assessment (see Section 6.3) but with the following differences:
   - Load for the first 24 hours is based on the 10% POE peak demand forecast under the expected demand growth scenario, as required under clause 4.10.5(e)(i) of the WEM Rules.
   - Load for the remaining hours (25 to 8,760) is based on a 50% POE peak demand forecast under the expected demand growth scenario.
   - Applying a smoothing function to the first 72 hours of the estimated LDC.
2. Adding the reserve margin and allowances for Intermittent Loads and LFAS to the forecast LDC as required under clause 4.5.10(e)(ii) of the WEM Rules.

This approach assumes that the difference between a 10% POE and a 50% POE peak year would only be evident in the first 24 hours of the LDC. Consequently, the forecast minimum capacity requirements for the twenty-fourth hour onwards are expected to match the load profile with a 50% POE peak demand forecast under the expected demand growth scenario.

7. Reliability assessment outcomes

This chapter reports the RCT determined for each Capacity Year of the 2020 Long Term PASA Study Horizon (2020-21 to 2029-30 Capacity Years). The RCT determined for the 2022-23 Capacity Year sets the RCR for the 2020 Reserve Capacity Cycle.

The RCR for the 2020 Reserve Capacity Cycle is 4,421 MW, and no capacity shortfall is anticipated across the 2020 Long Term PASA Study Horizon.

7.1 The Reserve Capacity Target

7.1.1 Defined scenario[154]

Table 20 shows the RCT, set by the expected 10% POE peak demand requirement of the Planning Criterion (defined scenario), for each Capacity Year of the 2020 Long Term PASA Study Horizon.

Table 20 Reserve Capacity Targets (MW)[A]

Capacity Year	10% POE peak demand	Intermittent Loads[B]	Reserve margin	Load following[B,C]	Total
2020-21[D]	4,008	3	331	85	4,427
2021-22[D]	4,018	3	331	85	4,437
2022-23	4,002	3	331	85	4,421
2023-24	3,913	3	331	85	4,332
2024-25	3,923	3	331	85	4,342
2025-26	3,964	3	331	85	4,383
2026-27	3,942	3	331	85	4,361
2027-28	3,959	3	331	85	4,378
2028-29	3,908	3	331	85	4,327
2029-30	3,937	3	331	85	4,356

A. All figures have been rounded to the nearest MW.
B. See Section 6.2 for further information.
C. With increasing levels of behind-the-meter PV, and large and small scale renewable generation connecting to the SWIS, AEMO expects the LFAS requirement to increase. Any changes will be reflected in future WEM ESOOs. The new Essential System Services framework (which is part of the WA Government's ETS) is underway, and this may also change the LFAS requirement.
D. Figures have been updated to reflect the current forecasts. However, the RCR of 4,581 MW set in in the 2018 WEM ESOO for the 2018 Reserve Capacity Cycle and the RCR of 4,482 MW set in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle do not change.

[154] As defined in Chapter 6 of this 2020 WEM ESOO.

The RCT determined for the 2022-23 Capacity Year is 4,421 MW, which sets the RCR for the 2020 Reserve Capacity Cycle. This is lower than:

- The RCT for the 2022-23 Capacity Year (4,481 MW) forecast in the 2019 WEM ESOO.
- The RCR for the 2021-22 Capacity (4,482 MW) set in the 2019 WEM ESOO.

In both cases, this is due to lower 10% POE peak demand forecasts (see Chapter 5 for more information).

7.1.2 Unserved energy assessment

The unserved energy assessment concluded that the RCT set by the defined scenario is sufficient to limit EUE to well below 0.002% of annual forecast expected energy consumption for each Capacity Year in the 2020 Long Term PASA Study Horizon. In summary, the EUE assessment found that:

- EUE has increased compared to the 2019 WEM ESOO EUE assessment[155], largely due to the retirement of the Muja C units (increasing the proportion of demand met by intermittent generation sources) combined with increasing winter demand (intermittent generation is lower during winter months) and higher Forced Outage rates of some large generation units.
- EUE is more likely to occur in both summer when demand is generally higher and in winter when less intermittent generation is available.
- There is a higher risk of unserved energy occurring between 17:00 and 19:00 than during daylight hours as a result of increasing behind-the-meter PV penetration shifting peak demand Trading Intervals to evening periods[156].

The results of the EUE assessment are provided in Appendix A3. For a description of the methodology used to determine these values, see Section 6.3.

7.2 Availability Classes

The minimum Availability Class 1 capacity requirement and the capacity associated with Availability Class 2 for the 2021-22 and 2022-23 Capacity Years are shown in Table 21. The description of the Availability Classes and the methodology used to determine these values can be found in Section 6.4.

Table 21 Availability Classes (MW)[A]

	2021-22[B]	2022-23
Minimum capacity required to be provided from Availability Class 1	3,557	3,371
Capacity associated with Availability Class 2	880	1,050
RCT	4,437	4,421

A. In general, Availability Class 1 capacity is associated with generation capacity and Availability Class 2 capacity is associated with DSM capacity. See Section 6.4 for further information.
B. These figures reflect the current forecasts. The RCT of 4,482 MW as determined in the 2019 WEM ESOO for the 2021-22 Capacity Year, which set the RCR for the 2019 Reserve Capacity Cycle, remains unchanged. This comprised capacity requirements of 3,657 MW of Availability Class 1 and 825 MW of Availability Class 2.
Source: AEMO and RBP.

[155] RBP 2019. Assessment of system reliability, development of Availability Curves, and DSM Dispatch Quantity forecasts for the South West interconnected system, at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

[156] In previous EUE assessments, the risk of unserved energy has been highest in the period 14:00 to 16:00. Improvements in the modelling methodology to better account for changing load shapes has shifted the risk of unserved energy into the evening period.

The minimum capacity required to be provided by Availability Class 1 for the 2021-22 Capacity Year has decreased by 100 MW from the value published in the 2019 WEM ESOO, and the capacity associated with Availability Class 2 has increased by 55 MW. These changes are largely due to the effect of behind-the-meter PV uptake on the load profiles, which has been captured in this year's Availability Classes modelling:

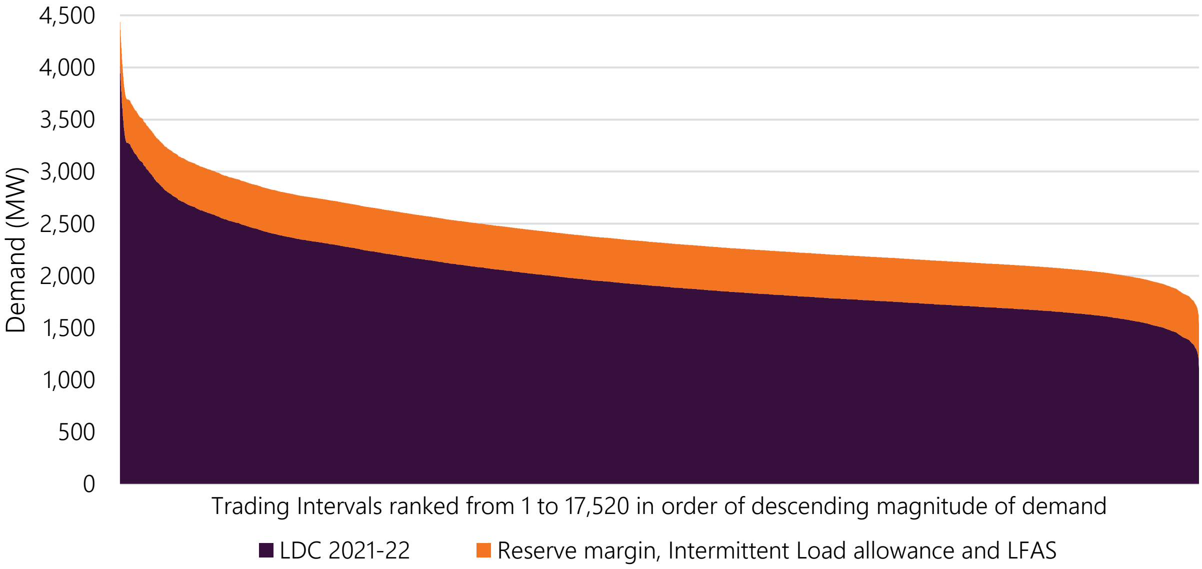
- In the 2019 WEM ESOO Availability Classes modelling, most of the EUE occurred in the shoulder season (autumn and spring)[157]. This was where most Planned Outages were scheduled to occur, and DSM was typically unavailable for dispatch because its full 200 hours of availability had been dispatched to minimise peak during summer.
- In the 2020 WEM ESOO Availability Classes modelling, increasing penetration of behind-the-meter PV reduces minimum demand values and operational consumption during the shoulder season.
- As operational consumption in the shoulder season has decreased, the capacity margin[158] in the shoulder season is higher. This in turn allows the minimum generation capacity requirement to be reduced and more DSM capacity in the market before unserved energy occurs[159].

For the 2020 WEM ESOO Availability Classes modelling, continued growth in the uptake of behind-the-meter PV is expected to further reduce the operational consumption in the shoulder season in the 2022-23 Capacity Year compared to the 2021-22 Capacity Year. This in turn increases the capacity margin in the shoulder season. The allowable DSM capacity is therefore increased in the 2022-23 Capacity Year.

7.3 Availability Curves

The Availability Curves for the 2021-22 and 2022-23 Capacity Years are shown in Figure 38 and Figure 39. These Availability Curves illustrate the number of Trading Intervals when the capacity requirement exceeds a given level of demand plus an amount of available capacity margin. Further information about the Availability Curves and their determination can be found in Section 6.5.

Figure 38 2021-22 Capacity Year Availability Curve



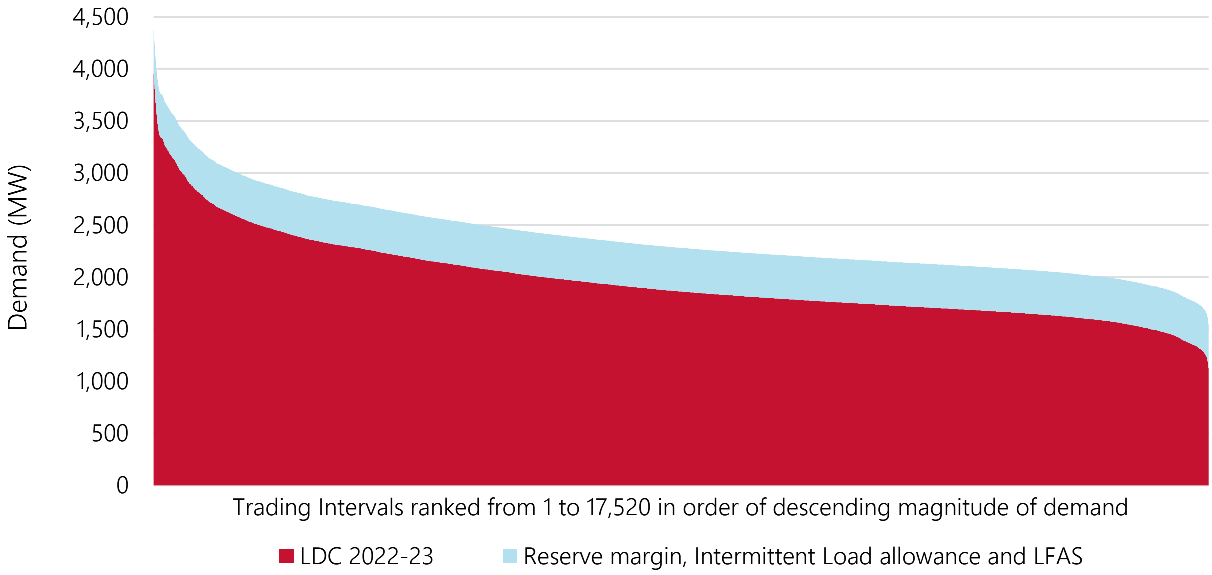
Source: RBP.

[157] Availability constraints for DSM considered in the Availability Classes modelling were not modelled in the EUE assessment as it was assumed that DSM will be dispatched in any 'last resort' situation, i.e. when there is risk of EUE.

[158] A capacity margin level is an amount of available capacity over demand.

[159] The Availability Classes modelling iterates the simulation to reallocate the amount of DSM and generating capacity (reducing the generating capacity as DSM increases, keeping the total capacity capped at the Reserve Capacity Target level) until the EUE requirement in clause 4.5.9(b) of the WEM Rules is no longer met for a Capacity Year.

Figure 39 2022-23 Capacity Year Availability Curve



Source: RBP.

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 the relevant Market Procedure[160]. The EDDQ and the DSM Activation Price are used to determine the DSM RCP. The formula used to determine the DSM RCP is:

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

A detailed explanation of the methodology used to calculate the EDDQ and the forecast EDDQ and DSM RCP for the 2020 Long Term PASA Study Horizon is provided in Appendix A1.

The DSM RCP for the 2020-21 Capacity Year is $16,730/MW. The EDDQ and DSM Activation Price for the 2020-21 Capacity Year are zero MWh per DSM Capacity Credit and $33,460/MWh respectively. AEMO has assigned 66 MW of DSM Capacity Credits under Availability Class 2 for the 2020-21 Capacity Year.

The amendments to the WEM Rules in February 2020 to implement changes to RCM pricing (see Section 8.1.2 for more information) have removed the DSM Reserve Capacity Price. From the 2021-22 Capacity Year, DSM will be paid the same price as generation capacity. As such, the EDDQ and the DSM RCP values will not be calculated and published in subsequent WEM ESOOs.

7.5 Opportunity for investment

7.5.1 Supply-demand balance

To forecast the capacity supply-demand balance over the 2020 Long Term PASA Study Horizon, AEMO has assumed that:

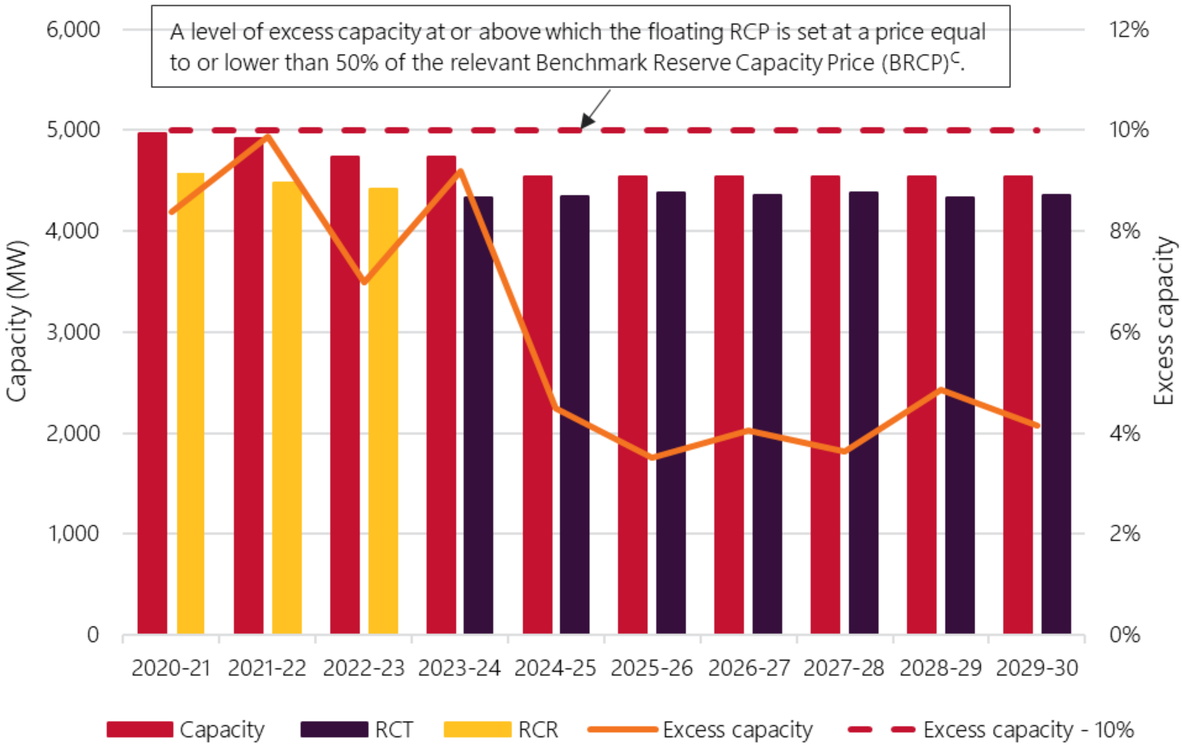
- There are no scheduled capacity retirements other than MUJA_G5 and MUJA_G6 at the beginning of the 2022-23 and 2024-25 Capacity Years respectively.
- The total DSM Capacity Credits are 66 MW for the 2020-21 Capacity Year and 84.5 MW for the remainder of the Long Term PASA Study Horizon.

160 Market Procedure: Determination of the DSM Dispatch Quantity and DSM Activation Price, at https://aemo.com.au/-/media/files/electricity/wem/procedures/2017/determination-of-expected-dsm-dispatch-quantity-and-dsm-activation-price.pdf.

- No new committed capacity[161] commences operation over the Long Term PASA Study Horizon, except new Facilities that were assigned Capacity Credits for the 2020-21 and 2021-22 Capacity Years.
- No probable projects[162] are developed over the Long Term PASA Study Horizon.

In Figure 40, the RCT is compared to the expected level of capacity in each Capacity Year of the Long Term PASA Study Horizon. The expected level of capacity declines in the 2022-23 Capacity Year and again in the 2024-25 Capacity Year with the retirement of MUJA_G5 and MUJA_G6, respectively. The forecast capacity supply-demand balance for the high and low demand growth scenarios can be found in Appendix A2.

Figure 40 Forecast capacity supply-demand balance, 2022-23 to 2029-30[A,B]



A. 2020-21 and 2021-22 capacity values are actuals and the remaining years are forecasts.
B. Excludes 2020 Expressions of Interest submissions.
C. The BRCP represents the marginal cost of providing one additional megawatt (MW) of Reserve Capacity in the relevant Capacity Year; see https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/benchmark-reserve-capacity-price.

Table 22 shows a more detailed capacity outlook for the 2020-21 to 2022-23 Capacity Years.

161 Committed capacity for a Capacity Year refers to new DSM or generation capacity that holds Capacity Credits for the relevant Capacity Year but has not previously held Capacity Credits for a previous Reserve Capacity Cycle.

162 Probable projects refer to Facilities that have not already received Capacity Credits for a previous Reserve Capacity Cycle but have been granted Certified Reserve Capacity for the current Reserve Capacity Cycle, as outlined in step 2.10.3 of the Market Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion at https://aemo.com.au/-/media/files/electricity/wem/procedures/2017/undertaking-the-long-term-pasa-and-conducting-a-review-of-the-planning-criterion.pdf?la=en&hash=AF14C23DA9F2AD49D023E473A78802AA.

Table 22 Capacity outlook in the SWIS, 2020-21 to 2022-23 Capacity Years (MW)[A]

Capacity category	2020-21	2021-22	2022-23[B]
Generation capacity	**4,900**	**4,840**	**4,645**
• Existing[D]	4,808	4,807[C]	4,645
• Committed[E]	92	33	0
DSM capacity	**66**	**85**	**85**
• Existing[D]	66	85	85
• Committed[E]	0	0	0
Total capacity	4,966	4,925	4,730
RCR	4,581	4,482	4,421
Excess capacity	385 (8.4%)	443 (9.9%)	309 (7.0%)

A. All capacity values are in terms of Capacity Credits, rounded to the nearest integer. Values for the 2020-21 and 2021-22 Capacity Years are Capacity Credits assigned for the 2018 and 2019 Reserve Capacity Cycles, respectively.
B. The capacity outlook for the 2022-23 Capacity Year excludes MUJA_G5 (195 MW of Capacity Credits). All other Facilities are assumed to receive the same quantity of Capacity Credits as for the 2019 Reserve Capacity Cycle.
C. The reduction in existing generation capacity between the 2020-21 and 2021-22 Capacity Years is largely due to year-on-year variation in Relevant Level for Intermittent Non-Scheduled Generators.
D. Existing generation and DSM capacity holds Capacity Credits for the relevant Capacity Year and has held Capacity Credits for a previous Reserve Capacity Cycle.
E. Committed capacity refers to new generation or DSM capacity that holds Capacity Credits for the relevant Capacity Year but has not held Capacity Credits for a previous Reserve Capacity Cycle.

Excess capacity increased from 385 MW (8.4%) to 443 MW (9.9%) between the 2020-21 and 2021-22 Capacity Years as a result of a decrease in the RCR and the inclusion of one new Scheduled Generator (33 MW of Capacity Credits) entering the market. Excess capacity is expected to decline to around 309 MW (7.0%) in the 2022-23 Capacity Year, largely as a result of the retirement of MUJA_G5 (195 MW) in October 2022.

The 2020 Long Term PASA study has considered the network constraints that apply to Constrained Access Facilities[163]. No localised supply restrictions are expected to exist in the SWIS that influence the ability of capacity to satisfy the RCT in each Capacity Year over the Long Term PASA Study Horizon[164]. In particular, the level of capacity that is made available to the market over the Long Term PASA Study Horizon may be affected by changes to the WEM Rules implemented under the WA Government's ETS (see Chapter 8 for further information). Project proponents, investors, and developers should make their own independent assessments of future possible supply and demand conditions.

AEMO does not include capacity offered through EOI submissions (a non-mandatory Reserve Capacity process) for the 2022-23 Capacity Year in the expected supply-demand balance, because EOIs do not necessarily include all future proposed projects, and only a few proposed projects progress through the Certified Reserve Capacity (CRC) process.

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 process for the 2020 Reserve Capacity Cycle closed on 1 May 2020 and AEMO received three EOIs. This includes a

[163] As defined in chapter 11 of the WEM Rules.

[164] This expectation may change in the future due to changes in the capacity mix or network augmentations in the SWIS.

non-intermittent generator with an estimated output of 29 MW at 41°C and two intermittent generators with a total estimated CRC assignment of 33 MW[165].

While the EOI process provides an indication of potential future capacity, a project proposed in an EOI does not necessarily progress to a committed project for the relevant Capacity Year. The EOI process is not mandatory, so new projects that skip the EOI process are still eligible to apply for CRC and be assigned CRC.

Table 23 shows the amount of nameplate capacity offered 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 New capacity offered through the EOI compared to capacity certified, 2015-16 to 2022-23 (MW)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22[A,B]	2022-23[A]
New capacity offered	59	56	0	42	323	10	32.4	62
New capacity offered and certified	0.4	0	0	0	65	0	33	TBD
Total other capacity certified[C]	35	18	12	16	0	93	0	TBD

A. Estimated Capacity Credit assignment provided by the project proponent.
B. One Facility that was offered through the EOI received a higher level of Capacity Credits than the estimate provided in the EOI.
C. New capacity that was not offered through an EOI but received Capacity Credits for the relevant Capacity Year.

[165] 2020 Expressions of Interest summary report, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2020/2020-eoi-summary-report.pdf?la=en.

8. Market developments and challenges

Chapter 8 highlights some developments and emerging issues in the WEM that are relevant to the RCM:

- WEM reviews and rule changes.
- Reserve Capacity Price amendments.
- Initiatives supporting DER integration.
- Infrastructure developments in the SWIS.
- WA's Energy Transformation Strategy.

8.1 WEM reviews and rule changes

8.1.1 WEM reviews

The ERA aims to complete several five-yearly reviews of methods underpinning various processes and calculations in the WEM Rules, including:

- Relevant Level Methodology (RLM), used to determine Certified Reserve Capacity for intermittent generators – the ERA completed the RLM review in March 2019[166]. This review concluded that the current methodology does not provide an accurate forecast of the capacity contribution of NSGs to reliability in the SWIS and a new method is required. The ERA is considering a new method which is to be developed as a Rule Change Proposal specifying the details.
- BRCP and energy price limits – the ERA has currently suspended its review of the BRCP and energy price limits methodologies[167], but intends to continue with the review of the Market Procedure, following feedback from generators indicating that some aspects of the Market Procedure are out of date and would benefit from a review[168].
- Planning Criterion and peak demand forecasting – the ERA will provide further information about when this review will commence. Further information on the proposed five-yearly reviews is expected to be made available on the ERA's website[169].

8.1.2 Reserve Capacity Price amendments

The RCP is the price paid by AEMO for Capacity Credits in the WEM. AEMO calculates the RCP based on a formula set in the WEM Rules. Key components of the RCP include the BRCP and the level of excess capacity each Capacity Year.

[166] See https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/review-of-method-used-to-assign-capacity-to-intermittent-generators-2018.

[167] See https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/benchmark-reserve-capacity-price-and-energy-price-limits-review-2019.

[168] See https://www.erawa.com.au/cproot/21240/2/NOTICE---Suspension-of-BRCPEPL-method-reviews.pdf.

[169] See https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews.

On 11 February 2020, the Minister for Energy amended the WEM Rules to implement changes to the RCP from the 2019 Reserve Capacity Cycle. The pricing method has been modified to improve the RCP's responsiveness to increasing, or decreasing, levels of available capacity. The BRCP continues to provide the basis for the pricing methodology with the following three key parameters:

1. Price cap – in periods of capacity shortfall, the RCP cannot exceed 1.3 times the BRCP.
2. Absolute zero point – if excess capacity exceeds 30%, the RCP will fall to zero.
3. Economic zero point – if excess capacity exceeds 10%, the RCP will fall to 50% of the BRCP, which is considered low enough to discourage new Facilities from entering the market.

The new capacity pricing model represents a significant change to the RCM arrangements. Consequently, transitional arrangements to ameliorate perceived revenue risk associated with the new capacity pricing, and to limit the scope of capacity price movements in respect of existing capacity assets, have been included[170].

Referred to as Transitional Facilities, generation Facilities that were assigned Capacity Credits for the 2019 Reserve Capacity Cycle will receive a floor price of $114,000 and a price cap of $140,000 (inflation adjusted). These transitional arrangements will remain in place for 10 consecutive years.

New generation Facilities will have the option of taking a floating RCP calculated each Capacity Year or locking in the price they receive in their first year of entry for five years as a Fixed Price Facility. The floating price is a product of the new RCM pricing methodology and its three key parameters mentioned above.

Using the forecast RCT for the 2022-23 Capacity Year published in the 2019 ESOO, and the amount of CRC assigned for the 2021-22 Capacity Year, the floating RCP is estimated to be approximately $78,573 per MW for the 2022-23 Capacity Year. The estimated floating RCP for the 2022-23 Capacity Year reflects the increased responsiveness of the new RCM pricing arrangements when there is excess Reserve Capacity.

DSM Facilities will receive the floating RCP but are not eligible to be a Transitional Facility or Fixed Price Facility. DSP will be required to provide DSM Reserve Capacity Security each year and will be subject to random Verification and Reserve Capacity Tests.

Further details on the amendments to the WEM Rules and the objectives of those changes can be found on the Energy Policy WA (EPWA) website[171].

8.1.3 Rule Change Proposals

There are multiple Rule Change Proposals currently under development that may affect the RCM, including:

- Relevant Demand calculation (RC_2019_01).
- Capacity Credit allocation methodology for Intermittent Generators (RC_2018_03).
- Reduced frequency of the review of the energy price limits and the Maximum Reserve Capacity Price (RC_2014_05).
- Administrative improvements to the outage process (RC_2014_03).

Further information about these Rule Change Proposals can be found on the Rule Change Panel's website[172].

8.2 Initiatives supporting DER integration

A WA Parliamentary Inquiry Into Microgrids and Associated Technologies[173] was finalised in February 2020 and found that renewable energy based microgrids offered a wide range of benefits uniquely suited to WA's electricity system, including:

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170 At https://www.wa.gov.au/sites/default/files/2019-08/Final-Recommendations-Report-Improving-Reserve-Capacity-pricing-signals_0.pdf.

171 See https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals.

172 See https://www.erawa.com.au/rule-change-panel/market-rule-changes.

173 See www.parliament.wa.gov.au/parliament/commit.nsf/(InqByName)/Inquiry+into+Microgrids+and+Associated+Technologies+in+WA?opendocument#Report.

- As a grid balancing resource.
- The reduction in total system costs by deferring, reducing, or removing the need to invest in new poles and wires.
- Improvements in supply, reliability, and power quality for fringe-of-grid consumers.
- Improved resilience to natural disasters, particularly in remote and regional areas of WA.
- Storage opportunities within existing transmission and distribution systems, and other market and network areas.

To realise the opportunities articulated in the Parliamentary Report, regulatory and market structures in WA need to change to reflect the physical realities of the electricity system, including advanced metering infrastructure that supports system security and encourages efficient asset development and utilisation.

The Parliamentary Report complements the work being delivered by the comprehensive ETS (see Section 8.4) and highlights most of the operational issues identified in AEMO's *Integrating Utility Scale Renewables and DER in the SWIS*[174]. Some of those operational issues are outlined in the sections below.

Ancillary Services

Traditionally, synchronous generation[175] has been the main provider of Ancillary Services (also referred to as Essential System Services[176]) in the SWIS. These services are necessary for the secure and reliable operation of the network. Renewable energy wind and solar generation (generally non-firm, asynchronous generation) is displacing traditional synchronous generation in the SWIS. This can become problematic as the full range of Ancillary Services required to keep the system secure and reliable cannot be easily sourced from non-firm asynchronous generators.

Until asynchronous generators[177] can demonstrate an ability to provide the full range of Ancillary Services under appropriate WEM Rules, Ancillary Services will continue to be sourced from synchronous generation. As synchronous generation and useable Ancillary Services decreases, threats to the secure operation of the SWIS increase. Other technologies such as batteries and synchronous condensers can be used to provide Ancillary Services, however changes are likely to be required to the WEM Rules to sufficiently incentivise that investment and ultimately optimise the provision of energy and Ancillary Services through a combination of synchronous and asynchronous generation and other technologies.

Minimum operational demand threshold

The minimum operational demand threshold is the operational demand amount (MW) at or below which the control of voltage on the network (due to the inadequate absorption of reactive power) would be compromised. AEMO has estimated the minimum operational demand threshold to be approximately in the order of 700 MW[178], below which voltage control will be compromised to the point that for a contingency event, voltages would go beyond standard operating levels, risking damage to the power system and customer equipment. To avoid this, AEMO would look to trip feeders that have high levels of

[174] See www.aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf.

[175] Synchronous generators are directly connected to the power system and rotate in synchronism with grid frequency. Thermal (coal, gas) and hydro (water) driven power turbines are typically synchronous generators.

[176] The term essential system services (referred to as Ancillary Services in the current WEM Rules) capture all services needed to maintain power system security and reliability. This term is proposed to be enshrined in the WEM Rules and will better reflect the essential nature and applicability of these services to the power system. Essential System Services including inertia, frequency control, and voltage control.

[177] Asynchronous generation includes wind farms, solar PV generators, and batteries that export power to the grid. They do not have moving parts rotating in synchronism with the grid frequency, but instead are interfaced to the power system via power electronic converters (refer to "power electronic converters") which electronically replicate grid frequency.

[178] The 700 MW threshold analysis considered various combinations of synchronous generation connected to the network (online and offline), ramp rate considerations, transmission equipment in service, and the minimum generating thresholds of the generation fleet in the SWIS, and is subject to change depending on the on-line equipment and as the power system evolves. For further information, see https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf.

behind-the-meter PV export, resulting in loss of supply to those customers[179]. Minimum operational demand in the SWIS is expected to fall below 700 MW as early as 2023-24. For more information regarding minimum demand forecasts, refer to Chapter 5.

Increasing swings in power generation

Increasing amounts of uncontrolled behind-the-meter-PV is decreasing the opportunity for synchronous generation to offer electricity into the WEM, leading to reduced levels of useable Ancillary Services (see above).

Behind-the-meter PV (currently more than 1.25 gigawatts [GW]) is also contributing to an increase in the frequency, size, and rate of fluctuations in underlying demand, and presents a challenge for the operational management of the SWIS due to the difficulty in forecasting fluctuations and dispatching generation accordingly[180]. Increasing large inter-interval and intra-interval swings in generation, and decreasing levels of available Ancillary Services, is leading to increases in the use of backup Load Following Ancillary Services (LFAS)[181] and LFAS costs.

8.2.1 Energy storage product trials

Network operators and electricity retailers across Australia are undertaking energy storage product trials. In WA, the Alkimos Beach energy storage trial lead by Synergy and Western Power uses a 1.1 MWh lithium battery to trial a number of energy storage products including a community virtual storage service. Other trials taking place in WA, listed in Table 24, use large-scale batteries connected to the local distribution system to store energy generated by behind-the-meter PV systems[182].

Table 24 List of large-scale energy storage trials

Methodology under review	Launch date and storage capacity
Meadow Springs, Mandurah	October 2018 – 105 kW (420 kWh)
East Village, Knutsford, Fremantle	March 2019 – 100 kW (670 kWh)
Falcon, Mandurah	November 2019 – 116 kW (464 kWh)
Ellenbrook PowerBank 2 trial	February 2020 – 116 kW (464 kWh)

8.2.2 AEMO VPP trials

AEMO is currently trialling virtual power plants (VPPs) in the National Electricity Market (NEM) to advance the integration of DER (behind-the-meter PV, batteries, and controllable-load devices)[183]. AEMO has engaged with pilot scale VPPs to participate in demonstrations that are providing evidence-based learning about how DER can be used to provide energy and system services such as Frequency Control Ancillary Service (FCAS),

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[179] A contingency event is an event that affects the power system in a way which would likely involve the failure or sudden and unexpected removal of a generating unit or transmission element from operational service.

[180] As evident on 26 February 2020 when operational demand increased from 2,200 MW to approximately 2,900 MW during the 11:00 to 12:30 Trading Intervals. Operational demand then decreased to 2,400 MW over the following 45 minutes. This significant fluctuation in operational load correlated with a passing dense cloud mass and increased the risk of destabilising the grid.

[181] LFAS is the power system security ancillary service whereby assigned generators automatically and constantly change their output to compensate for load and wind fluctuations and thus regulate the system frequency. Load following units will respond automatically to any over or under frequency events (including generator trips and load rejection events).

[182] See https://www.synergy.net.au/Our-energy/Future-energy/Alkimos-Beach-Energy-Storage-Trial and https://westernpower.com.au/community/news-opinion/powerbank-brings-bulk-battery-storage-to-wa-homes-in-australian-first-trial/.

[183] For further information, see https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/pilots-and-trials/virtual-power-plant-vpp-demonstrations.

traditionally performed by a conventional power plant[184]. AEMO has already gained several valuable insights for the industry:

- Data obtained to date indicates that VPPs can effectively respond to power system events and price signals, including frequency excursions and pre-charging/discharging to cater for future price events.
- Revenue can be earned by participating in the NEM's contingency FCAS markets.
- Several regulatory amendments have been identified for full deployment of VPPs in the NEM, which may provide lessons for VPPs in the WEM (see Section 8.2).
- A modern toolset and technology were used to develop the required VPP applications.

8.2.3 DER registers

Australia's first DER Register was launched in the NEM on 1 March 2020[185]. AEMO intends to use the DER Register for application in the WEM which is expected to be ready for launch by the end of 2020.

A DER Register is a database that stores information about DER devices installed on-site at a residential or business location. A secure and functional DER Register will be part of to the DER Program, by enabling AEMO to:

- Forecast, plan, and operate the grid more efficiently, ensuring the system and market can deliver energy at an efficient price for all customers.
- Be better prepared for major disruptions to the system, with a greater understanding of how DER assets will behave during these events.
- Prepare the grid for major innovations with DER such as VPPs, and enable customers to consider and participate in new markets with their DER.
- Allow networks to make more informed decisions about network investment options in the future as demand changes and DER increases.

8.3 Infrastructure developments in the SWIS

While strategies that support a future energy system are being developed, Western Power continues to manage and operate the SWIS infrastructure in its current state and format.

In accordance with clause 4.5.10 of the WEM Rules, this section highlights how infrastructure developments are proceeding in the SWIS and how consumers and Market Participants currently access the SWIS to connect generation or load.

8.3.1 Western Power's Applications and Queuing Policy

Western Power's Applications and Queuing Policy (AQP)[186] sets out how connection applications and access offers are managed. It is designed to manage applications in an orderly, transparent, and fair manner, especially where network capacity is scarce. The AQP underpins and regulates the connection process, which progresses customers along a pathway consisting of several milestones, leading to an Access Offer for connection to the Western Power network.

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[184] See AEMO's Virtual Power Plant Demonstration, Knowledge Sharing Report #1 for details concerning VPP responses to contingency FCAS and energy events in South Australia.

[185] See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program and https://aemo.com.au/en/energy-systems/electricity/der-register.

[186] Applications and Queuing Policy, at https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/western-power-access-arrangement-period-2017-2022.

8.3.2 Network access for generators

Several areas in the network have very limited network capacity[187] to support new generator connections on a reference service basis without significant network augmentation while an unconstrained network access model is in place. Western Power's Annual Planning Report (APR) 2018-19 Overview[188] describes the network configuration and provides an indication of network capacity to support new load and generation connections.

Western Power is assisting the WA Government to deliver the ETS which includes a new network access regime and will consider:

- Existing network constraints/congestion.
- The effect of the new regime on existing generators.
- Generator dispatch outcomes.
- Revenue projections.
- Generation supply adequacy.

While the ETS is being progressed, the Generator Interim Access (GIA) solution was launched in July 2018, with the aim of providing an interim, constrained access connection for a limited number of renewable generators to facilitate further connections to the SWIS.

The first GIA generator, Badgingarra Wind and Solar Farm (130 MW), connected under the GIA and was commissioned in January 2019. Additional renewable generation capacity totalling approximately 500 MW is expected to connect during 2020, including Yandin Wind Farm (210 MW), the Warradarge Wind Farm (180 MW), and the Merredin Solar Farm (100 MW).

Based on operational experience and after undertaking a review of GIA, including engaging with the industry on its use and impacts, Western Power is working with key stakeholders, including AEMO, on prudent improvements to GIA.

8.3.3 Connecting new loads

Both the Electricity Network Access Code and WEM Rules contemplate application of non-network solutions to address network limitations. Non-network options may be provided by a Network Control Service (NCS) and/or DSM.

Where Western Power identifies a network limitation affecting the connection of a new block load, network augmentation as well as alternative options (such as NCS, demand management or connecting on a non-reference service basis) will be considered. Proponents who have installed (or are planning to install) generation capacity or DSM capacity capable of providing network support should contact Western Power to discuss these opportunities.

Western Power continues to work with large mining customers, local government, and other stakeholders including those in the Kwinana, Mid-West, Eastern Goldfields, and South West regions to facilitate their energy needs, and is in the process of developing revised transmission network strategies for these and other regions. Key activities include:

- Installing additional 330/132 kilovolt (kV) transformer capacity at Kemerton to address asset issues and provide future growth opportunities for the region, as well as providing reference capacity to existing and new industrial loads supplied from Kemerton.
- Undertaking several projects in the Eastern Goldfields region to increase network capacity in the area and facilitate providing supply to regional mining loads, including:

[187] Public Utilities Office, *Modelling the impacts of constrained network access*, Public report, 1 October 2018.

[188] Western Power, Annual Planning Report 2018-19 Overview, at https://westernpower.com.au/about/reports-publications/annual-planning-report-201819-overview/.

– Replacement of static VAR compensators[189] at West Kalgoorlie terminal.
– Installing a third 220/132 kV transformer at West Kalgoorlie terminal and additional static synchronous compensators.
– Addressing capacity issues at Black Flag substation.

8.4 WA's Energy Transformation Strategy

The ETS is a significant WA Government initiative being delivered by Energy Policy WA (EPWA). The ETS has four key components which are detailed below (see Sections 8.4.1 to 8.4.4). Further detail and relevant documents regarding the ETS can be found on EPWA's website[190].

8.4.1 Whole of System Plan

The WoSP aims to present a unified system plan by integrating demand forecasting and network planning in the SWIS. In collaboration with Western Power and AEMO, EPWA is currently developing the initial WoSP for release in mid-2020. The WoSP is anticipated to become a regular, biennial process from 2022.

In August 2019, EPWA released an information paper[191] detailing the four modelling scenarios being used for the initial WoSP. These scenarios reflect different levels of decarbonisation and decentralisation in the electricity sector:

1. Cast Away – low economic growth, decarbonisation, and on-grid DER uptake. In this scenario, consumers disconnect from the electricity grid and there is limited investment in utility-scale renewable energy.
2. Groundhog Day – medium economic growth, high decarbonisation, and extreme DER uptake. This scenario is the closest to continuing the current trajectory for consumer behaviour and grid connectivity.
3. Techtopia – medium economic growth, high decarbonisation, and high DER uptake. The main difference between this scenario and Groundhog Day is less DER uptake due to the availability of other technology options, plus more smart appliances that enables better utilisation of generation and the network.
4. Double Bubble – high economic growth, medium decarbonisation, and medium DER uptake. In this scenario, there is strong growth in demand and energy consumption as people move from the north of WA to the SWIS due to extreme weather patterns.

Documentation about modelling assumptions and inputs can be found on EPWA's website.

8.4.2 Improving access to the SWIS

The SWIS currently operates as an unconstrained network. However, increasing network congestion is limiting the ability for new generators to connect on an unconstrained basis. Transitioning to a security-constrained market design will support increased utilisation of existing network infrastructure by facilitating the efficient entry of new generators in a manner that efficiently manages the increasing complexity of network constraints.

This workstream will also deliver (in conjunction with the future market operations workstream) changes to the RCM to allow Capacity Credits to be allocated in a constrained network. Further detail and relevant documents can be found on EPWA's website[192].

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[189] A VAR compensator is a set of electrical devices for providing fast-acting reactive power on high-voltage electricity transmission networks.
[190] For further information, see https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.
[191] EPWA 2019. *Whole of System Plan Modelling Scenarios: Information Paper*, at https://www.wa.gov.au/sites/default/files/2019-08/Information-paper-Whole-of-System-Plan-Modelling-Scenarios.pdf.
[192] See https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

8.4.3 Delivering the future power system

This workstream includes two key projects:

- Power system security and reliability – includes essential system services frameworks, generator performance standards, regulatory architecture and governance, and reliability standards.
- Future market operations – includes security constrained economic dispatch, Synergy Facility bidding, constrained access in the RCM, and market power mitigation controls.

As part of the future market operations project, the ETS is adopting a model of constrained network access for Western Power's Network in the SWIS with the aim of reducing barriers to entry and participation in the WEM and improving the utilisation of the grid.

To support the adoption of a constrained network access model, changes to the assignment of Capacity Credits under the RCM are required so that under the new constrained model, the RCM continues to achieve its intended purpose of incentivising the investment needed to ensure a reliable power system. Therefore, a high-level design has been developed by the Energy Transformation Implementation Unit (ETIU) in consultation with industry participants.

The Network Access Quantity

The Network Access Quantity (NAQ)[193] is an instrument, assigned to a generation Facility and measured in MW, that establishes a preferential right to receive Capacity Credits. A Facility that has been assigned a NAQ will receive Capacity Credits up to the amount of the NAQ that it holds ahead of other facilities that do not hold NAQ. The NAQ has two functions:

1. It provides a cap on the amount of Capacity Credits a Facility can receive based on the available network capacity at the relevant connection point[194]. The NAQ is assigned to a Facility up to the Facility's CRC at peak times or other periods of low reserve, subject to available network capacity, ensuring that Capacity Credits are assigned based on the transfer capability of the network.
2. It provides investment certainty against an 'unhedgeable' risk of losing Capacity Credits due to network constraints caused by a new entrant locating in the same constrained region of the network. The NAQ protects a Facility's quantity of Capacity Credits from being displaced by the new entrant and signals the value of additional capacity from a reliability perspective at locations throughout the SWIS.

Once a NAQ has been assigned to Facilities in a given region of the network, subsequent facilities seeking to connect in that region can only receive a NAQ up to the residual physical capacity of the network in that region (i.e. net of the NAQ that has already been assigned).

The NAQ is a performance-based instrument and is not time-limited; that is, the NAQ has no predetermined term or expiry. Once assigned, a Facility's NAQ will be preserved for the life of the Facility and can only be reduced under a limited and prescribed set of conditions.

In the first Reserve Capacity Cycle of the new NAQ framework, NAQ will be assigned first to Facilities that have been assigned Capacity Credits in the year immediately preceding the Capacity Cycle. Facilities seeking new or additional Capacity Credits will then be assigned NAQ up to the lesser of their CRC and the residual network capacity in the region where they are connecting (net of any NAQ that has already been assigned).

The NAQ available to a Facility will be determined by a 'network capacity modelling' exercise conducted annually by AEMO to assess the capacity of the network to accept the Facility's CRC at the 10% POE peak demand forecast for the relevant Capacity Year, subject to network constraints.

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[193] The NAQ information presented in this section is valid from February 2020 and changes to the NAQ mechanism may occur subsequent to this date.

[194] A network capacity model is used to estimates the available capacity of the network by modelling the output of a facility that can be accepted at the connection point across a large range of credible generation dispatch scenarios to meet a particular demand level, subject to network constraints.

When the NAQ will be implemented is still being considered, but it is expected to occur as part of the 2021 Reserve Capacity Cycle. Further information about these changes and implementation considerations can be found on EPWA's website[195].

8.4.4 Distributed Energy Resources

Under the DER workstream, the outputs will be:

- DER Roadmap (see below).
- DER Register.
- DER Connection Guidelines.

DER Roadmap

The WA Energy Transformation Taskforce has delivered a comprehensive DER Roadmap charting changes to standards, rules, and regulation that support active DER[196]. Active DER can contribute to the safe, secure, reliable and efficient delivery of electricity to consumers connected to the SWIS, in contrast to passive DER[197].

The DER Roadmap for the SWIS is framed within four themes, which are distilled down into 36 actions. These actions are scheduled to be delivered by the end of 2024 and are grouped according to 14 different elements. Figure 41 shows the four DER Roadmap themes and their associated elements.

Figure 41 DER Roadmap themes

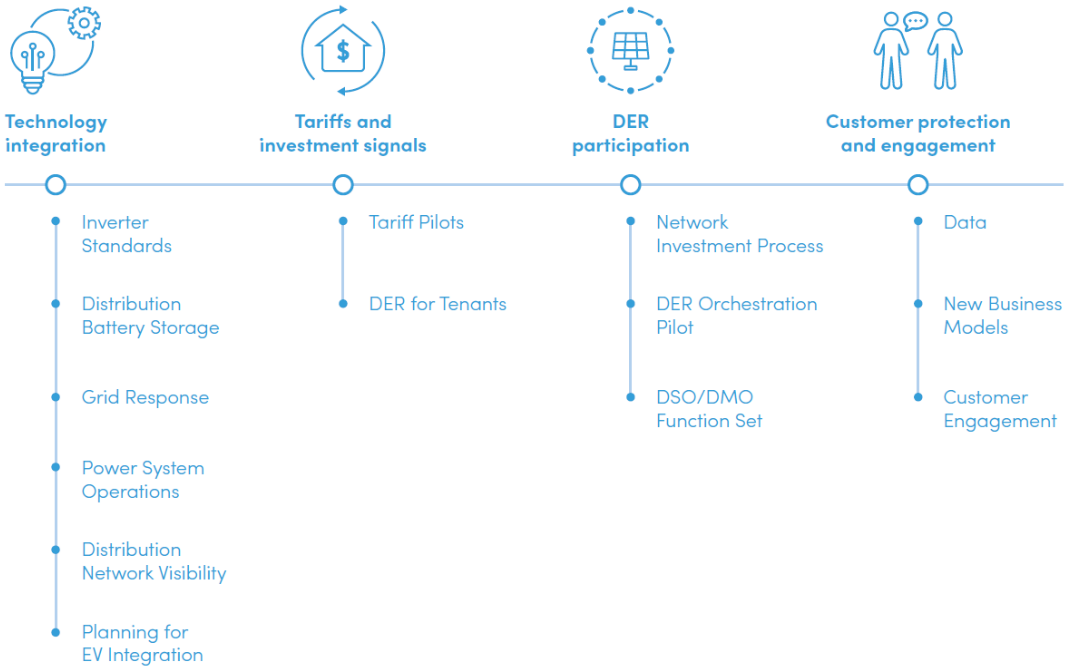

Table 25 lists the AEMO-related DER Roadmap actions that will be delivered by the end of 2020. More details about the complete set of 36 actions can be found in the DER Roadmap for the WEM[198].

[195] EPWA 2020, *Assigning Capacity Credits in a constrained network*, at https://www.wa.gov.au/sites/default/files/2020-03/Information%20Paper%20-%20Assigning%20Capacity%20Credits%20in%20a%20Constrained%20Network.pdf.

[196] Active DER systems incorporate smart controllers that can respond to parameters such as price, or directly to control signals for system security purposes.

[197] Passive DER are essentially 'set and forget' installations which may have some local independent control for use by the owner.

[198] See https://www.wa.gov.au/government/distributed-energy-resources-roadmap.

Table 25 DER Roadmap actions to be delivered by AEMO during 2020

Element	Action	Delivery date
Inverter standards	Deliver improved inverter functions through the Standards Australia national review process for AS/NZS 4777.	October 2020
Grid response	Review Under Frequency Load Shedding arrangements, and assess implications for AA5 investment program.	June 2020
Power system operations	Revise system restart arrangements to consider DER.	June 2020
Distribution network visibility	Deliver a register of static DER data for the SWIS, with processes to support data collection and future DSO functionality.	September 2020
Distribution System Operator (DSO)/Distribution Market Operator (DMO)	Develop a plan for the establishment of a DSO and DMO in the SWIS, including the identification of roles, functions, costs and practical operations. This plan should include an assessment of the costs and benefits to the system for the establishment of these functions.	December 2020
DSO/DMO	Identify legislation and regulatory framework requirements including timeframes for development and implementation to establish DSO and DMO functions.	December 2020

A1. Expected DSM Dispatch Quantity and DSM Activation Price

The Market Procedure: Determination of the DSM Dispatch Quantity and DSM Activation Price outlines the methodology that AEMO must follow when calculating the EDDQ and DSM Activation Price.

A1.1 Expected DSM Dispatch Quantity

The EDDQ is the level of EUE avoided as a result of each DSP that holds Capacity Credits being dispatched for 200 hours in a given Capacity Year.

EDDQ is calculated using the following formula:

$$EDDQ_t = \frac{EUE_{(t,0)} - EUE_{(t,200)}}{CC_t}$$

where:

- $EUE_{(t,0)}$ denotes the EUE in MWh in Capacity Year t where no DSPs are dispatched.
- $EUE_{(t,200)}$ denotes the EUE in MWh in Capacity Year t where all available DSPs are dispatched for 200 hours.
- CC_t denotes the sum of all DSM Capacity Credits assigned or expected to be assigned in Capacity Year t.

RBP forecasts the EDDQ over the Long Term PASA Study Horizon based on the assessment of part (b) of the Planning Criterion and using the load profiles developed in Phase 1 of the EUE assessment (see Section 6.3). DSM dispatch is based on an optimisation model that dispatches DSM to minimise peak demand while accounting for availability constraints[199].

The approach to forecasting EDDQ can be summarised as follows:

1. Forecast EUE with no DSM dispatch.
   - Repeat the assessment of part (b) of the Planning Criterion as specified in Section 6.3 but set the capacity of all DSPs in the market to zero, so that the total available Reserve Capacity is equal to only the generation capacity.
2. Forecast EUE with DSM dispatched for 200 hours.
   - Repeat step 1 but adjust the load profile by deducting DSM dispatch for exactly 200 hours.
3. Calculate EDDQ by applying the formula above using the EUE forecasts derived in steps 1 and 2.

Detailed information on the methodology used to calculate the EDDQ is included in RBP's report. The forecast EDDQ over the Long Term PASA Study Horizon is shown in Table 26.

[199] DSM capacity must be available for dispatch for at least 12 hours a day and 200 hours in total for a Capacity Year in accordance with clause 4.10.1(f) of the WEM Rules.

Table 26 EDDQ, 2020-21 to 2029-30 Capacity Years

Capacity Year	EUE no DSM dispatched (MWh)	EUE DSM dispatched for 200 hours (MWh)	DSM Capacity Credits (MW)	EDDQ (MWh)
2020-21	0.0000	0.0000	66	0.0000
2021-22	0.0000	0.0000	84.5	0.0000
2022-23	0.0605	0.0000	86	0.0007
2023-24	0.6623	0.1611	86	0.0058
2024-25	5.1361	2.4442	86	0.0313
2025-26	0.3123	0.0000	86	0.0036
2026-27	1.2895	0.1491	86	0.0133
2027-28	4.1792	1.0681	86	0.0362
2028-29	5.3643	1.5083	86	0.0448
2029-30	8.1427	2.0894	86	0.0704

Source: RBP.

A1.2 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 that customers place on the reliable supply of electricity, or an indicator of the customers' willingness to pay for uninterrupted supply. The DSM Activation Price aims to reflect the dollar value derived through a reduction of unserved energy because of DSM dispatch.

AEMO has not undertaken a VCR study for the WEM, given the DSM Reserve Capacity Price is being removed for the 2021-22 Capacity Year and future Capacity Years (see Section 8.1.2 for further information).

AEMO has determined the DSM Activation Price to be $33,460/MWh in accordance with clause 4.5.14F of the WEM Rules, based on the VCR in the NEM.

A1.3 Forecast EDDQ and DSM RCP

The forecast EDDQ and DSM RCP for the 2020 Long Term PASA Study Horizon are shown in Table 27. The forecasts assume:

- DSM Capacity Credits are 66.0 MW for the 2020-21 Capacity Year, 84.5 MW for the 2021-22 Capacity Year, and 86.0 MW for the remainder of the outlook period[200].
- The DSM Activation Price of $33,460/MWh remains unchanged.
- The DSM capacity assigned under Availability Class 2 is expected to be available for dispatch for at least 12 hours a day and 200 hours in total for a Capacity Year[201].

[200] Based on Capacity Credits assigned for the 2020-21 and 2021-22 Capacity Years, and information provided by Market Participants for the remainder of the outlook period.

[201] As required by clause 4.10.1(f) of the WEM Rules.

Table 27 EDDQ and DSM RCP, 2020-21 to 2029-30 Capacity Year

Capacity Year	EUE no DSM dispatched (MWh)	EUE DSM dispatched for 200 hours (MWh)	DSM Capacity Credits (MW)	EDDQ (MWh)	DSM RCP ($/MW)
2020-21	0.0000	0.0000	66	0.0000	$16,730.00
2021-22	0.0000	0.0000	84.5	0.0000	$16,730.00
2022-23	0.0605	0.0000	86	0.0007	$16,753.53
2023-24	0.6623	0.1611	86	0.0058	$16,924.99
2024-25	5.1361	2.4442	86	0.0313	$17,777.33
2025-26	0.3123	0.0000	86	0.0036	$16,851.49
2026-27	1.2895	0.1491	86	0.0133	$17,173.69
2027-28	4.1792	1.0681	86	0.0362	$17,940.42
2028-29	5.3643	1.5083	86	0.0448	$18,230.26
2029-30	8.1427	2.0894	86	0.0704	$19,085.14

Source: RBP.

Overall, EDDQ is higher over the 2020 Long Term PASA Study Horizon compared to the EDDQ values published in the 2019 WEM ESOO, as well as being more volatile. This is due to increasing behind-the-meter PV generation reduces the load in shoulder periods which increases the value of DSM in reducing peak demand and preventing EUE. As a result, the DSM RCP is expected to increase over the outlook period.

A2. Supply-demand balance under different demand growth scenarios

Table 28 Supply-demand balance, high demand growth scenario (MW)

Capacity Year	RCT[A]	Committed capacity	Balance
2020-21	4,472	4,966	494
2021-22	4,444	4,925	481
2022-23	4,445	4,730	285
2023-24	4,408	4,730	322
2024-25	4,402	4,537	135
2025-26	4,463	4,537	74
2026-27	4,466	4,537	71
2027-28	4,520	4,537	17
2028-29	4,499	4,537	38
2029-30	4,557	4,537	-20

A. The RCT is calculated based on the 10% POE peak demand forecasts under the high demand growth scenario.

Table 29 Supply-demand balance, expected demand growth scenario (MW)

Capacity Year	RCT[A]	Committed capacity	Balance
2020-21[B]	4,427	4,966	539
2021-22[B]	4,437	4,925	488
2022-23	4,421	4,730	309
2023-24	4,332	4,730	398
2024-25	4,342	4,537	195
2025-26	4,383	4,537	154
2026-27	4,361	4,537	176
2027-28	4,378	4,537	159
2028-29	4,327	4,537	210
2029-30	4,356	4,537	181

A. The RCT is calculated based on the 10% POE peak demand forecasts under the expected demand growth scenario.
B. Figures have been updated to reflect the current forecasts. However, the RCR of 4,581 MW set in in the 2018 WEM ESOO for the 2018 Reserve Capacity Cycle and the RCR of 4,482 MW set in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle do not change.

Table 30 Supply-demand balance, low demand growth scenario (MW)

Capacity Year	RCT[A]	Committed capacity	Balance
2020-21	4,425	4,966	541
2021-22	4,397	4,925	528
2022-23	4,402	4,730	328
2023-24	4,304	4,730	426
2024-25	4,288	4,537	249
2025-26	4,329	4,537	208
2026-27	4,311	4,537	226
2027-28	4,306	4,537	231
2028-29	4,269	4,537	268
2029-30	4,263	4,537	274

A. The RCT is calculated based on the 10% POE peak demand forecasts under the low demand growth scenario.

A3. Expected unserved energy assessment results

Table 31 EUE assessment results

Capacity Year	Operational consumption (MWh)[A]	0.002% of operational consumption (MWh)	EUE (MWh)	EUE (%)
2020-21	17,935,419	359	0	0
2021-22	17,539,137	351	0	0
2022-23	17,253,793	345	0	0
2023-24	16,986,658	340	0.15	<0.002
2024-25	16,828,732	337	2.22	<0.002
2025-26	16,746,365	335	0	0
2026-27	16,743,152	335	0	0
2027-28	16,793,621	336	1.06	<0.002
2028-29	16,888,850	338	1.45	<0.002
2029-30	17,033,731	341	1.92	<0.002

A. These values are the operational consumption forecasts developed under the expected demand growth scenario; see Chapter 5 for more information.
Source: AEMO and RBP.

A4. Summer peak demand forecasts

Table 32 Summer peak demand forecasts under the expected demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	4,008	3,774	3,544
2021-22	4,018	3,782	3,525
2022-23	4,002	3,758	3,520
2023-23	3,913	3,707	3,465
2024-25	3,923	3,684	3,438
2025-26	3,964	3,727	3,498
2026-27	3,942	3,719	3,482
2027-28	3,959	3,733	3,491
2028-29	3,908	3,683	3,451
2029-30	3,937	3,720	3,492
Average growth	-0.2%	-0.2%	-0.2%

Table 33 Summer peak demand forecasts under the high demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	4,053	3,804	3,571
2021-22	4,025	3,796	3,545
2022-23	4,026	3,805	3,566
2023-23	3,989	3,752	3,515
2024-25	3,983	3,753	3,519
2025-26	4,044	3,812	3,553
2026-27	4,047	3,844	3,592
2027-28	4,101	3,880	3,620
2028-29	4,080	3,863	3,613
2029-30	4,138	3,940	3,685
Average growth	0.2%	0.4%	0.3%

Table 34 Summer peak demand forecasts under the low demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	4,006	3,768	3,531
2021-22	3,978	3,734	3,490
2022-23	3,983	3,726	3,482
2023-23	3,885	3,658	3,433
2024-25	3,869	3,648	3,404
2025-26	3,910	3,668	3,406
2026-27	3,892	3,657	3,418
2027-28	3,887	3,660	3,415
2028-29	3,850	3,606	3,350
2029-30	3,844	3,615	3,366
Average growth	-0.5%	-0.5%	-0.5%

A5. Winter peak demand forecasts

Table 35 Winter peak demand forecasts under the expected demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	3,096	3,012	2,929
2021-22	3,092	3,011	2,923
2022-23	3,085	2,997	2,924
2023-23	3,063	2,978	2,892
2024-25	3,062	2,971	2,883
2025-26	3,076	2,988	2,904
2026-27	3,081	2,998	2,916
2027-28	3,089	3,006	2,920
2028-29	3,102	3,019	2,930
2029-30	3,120	3,028	2,949
Average growth	0.1%	0.1%	0.1%

Table 36 Winter peak demand forecasts under the high demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	3,106	3,032	2,954
2021-22	3,121	3,039	2,956
2022-23	3,131	3,042	2,958
2023-23	3,130	3,050	2,964
2024-25	3,163	3,068	2,985
2025-26	3,203	3,114	3,027
2026-27	3,232	3,152	3,068
2027-28	3,282	3,200	3,125
2028-29	3,344	3,248	3,168
2029-30	3,411	3,326	3,233
Average growth	1.0%	1.0%	1.0%

Table 37 Winter peak demand forecasts under the low demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	3,077	2,993	2,914
2021-22	3,056	2,973	2,894
2022-23	3,043	2,959	2,877
2023-23	3,025	2,937	2,845
2024-25	3,009	2,927	2,836
2025-26	3,022	2,936	2,859
2026-27	3,014	2,930	2,850
2027-28	3,015	2,933	2,849
2028-29	3,010	2,926	2,841
2029-30	3,043	2,934	2,844
Average growth	-0.1%	-0.2%	-0.3%

A6. Minimum demand forecasts

Table 38 Minimum demand forecasts under the expected demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	1,102	997	908
2021-22	991	900	813
2022-23	878	785	699
2023-24	785	697	615
2024-25	680	591	507
Average growth	-11.4%	-12.3%	-13.6%

Table 39 Minimum demand forecasts under the high demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	1,115	1,016	925
2021-22	1,013	934	840
2022-23	917	830	738
2023-24	843	753	668
2024-25	756	658	574
Average growth	-9.2%	-10.3%	-11.2%

Table 40 Minimum demand forecasts under the low demand growth scenario (MW)

Capacity year	10% POE	50% POE	90% POE
2020-21	1,065	965	878
2021-22	939	860	781
2022-23	825	740	660
2023-24	723	638	563
2024-25	624	533	454
Average growth	-12.5%	-13.8%	-15.2%

A7. Operational consumption forecasts

Table 41 Operational consumption forecasts (financial year basis) (GWh)

Financial year	Expected	High	Low
2020-21	17,589	18,000	17,082
2021-22	17,467	17,987	16,868
2022-23	17,208	17,889	16,580
2023-24	17,009	17,966	16,289
2024-25	16,841	18,144	16,079
2025-26	16,773	18,211	15,993
2026-27	16,749	18,379	15,914
2027-28	16,803	18,698	15,880
2028-29	16,894	19,234	15,857
2029-30	17,029	19,778	15,846
Average growth	-0.4%	1.1%	-0.8%

Table 42 Operational consumption forecasts (Capacity Year basis) (GWh)

Capacity year	Expected	High	Low
2020-21	17,935	18,025	17,065
2021-22	17,539	17,987	16,812
2022-23	17,254	17,886	16,520
2023-24	16,987	18,037	16,246
2024-25	16,829	18,168	16,064
2025-26	16,746	18,257	15,977
2026-27	16,743	18,456	15,908
2027-28	16,794	18,848	15,874
2028-29	16,889	19,498	15,850
2029-30	17,034	20,120	15,849
Average growth	-0.6%	1.2%	-0.8%

A8. Power station information in the SWIS

Table 43 Scheduled Generators in the SWIS, 2018-19 Capacity Year

Market Participant	Power Station (units included)	Classification	Energy Generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)[B]
Alcoa of Australia	Alcoa Wagerup	Baseload	105.09	0.61	26.00	0.54
Alinta Sales	Alinta Pinjarra (1 and 2)	Baseload	1988.19	11.52	270.50	5.61
	Alinta Wagerup (1 and 2)	Mid-merit	551.17	3.19	392.00	8.13
Bluewaters Power 1 **Bluewaters Power 2**	Bluewaters (1 and 2)	Baseload	3143.54	18.22	434.00	9.01
Goldfields Power	Parkeston	Mid-merit	15.89	0.09	59.40	1.23
Landfill Gas and Power	Kalamunda	Peaking	0.01	0.00	1.30	0.03
Merredin Energy	Merredin	Peaking	0.26	0.00	82.00	1.70
NewGen Neerabup Partnership	NewGen Neerabup	Mid-merit	158.80	0.92	330.60	6.86
NewGen Power Kwinana	NewGen Kwinana	Baseload	1988.40	11.52	327.80	6.80
Southern Cross Energy	Southern Cross	Baseload	167.93	0.97	20.00	0.42
Synergy	Cockburn	Peaking	83.73	0.49	240.00	4.98
	Collie	Baseload	1278.93	7.41	317.20	6.58
	Kemerton (11 and 12)	Peaking	47.36	0.27	310.00	6.43
	Kwinana GT (2 and 3)	Baseload	872.42	5.06	197.70	4.10
	Muja CD (5 to 8)	Baseload	3411.25	19.77	810.00	16.81
	Mungarra (1 and 3)[A]	Peaking/Mid-merit	4.11	0.02	0.00	0.00
	Pinjar (1 to 5, 7)	Peaking	26.28	0.15	210.00	4.36
	Pinjar (9 to 11)	Mid-merit	458.92	2.66	345.00	7.16
	Perth Power Partnership Kwinana	Baseload	541.65	3.14	80.40	1.67

Market Participant	Power Station (units included)	Classification	Energy Generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)[B]
	West Kalgoorlie (2 and 3)[A]	Peaking	2.50	0.01	0.00	0.00
Tesla Corporation Management	Tesla Picton	Peaking	0.03	0.00	9.90	0.21
Tesla Geraldton	Tesla Geraldton	Peaking	0.05	0.00	9.90	0.21
Tesla Kemerton	Tesla Kemerton	Peaking	0.02	0.00	9.90	0.21
Tesla Northam	Tesla Northam	Peaking	0.02	0.00	9.90	0.21
Tronox Management	Tiwest Cogeneration	Baseload	220.75	1.28	36.00	0.75
Western Energy	Perth Energy Kwinana	Mid-merit	83.56	0.48	109.00	2.26

A. Registered Facilities that did not participate in the RCM for the 2018-19 Capacity Year.
B. The Capacity Credits Share (%) is calculated from a total of 4,761.607 MW of Capacity Credits assigned to Scheduled and Intermittent Non-scheduled Generators for the 2018-19 Capacity Year. A total of 4,819.033 MW of Capacity Credits were assigned for the 2018-19 Capacity Year, including 57.426 MW of Capacity Credits assigned to Demand Side Programmes.

Table 44 Non-Scheduled Generators in the SWIS, 2018-19 Capacity Year

Market Participant	Power Station (units included)	Energy Source	Nameplate Capacity (MW)	Energy Generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)[B]
Alinta Sales	Walkaway	Wind	89.10	346.37	2.01	26.10	0.54
	Badgingarra[A]	Wind	130.00	346.08	2.01	0.00	0.00
Blair Fox	Karakin	Wind	5.00	6.17	0.04	0.82	0.02
	Beros Road Wind Farm[A]	Wind	9.25	0.88	0.01	0.00	0.00
	Westhills[A]	Wind	5.00	2.24	0.01	0.00	0.00
CleanTech Energy	Richgro Biogas	Biogas	2.00	3.21	0.02	1.65	0.03
Collgar Wind Farm	Collgar	Wind	206.00	669.51	3.88	20.57	0.43
Denmark Community Windfarm	Denmark Wind Farm	Wind	1.44	5.01	0.03	0.70	0.01
EDWF Manager	Emu Downs	Wind/solar	80.00	280.62	1.63	28.04	0.58
Landfill Gas and Power	Red Hill	Biogas	3.64	22.19	0.13	2.78	0.06
	Tamala Park	Biogas	4.80	35.17	0.20	4.21	0.09
Merredin Solar Farm Nominee	Merredin[A]	Solar	100.00	0.00	0.00	0.00	0.00
Metro Power Company	Ambrisolar[A]	Solar	0.96	2.06	0.01	0.00	0.00

Market Participant	Power Station (units included)	Energy Source	Nameplate Capacity (MW)	Energy Generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)[B]
Mt. Baker Power Company	Mount Baker	Wind	2.43	5.97	0.03	0.77	0.02
Mumbida Wind Farm	Mumbida	Wind	55.00	195.29	1.13	10.63	0.22
Northam Solar Project Partnership	Northam	Solar	9.80	11.75	0.10	4.10	0.09
Perth Energy	Rockingham	Biogas	4.00	16.03	0.09	2.02	0.04
	South Cardup	Biogas	4.16	27.39	0.16	2.95	0.06
SRV AGWF Pty Ltd as trustee for AGWF Trust	Albany	Wind	21.60	44.75	0.26	7.76	0.16
	Grasmere	Wind	13.80	36.02	0.21	5.07	0.11
	Greenough River	Solar	40.00	22.82	0.13	2.53	0.05
Synergy	Bremer Bay	Wind	0.60	1.56	0.01	0.15	0.00
	Kalbarri	Wind	1.60	3.96	0.02	0.32	0.01
Waste Gas Resources	Henderson	Biogas	3.00	13.90	0.08	1.94	0.04

A. Registered Facilities that did not participate in the RCM for the 2018-19 Capacity Year.
B. The Capacity Credits Share (%) is calculated from a total of 4,761.607 MW of Capacity Credits assigned to Scheduled and Intermittent Non-scheduled Generators for the 2018-19 Capacity Year. A total of 4,819.033 MW of Capacity Credits were assigned for the 2018-19 Capacity Year, including 57.426 MW of Capacity Credits assigned to Demand Side Programmes.

A9. Facility capacities

Table 45 Registered generation Facilities – existing and committed (MW)

Market Participant	Facility	Capacity Credits (2021-22)	Maximum Capacity
Alcoa of Australia	ALCOA_WGP	26.000	26.000
Alinta Sales	ALINTA_PNJ_U1	136.962	143.000
Alinta Sales	ALINTA_PNJ_U2	136.962	143.000
Alinta Sales	ALINTA_WGP_GT	196.000	196.000
Alinta Sales	ALINTA_WGP_U2	196.000	196.000
Alinta Sales	ALINTA_WWF	17.185	89.100
Alinta Sales	BADGINGARRA_WF1	26.621	130.000
Alinta Sales	YANDIN_WF1[A]	36.196	211.680
BEI WWF Pty Ltd as Trustee for WWF Trust	WARRADARGE_WF1[A]	30.223	180.000
Blair Fox	BLAIRFOX_BEROSRD_WF1[B]	0.000	9.252
Blair Fox	BLAIRFOX_KARAKIN_WF1	0.486	5.000
Blair Fox	BLAIRFOX_WESTHILLS_WF3[B]	0.000	5.000
Bluewaters Power 1	BW1_BLUEWATERS_G2	217.000	217.000
Bluewaters Power 2	BW2_BLUEWATERS_G1	217.000	217.000
CleanTech Energy	BIOGAS01	1.180	2.000
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	15.823	206.000
Denmark Community Windfarm	DCWL_DENMARK_WF1	0.364	1.440
EDWF Manager	EDWFMAN_WF1	16.209	80.000
Goldfields Power	PRK_AG	59.748	68.000
Kwinana WTE Project Co	PHOENIX_KWINANA_WTE_G1[A]	33.000	36.000
Landfill Gas and Power	KALAMUNDA_SG	1.300	1.300
Landfill Gas and Power	RED_HILL	2.842	3.640
Landfill Gas and Power	TAMALA_PARK	4.351	4.800
Merredin Energy	NAMKKN_MERR_SG1	82.000	92.600
Merredin Solar Farm Nominee	MERSOLAR_PV1	16.320	100.000

Market Participant	Facility	Capacity Credits (2021-22)	Maximum Capacity
Metro Power Company	AMBRISOLAR_PV1	0.198	0.960
Mt.Barker Power Company	SKYFRM_MTBARKER_WF1	0.521	2.430
Mumbida Wind Farm	MWF_MUMBIDA_WF1	7.029	55.000
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600	342.000
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	327.800	335.000
Northam Solar Project Partnership	NORTHAM_SF_PV1	1.798	9.800
Perth Energy	ATLAS[B]	0.000	0.000
Perth Energy	GOSNELLS[B]	0.000	0.000
Perth Energy	ROCKINGHAM	2.323	4.000
Perth Energy	SOUTH_CARDUP	2.966	4.158
Southern Cross Energy	STHRNCRS_EG	20.000	23.000
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	5.294	21.600
SRV AGWF Pty Ltd as trustee for AGWF Trust	GRASMERE_WF1	3.712	13.800
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	7.377	40.000
Synergy	BREMER_BAY_WF1	0.166	0.600
Synergy	COCKBURN_CCG1	240.000	249.700
Synergy	COLLIE_G1	317.200	318.300
Synergy	KALBARRI_WF1	0.259	1.600
Synergy	KEMERTON_GT11	155.000	154.700
Synergy	KEMERTON_GT12	155.000	154.700
Synergy	KWINANA_GT2	98.500	103.200
Synergy	KWINANA_GT3	99.200	103.200
Synergy	MUJA_G5	195.000	195.800
Synergy	MUJA_G6	193.000	193.600
Synergy	MUJA_G7	211.000	212.600
Synergy	MUJA_G8	211.000	212.600
Synergy	MUNGARRA_GT1[B]	0.000	39.500
Synergy	MUNGARRA_GT3[B]	0.000	38.000
Synergy	PINJAR_GT1	30.700	38.500
Synergy	PINJAR_GT10	111.000	118.200
Synergy	PINJAR_GT11	124.000	130.000

Market Participant	Facility	Capacity Credits (2021-22)	Maximum Capacity
Synergy	PINJAR_GT2	30.300	38.500
Synergy	PINJAR_GT3	37.000	39.300
Synergy	PINJAR_GT4	37.000	39.300
Synergy	PINJAR_GT5	37.000	39.300
Synergy	PINJAR_GT7	37.000	39.300
Synergy	PINJAR_GT9	111.000	118.200
Synergy	PPP_KCP_EG1	80.400	85.700
Synergy	WEST_KALGOORLIE_GT2[B]	0.000	41.200
Synergy	WEST_KALGOORLIE_GT3[B]	0.000	23.300
Tesla Corporation Management	TESLA_PICTON_G1	9.900	9.900
Tesla Geraldton	TESLA_GERALDTON_G1	9.900	9.900
Tesla Kemerton	TESLA_KEMERTON_G1	9.900	9.900
Tesla Northam	TESLA_NORTHAM_G1	9.900	9.900
Tronox Management	TIWEST_COG1[B]	0.000	42.100
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	1.632	3.000
Western Australia Biomass	BRIDGETOWN_BIOMASS_PLANT[B]	0.000	40.000
Western Energy	PERTHENERGY_KWINANA_GT1	109.000	116.000

A. Candidates for Registration that hold Capacity Credits for the 2021-22 Capacity Year.
B. Registered Facilities that did not participate in the RCM for the 2021-22 Capacity Year.

Table 46 Registered DSM Facilities – capability and availability (MW)

Market Participant	Facility	Capacity Credits (2021-22)
Bluewaters Power 1	GRIFFINP_DSP_01	20.000
Synergy	SYNERGY_DSP_04	42.000
Wesfarmers Kleenheat Gas	PREPWR_DSP_02	22.500

A10. WEM rule changes

This appendix highlights WEM rule changes and review activities that have been actioned, or considered, since the publication of the 2019 WEM ESOO[202].

Table 47 Amending WEM Rules made by the WA Minister for Energy over the past 12 months

Gazette	Gazettal Date	Name	Commencement Date
2020/24	21/02/2020	Wholesale Electricity Market Amendment (Reserve Capacity Pricing Reforms) Rules 2019	22/02/2020 (8:00 am) 01/10/2021 (8:00 am)
21/02/2020	22/10/2019	Wholesale Electricity Market Amendment (AEMO to provide information to the Minister) Rule 2019	01/11/2019 (8:00 am)

Source: Rule Change Panel.

Table 48 WEM Rules commenced over the past 12 months

ID	Title	Submitted by	Date commenced
RC_2020_01	Market Participant Fee calculation manifest error	Rule Change Panel	30/03/2020
RC_2013_15	Outage Planning Phase 2 – Outage Process Refinements	Independent Market Operator[A]	01/02/2020
RC_2015_03	Formalisation of the Process for Maintenance Applications	Independent Market Operator[A]	01/10/2019
RC_2018_06	Full Runway Allocation of Spinning Reserve Costs	Public Utilities Office[B]	01/09/2019
RC_2015_01	Removal of Market Operation Market Procedures	Independent Market Operator[A]	01/08/2019
RC_2014_06	Removal of Resource Plans and Dispatchable Loads	Independent Market Operator[A]	01/07/2019

Source: Rule Change Panel.
A. The Independent Market Operator has been abolished and its functions transferred to AEMO, the ERA, or the Rule Change Panel.
B. Renamed EPWA.

[202] Further information can be found at https://www.erawa.com.au/rule-change-panel/market-rule-changes.

Measures and abbreviations

Units of measure

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

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
AQP	Applications and Queuing Policy
BIS Oxford	BIS Oxford Economics
BOM	Bureau of Meteorology
CDD	Cooling degree day
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DMO	Distribution Market Operator
DSM	Demand Side Management
DSO	Distribution System Operator
DSP	Demand Side Programme

Abbreviation	Expanded name
EDDQ	Expected DSM Dispatch Quantity
EOI	Expressions of Interest
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
ESS	Essential System Service
EUE	Expected unserved energy
EV	Electric vehicle
GEM	Green Energy Markets
GIA	Generator Interim Access
GSP	Gross state product
HDD	Heating degree day
INSG	Intermittent Non-Scheduled Generator
LDC	Load duration curve
LFAS	Load Following Ancillary Service
NEM	National Electricity Market
NCS	Network Control Services
NSG	Non-Scheduled Generator
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
SG	Scheduled Generator
SWIS	South West interconnected system
TSOG	Total Sent Out Generation
WEM	Wholesale Electricity Market

Glossary

This document uses many terms that have meanings defined in the WEM Rules. The WEM Rules meanings are adopted unless otherwise specified.

Term	Definition
asynchronous generation	Asynchronous generation includes wind farms, solar PV generators, and batteries that export power to the grid. They do not have moving parts rotating in synchronism with the grid frequency, but instead are interfaced to the power system via power electronic converters which electronically replicate grid frequency.
baseload capacity	Facilities that operate more than 70% of the time.
behind-the-meter	PV and battery systems that produce energy and are connected at a customer's premises. In this WEM ESOO, behind-the-meter PV capacity includes both residential and commercial PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 10 MW.
capacity factor	The percentage of actual generation relative to the maximum theoretically possible generation based on a Facility's nameplate capacity.
cooling degree days (CDD)	The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.
contingency event	A contingency event is an event that affects the power system in a way which would likely involve the failure or sudden and unexpected removal of a generating unit or transmission element from operational service.
Distributed energy resource (DER)	DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter. Any generators that are connected to the distribution network that are assigned Capacity Credits are not included in the definition of DER technologies, for example Northam solar farm.
Essential System Services	The term essential system services (referred to as Ancillary Services in the current WEM Rules) capture all services needed to maintain power system security and reliability. This term is proposed to be included in the WEM Rules and will better reflect the essential nature and applicability of these services to the power system. Essential System Services including inertia, frequency control, and voltage control.
Generator Interim Access (GIA)	The GIA arrangement was developed to facilitate new generation connections on a constrained basis. It is not scalable and was intended as an interim solution. Generators connected under the GIA arrangement will be migrated to the new security-constrained dispatch engine as part of the implementation of constrained access (to be delivered under the WA Government's ETS), and the GIA tool will be decommissioned.
heating degree days (HDD)	The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.
installed capacity	The generating capacity (in MW) of single or multiple generating units.
large industrial load (LIL)	LILs are a business sub-sector representing the largest customers in the SWIS. A threshold of demand greater than 10 MW for greater than 10% of the latest financial year is applied as the minimum threshold for large industrial loads.

Term	Definition
load shedding	Load shedding is the controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure.
maximum capacity	Maximum capacity of a Facility is based on net sent out generation or installed capacity of the Facility.
mid-merit capacity	Facilities that operate between 10% and 70% of the time.
minimum demand	The lowest amount of demand consumed at any one time. Minimum demand refers to operational minimum demand unless otherwise stated.
operational consumption	Electricity consumption that is met by all utility-scale generation. Consumption met by behind-the-meter PV generation is not included in this value. Operational consumption includes consumption from EVs.
operational demand	Operational demand refers to network demand, met by utility-scale generation and excludes demand met by behind-the-meter PV generation. Operational demand is measured in MW and averaged over a 30-minute period. It is reported on a "sent-out" basis and calculated as the TSOG x 2 to convert MWh to MW for a Trading Interval. The operational peak demand is identified as the highest operational demand calculated for a Capacity Year.
peak demand	The highest amount of demand consumed at any one time. Peak demand refers to operational peak demand unless otherwise stated.
peaking capacity	Facilities that operate less than 10% of the time.
probability of exceedance	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
synchronous generation	Synchronous generators are directly connected to the power system and rotate in synchronism with grid frequency. Thermal (coal, gas) and hydro (water) driven power turbines are typically synchronous generators.
underlying consumption	Operational consumption plus an estimate of behind-the-meter PV generation.
underlying demand	Operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage (due to small uptake of battery storage to date, for historical values the impact of behind-the-meter battery is assumed to be negligible).
virtual power plant (VPP)	A VPP broadly refers to an aggregation of resources (such as decentralised generation, storage and controllable loads) coordinated to deliver services for power system operations and electricity markets.